Final report on the transmission to enable renewables project (Phase 1)

Prepared by the Electricity Commission

11 July 2008

Important note

This is the Electricity Commission's final report on the transmission to enable renewables project (Final TTER Project Report). It contains information on potential wind, hydro and geothermal generation sites in New Zealand and the transmission investments which are likely to be needed to support generation from renewable sources.

The analysis contained in this report has been undertaken at a high level using a broad set of assumptions. It is important to note that this report is only one source of information on the matters discussed in it, and differing views may be held on the material and conclusions set out. Persons considering or making decisions on these matters, or on any aspect of them, must make their own enquiries and form their own views based on all the information and advice available to them.

To the fullest extent permitted by law, the Electricity Commission does not accept any liability for any view, information, error or omission in this report.

This report is current as at the date of its publication only, and will not necessarily be updated to reflect any changes in circumstances or Electricity Commission views.

Glossary of abbreviations and terms

APR	Annual Planning Report
AWATEA	Aotearoa Wave & Tidal Energy Association Incorporated
Commission	Electricity Commission
Connell Wagner	Connell Wagner Limited
Contact	Contact Energy Limited
GEM	Generation Expansion Model
Genesis	Genesis Energy Limited
GIS	Geographic Information System
GIT	Grid Investment Test
GPA	Grid Planning Assumptions
GPS	Government Policy Statement on Electricity Governance (May 2008)
GUIRP	Grid Upgrade and Investment Review Policy
GUP	Grid Upgrade Plan
LRMC	Long Run Marginal Cost
MDS	Market Development Scenarios
Meridian	Meridian Energy Limited
MEUG	Major Electricity Users Group
MIP	Mixed Integer Programming
MRP	Mighty River Power Limited
Neptune	Neptune Power Limited
NZES	New Zealand Energy Strategy
PBA	Parsons Brinckerhoff Associates Limited
Powerco	Powerco Limited
PSA	Power Systems Analysis
rules	Electricity Governance Rules 2003
SDDP	Stochastic Dual Dynamic Programming
SEF	Sustainable Energy Forum
SO	System Operator
SOO	Statement of Opportunities
SRMC	Short Run Marginal Cost

SSG	System Studies Group NZ Limited
SVC	Static VAR Compensator
TPM	Transmission Pricing Methodology
Transpower	Transpower New Zealand Limited
TrustPower	TrustPower Limited
TTER	Transmission to Enable Renewables

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1.1 Project overview

1.1.1 The New Zealand Energy Strategy (**NZES**) sets a target of 90% of electricity being generated from renewable sources by 2025 (based on an average hydrological year) to reduce greenhouse gas emissions. The NZES also proposed a 10-year moratorium on new baseload fossil-fuelled thermal electricity generation. The moratorium will be implemented by legislation. A Bill[1] regarding the moratorium has already been introduced in Parliament.

1.1.2 New Zealand currently generates 70% of its electricity from renewable sources (mainly hydro).

1.1.3 The NZES and the 10-year restriction[2] on new baseload fossil-fuelled thermal electricity generation are expected to ensure that most new investments in electricity generation will be from renewable sources.

1.1.4 The availability of transmission capacity has implications for the future development of generation, particularly those forms of renewable generation limited to specific geographical locations, for physical (e.g. location of geothermal fields) or economic reasons (e.g., quality of the wind resource). New investment in transmission will often be required where there is investment in renewable generation, as renewable generation is often remote from existing load and major transmission lines.

1.1.5 As development timing differences can exist between renewable generation assets and the required new transmission assets, some generators might be deterred from investing in renewable plants or may invest in higher cost locations because of access to existing transmission.

1.1.6 In order to facilitate the coordination of electricity generation from renewable sources and transmission investment, in October 2007, the Electricity Commission (**Commission**) initiated a project called the "transmission to enable renewables project" (**TTER project**). The TTER project had three objectives :

(a) enabling participants to better understand how the current framework (in particular section III of part F of the Electricity Governance Rules 2003 (**rules**[3])) can be utilised to support the integration of renewables;

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1 Climate Change (Emissions Trading and Renewable Preference) Bill.

2 In its report back to Parliament the Finance and Expenditure Select Committee recommended that the term "moratorium" be replaced with the term "restriction"

(b) providing an up-to-date "map" of potential renewables locations and potential renewable fuel resource sizes (wind, hydro and geothermal) which can be factored into:

(i) the next Statement of Opportunities (**SOO**); and

(ii) Transpower's 2009 Annual Planning Report (**APR**); and

(c) investigating the possible economic transmission investments that Transpower could put forward for approval under Part F of the rules to support the development of renewable generation.

1.1.7 The TTER project report focused only on hydro, wind and geothermal generation. Other renewable energy sources, such as solar, may also contribute to New Zealand's electricity supply. However, it is recognised that the current technology and the costs of those sources do not, at this stage, make them attractive for large scale generation.

1.1.8 The Commission has initiated further work investigating marine energy opportunities. This work will consider the status of marine energy development in New Zealand and internationally, and include an assessment of energy potential within New Zealand based upon detailed numerical modelling at several sites. The Commission expects to publish a report on this work in July 2008

1.2 Link to the 2008 Statement of Opportunities

1.2.1 As part of its role in overseeing aspects of transmission investment, the Commission is required to prepare and publish a SOO[4].

1.2.2 The Government Policy Statement on Electricity Governance (May 2008) (**GPS**) states the Government's expectation that a SOO should be prepared at least biennially. The TTER project has greatly assisted the preparation of the draft 2008 SOO[5].

1.2.3 The purpose of a SOO is to enable identification of potential opportunities for efficient management of the grid, including investment in upgrades and investment in transmission alternatives (rule 9.1.2).

1.2.4 To this end, rule 9.2.1 states that, in preparing a SOO, the Commission must have regard to the principle that a SOO should aim to meet the reasonable requirements of Transpower, investors in generation, other participants, end use customers and those interested in evaluating transmission alternatives.

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[3] References to rules in this report are to the rules in section III of part F of the rules unless otherwise stated.

[4] The requirement to prepare and publish a SOO is set out in rule 9.

[5] The document is available at http://www.electricitycommission.govt.nz/opdev/transmis/soo.

1.2.5 Scenario planning techniques are typically adopted in order to show a range of plausible futures and test investment strategies against those future states. The reason for this approach is to ensure the range of credible future states is sufficiently wide in order that the transmission planning outcomes will be fundamentally different under the different credible futures.

1.2.6 The scenarios used for a SOO must include the grid planning assumptions (**GPAs**) prepared in accordance with rule 10. The GPAs are required to include a reasonable range of credible future, high level generation scenarios. The GPAs must also include a reasonable range of credible demand forecasts by region or grid exit point.

1.2.7 In a SOO, the key uncertainties relate to the projected regional supply and demand balances, which in turn depend largely on the type, timing, location and cost of generation investment and on the profile and location of demand growth.

1.2.8 Consultation on the generation scenarios included in the Commission's draft GPAs commenced in February 2008. The consultation focused more on the method used to develop the generation scenarios rather than the generation scenarios themselves. The Commission, through the TTER project, has updated its database of generation schemes and as more information becomes available, will further refine the scenarios anticipated by the GPAs.

1.2.9 Therefore, the TTER project contributed to the content of the next SOO as it was used to update a number of the key inputs of the generation scenarios i.e. location, size, type, timing and costs of existing, highly likely and potential generation. Information gathered through the TTER project was used in formulating the generation scenarios which in turn will be used to apply the Grid Investment Test (**GIT**) to investment proposals.

1.2.10 Furthermore, the Commission has used the information gathered through the TTER project to:

(a) analyse the potential grid transmission augmentations which would be required to accommodate renewables; and

(b) update the Commission's Generation Expansion Model (**GEM**)[6] to enable transmission investment analysis to consider co-optimisation of investments in transmission and generation.

[6] The analysis continues to be refined and will be published on the Commission's website when completed.

1.3 Advice commissioned

1.3.1 Table 1 summarises the key tasks carried out by the Commission and its consultants to assist with the work on the TTER project.

Table 1: Key resources and high level summary of report prepared

Consultant/Source	High-level overview of reports prepared
Connell Wagner Limited (**Connell Wagner**)	• Report on wind generation including: – national wind resource location, capacity timing factor and possible development; – issues that may influence developer preferences for one site rather than another; and – an update on wind generation costs.
Parsons Brinckerhoff Associates Limited (**PBA**)	• Reports on hydro generation including: – a shortlist of projects likely to be the most economically feasible. The shortlist included projects with a long run marginal cost (**LRMC**) of less than $100/MWh; and – estimated capital costs for civil, mechanical, and electrical works for the short-listed projects (within +/- 30% accuracy).
Commission	• Reports on geothermal generation including: – consenting processes and timing; and – estimated cost ranges for consenting for geothermal.
System Studies Group NZ Limited (**SSG**)	• Reports on transmission network reinforcement including: – a review of transmission connection; and – interconnection options for renewables.

1.3.2 In addition, in February 2008, the Commission engaged Power Projects Limited to:

(a) conduct a review of current marine energy technologies both overseas and in New Zealand;

(b) prepare a timetable estimating the dates by which the maturing technologies could penetrate the New Zealand generation market; and

(c) provide a short-list of potential marine energy schemes, including location, timeframe, capital cost estimates, installed capacity (MW) and electricity production (GWh).

1.3.3 The results of this work were not available to be presented and discussed as part of the TTER project. However, the Commission expects to publish a report on this work on its website in late July 2008.

1.4 Purpose of the Final TTER Project Report

1.4.1 The purpose of the Final TTER Project Report is to:

(a) summarise the feedback received during the consultations carried out on the TTER project (written submissions in February 2008, presentations and feedback from the workshop held on 17 December 2007);

(b) summarise the issues raised during the second round of submissions (including feedback at the 2 May 2008 workshop) in response to the Commission's questions and any other matters raised;

(c) respond to issues raised in the submissions;[7]

(d) list the policy issues identified by the Commission, including any barriers in the transmission regime to the development of renewable generation; and

(e) provide an overview of the next phase of the TTER project.

[7] A summary of the submissions together with the Commission's responses is attached as Appendix 1 .

2. Previous consultation

2.1 Introduction

2.1.1 In December 2007, the Commission released draft reports on possible hydro, geothermal and wind-based power schemes in New Zealand for the purpose of constructing a 'resource map' of potential hydro, geothermal and wind generation. Interested parties were invited to provide written submissions on the respective draft reports. The submissions received are available from the Commission's website.[8]

2.1.2 Also in December 2007, the Commission held a workshop to present the preliminary results of the draft reports and to provide participants with an opportunity to comment on the approach the Commission had taken. The presentations made at the workshop by the Commission and participants are available from the Commission's website.[9]

2.1.3 The Commission has taken into account the relevant comments made at the workshop and included in written submissions prior to finalising the reports. Final versions of the reports can be found in the Appendix section of this report. The general thrust of comments received is summarised in the section below as well as the Commission's response to those comments.

2.2 Comments received at the December 2007 workshop

2.2.1 At the 17 December 2007 workshop 15 presentations were given, six of which were given by the Commission or consultants engaged to investigate aspects of the TTER project.

2.2.2 Of the nine industry presentations, six were made by participants involved in either existing renewable generation or renewable generation in the planning stages. In this section some key issues raised by the nine industry participants will be summarised and commented on where necessary.

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8 http://www.electricitycommission.govt.nz/submissions/substransmission/renewables

9 http://www.electricitycommission.govt.nz/opdev/transmis/renewables

Table 2: List of presenters

	Presenters
Generators/retailers	Contact Energy Limited (**Contact**), Genesis Energy Limited (**Genesis**), Meridian Energy Limited (**Meridian**), Mighty River Power Limited (**MRP**), TrustPower Limited (**TrustPower**)
Lines companies	Transpower New Zealand Limited (**Transpower**)
Others	Neptune Energy Limited (**Neptune**), Aotearoa Wave & Tidal Energy Association Inc. (**AWATEA**), the Sustainable Energy Forum (**SEF**)

2.2.3 The two main themes that emerged during discussions at the workshop were:

(a) the disparity between lead times for building transmission compared with generation; and

(b) how the criteria for approving economic investments set out in section III of part F would be applied to an investment required to connect new renewable generation to the grid.

2.2.4 The points made by presenters regarding these two themes are summarised below.

Transmission and generation lead time

2.2.5 Presenters commented that transmission and generation investment had different lead times from inception to completion. For example:

(a) TrustPower noted that generation projects typically have a lead time that is only 40% of the lead time for new-build transmission projects; and

(b) Contact noted that at least 4 years notice of a committed renewable generation project appears to be required before a renewable generation project triggers any transmission investment.

2.2.6 As a possible way of reducing this timing difference TrustPower advocated the acquisition by Transpower of options to acquire land, commenting further that having land options and resource consents in place for new transmission lines

would greatly reduce the "lead-time" gap. Genesis recommended that Transpower should focus on the resource consent process as a means to reducing these timing differences.

2.2.7 The Commission has been considering the issue of how transmission and generation lead times could be better coordinated for some time. This was a key issue in developing the Grid Upgrade and Investment Review Policy (**GUIRP**)[10] with Transpower. In light of the recent NZES, this aspect of the Commission's work has gained extra focus, particularly given that there appears to be a number of large-scale renewable projects that could be constructed within the next 5 years.

2.2.8 Genesis and TrustPower also commented that one means that may close the transmission/generation investment timing gap that is not presently available to generators is the generator's ability to directly fund interconnection asset upgrade costs. Currently generation cannot be guaranteed capacity on upgraded lines (which are interconnection assets) and therefore paying for interconnection assets may not be a commercially viable option. However, the Commission notes that the rules do not prohibit generators paying for upgrades to interconnection assets if they desire to do so.

2.2.9 The Commission notes that lead time issues were one of the main reasons why the TTER project was initiated. The TTER project has identified renewable resource-rich regions which can be used to help define regional generation scenarios for use in the GIT process in order that preliminary steps for generation enabling transmission projects can be considered.

Criteria for approving economic investments needed for renewable generation

2.2.10 Presenters also submitted that the part F transmission investment approvals criteria had not yet been fully tested for transmission economic investments to accommodate generation development, having (at that stage) only been applied to reliability investments. In that context, Contact said that the GIT should be worked through prior to making amendments to the rules, as the rules may be sufficient as they are.

2.2.11 Meridian and TrustPower stated that, first and foremost, Transpower should focus on incremental transmission upgrades first. Meridian requested that Transpower focus on three specific upgrades, namely:

(a) lower North Island;

[10] The GUIRP is available at http://www.electricitycommission.govt.nz/opdev/transmis/gridupgradepolicy

(b) Wairakei Ring; and

(c) Roxburgh – Islington.

2.2.12 Meridian also provided preliminary analysis results suggesting that a Roxburgh – Islington 220kV line upgrade was cost effective using the GIT. Meridian stated that it had used Stochastic Dual Dynamic Programming (**SDDP**) to calculate the likely annual hydro spill cost at $16 million, while the annualised transmission upgrade cost to accommodate this generation development was approximately $9 million.

2.2.13 Meridian also stated that Stage II of Project Hayes (approximately 434 MW) is provisionally planned to be completed in 2013, and given that the Roxburgh – Islington 220kV line upgrade may take up to three years to complete, the approval for that upgrade needed to occur by the end of 2008 at the latest. Further Meridian suggested that the Wairakei Ring upgrade was similarly straightforward to analyse.

2.2.14 Meridian said that an upgrade to the Otago to Waitaki transmission line, costing approximately $37 million, could "unlock" over $1.5 billion of new generation investment. However, Meridian said it had no way to require Transpower to progress such an upgrade.

2.2.15 Transpower responded to Meridian's suggestion stating that many such transmission projects were presently being considered but that it was only analytical resource issues that had so far held back progress on these.

2.2.16 The Commission notes however that under the new Interconnection Rules (part F section VI – rule 6.2), Transpower is required to identify economic investments that could be made and publish a timetable to consider these.

Other points of note

2.2.17 A number of presenters identified potential renewable projects using emerging technologies. While Contact stated that between 230MW and 280MW of geothermal development was likely in the Central North Island, two presenters discussed the possibility of developing marine-based technologies.

2.2.18 The presentation from AWATEA discussed possible wave and tidal generation developments in New Zealand. AWATEA estimated that there was potential for up to 5GW of wave generation and possibly 100MW of tidal stream based generation around the New Zealand coastline. In addition, AWATEA provided a list of known projects currently being investigated.

2.2.19 Neptune, listed by AWATEA as a marine project developer carrying out investigations, also made a presentation. Neptune indicated that its analysis to date had identified a significant marine current based generation resource in the

Cook Strait and that a resource consent for a development machine was in the final stages of being granted. Neptune estimated that the site could feasibly be fully developed by 2021 if the technology was sufficiently developed and site operational results were favourable.

2.2.20 Finally, SEF highlighted the role that small scale renewables could play in meeting New Zealand's electricity needs, and the 2025 90% renewables target. SEF stated that using small scale wind and biomass generation, in conjunction with the use of wood fired heating in homes, could assist in meeting the Government's renewables target. In addition SEF argued that these types of developments would reduce the need for additional transmission which may be expensive due to easement requirements.

2.2.21 SEF cited other advantages of an embedded generation approach such as reduced Resource Management Act issues, generation diversity, and increased security of supply for domestic consumers. SEF stated that there were many barriers to such developments, such as the present transmission pricing structure, where large scale generating companies have no incentive to develop distributed generation as they presently don't pay the network costs.

2.3 Comments received in submissions

2.3.1 In December 2007, the Commission invited submissions on the draft hydro, geothermal and wind reports. Submissions closed on 1 February 2008. Nine written submissions were received, one of which was confidential. Submissions were received from the following:

Table 3: List of submitters

	Submitters
Generator/retailers	Contact, Genesis, Meridian, MRP
Lines companies	Transpower
Others	Hydra Software Limited, WM Duncan, Allco Wind Energy NZ Limited, Wind Farm Developments Limited (confidential).

2.3.2 The Commission appreciates the effort of those who devoted time and resources to preparing and providing submissions.

2.3.3 After reviewing the submissions in detail, the Commission decided that some of the comments made, which were quite specific to the draft wind, hydro and geothermal reports were better addressed through the reports themselves.

2.3.4 Other comments, which represent the matters most commonly raised by submitters, are discussed in sections 2.4 to 2.7 of this report and include:

(a) how the HVDC link is charged;

(b) clarification of the respective roles of the Commission and Transpower;

(c) consideration of other resources such as tidal and solar generation; and

(d) the process for seeking information directly from generators.

2.4 HVDC Charges from 1 April 2008

2.4.1 Meridian commented that the HVDC charge in Transpower's transmission pricing methodology (**TPM**) effective 1 April 2008 will disincentivise renewable generation investment in the South Island (where there are substantial renewable fuel sources).

2.4.2 Meridian also stated that it will not face additional transmission charges if it connects to a point of interconnection on the grid that does not require any grid upgrades. In contrast, if Meridian connects to a connection point that does require any upgrades, it will be allocated a proportion of the charges attributable to that point of connection. This allocation is inconsistent with that for distribution charges faced by embedded generators in distribution networks, who are only allocated costs if upgrades are required. This comment by Meridian appeared to reflect the specific circumstances of the connection arrangements for Meridian's West Wind project.

2.4.3 In addition, Meridian noted that the HVDC charge is not consistent with either a beneficiary-pays or a user-pays approach.

2.4.4 Contact noted that the HVDC charge means that South Island wind generation investments require 0.5 m/s greater wind speed than equivalent plant in the North Island.

2.4.5 Contact considered that the HVDC charge advantages incumbent South Island generators and disadvantages new entrants, which is "at odds with the Commission's initiative of Transmission enabling renewables."[11]

[11] http://www.electricitycommission.govt.nz/pdfs/submissions/pdfsecgeneral/appropriation0708/Contact.pdf

2.4.6 The Commission has considered whether the submissions on HVDC charges are relevant to the objectives of the TTER project set out in paragraph 1.1.6 of this report.

2.4.7 The Commission considers that submissions on HVDC charges are not directly relevant to the objectives of the TTER project but acknowledges some of the concerns about the impact of the HVDC charge on renewables located remote from the load in the South Island.

2.4.8 The Commission has previously set out its reasons for the transmission pricing guidelines[12] in terms of HVDC charges, and specifically the impact on renewables of HVDC charges being allocated to South Island generation plant.

2.4.9 The TPM is required by the rules to be consistent with the guidelines. The Commission's decision on the guidelines involved considering a complex range of longstanding issues and balancing a wide range of conflicting interests. For details, see the Commission's explanatory paper on its decision (HVDC Guidelines Decision).[13]

2.4.10 The Commission does not agree that the approach to the pricing of the HVDC link creates undue barriers to investment in renewables. The Commission considers its decision on the HVDC charge results, on balance, in efficient outcomes.

2.4.11 The Commission also notes:

(a) there is no requirement to treat renewables preferentially but rather to adopt efficient pricing so that undue barriers do not exist;

(b) the objective in section 172N(2)(g) of the Electricity Act 1992 to remove barriers to investment in new generation technology and renewables has to be considered along with the Commission's other objectives and functions set out in the Act, the rules, and the GPS;

(c) the HVDC charge is not directed at renewables as it is more to do with location than type of generation (e.g., it impacts negatively on South Island coal versus North Island wind); and

(d) the HVDC charge promotes efficient uptake of renewable generation by signalling the locational cost of connection in the South Island.

2.4.12 The Commission does not consider that any compelling evidence was presented which shows the impact of the transmission pricing guidelines on renewables,

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[12] Transmission pricing guidelines - http://www.electricitycommission.govt.nz/pdfs/opdev/transmis/tpg/TPM-guidelines-mar06.pdf

[13] Electricity Commission Explanatory paper, "*Commission's final decision: HVDC transmission pricing methodology*", March 2006 - http://www.electricitycommission.govt.nz/pdfs/opdev/transmis/tpg/Final-hvdc-pricing-10mar06.pdf

from a national standpoint, will be negative. As previously noted, and confirmed by this report, substantial renewable resources exist in both the North and South Island.

2.4.13 The Commission considers that a transmission customer being allocated some proportion of the costs when it connects to a connection point as opposed to an interconnection point (without the consequential need for an upgrade) is not inefficient.

2.4.14 The Commission considers that the HVDC charge does not favour incumbent South Island generators versus new entrants. The charge attributable to a new generation plant is the same regardless of whether the plant's developer is a new entrant or an existing South Island generator.

2.4.15 In summary, the Commission considers the HVDC charge does not create undue barriers to investment in new renewable generation but rather encourages the efficient location of such investment.

2.5 Role clarification

2.5.1 Meridian commented that, as a priority, the Commission and Transpower should clarify their respective roles, processes and timetables for completing a suite of transmission investments to enable renewables[14].

2.5.2 The Commission, through the TTER project, aims to ensure that:

(a) information on existing and potential renewable generation in New Zealand is made available to the public; and

(b) barriers to renewables entry are identified.

2.5.3 Investment proposals are submitted by Transpower in a grid upgrade plan (**GUP**). In short, an investment proposal must be one of the following types of investment:[15]

(a) *reliability investments*: a reliability investment is an investment by Transpower in the grid, or alternative arrangements by Transpower, the primary effect of which is, or would be, to reduce expected unserved energy; or

[14] The Commission has now published the GUIRP. As previously noted, the GUIRP sets out how the Commission and Transpower interact during the preparation and review of investment proposals by Transpower. The GUIRP clarifies the respective roles of the Commission and Transpower.

[15] "Economic investments" and "reliability investments" are defined in part A of the rules.

(b) *economic investments*: an economic investment is an investment in the grid that can be justified on the basis of the GIT and is not a reliability investment.

2.5.4 Once an investment proposal is submitted for approval as part of a GUP, the Commission is responsible for making a decision on the proposed investment. In doing so, the Commission must ensure that the proposal meets the criteria for approval. For both types of investment, this means that the Commission must be reasonably satisfied that the proposal satisfies the GIT.

2.5.5 In determining the inputs and assumptions used in applying the GIT to an investment proposal, the Commission may exercise judgment, based on its expertise and industry knowledge. In exercising its judgment, the Commission takes into account relevant objectives and outcomes specified in the Act and the rules, as well as the objectives and outcomes in the GPS. These objectives and outcomes include matters relating to the importance of enabling renewables.

2.5.6 However, it is not enough that the investment may enable renewables. The investment must satisfy the economic test set out in the GIT.

2.5.7 Transpower is currently in the process of developing two economic investments which would enable renewables in the central North Island and lower South Island. The two proposals are:

(a) the upgrade of the Wairakei ring; and

(b) the Waitaki to Southland Valley upgrade.

2.5.8 Once submitted for approval, the Commission will assess a proposal against the rules and make a decision.

2.5.9 In summary:

(a) Transpower is responsible for developing proposals and submitting them to the Commission; and

(b) the Commission is responsible for assessing proposals against the criteria set out in the rules.

2.6 Consideration of solar and marine resources

2.6.1 The Commission considers that near-term solar energy utilisation is unlikely to reduce the demand for grid services. Solar water and space heating clearly reduce demand for electricity, but small scale solar-electricity generation is unlikely to do anything more than reduce the rate of demand growth.

2.6.2 In the longer term, it may become economic to install ‘utility scale’ solar generation in New Zealand. This could be either solar thermal or photovoltaic

type generation, and the Commission is aware that this type of technology is progressing rapidly in California and parts of Europe.

2.6.3 The best location in New Zealand for this type of generation appears to be Nelson/Marlborough. Again, this generation is likely to reduce the need for transmission to be exported north from Christchurch. However, in this particular region there may also be competition for land-use.

2.6.4 On balance, the Commission considers that further investigation (by the Commission) of solar energy development is not warranted at this point in time, as it is unlikely to change any investment proposal for transmission. As solar technology develops and becomes more economic compared to other energy options, the Commission will reconsider its impact on transmission investment.

2.6.5 One submitter commented that the Commission should consider the potential of tidal and marine generation as a viable medium to long term source of energy.

2.6.6 The Commission considers that marine generation technology is more likely to be economic in New Zealand than large scale solar technology. The Commission notes that New Zealand has significant potential marine energy resources and it is realistic to assume that it will be economic to utilise this resource for generation in the future.

2.6.7 In order to understand the likely timeframe and potential resource available to be utilised, the Commission has engaged consultants to report on the status of the technology both in New Zealand and internationally, and the potential for development in New Zealand.

2.7 Seeking information from generators

2.7.1 Some submitters suggested that the Commission should request information directly from generators as they hold more specific and accurate information.

2.7.2 In undertaking economic analysis, and in modifying the scenarios, the Commission considers that it is inappropriate to rely on generator or proponent information unless such information is able to be verified or tested independently by the Commission or other interested parties.

2.7.3 The Commission's ability to determine whether the GIT has been applied reasonably may be compromised if the GIT analysis relies on confidential information that is unable to be tested or verified. For this reason, the Commission uses publicly available information on generation location, cost, capacity and timing to develop the generation scenarios. The scenarios can then be tested in the public arena.

2.7.4 If generators hold more accurate information and are willing to make it publicly available or, at least, are willing to allow it to be verified and tested, then the Commission would use such information.

2.7.5 In this regard, the Commission can request information from participants:

(a) on a co-operative basis; or

(b) pursuant to rule 3.

2.7.6 Rule 3 provides:

> 3.1 All **participants** must provide information reasonably required by the **Board** for the purposes of this section and respond to requests from the **Board** under this section promptly and accurately.
>
> 3.2 **Participants** must use reasonable endeavours to provide accurate information.
>
> 3.3 The **Board** is not liable for the accuracy of any information provided by **participants**.
>
> 3.4 Subject to the Official Information Act 1982, the **Board** may at its discretion, or on application of an affected party, withhold **publication** of confidential aspects of the information provided by **participants** to the **Board** if the **Board** reasonably considers that there is good reason for withholding it.

2.7.7 However, while the Commission has the power to request information from participants, the Commission prefers to work with participants on a co-operative basis.

2.7.8 The Commission is also aware that some of this information could be commercially sensitive and therefore, it would not be appropriate for the Commission to release it into the public arena.

3. Second round of submissions

3.1 Introduction

3.1.1 In April 2008, the Commission published the draft report on transmission to enable renewables (**draft TTER report**)[16] and sought comments on Commission's approach to the:[17]

(a) accuracy of data, including:

(i) identification of potential future renewable generation resources;

(ii) power system analysis; and

(iii) GEM analysis;

(b) consideration of real options in justifying transmission investment;

(c) consideration of non-transmission alternatives to enhance interconnected grid capacity to better enable renewable connection;

(d) process for provision or upgrading of connection and deep connection asset;

(e) consideration of the feasibility of parties such as generators contracting with Transpower for upgrades to the existing interconnected grid; and

(f) consideration of confidential information on renewable generation projects.

3.1.2 Specific comments made on the draft wind, hydro and geothermal reports have been addressed in the final wind, hydro and geothermal reports but are also discussed in the *accuracy of data* section below. The final hydro, wind and geothermal reports are separate appendices to this report.

3.1.3 On 2 May 2008, the Commission held a second workshop[18] on the TTER project. At this workshop, the preliminary results of the transmission analysis and the GEM analysis were presented and participants were provided with an opportunity to comment on the approach the Commission had taken to assist them in finalising their submissions. Transpower also made a presentation on the transmission planning challenges in facilitating the connection of renewable generation.

3.1.4 Two matters dominated the discussions at the workshop:

[16] The draft report is available at http://www.electricitycommission.govt.nz/consultation/draftrenewables

[18] Presentations made at the workshop are available at http://www.electricitycommission.govt.nz/opdev/transmis/renewables

(a) the accuracy of the data used for the analysis; and

(b) concerns regarding possible subsidising the cost of connection to the grid to reduce barriers to renewable generation entry

3.1.5 The comments made at the workshop were largely repeated in the submissions received and have been responded to in the relevant sections below.

3.2 Comments received in submissions

3.2.1 Submissions closed on the draft TTER report on 9 May 2008. The Commission received 13 written submissions[19] from the following:

Table 4: List of submitters

	Submitters
Consumers	Federated Farmers, Major Electricity Users' Group (**MEUG**), Molly Melhuish
Generator/retailers	Contact, Genesis, Meridian, MRP, TrustPower
Lines companies	Transpower, Powerco Limited (**Powerco**), Vector Limited (**Vector**)
Others	Electricity Efficiency and Conservation Authority (**EECA**), New Zealand Wind Energy Association Incorporated (**NZWEA**)

3.2.2 As well as the matters listed in paragraph 3.1.1, submitters also provided comments on a number of other matters including:

(a) transmission pricing methodology:

  (i) HVDC charges;

  (ii) connection charges.

(b) annual payment to landowners for use of their land by Transpower;

[19] The submissions received are available at: http://www.electricitycommission.govt.nz/submissions/substransmission/tter

(c) potential for distributed wind generation/small scale versus large scale renewables;

(d) purpose of the TTER project; and

(e) competition in the wholesale market.

3.3 Accuracy of data provided

Introduction

3.3.1 A key objective of the TTER project was to provide an up to date map of potential renewable resources for geothermal, hydro and wind in New Zealand. The Commission itself prepared a report on existing and potential geothermal generation in New Zealand and engaged:

(a) PBA to prepare a report on the most likely economic hydro schemes in New Zealand; and

(b) Connell Wagner to prepare a report on the potential wind capacity available in New Zealand.

3.3.2 A number of submitters noted that the three reports did not follow the same approach in identifying renewable resources. The different approaches were:

(a) the geothermal report sought to record mostly known resources;

(b) the hydro report focused on identifying the eight most economic hydro schemes; and

(c) the wind study identified potential wind resources across New Zealand on an aggregated basis using advanced mesoscale meteorological modelling techniques combined with terrain analysis using advanced GIS tools.

3.3.3 The different approaches reflect that the amount of available information varies significantly between the resource categories:

(a) *Geothermal* — the Commission already had a database of existing capacities and possible future geothermal schemes, and a number of reports were available from consultants and government agencies on this topic.

(b) *Hydro* — a large database of potential and existing hydro schemes was available;

(c) *Wind* — minimal information was available.

3.3.4 The information gathered in these reports was used to:

(a) improve the accuracy of the input data applied in formulating the GPA; and

(b) co-optimise GEM.

3.3.5 During the consultations on the TTER project, the Commission sought submissions on the accuracy of the information contained in the draft hydro, wind and geothermal reports.

3.3.6 The key issues raised in submissions around the accuracy of data contained in the wind, hydro and geothermal reports were:

(a) the appropriateness of the use of a risk de-rating factor for geothermal generation;

(b) inaccuracies in the hydro schemes identified by PBA; and

(c) the importance of other criteria (e.g. consentability) in determining the potential wind resources in a particular region.

Geothermal report – risk de-rating factor

Introduction

3.3.7 During the first round of consultation, some submitters commented that the Commission had overstated the potential for further geothermal generation capacity. Those submitters who were critical of the estimate noted that the capacity identified relied on developers' forecasts prior, in many cases, to the completion of exploration and drilling.

3.3.8 The Commission reconsidered the issue as more information became available. Risk de-rating factors specific for each of the future capacities was applied to all of the schemes to recognize the fact that actual developed capacity may be less than developers' expectations

3.3.9 A straightforward risk de-rating factor which diminished over time to reflect greater knowledge about the field's capacity was selected. The Commission assumed that the early schemes already held consents and had performed extensive field studies while later ones were more uncertain as the reservoirs have little or no drilling exploration history. In addition, the Commission assumed that these more speculative developments did not have any resource consents. The factor started at 0.9 in 2008 and linearly decreases down to 0.66 by 2016.

3.3.10 By applying this risk de-rating factor, the overall additional geothermal generation capacity identified by the Commission was reduced from 756 MW down to 596 MW.

Submissions

3.3.11 Contact commented that there could be an equivalent risk with other types of renewables but the Commission had not applied a de-rating factor for these developments. Contact also commented that its recently developed geothermal generation operated at above or close to nameplate capacity.

3.3.12 MRP commented that generator expectations of generation capacity can be reasonably relied upon without making adjustments using a de-rating factor.

Commission response

3.3.13 After further analysis and consideration of the submissions received, the Commission decided not to apply a risk de-rating factor. The Commission's conclusion is that developers are likely to have already de-rated the installed capacities as prudent investors. On that basis, the Commission can rely on information provided by generators. Accordingly, a risk de-rating factor has not been used by the Commission in its analysis nor for the development of the GPAs.

3.3.14 The Commission has updated its report on existing and potential geothermal generation in New Zealand. The updated version of this report can be found in Appendix 2 of this report.

3.3.15 However, the Commission will continue to monitor the capacity specified by developers at the early stage of scheme developments and compare that to the actual capacity once the plant is running in order to ascertain that the information provided by developers is accurate.

Hydro report – accuracy of the Mokihinui and North Bank tunnel schemes

Submissions

3.3.16 Meridian commented that the cost of construction of the Mokihinui Dam as assessed by PBA resulted in an output cost of 18 c/kWh. The main contributing factor being the 80 – 90% higher cost of concrete than Meridian's estimates and the volume of mass concrete required (PBA assumed 80,000 cubic meters while Meridian assumed 1,250 cubic meters).

3.3.17 Meridian also questioned the assumed construction cost of the North Bank tunnel. Meridian noted that PBA had assumed very poor ground conditions requiring full concrete tunnel lining. Meridian considered this assumption to be overly conservative and contrary to available information. The assumption of a

full concrete tunnel lining resulted in PBA's estimate of the tunnel cost being $400m to $600m higher than Meridian's estimate. .

Commission response

3.3.18 New information has altered PBA's underlying input assumptions and, accordingly, the cost estimates for the Mokihinui and the North Bank Tunnel schemes have been revised downwards.

3.3.19 PBA, in its revised report, has made changes to two of its assumptions for the Mokihinui scheme:

(a) construction time of 3 to 5 years (instead of 6 to 7 years); and

(b) use of enriched roller compacter concrete for the upward and downward face of the dam (instead of conventional mass concrete).

3.3.20 As a result, the cost of generation now equates to approximately 9.82 cents/kWh instead of 18.32 cents/kWh and the overall cost of the project is now estimated at $304m instead of $488m.

3.3.21 In respect to the North Bank tunnel scheme, PBA has now assumed that 25% of the tunnel is fully concrete lined, with the remainder utilising a shotcrete lining. As a result, the cost of generation has been amended to 9.55 cents/kWh instead of 13.5 cents/kWh and the overall cost of the project is now estimated at $974m instead of $1,381m.

3.3.22 In order to demonstrate the sensitivity of the tunnel costs, the summary cost estimates for the main components of the North Bank Tunnel scheme assuming a fully concrete lined tunnel are still contained in the hydro report.

3.3.23 The final version of the PBA report can be found in Appendix 3 of this report.

3.3.24 The Commission will include this new information when updating the GPAs next year but this new information has not been used in developing the 2008 SOO.

Wind report

Submissions

3.3.25 Contact commented that:

(a) the $80 MWh cost of wind is understated and that the average total capital expenditure of $2,600 kW is too low; and

(b) wind turbine prices should not abate in the near term as the underlying causes of the increase (high steel prices and high demand) are structural.

3.3.26 Meridian commented that the availability of wind resource is not the only critical factor. Meridain noted that other factors are equally critical including: physical access, contractual access, land use, land form, access to the grid and consentability. Meridian noted that absolute wind speeds are not solely used by developers to assess wind farm economics, but rather average wind speed, its distribution, turbulence and wind shear are all factors that influence turbine choice and each of these factors influence the relative economics of a wind farm; project scale; and lifecycle cost.

3.3.27 NZWEA commented that the wind report may not accurately depict the amount of wind generation realisable because of:

(a) the application of a single factor (50%) to estimate the amount of suitable land that might be available by landowners. A change in this factor can lead to a significant change in the identified potential;

(b) consentability;

(c) spatial resolution of 3 km is likely to lead to a smoothing of the results;

(d) the accuracy of 10 MW per square kilometre assumption; and

(e) availability, financing problems and cumulative effects prevent large developments.

Commission response

3.3.28 The Commission noted that the wind report confirmed Contact's comments regarding the cost of the wind generation potentially being understated. The wind report noted that the $2,600/kW capital cost was historical and indicated that turbine prices are continuing to rise. The wind report emphasised that there was significant uncertainty on future prices due to exchange rate variation, raw material prices, and international demand for turbines.

3.3.29 The Commission agreed that the factors listed by Meridian and NZWEA were important considerations for individual wind farms and further work could be done to incorporate these into the TTER findings to improve their accuracy. In particular, consentability is one of biggest single factors that would impact the overall size of potential wind resources.

3.3.30 However, the purpose of the TTER project was to identify the approximate size and location of potential wind generation sites. The assumptions that were made were appropriate for obtaining a high level estimate of the wind capacity available in New Zealand. For instance, analysing the consentability of each potential site would have required a significant amount of work which the Commission does not consider to be necessary at this stage. Submitters did not provide sufficient

analysis to assist the Commission in making material changes to these high level estimates.

3.4 GEM Analysis

Introduction

3.4.1 GEM has recently been modified to enable transmission investments to be co-optimised along with investments in generation plant.[20] This recently modified version of GEM will be used to undertake the analysis of TTER. This analysis is still being undertaken and will be reported later in 2008.

3.4.2 GEM has previously been explained and demonstrated to various industry participants. The model codes, data files and documentation are also available for download from the Commission's website. Comprehensive documentation to accompany the most recent release of GEM is still in the process of being prepared.

3.4.3 GEM is a long range capacity planning model. The key purpose of GEM is to create "build schedules" for new generation plant and interregional transmission upgrades. GEM selects which generation plant or transmission upgrade is commissioned, and when, given a large list of possible generation and transmission options. When choosing investment options, GEM seeks to minimise the discounted capital expenditure and ongoing operating and maintenance costs over the entire time horizon for which the model is run – typically about 30 years – while at the same time ensuring the model's economic, physical and technical constraints are satisfied.

3.4.4 The principle behind GEM is the solving of a canonical capacity expansion problem formulated as a mixed integer programming (**MIP**) problem. The computer code is written using the GAMS optimisation software and the model is solved with CPLEX, a commercial MIP solver accessed via the GAMS/CPLEX interface. The model's input data is compiled as a series of thematic worksheets in an Excel spreadsheet. Model outputs are written to spreadsheet-compatible files, allowing further processing and/or plotting using software such as Matlab or Excel.

3.4.5 The Commission notes that some submitters expressed concern about the Commission appearing to engage in transmission planning (by using a model that co-optimises generation and transmission), a task more appropriately undertaken by Transpower.

[20] See version 4.1.2 of GEM at http://www.electricitycommission.govt.nz/opdev/modelling/gem/index.html.

3.4.6 The roles of the Commission and Transpower are clearly set out in the GPS and are repeated in paragraph 2.5 of this report. The use of a co-optimised GEM does not imply that the Commission is attempting transmission planning or generation development. Indeed, GEM was not designed for that purpose and the application of GEM alone should not be confused with the careful and rigorous analysis of transmission investment options. At best, the co-optimising version of GEM used for the present analysis is able to provide indicative information about the need for and overall economic viability of transmission upgrades based on a particular set of assumptions.

3.4.7 The Commission also notes that several submitters have commented that the reliability of the GEM analysis is dependent on the input data and underlying assumptions. The Commission agrees and notes that such an observation is true of any quantitative analysis.

Co-optimisation in GEM

3.4.8 In order to enable generation and transmission investments to be co-optimised, GEM has been configured with a more detailed regional representation than has typically been used in the past. Eighteen regions (nine per island) and 18 interregional transmission paths have been defined to characterise the current state of the national grid.

3.4.9 However, for the purposes of the TTER project, a further 15 nodes, each associated with a dummy region, have been added to the network. This was necessary to enable the model to appropriately trade off generation with transmission in areas where more than one potential new remote wind resource is located. The 15 additional nodes are illustrated in Figure 5.

3.4.10 The network in GEM is radial and the 15 extra nodes have been modelled as eight spur lines, each containing one to three nodes in series. The reason for treating each of these 15 nodes as if they were a new region is so that the transmission investments required to enable the new generation resources to be exploited can be modelled explicitly. Furthermore, the decision to undertake (or not) the transmission investments, and their timing, can be considered along with the cost of exploiting the remote generation.

3.4.11 In previous versions of GEM, the assumption has been made that the cost of connecting new plant to the grid is incurred by the owner of the new plant and is simply added on to the capital cost of the new plant. However, this assumption has been relaxed for the TTER project so that the Commission can investigate cases where there may be more than one potential new generator able to connect to the grid at a given location.

3.4.12 Seventy-three potential transmission upgrades and 201 potential new generation plants have been identified for the period 2008 – 2040. The state of each current transmission path is described in the model by parameters representing the interregional transfer capacity and a transmission loss function. A transmission path is an electrical aggregation of actual lines available to transfer electricity between regions.

3.4.13 Transmission upgrades are modelled as a state change. In other words, the state of a path, as characterised by the interregional transfer capacity and loss function, is able to transition to another state. A cost is incurred to transition from one state to another. All possible state transitions, and their order in cases where they are ordered, for each transmission path are defined in the input data file.

3.4.14 When GEM is run, the overall cost of satisfying the load in each region is minimised by appropriately trading off generation investments with transmission upgrades.

3.4.15 As noted earlier, the analysis using GEM is still being undertaken and will be reported separately.

3.4.16 The completed GEM analysis will assist in developing answers to the following questions:

(a) how much of the identified potential renewable capacity - much of which is remote from the existing grid - is likely to be economic to develop?

(b) how sensitive is the answer to (a) to assumptions about the ability of wind generation to contribute to peak load?

(c) how sensitive is the answer to (a) to the assumptions around generation and transmission plant costs?

(d) how much transmission infrastructure (at a high level) is justified? In other words, on a national basis, is it more economic to build additional transmission infrastructure to enable remote generation or to build generation closer to the existing grid?

(e) are deep connection assets likely to create problems? If development of problematic deep connection assets was somehow enabled, what would be the extent of the national net benefit, if any?

3.5 Transmission investment timing - real options analysis

Introduction

3.5.1 One of the key concerns in facilitating renewable generation investment has been the apparent difference in timing between transmission and generation investment. Transpower has advised the Commission that it should allow a lead time of eight years for the provision of a new transmission line, and two to three years for less substantial transmission work such as thermal upgrades, re-conductoring and duplexing.

3.5.2 New wind generation can often be developed rapidly, in some cases taking as little as 12 months from the granting of consents to full operation. Committing to transmission investment in advance of generation to address this lead time disparity risks over investment in transmission as there is often uncertainty as to whether consents will be obtained for an identified wind resource, and whether a potential developer will choose to proceed after taking into account current market prices, wind turbine prices and construction costs.

3.5.3 As the TTER project shows, substantial potential economic wind resources have been identified. However it is not likely that all of the resource will be developed in the short or medium term. Decisions made now to carry out transmission upgrades and to build new transmission lines to accommodate the development of all of these resources could therefore lead to creation of a number of stranded transmission assets.

3.5.4 For this reason the Commission has been considering how transmission investment can better enable development of identified viable wind resources without committing expenditure that may turn out to be unnecessary. The key questions that underpin this analysis relate to the level and timing of transmission investments.

3.5.5 In order to better understand the economic tradeoffs involved, the Commission has considered the development of a real options analytical framework. Real options analysis gives decision-makers the ability to analyse the value of options to either commit to, or pull out of, further investment as information becomes more certain[21].

3.5.6 In the case of an identified wind resource region there will be many uncertainties, but also key information points, or times when key information becomes available, that enable the uncertainties to be minimised or eliminated. At this

[21] The use of a real options approach was anticipated in development of the GIT. Clause 13 of the GIT requires either a real options analysis or standard net present value analysis to be used.

stage the Commission considers that there may be five key information points in the wind farm development process[22] namely:

(a) what is the capacity of the potential wind resource?

(b) is the potential wind resource being seriously investigated, e.g. using wind data gathering methods?

(c) is the potential wind resource being progressed through the resource consent process?

(d) has the potential wind resource been consented and to what capacity?

(e) has the proponent of the potential wind resource publicly committed to developing the resource?

3.5.7 In Appendix 6, a sample analysis is presented to highlight how a real options analysis may be applied to evaluate the options to make investment decisions in the future when confronted by uncertainty in the present day.

3.5.8 In the example shown in Figure 7 of Appendix 6 it is assumed that a wind resource has been identified and, by treating the identified resource as a modelled project based on the GIT, a decision is made immediately to purchase easements for a new transmission line that would accommodate that wind resource. In one path of the decision tree (Figure 7 of Appendix 6) the transmission investment is carried out immediately after the easement is secured, while the second path delays the transmission investment until there is more certainty that the wind generation will be developed. The analysis shows that for the capital cost, easement cost, wind farm capacity and project committal assumptions made there may be option value in waiting for more information to come to light[23] before commencing construction of a new transmission line.

3.5.9 However, there are additional issues to resolve. Many transmission investments to accommodate generation plant using a renewable resource may be connection assets. In such cases the investment cost would fall directly to the generation developer who will match the transmission asset capacity with the generation being developed. However, it may be that investment in a large transmission asset to accommodate a number of renewable resources in a region may be more economic than numerous smaller upgrades. Accordingly it may be desirable for existing grid customers to fund these investments until new generation is developed.

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[22] The Commission is interested to hear submissions on these five key information points and whether these are appropriate for the purpose of real options analysis.

[23] The next stage of this analysis is to carry out a case study for an identified wind resource region and apply Monte Carlo simulation to the solution variables.

3.5.10 The Commission was very interested to receive views on the analysis approach and issues raised in the draft TTER report regarding the level of transmission investment that can be justified when a renewable resource is identified. The analytical approach in Appendix 6 provided one framework for such early investment decisions, and the Commission sought submissions on this approach, and what might be alternatives.

Submissions

3.5.11 Contact indicated a keenness to engage with the Commission on the suggested real options approach. Contact considered that spending on transmission preparations in order to build option value for transmission routes is valuable and that most of the value comes from truncating the time to commission new transmission lines. Contact considered that a key issue to investigate is the extent to which costs incurred in preparing for potential transmission can be recouped, should the forecast required generation not materialize.

3.5.12 EECA considered that real options analysis is likely to assist the Commission's understanding of the co-ordination problem but had some concerns about its practical application in the GIT process. For example, EECA suggested that it may not be practical or cost-effective for all projects (particularly for small projects), and questioned how probabilities or probability distributions will be able to be assigned in an objective and transparent manner without inviting some degree of gaming.

3.5.13 EECA also stated that the real options examples appear to imply that the probability of developing a renewable project will remain the same regardless of the level of transmission investment. EECA expects that, as the level of commitment to a transmission project increases, uncertainty around transmission capacity faced by developers of renewable generation would be reduced and the probability of investment in the renewable resource would increase.

3.5.14 Meridian considered that real options analysis would be suitable in terms of evaluating the benefits of early acquisition of easements prior to committing to developing new renewables, but noted that:

(a) results of the analysis are dependent on the quality of the inputs used; and

(b) real options analysis needs to take into account the long lead time for developing the transmission assets.

3.5.15 Powerco considered that a market based approach should be explored in more detail in line with the action plan of the NZES.

3.5.16 Transpower generally supported the use of real options analysis, and supported the acquisition of transmission corridors as a mechanism that may assist this.

However, Transpower suggested that the outline in the draft TTER report lacked the detail needed to clearly show how the approach will be applied. In addition Transpower suggested:

(a) there is more uncertainty associated with a range of relevant factors (such as fuel costs, demand growth etc) than described;

(b) transmission should facilitate new generation rather than being initiated by it;

(c) national value relates to the generation plant options rather than transmission; and

(d) assumed independence between generation and transmission investment decisions is questionable.

3.5.17 Transpower suggested that because of the uncertainties associated with transmission investment there is little value in analysing real options for a single investment. Instead, Transpower proposed calculating an expected outcome based on the range of relevant assumptions and recognition of uncertainties.

3.5.18 Transpower acknowledged that there will be option value in preserving investment options by, for example, securing designations and easements, but questioned whether the option value will be sufficient to justify their purchase.

3.5.19 Transpower noted that real options analysis can be useful for considering the economic benefits of strategic transmission investment and the timing of an investment (e.g. to bring forward or delay) to the extent that the choice (to bring forward or delay) can open up investment options.

3.5.20 Transpower concluded that option values should be considered, both for generation and transmission.

Commission response

3.5.21 Transmission access issues are a key concern for developers of new renewable generation. Some issues, such as the location signals provided by the TPM and the GIT are intended to promote overall efficient outcomes, and developers need to be mindful of these when selecting candidate sites on which to develop generation.

3.5.22 Nevertheless, the Commission is concerned about timing differences between transmission and generation investment and is actively investigating ways to address the timing differences. The Commission will support Transpower's efforts to propose timely and efficient transmission investments, to the extent possible under the rules. In this regard, the Commission will encourage the use of real options analysis.

3.5.23 The Commission notes the comments received on this analytical approach and will ensure that relevant points raised are taken into account in any further analysis.

3.5.24 The Commission will also monitor Transpower's progress in dealing with the provision of connection and deep connection assets generally.

3.6 Consideration of non-transmission alternatives to enhance interconnected grid capacity to better enable renewables

Introduction

3.6.1 The Commission noted in the draft TTER report that there may be economic alternatives to investing in additional transmission line capacity, which can improve transmission capacity, and relieve generation constraints thereby facilitating the use of renewable sources in electricity generation. The economic alternatives specifically referred to were special protection schemes (**SPS**) and include generation runback or intertrip schemes.

3.6.2 The Commission also noted that the System Operator (**SO**) when dispatching[24] generation, sometimes constrains generation to ensure that if a contingent event occurs the assets remaining in service are not overloaded (i.e. rated beyond the thermal rating of the circuit,) as this may lead to:

(a) cascade failure i.e. more assets tripping out; and

(b) equipment damage (would could take a long time to repair) or public safety concerns arise (transmission line conductors droop closer to the ground).

3.6.3 The draft TTER report noted that additional investment in transmission can be proposed to relieve this constraint, but also that the investment may not be cost effective.

3.6.4 SPS allow the transmission system to be operated securely at *N* security from a transmission circuit viewpoint and in some cases twice as much transmission capacity can be made available at minimal cost.

3.6.5 Thermally upgrading the existing circuits or building new transmission lines is expensive compared to the economic cost of very occasionally constraining generation. The economic value (typically the bid price is a good proxy for this) of constraining generation is quite low, often at the most $100/MWh.

[24] The generators electricity is conveyed via the transmission system

3.6.6 Runbacks or intertrips only occur when a circuit actually trips. Assuming this occurs once a year and a 100MW of generation was reduced for 5 hours then $50,000 ($100MWh) of costs could be expected to be incurred each year. The hardware costs for the protection would usually be significantly less than $1 million. In total, therefore, runbacks or inter-trips would be significantly cheaper than say $5 million per year to service a $50 million transmission investment.

3.6.7 The Commission also drew attention to the use of SPS internationally as an alternative to additional transmission capacity, citing the rules for their application administered by the California ISO (CASIO).[25]

3.6.8 The Commission noted that, as is often the case, if the constrained lines terminate at the same substation to which the generation connects, then it is quite simple for a local protection circuit to ensure that when a permanent fault occurs on one circuit of the transmission line, generating units at the connected generating station are then immediately inter-tripped or runback to a lower output.

3.6.9 There is currently limited application of SPS in New Zealand. For example, Meridian has such schemes in place with Transpower at Manapouri and Te Apiti. The HVDC link has runbacks for outages of transmission circuits connected to it at Haywards in the North Island which have been in operation since 1992. Arrangements like these have long been used internationally for generation connected to HVDC links.

3.6.10 The adoption of a robust approach to use of generation runbacks and inter-trips could provide an efficient and cost effective means of providing additional grid capacity to better support connection of new remote renewable generation. Transmission assets are generally very reliable and circuit outages for which runbacks or inter-trips would be required would be infrequent.

3.6.11 The Commission suggested in the draft TTER report that while generators are incentivised to enter into such arrangements in respect of connection assets, as they fully meet the costs of these assets, the incentives are weaker for generators to enter such arrangements to substitute for interconnected grid capability. In this case, the costs of grid investment are not met by generators, and so alternative arrangements may not be in the commercial interests of generators. It could also be unsatisfactory to allow generators to choose whether or not to participate in such arrangements. If generators were able to choose whether or not to provide such arrangements, a generator could withdraw the facility and create a constraint in the transmission grid by doing so.

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[25] While the CAISO rules apply to SPS for new generators, in New Zealand they could apply to both new and incumbent generators.

http://www.caiso.com/docs/09003a6080/14/37/09003a608014374a.pdf

3.6.12 The Commission sought submissions on its approach; and specifically:

(a) the need to consider whether such an arrangement could be an alternative to the proposed investment (clause 19 of the GIT);

(b) whether SPS may remain a more economic arrangement overall even where complex arrangements relying on good telecommunications are needed and if meshed grid elements involving multiple substations need to be monitored; and

(c) implementation issues around the selection and participation of both new and existing generators in such arrangements with Transpower. The Commission considered that the SPS arrangements should use the most efficient arrangement of generators when taking into account net market benefits,[26] regardless of whether they are existing or new generators.

Submissions

3.6.13 A number of submitters considered that SPS:

(a) should be adopted as an interim measure only on the interconnected grid until such time as a satisfactory transmission solution can be implemented;

(b) are a solution for connection where individual customers agree to the use of such schemes for commercial reasons;

(c) have significant reliability implications and commercial complexities, on the interconnected grid. For example:

(i) they may introduce risk to the operation of the power system as coordination of a large number of such schemes would be complex;

(ii) require run-up generation as the circuit comes back into service. This would require regionally based reserves and consequential changes to the market system; and

(d) be via voluntary arrangements I.e. implementation must be through commercial arrangements as per other ancillary services products.

3.6.14 Contact noted the following issues would need to be resolved with respect to SPS:

(a) significant energy could be constrained versus the alternative of transmission upgrade to maintain *N-1*;

[26] For example a hydro generator with storage capability located at one of the terminating circuits could be the most efficient provider as communication costs would be minimal, electrical participation greatest and likelihood of energy spill minimised.

(b) generator availability (outages and amount of fast start generation available in different parts of the grid);

(c) greater flexibility of a transmission upgrade; and

(d) SPD relies on *N-1* when scheduling reserves.

3.6.15 Genesis recommended that, until the Commission has worked through the reliability and contracting issues, Transpower should not be obliged to analyse generator run-backs as alternatives when submitting investment proposals for approval for cost recovery.

3.6.16 Meridian also noted the following issues with respect to use of SPS for other parts of the interconnected grid:

(a) SPS require fast starting plant or spinning reserve to be located on the demand side of the constraint and over time this generation will be generally more expensive than incremental transmission. It is therefore unlikely that this would provide a least net market cost solution; and

(b) competition for generating plant may increase the cost of ancillary services and energy.

3.6.17 MRP considered that any mandated requirement for generators to install runbacks would amount to substantial interference with the competitive operation of the generation market.

3.6.18 NWEA and Meridian were concerned about the potential for spilling energy because of the use of SPS. NWEA considered that the value of spill or lost generation should be considered as part of the economic assessment of the alternatives and that the value of that spill should be based on the value of the electricity that is dispatched in its place (i.e. the market price).

3.6.19 NWEA also noted that there may be complications with scheduling and compensation. For example, if there are several connections on an interconnected section of the grid where a runback is required, how would it be determined which party would be runback, and would they be compensated by the other parties accordingly?

3.6.20 Transpower considered that the Commission is overstating the role of SPS with regard to enabling renewables. Transpower noted it already investigates inter-trips and runback schemes as non transmission alternatives in the assessment of transmission investments to relieve generation constraints.

3.6.21 Transpower referred to its comments on the use of runbacks and inter-trips in its revised investment proposal for the Central North Island Thermal Upgrades provided to the Commission in April and May 2008.

3.6.22 TrustPower agreed that investigations into the use of SPS have the potential to result in the existing grid being used more effectively to enable renewable generation remote from load centres.

3.6.23 Vector regarded the use of SPS as reasonable as long as security of supply was not put at risk.

Commission response

3.6.24 The Commission considers that the use of SPS can be an interim measure, and in some circumstances they may be the most efficient long term solution. Plainly, this is the case in many of the connection applications in New Zealand. The Commission also acknowledges that, in certain circumstances, load growth and generator development will, in the long run, require the construction of new lines, but that significant economic benefit may also be provided by SPS arrangements over both short and long time horizons.

3.6.25 The Commission agrees that there are cost and operational issues (e.g. operation of regional reserves) for the SO from the wider application of SPS. However, these are not reasons in themselves for not employing such schemes. The additional complexity will require investigation into the cost and benefits of these schemes for each particular circumstance. However, the Commission notes that there is considerable benefit from deferring an augmentation or substituting for it by use of a run back or inter-trip. The availability of fast start generation is, of course, an issue but the existence of SPS may have little bearing on whether such plant is available or its location as this plant is already provided by the reserves market.

3.6.26 Many submitters noted that security of supply may be degraded through the use of SPS. Submitters did not adequately identify why security supply would be jeopardised and this seems to be a generalised concern. The Commission notes that the secondary systems and generation arrangements required to implement the SPS can be designed to be at least as reliable as transmission line. The key issue to be considered is the cost efficiency of such a scheme, as at times the additional reliability benefits of higher reliability SPS, or transmission assets, may not justify the additional costs involved. In fact, the Commission considers that SPS may provide an increase in reliability and pass the GIT, where it would not be possible to justify additional primary transmission assets.

3.6.27 The Commission does not agree that SPS should be treated as an ancillary service as they are not directly required for the operation of the wholesale market but rather they would be used when they were an efficient alternative to transmission.

3.6.28 Contact provided reasons why SPS have to be carefully designed but the Commission does not regard the problems as significant enough to prevent their application in appropriate circumstances. The Commission does not see that SPS necessarily limit flexibility, in fact they are likely to provide greater flexibility in respect to the use of existing transmission assets and also significant savings while providing an equivalent transfer capacity.

3.6.29 The Commission considers that it is unlikely that the incremental cost of providing plant on the demand side of the constraint will be generally more expensive than incremental transmission. Reserves on the demand side of the constraint are likely to be there already because of the need to cover generation outages. Also enhanced demand side reserves products are also more likely in future with smart metering.

3.6.30 The Commission used $100 MWh as a proxy for the economic cost of generation and five hours for the expected outage duration of transmission to compare against the cost of an upgrade. The Commission considers the assumptions to be conservative. For example, the average wholesale price for Haywards has ranged between $30/MWh and $53/MWh[27] for the last 11 calendar years. In New Zealand's hydro dominated environment, if the inter-tripped or runback plant was a hydro generator with storage then the energy generation would simply be shifted to another time period at close to zero cost.

3.6.31 The expected economic cost of providing SPS compares very favourably with the cost of providing transmission and this fact is driving electricity markets and regulators elsewhere to consider such schemes.

3.6.32 Meridian also considers that competition for generating plant may increase the cost of ancillary services and energy. The Commission does not accept that the provision of SPS will be an ancillary service. The Commission's initial view was that it will be a regulated obligation with no availability fee. Generators would not be compensated for providing the capacity. Some of the issues with this proposed policy are discussed below.

3.6.33 The Commission does not understand how SPS would materially affect the cost of energy.

3.6.34 MRP considered that the mandatory implementation of SPS would be interference in the market. The Commission notes that there is no market in the provision of interconnection assets and generators have no entitlement to capacity on the interconnected grid. That is, the owner of the interconnected grid is entitled to seek the least cost way to manage the grid and act in the interests of those paying for the service provided. This may have consequential impacts on how generators are dispatched, but as noted above, the SO currently has the

[27] Period 1/1/1997 – 1/12/2007

ability to constrain generation to ensure that if a contingent event occurs the assets remaining in service are not overloaded without compensating generators. The Commission does not see any difference in the rationale for SPS and the aforementioned capability.

3.6.35 In addition, the Commission does not consider it reasonable for consumers to pay an availability fee for the provision of SPS, if that is what is required to make a voluntary implementation work.

3.6.36 The Commission considers NZWEA's concern about spilling energy from the operation of SPS to be overstated. It is true that the bid price for wind may not reflect the economic value and, unlike hydro, the energy cannot be stored. For these reasons, the Commission has reconsidered this issue. It agrees that it may be necessary to consider the selection process for which generator plants has to ramp down is on a net benefits basis.

3.6.37 The selection of which generator was constrained off or on where there were identical costs would need to be considered. In this instance it could be on a rotational basis. In some cases generators with identical costs will be at different locations and reducing generation at some specific locations may more strongly influence the constraint and so these generators would be preferred.

3.6.38 An even simpler system (that recognises the low likelihood of triggering the SPS), would be to have a more mechanical implementation of the SPS. In this case, the SO would schedule the generators on both sides of the constraint on the basis of pre-existing plan that recognised a particular generator's capability to alleviate the issue

3.6.39 The Commission has reconsidered the comments on the use of SPS that Transpower provided in its revised investment proposal for the Central North Island Thermal Upgrades. The Commission notes that Transpower sought comments from interested parties on whether runbacks should be preferred over relatively low cost upgrades that provide permanent capacity increases as well as general comments on the desirability of runbacks on the core grid and any market impacts.

3.6.40 The Commission understands that only Genesis responded on the above question and these comments are largely reflected in Genesis's submission to the Commission on the draft TTER report. The Commission notes that Genesis was interested in further analysis on the SPS option as an alternative to an upgrade.

3.6.41 The Commission disagrees with Transpower that use of the HVDC runback will be limited if there is insufficient generation in the South Island in a dry year as even in a dry year there will be some water available to provide the few hours required to compensate for a circuit outage. However, most of the comments

provided in its Attachment A[28] have been addressed (e.g. operational complexity and the need to investigate the practicality on case by case basis). One additional issue that merits comment is Transpower's claim that SPS provide no physical capacity increase. However, the Commission notes that SPS increase useable capacity, avoiding under utilisation of assets.

3.6.42 The Commission considers that submitters have overstated the complexity of SPS and the technical and operational issues can be addressed satisfactorily.

3.6.43 There is nothing particularly special about SPS in terms of requirements on the SO who already has experience in operating a number of such schemes in New Zealand (at certain connection points and for the HVDC). The Commission also notes these schemes are increasingly used internationally with no particular problems being evident.

3.6.44 Clearly each of the technical and operational issues raised needs to be carefully considered in the design of specific SPS and at times these issues could result in the SPS approach being over expensive or impractical. However it is unsatisfactory to condemn an overall approach on the basis of generalised concerns.

3.6.45 The interconnected grid capacity is a key issue in the development of new renewable generation. The Commission intends to further investigate SPS to establish whether current regulatory arrangements are adequate or require revision, e.g., to require all generators to provide inter-trip or runback facilities. In many respects intertrip arrangements are consistent with current arrangements to receive protection signals and it may not be necessary to require more than this.

3.7 Grid connection—upgrading connection and deep connection assets

Introduction

3.7.1 The timely and efficient provision of connections to the grid is affected by the way Transpower deals with the parties requiring connection and deep connection assets.

3.7.2 Connection and deep connection assets are commissioned as a result of bilateral negotiation between Transpower and the party requiring the relevant asset. Under the bilateral agreements, Transpower seeks full recovery of costs associated with the construction of the relevant asset.

[28] Revised investment proposal for the Central North Island thermal upgrades – Attachment A – Use of Special Protection Schemes and Inter-trips in the Central North Island – April 2008

3.7.3 In theory while any party could own the necessary connection assets, some parties regard Transpower as having a dominant position in providing such assets given its ownership of the grid and with it the associated economies. In the past, some have seen Transpower as inflexible, expensive and effectively having a “take it or leave it” negotiating position with parties requiring connection assets.

3.7.4 Transpower has recognised that concerns exist and in recent months has initiated a complete revision of its new investment and connection application processes.

3.7.5 The Commission has asked its Transmission Advisory Group to assist in considering the new arrangements.

3.7.6 Furthermore, at times, Transpower is the only party that can carry out the necessary grid connection design studies, a situation that could create a bottleneck and associated time delays for potential generation development. The Commission has sought to address this by providing comprehensive data and analysis in the centralised dataset and SOO. In addition, the new Interconnection rules clearly specify the capability of the existing grid, and so potential investors should have choice between using their own staff or a number of local and international consultants who could perform the design studies required.

3.7.7 While some parties may have expected that the Commission would move to regulate this area (it is highly regulated in Australia), the Commission prefers to monitor how Transpower deals with this concern and the industry response to the information published by the Commission.

Submissions

3.7.8 Genesis suggested that there is no need for the Commission to focus on the construction of connection assets, and that any signal that some proponents might receive ‘free’ connection assets is likely to have a dampening effect on construction of connection assets.

3.7.9 Genesis also suggested that the Commission should not attempt to ‘pick winners’ in the generation market, and considered that the Commission should leave it to market forces to influence those investment decisions. It also suggested that if costs of connection assets were to be shared, enabling multiple regions would be better than just one or two.

3.7.10 MRP supported the Commission’s chosen approach to monitor the way Transpower deals with parties requiring connection and deep connection. Similarly, TrustPower provided an illustration of what it described as an effective

monopoly held by Transpower with respect to grid connections and grid connection studies, and supported the Commission's efforts to address this.

3.7.11 Powerco suggested that the provision of connection assets could be competitively sourced, and further that competition may be the only way to meet the growth in the transmission grid that is required.

3.7.12 Transpower commented that the draft TTER report did not make a distinction between two types of connection assets – those connected to the grid directly and those connected to the grid via a circuit breaker, and that they each have different effects on grid users. Transpower also commented that a number of generation proponents have used non Transpower resources to undertake power system studies, and clarified some points of detail in relation to the way new connection asset investments are recovered under the TPM (for details see its submission section 3.10.4).

Commission response

3.7.13 The Commission notes the comments. It is not the intention of the Commission to 'pick winners' in the generation market but to facilitate the efficient and timely provision of connection assets.

3.7.14 The Commission remains of the view that it should monitor how Transpower deals with concerns that have been expressed about the degree of control Transpower has over customer connection arrangements and to what extent the arrangements the Commission has discussed impact on this issue. These include:

(a) gaining input from the Transmission Advisory Group as appropriate;

(b) providing comprehensive data and analysis in the centralised dataset and in SOOs; and

(c) ensuring that the new interconnection rules clearly specify the capability of the existing grid (so potential investors should have a choice between using their own staff or a number of local and international consultants who could perform the design studies required).

3.8 Feasibility of the Commission approach to parties such as generators contracting with Transpower for upgrades to the existing interconnected grid

Introduction

3.8.1 Developers of new generation face uncertainty regarding the availability of transmission capacity in the interconnected grid (as well as timely and efficient provision of connections to the grid which is dealt with in section 3.7).

3.8.2 Renewable generation is usually located away from demand and sometimes away from the existing transmission grid. The capability of the interconnected grid and connection issues are significant concerns for developers of new renewable generation.

3.8.3 Under the current regulatory framework, with transmission services provided independently by an entity with no generation assets, incumbent generators do not have preferential rights to use grid assets.

3.8.4 While the benchmark agreement and interconnection rules specify obligations on Transpower to make transmission assets available to grid users, neither give existing grid users preferential rights to use grid assets.

3.8.5 Generators are dispatched on the basis of the prices they bid into the wholesale electricity market at the relevant point of injection. If a transmission constraint exists such that generation within the region exceeds both demand and transmission capacity going out of the region, in order to avoid overloading transmission lines, generators with the lowest priced bids are dispatched first and those with higher priced bids are ‘constrained off’. This results in a reduction in the market price within the constrained region and a possible increase in prices outside the region.

3.8.6 If this occurs, generators may experience a significant reduction in revenue from electricity sold within the constrained region. However, generators within a constrained region have also been observed to offer prices which do not over-utilise the available transmission, so that the constraint does not bind.

3.8.7 Typically, it has been observed that a hydro generator will offer electricity at a price that the generator anticipates will not cause the constraint to bind so as to retain water in storage for use in later periods when the constraint is not likely to bind. This may still result in an overall reduction in revenue for the generator and higher costs and prices in the rest of the market, but to a lesser degree than if they had not responded to avoid the constraint. However it also increases the possibility that spill could occur from hydro reservoirs in future periods if higher hydro inflows occur.

3.8.8 If a “must run” dispatch auction is held, generators are allowed to offer at $0/MW and separately bid to ensure they are dispatched whatever the nodal price. It is also expected that wind farms will be able to deliberately spill wind energy at times when it cannot be accommodated by the grid as they would not want to pay to inject energy into the grid in these circumstances.

3.8.9 Occasionally some areas of the grid are constrained. Introducing additional generation into these potentially constrained regions without upgrading transmission capacity would increase the risk of spilling and reduce the revenues received by existing generators within the region. However this impact also makes these locations less attractive for new generation investment.

3.8.10 Accordingly, new and existing generators have the same opportunity to use the capacity of the existing grid, and decisions on transmission investment can send strong locational signals to generation developers

3.8.11 One of the purposes of the rules is to facilitate Transpower’s ability to develop and implement long-term plans (including timely securing of land access and resource consents) for investments in the grid (rule 2.1). When it comes to upgrading the interconnected grid, approval of transmission investment by the Commission ensures that Transpower can recover the cost of providing it from designated transmission customers in accordance with the TPM.

3.8.12 Lines that are used solely to connect generators or loads to the grid (so called “connection” or “deep connection” assets) are committed when the party requiring them agrees on the transmission services required and agrees to pay Transpower the charges for those services. In contrast, transmission assets that are part of the interconnected grid are paid for by grid off-take (demand) customers (consumers) and not by generators.

3.8.13 The Commission uses the GIT to establish whether investment in additional transmission capacity in the interconnected grid meets the criteria for approval in the rules. The GIT assesses the economic benefits of relieving grid constraints compared with the costs of not doing so.

3.8.14 In some cases transmission costs are very substantial (in economic terms very ‘lumpy’) and sometimes it may not be economically rational to relieve constraints in the interconnected grid or to build new generation behind these constraints. This is especially the case with wind generation if other locations exist that have similar opportunities but which are not transmission constrained.

3.8.15 In order to assess the economic benefits of transmission investment the Commission requires the following (through the GIT) to be modelled:

(a) the operation of existing generators and likely future new generation; and

(b) demand, including projected future demand

3.8.16 The economic parameters of possible future generation can have a significant effect on the results of the economic analysis of transmission investment. For this reason, the scenarios in a SOO are the starting point for the GIT analysis (clause 6.1 of the GIT).

3.8.17 If a generator (or, possibly, a group of generators) saw a significant benefit in a transmission investment that did not satisfy the GIT, then it (they) could enter into a new investment contract with Transpower to make the investment and pay the capital costs of the investment.[29]

3.8.18 As noted earlier no parties have prior rights to the capacity in the grid or the ability to obtain special rights if they were to fund investment. However, currently loss and constraint rentals are allocated to those that pay for transmission assets. These are the financial equivalent of capacity rights as whenever a transmission constraint occurs the difference in the value of the electricity that flows through the constraint link is refunded as a constraint rental.

3.8.19 The Commission sought submissions on any barriers to or possible improvements to the current arrangements to enable parties to contract with Transpower for upgrades to the existing interconnected grid. This was to cover situations where the investment may fail the GIT or to expedite the investment.

3.8.20 The Commission suggested that if a generator paid for new interconnected grid investment then it was reasonable to expect the generator to receive the loss and constraint rental rebates associated with these assets. The Commission noted:

(a) it is not specified how capacity components of a single interconnection link would be divided (say between upgraded and pre-upgrade ratings);

(b) there is also limited certainty that rental rebates would continue in future to be paid in respect of the investment assets; and

(c) these issues could be clarified through regulation if necessary.

3.8.21 This discussion was to both prompt debate about an appropriate mechanism and to respond to Genesis and TrustPower's previous observations that generators are not able to directly fund interconnection asset upgrade costs, and as generation cannot be guaranteed capacity on the upgraded interconnection, it may not be a commercially viable option. Genesis and TrustPower suggested that allowing generators to fund upgrades, with associated access rights, may close the transmission/generation investment timing gap.

[29] Operating and maintenance costs are recovered via the TPM.

Submissions

3.8.22 Contact recommended that the GIT be reviewed if there were significant benefits for renewable generation from a proposed investment in the interconnected grid but the net benefits of the proposed transmission investment fell short under the GIT. Contact recommended that the Commission make a discretionary call and approve the investment where there are significant benefits.

3.8.23 EECA noted that, where investments in the interconnected grid provided economic benefits to consumers, it would be reasonable that these benefits should be able to be recovered by the generator. EECA recommended that the Commission consider other options for recovery of benefits gained by consumers besides redistribution of loss and constraint rentals.

3.8.24 Genesis noted the difficulty in finding a solution to the funding issue but recommended that the issue of securing rights to private investment in the interconnected grid should be a priority area for the Commission.

3.8.25 MEUG considered that the Commission's suggestions had significant merit. MEUG noted there is no need for the Commission to intervene where there is considerable benefit to generators from undertaking the investment compared to the cost.

3.8.26 As an example, MEUG referred to the incentive on Meridian to fund the $37m needed to upgrade the Otago to Waitaki transmission line. It noted that Meridian should willingly pay the $37m as only 2.5% of the capital cost of unlocking $1,500m of renewable generation investment. It considered that the Meridian paying for the upgrade was a better outcome than socialising the cost across all consumers and allowing Meridian to receive a windfall gain.

3.8.27 Meridian did not directly comment on the Commission's suggestion but commented on related issues:

(a) the relieving of constraints is important for enhancing competition and this should be factored into the Commission's transmission investment decision making;

(b) transmission upgrades should be considered in the context of the fraction of their cost relative to generation. The approval process must be practical, pragmatic and commensurate to cost; and

(c) incremental upgrades should be given priority and the process is inaccurate for dealing with such upgrades.

3.8.28 MRP recommended that locational pricing be investigated and implemented to deal with this issue. MRP argued that efficient locational prices would result in charges to connecting parties willing to pay for those assets equivalent to the benefit they receive.

3.8.29 NWEA suggested the Commission investigate the feasibility of an investment approval and cost recovery process being developed in California that could apply to interconnection as well as connection. This requires parties to pay a portion of the costs (deposit) of the required augmentation up-front to fund the investment but with the bulk of the money coming from consumers. However the transmission investment cannot proceed unless a certain level of commitment is reached. This enables the market operator to prioritise investments on the basis of level and amount of interest from generation developers who have to declare their interest by paying a deposit.

3.8.30 Powerco did not specifically comment on this issue but did recommend that the Commission or a similar entity should run an auction on capacity for any proposed upgrade to ascertain demand and price, i.e. make the provision of transmission assets contestable. Powerco suggested that would indicate if there was sufficient demand to justify the expansion and if any shortfall was required to be covered by a subsidy.

3.8.31 Transpower noted that it is not correct to say that constraint costs on the interconnected grid are refunded as a constraint rental to those who pay for them. It noted that this is correct only for radial connection assets.

3.8.32 TrustPower recommended that property rights are allocated to generators who pay for interconnection asset investments. It also agreed that if generators pay for new interconnected grid investment then those generators should receive the loss and constraint rentals.

3.8.33 Vector noted that there are minimal locational signals for generation in the current regime where generators do not pay for interconnection services. Vector considered that the current impasse over spending $37m to remove the constraint on the Otago to Wataki line (and unlock $1,500m of generation capacity) was a clear signal for a review of appropriate counterparties to transmission agreements. It noted "if generators were counterparties for interconnection (and therefore paid for use of system) their decisions would reflect all costs and provide strengthened incentives to influence transmission upgrades".[30]

Commission Response

3.8.34 The Commission notes that the rules do not prohibit generators paying for upgrades to the interconnected grid if they desire to do so. However, as noted earlier, no parties have prior access rights to the capacity in the grid or the ability to obtain special access rights if they were to fund investment. This reduces the

[30] Paragraph 8 of Vector's submission on the draft TTER report.

incentive to invest where the investing party may subsequently have its transfer capacity constrained as other generators connect.

3.8.35 The Commission does not agree with Contact that it should approve interconnection investments that fail the GIT. The GIT process will result in investments in the interconnected grid that show a positive net benefit. It is not a failing of the GIT that it does not account for all of the benefits (e.g. wealth transfers) accruing to the parties requiring the upgrade.

3.8.36 The rationale for the Commission's suggestion was that while there may be significant benefits for those parties to pay for the upgrade, uncertainty about the retention of those benefits may discourage those parties from investing. To encourage a joint contracting approach, the Commission recommended that a mechanism be devised that allocates efficiently and fairly the benefits (e.g. a commensurate share of the loss and constraint rental rebates).

3.8.37 EECA suggested that generators who invest in interconnection assets are compensated by consumers. However, if the investment had not passed the GIT then there is no net benefit to consumers. With respect to EECA's recommendation that the Commission seek alternative incentives to the allocation of loss and constraint rentals, the Commission is open to any practicable and efficient means to encourage participants to invest in interconnection assets where those participants see benefits not captured by the GIT.

3.8.38 MEUG's example ignores the commercial drivers acting on Meridian and other developers. It assumes Meridian is the beneficiary of the $1,500m of wind resource and the development occurs relatively quickly after its initial $37m investment. MEUG does not address the free riding issue, that is, Meridian paying for the investment and potentially having its transfer capacity limited at some point in the future by new generation. There may be incentives for a joint contracting approach but as the Commission has noted in the past, joint contracting is problematic in the case of interconnection assets. However, as noted below, the allocation of loss and constraint rentals may be a solution as it would provide an incentive for parties to, voluntarily, contract for the upgrade as it protects against free riders and "hold out" behaviour.

3.8.39 The Commission considers Meridian's suggestions are addressed adequately by the GIT process (e.g. competition benefits are included if appropriate). The Commission also notes that implementing the GUIRP should further address Meridian's concerns about expeditious development of investment proposals by Transpower and their review by the Commission. The Commission considers that it has not been presented with any compelling reasons why the current process is inaccurate for dealing with incremental upgrades. The Commission also notes that incremental upgrades are generally given priority as evidenced by

the number of these investments approved by the Commission over the last three years.

3.8.40 The Commission agrees with Vector and MRP that efficient locational prices would address the issue of when and where transmission investment occurs and who pays. However, the Commission has noted, on prior occasions, the implementation of an efficient locational pricing regime is a complex and difficult undertaking. Successfully replacing the current TPM will require significant analysis and consultation over a lengthy period. The Commission has such a study on its medium term work plan but is mindful that a period of stability in transmission pricing would also be desirable.

3.8.41 NWEA's suggestion does not fully address the issue as it appears more focussed on providing the grid planner with more accurate information about priority areas to invest. It may, however, be a mechanism to provide a top-up for any shortfall in the GIT evaluation. The Commission would oppose such a mechanism especially where a too low level of "subscription" may provide inappropriate signals for investment. Also, the GIT provides an evaluation of consumer benefit, hence if the investment fails the GIT then it is inefficient and unfair for consumers to provide the balance to fund the investment.

3.8.42 TrustPower and Powerco have suggested that capacity rights to transmission be introduced. Although Powerco appeared to be suggesting capacity rights only for new transmission assets (i.e. an auction would be held for capacity rights to any upgraded asset). Powerco was also suggesting that any shortfall could be subsidised. The Commission considers its suggestion of allocating the loss and constraint revenue to investors has an equivalent benefit to allocating physical capacity rights. As noted above, the Commission is concerned about consumers providing top-up funding.

3.8.43 Transpower queried the statement that "loss and constraint rentals are allocated to those that pay for transmission assets. These are the financial equivalent of capacity rights as whenever a transmission constraint occurs the difference in the value of the electricity that flows through the constraint link is refunded as a constraint rental."

3.8.44 The Commission acknowledges that it was possible to infer it was stating that there was a direct relationship between the surpluses generated from constrained parts of the grid and the payees and refund of loss and constraint rentals to those payees. Any such inference was misleading. Loss and constraint rentals are allocated amongst Transpower's customers "firstly, by calculating the proportion of the 'Rentals Received' attributable to the connection and HVDC assets. These proportions are allocated to the customers paying those charges. The remainder

is the proportion attributable to the interconnection assets, and, as such, is allocated to the offtake customers paying interconnection charges."[31]

3.8.45 Moving beyond the current allocation method, the Commission understands that it could be feasible to allocate loss and constraint rentals attributable to particular interconnection assets.

3.8.46 The Commission was seeking submissions on the efficiency, fairness and practicality of separating out part of the interconnected grid where a party has paid for an upgrade and allocating the loss and constraint rentals attributable to that part. The Commission considers that this can be practically implemented. In this way, those who paid for the upgrade would be provided compensation as demand grows to the extent that that part of the grid becomes constrained, but only in proportion to the amount of new capacity provided. Existing connected parties and new connections would not be disadvantaged but would be prevented from free riding as they would not have access to the loss and constraint rentals being paid to the investors in the upgrade.

3.8.47 The Commission was encouraged that submitters did not find any substantial fault with the concept but is cognisant that analysis on the allocation of loss and constraint rentals is ongoing and there may be compatibility issues with the adopted solution. The Commission is aware that none of the debate so far precludes such an arrangement and is interested in developing this concept further.

3.9 Consideration of confidential information on renewable energy

Introduction

3.9.1 The Commission noted in its consultation document that:

(a) it is inappropriate to rely on generator or proponent information unless such information is able to be verified or tested independently by the Commission or other interested parties;

(b) its ability to determine whether the GIT has been applied reasonably may be compromised if the GIT analysis relies on confidential information that is unable to be so tested or verified; and

(c) it will use confidential information, if the provider is willing:

(i) to make it publicly available; or

[31] Page 7, *Transmission Rentals – March 2008* – Transpower New Zealand Ltd -

(ii) allow it to be independently verified and tested.

3.9.2 The Commission sought submissions on its approach to the use of confidential information on renewable energy.

Submissions

3.9.3 Contact recommended that the Commission accepts the validity of the generator supplied information if it falls within an acceptable range. If information provided by generators is not within the upper and lower bounds, then discussion and consultation can occur on these bands. Contact was supportive of the process that has been used to date for the TTER project as it said generators have the most accurate and up-to-date information.

3.9.4 Meridian stated that the parties with the best information on generation development costs and technical issues are the developers themselves. Meridian stated that developers may have considerable intellectual property on specific wind, water or geothermal resources, development processes and technologies that are not generally available to the consultants that are engaged by the Commission. The intellectual property is a source of competitive advantage to the particular developer. Meridian stated that it is happy to share information with the Commission or Transpower's consultants under an appropriate confidentiality agreement.

3.9.5 Transpower stated that it believes the Commission's concerns, regarding generators understating costs because of commercial drivers, can be substantially mitigated by other means including:

(a) obtaining agreement on assumptions by multiple generators. This would substantially mitigate the risk of a distorted outcome, and allow the generators' significant experience to be injected effectively into the process; and

(b) testing information provided by generators through consultation. This would allow other interested parties to comment on any distortions they perceive in the information.

3.9.6 Transpower noted:

(a) that it is in the best long-term interests of generators to be open with information; and

(b) it is not clear who could provide useful independent verification or testing that added value to generators' estimates of their development costs.

3.9.7 TrustPower supported the Commission's preference for any information provided to be available to be tested publicly. However, it noted that this may mean that prospective generators may release information that could disadvantage a

commercial position. TrustPower suggested that confidential Information should be verified without releasing the details into the public arena and can be summarised or combined such that sensitive information is not identified separately.

Commission Response

3.9.8 All submitters noted that developers have the most up to date information and have an interest in ensuring its accuracy. However, as the submissions highlighted, generators have questioned the accuracy of competitors' description of costs. Accordingly, the Commission is placed in a difficult position of deciding the validity of the claims and counter claims.

3.9.9 The majority of submissions focussed on verifying the generator supplied information rather than the specific issue of the Commission's approach to the treatment of confidential information in preparing generation scenarios and its consideration of transmission investments. The Commission considers Contact's suggestion to be impractical. If the Commission was to rely on generator supplied information if it fell within certain accuracy bounds, it would need to test what the reasonable bounds are in the first instance. This process would inevitably require disclosure. If the information fell outside the accuracy bounds further scrutiny would be required. In addition, the GIT test would be distorted if the boundaries were too wide.

3.9.10 The Commission considers that Meridian's suggestion that the Commission and/or Transpower sign a confidentiality agreement may have merit depending on the terms of the confidentiality agreement. Such a confidentiality agreement should not restrict the Commission from seeking independent advice on the information provided. However, the Commission agrees with Transpower that it may be difficult to find independent advice competent to comment on the estimates of their development costs provided by generators.

3.9.11 Transpower noted that the Commission could use the information supplied by multiple generators. However, as noted above, there is often no consensus on the costs of generation as it relates to competitors' developments.

3.9.12 Transpower also suggested that the information provided by generators could be tested through consultation, allowing other interested parties to comment on any distortions. However, if the information is confidential, consultation cannot occur.

3.9.13 The Commission considers TrustPower's suggestion that information be verified without releasing the details into the public arena may be workable depending on the limits placed on the Commission's use. For this to be practicable, the information would need to be available to the Commission and its advisors. TrustPower also suggested that the information be presented in such a way that

sensitive information is not identified separately. However, this may be difficult given the size of the market and specificity of transmission investments.

3.9.14 The Commission will continue to work with stakeholders to improve the accuracy of the information available to it. The Commission agrees with Transpower's view that it is in the best long-term interests of generators to be open with this information. For the generation scenarios to be credible and the investment approval process to be robust, the Commission has to be cautious in its approach to confidential information that is unable to be tested or verified. The Commission has also stated in its Consultation Protocol that when it carries out consultation, it will design its processes to comply with the standards for consultation established by case law.

3.9.15 This means that the Commission will seek to arrange each consultation undertaken to comply with the principles specified by the Court of Appeal in *Wellington International Airport Ltd* v *Air New Zealand* [1993] 1 NZLR 671. One of those principles is that for consultation to be meaningful, the decision-maker must make available sufficient information to enable parties who are consulted to be adequately informed to make "intelligent and useful" responses. The Commission considers that it is inappropriate to rely on confidential information which has a material impact on its decisions to approve or decline an investment if the information cannot be independently tested or verified by the Commission or other interested parties.

3.10 Other Issues

Introduction

3.10.1 Submitters also commented on the following issues:

(a) transmission pricing methodology:

  (i) HVDC charges;

  (ii) connection charges.

(b) annual rental payment for land used by Transpower;

(c) potential for distributed wind generation/small scale versus large scale renewables;

(d) purpose of the TTER project; and

(e) competition in the wholesale market.

TPM—HVDC Charges from 1 April 2008

3.10.2 The Commission received four submissions on the impact to the development of renewable generation from the HVDC charges applying from 1 April 2008.

3.10.3 Meridian has not presented any new information not previously considered by the Commission and the Commission's responses set out in earlier consultations remain. However, Contact and TrustPower presented information that countered the Commission's claim that the HVDC charge does not favour incumbent South Island generators versus new entrants as the charge attributable to a new generation plan is the same regardless of whether the plant's developer is a new entrant or an existing South Island generator. Contact and TrustPower demonstrated that, while the rate may well be the same, the incremental charge decreases in proportion to how much of the existing South Island generation plant an incumbent owns.

3.10.4 While the Commission agrees that the incremental charge is higher for a small new entrant versus Meridian, it is probably not significant enough to create a barrier to entry and is probably no more significant than the other economies of scale (e.g. corporate overheads, design expertise, access to capital) and scope (e.g. large retail base) that Meridian has over smaller new entrants in any event.

3.10.5 Transpower noted that the draft TTER report stated the HVDC charge promotes efficient uptake of renewable generation by signalling the locational cost of connection in the South Island. Transpower considered that this is true only to the extent that the charge influences investment in new HVDC capacity and, even then, it cannot be claimed that the charge in any way accurately reflects the LRMC of investment in HVDC capacity.

3.10.6 The Commission has repeatedly noted in its decision documents on the pricing guidelines and TPM that there are efficiency gains from improving location decisions of generators, and that efficiency is enhanced if South Island generators face the costs of the HVDC link.

3.10.7 The Commission has acknowledged that the locational signal provided by such a charge is not exact, but charging South Island generation plant is desirable as it sends a stronger locational signal for new plant. It can be reasonably argued that it is more efficient to locate generation close to load and that locating in the South Island may contribute to the need for an expanded link. In addition, the Commission has noted that the charges faced by South Island generators should be viewed in the context of the TPM as a whole, which recovers Transpower's revenue requirement for the entire grid, and over time. The costs of locating in the South Island should not be simply compared with the LRMC of investment in the HVDC capacity but also with the LRMC of the required consequential investment in the HVAC network. Accordingly, the Commission's remains of the same view in respect of this issue.

TPM—new connection assets

3.10.8 Transpower considered that the Commission's explanation about the sharing of connection costs to be misleading at paragraph 6.2.9 and its potential impact on generation investment in remote regions. The Commission accepts this and makes the following clarification.

3.10.9 The discussion in the draft TTER report was about how GEM handled the decision-making around transmission investments, their timing and the cost of exploiting remote generation. The issue goes beyond the modelling problem it creates.

3.10.10 The Commission's objective is to promote efficient transmission investment that matches the economic (but not technical) potential of a given region with respect to generation, and specifically renewable generation. The Commission was seeking submissions on whether there are any significant barriers that can be removed and/or improvements made to the current transmission contracting and pricing arrangements in order that efficient investment in transmission can occur.

3.10.11 The Commission, after considering submissions, remains of the view that there is a potential issue that needs to be addressed. This can be illustrated by the following examples:

Example 1

3.10.12 The preferred size for a connection to a remote new generator is larger than the capacity requirements of the generator. The generator does not proceed because the additional connection costs make the project uneconomic. However, the remote generator is located in a region where there are significant energy resources and there is a strong likelihood that further generation development will occur.

Example 2

3.10.13 The preferred size of a connection to a remote generator matches the capacity requirements of the generator but will provide minimal additional transmission capacity. However, the remote generator is located in a region where there are significant energy resources and there is a strong likelihood that further generation development will occur.

3.10.14 The current pricing and contracting regime for connection assets may not lead to the most desirable outcome. In both examples, the regulatory contracting and pricing regime should result in the new generator only being required to pay for the capacity it requires but the preferred sized connection asset is built given the economic potential of a given region with respect to generation.

Annual Payment to Landowners

3.10.15 Federated Farmers recommended that Transpower pay landowners an annual fee for the use of their land. Federated Farmers considered that transmission infrastructure has an injurious effect on the land it occupies as well as the surrounding land through the imposition of reverse sensitivities. Federated Farmers also disagreed with the elevation of transmission's importance above any other land use and suggested that annual payments would be an effective method for correcting historical planning deficiencies. Such payments would also avoid the need for an upfront capital payment.

3.10.16 The Commission notes that whether Transpower compensates landowners (and by how much) is outside its jurisdiction. However, the Commission notes that Transpower is required to compensate landowners for new lines, either by having to buy the land or easements. For lines constructed prior to 1 January 1988, the issue of compensation has been considered on a number of occasions and the conclusion has been that no compensation be paid. The current Electricity Act entitles Transpower to occupy the land, operate, maintain and upgrade those lines provided that any upgrade does not injuriously affect the land.

Potential for distributed wind generation/small scale versus large scale renewables

3.10.17 Molly Melhuish suggested that there is large potential for distributed wind generation due to its favourable economics and that enabling remote large renewables was anti-competitive. The relatively low cost of widely dispersed potential wind generation capability suggests that it would be possible to embed smaller wind projects in local 33 kV networks and avoid the high transmission costs associated with large wind generation projects. Molly Melhuish questioned whether the enabling aims of the TTER project were anti-competitive as it may result in subsidising the cost of connection for large wind generation projects.

3.10.18 Vector supported the Commission's focus on supply-side investments. However, Vector recommended that the Commission provide further clarity around the respective roles of larger scale supply-side renewable investments and smaller scale demand-side solutions in terms of meeting the Government's 90% renewables target.

3.10.19 The Commission considers that the current connection arrangement for distributed generation is probably more favourable than the connection regime for

generators connecting to the grid. The new regulations[32] require local lines companies to:

(a) expeditiously consider and action connection requests; and

(b) compensate distributed generators for the benefits they provide to the line company.

3.10.20 The Commission was interested in obtaining information on whether there were significant barriers to renewable generators connecting to the grid and submitters' views on potential benefits to consumers from optimally-sized connection assets being constructed into a resource rich region. The Commission was not suggesting that the connection costs should be subsidised as a starting point.

3.10.21 The Commission agrees with Vector that demand-side initiatives should be pursued as well. The Commission notes that other workstreams are dealing with this issue and it would be duplication if the TTER project's brief was extended.

Purpose of the TTER project

3.10.22 Transpower strongly disagreed with the stated purpose of the TTER project noted in the consultation document. Transpower considered that presenting the augmentations required for the identified renewable generation may be interpreted as predetermination by the Commission that such upgrades of the transmission system should be approved.

3.10.23 The Commission notes that the intention of the TTER project was to generate debate around the various transmission regulatory options identified to ensure that renewable energy resource areas are utilised efficiently. The purpose of the TTER project is not to provide pre-approval advice. The work undertaken by the Commission is necessary to provide sufficient detail to enable a meaningful evaluation by interested parties of the merits of a range of different transmission options.

Competition in the wholesale market

3.10.24 Contact queried whether the generation economics in the co-optimised GEM accurately reflected competition in the wholesale market. Contact did not elaborate on this point in its submission, so it is not clear to the Commission exactly what aspect of the competition wholesale market is not being accurately modelled.

3.10.25 The Commission notes the following:

[32] Electricity Governance (Connection of Distributed Generation) Regulations 2007.

(a) GEM, whether co-optimised or not, assumes perfect competition in all markets, including the wholesale electricity market;

(b) perfect competition is an appropriate assumption to make in a long term planning model;

(c) if Contact is suggesting that the wholesale market is not competitive and therefore, by assuming that the wholesale market is competitive, this is introducing imprecision into the Commission's analysis, the Commission could easily introduce some element of imperfectly competitive behaviour into the analysis by using generator offers (e.g. derived from some other model) in place of short run marginal cost (**SRMC**) as the basis for GEM determining what plant to dispatch (and, indirectly, build);

(d) introducing alternative bidding behaviour requires the following assumptions:

  (i) that the Commission understands the gaming behaviour of the generators and therefore their offer strategies; and

  (ii) anti-competitive behaviour is likely to persist;

(e) if this were true, it is reasonable to assume that the regulatory authorities would eventually identify this and do something about it; and

(f) in any event, in a market without barriers to entry, the expectation that prices will be above SRMC is what drives investment and it is such investment that puts downward pressure on prices. Hence, SRMC is the most appropriate assumption for long range capacity expansion analyses.

4. Summary of Findings

4.1.1 This section provides a high-level overview of the information gathered through the wind, hydro and geothermal investigations. The final reports are available in Appendix 2 to Appendix 4of this report.

4.2 Geothermal

4.2.1 The location and fuel resource sizes of New Zealand's geothermal fields are relatively well-defined.

4.2.2 To provide short and long-term forecasts of New Zealand's geothermal generation, the Commission has applied information obtained from:

(a) a database of existing capacities and possible future geothermal schemes; and

(b) an extensive range of public reports available from consultants and government agencies.

4.2.3 The Commission estimates that the total technical capacity is large at approximately 3600 MW (including the current capacity). However, environmental limitations, regulatory constraints and the need for sustainability reduces this gross figure to approximately 1100 MW of additional capacity.

4.2.4 The Commission estimates the current maximum operating capacity at around 450 MW. As it appears that around 750 MW of additional capacity has been committed, or is likely to be built over the next 10 years, this brings the total New Zealand geothermal generation to close to 1200 MW in the near future. The long-term forecast anticipates cumulative capacity reaching approximately 1500 MW by 2025. These resources are in the Taupo volcanic zone close to the existing HVAC network.

4.2.5 The report can be found in Appendix 2of this report.

4.3 Hydro

4.3.1 PBA has completed a review of known hydro opportunities in New Zealand and produced a report that estimates the cost for eight potentially economical and viable New Zealand hydro schemes. The review includes:

(a) the gathering and review of information available in the public domain on potential hydro opportunities throughout the country;

(b) a series of discussions with senior personnel in Contact, Meridian Energy, MRP, TrustPower and Pioneer Generation to identify hydro opportunities included in their development portfolios;

(c) a critical review of all identified hydro opportunities and the development of a short list of schemes for more detailed study. The short list was assembled using a number of selection criteria, including the size of the opportunity, the likelihood of cost-effective development and the likelihood of securing the necessary consents for the development of the scheme; and

(d) the completion of conceptual designs and cost estimates for each of the short-listed schemes. In some cases (e.g. the proposed Wairau and Arnold schemes being promoted by TrustPower) conceptual designs were available in the public domain. In other cases (e.g. the possible Mokihinui and North Bank Tunnel Concept schemes being investigated by Meridian) it was necessary to develop conceptual designs to provide baselines for the estimation of development costs.

4.3.2 The development parameters and estimated cost prepared by PBA are presented in the table below.[33]

Scheme	Installed capacity (MW)	Annual Generation (GWh)	Base Cost ($million)	Base Cost Yield (cents/kWh)
Wairau	73	415	330	9.89
Arnold	46	220	223	12.6
North Bank Tunnel Concept	280	1,261	974	9.55
Mokihinui	85	358	304	9.82
Luggate	99	435	391	11
Queensberry	180	860	639	9.1
Beaumont	190	870	604	8.68
Tuapeka	340	1,590	1,022	7.87

[33] A more detailed version of this table can be found in the PBA report in Appendix 3 of this report.

4.3.3 It should be noted that each of the short-listed schemes have site-specific features that could have an effect on the final development costs.

4.3.4 A detailed description of the schemes can be found in the PBA report in Appendix 3 of this report.

4.4 Wind

4.4.1 Connell Wagner prepared a report which provides information on the geographical spread of potential wind resources.

4.4.2 The analysis has been performed largely by quantitative and objective methods, using meteorological models and GIS tools. Through modelling the weather patterns and the interaction of the atmosphere with the terrain, the models predict wind speeds at any given location and height above ground.

4.4.3 The report presents:

(a) the estimated useable land area aggregated to regional summaries;[34]

(b) the potential installed wind capacity by region; and

(c) the estimated cost of generation for current and future scenarios.

4.4.4 The wind resource has been split into 2 categories equating to an average of:

(a) 7.5-8m/s, which would require Class 1 or 2 turbines; and

(b) 8.0m/s, which would require Class 3 or 4 turbines.

4.4.5 The overall quantity of economic wind farm potential has also been split into 3 tranches covering potential sites that may:

(a) be economic in the near future; and

(b) become viable with a significant rise in the wholesale price of electricity.

4.4.6 Connell Wagner allocated a portion of the wind speed category 1 to Tranche 1 and the remaining portion to Tranche 2. Tranche 1 consists of sites in the wind speed category that have a more favourable wind regime or more favourable construction costs. Likewise, Tranche 3 consists of a portion of sites in wind speed category 2 that have a less favourable wind regime or construction costs, with the remaining portion allocated to Tranche 2.

[34] A series of criteria, detailed in the document, have been applied to remove impractical areas.

4.4.7 The total quantity of potential wind generation (all tranches) identified in this study is fairly large with about:

(a) 9,000 MW of capacity in the North Island and about 6,000 MW of capacity in the South Island for Tranche 1;

(b) 9,000 MW of capacity in the North Island and about 5,000 MW of capacity in the South Island for Tranche 2; and

(c) 8,5000 MW of capacity in the North Island and about 4,500 MW of capacity in the South Island for Tranche 3.

Figure 1: Estimated wind capacity for New Zealand: total 41,000 MW

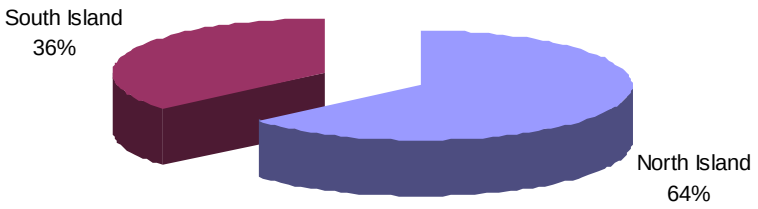


Figure 2: Estimated wind capacity for the North Island: total 26,000 MW

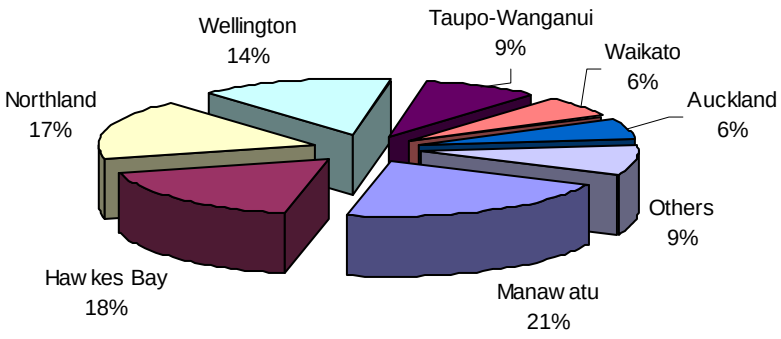


Figure 3: Estimated wind capacity for the South Island: total 15,000 MW

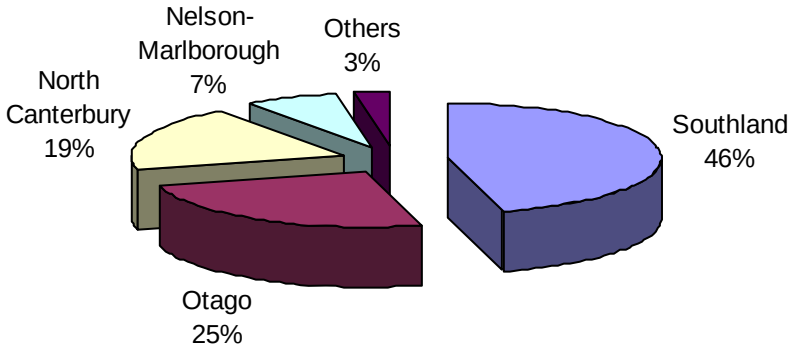
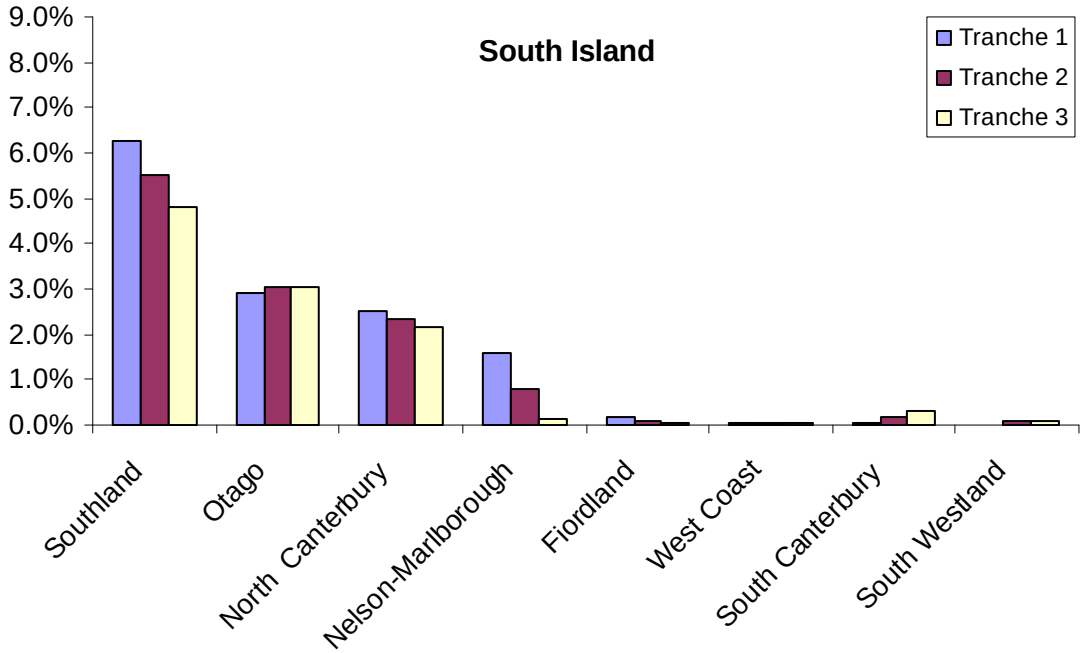
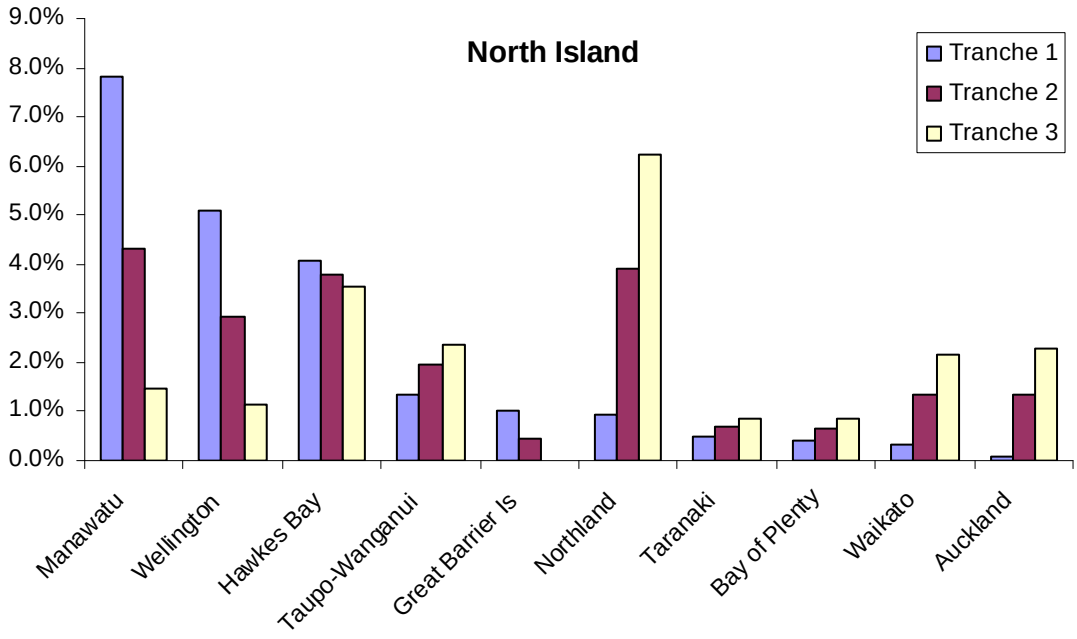


Figure 4: Estimated wind capacity per tranches and regions for the North and South Island





4.4.8 The detailed regional results for the three tranches of wind are presented the Connell Wagner report in Appendix 4of this report.

Table 5: Regional results – Tranche 1

Region (Tranche 1)	Capacity (MW)	Annual Energy (GWh)	Region proportion (capacity)
North Island total	8,910	31,230	61.5%
South Island total	5,580	19,550	38.5%
NZ total	**14,490**	**50,780**	**100.0%**

Table 6: Regional results – Tranche 2

Region (Tranche 2)	Capacity (MW)	Annual Energy (GWh)	Region proportion (capacity)
North Island total	8,850	27,140	63.9%
South Island total	4,990	15,280	36.1%
NZ total	**13,840**	**42,420**	**100.0%**

Table 7: Regional results – Tranche 3

Region (Tranche 3)	Capacity (MW)	Annual Energy (GWh)	Region proportion (capacity)
North Island	8,620	22,670	66.4%
South Island	4,370	11,500	33.6%
NZ total	**12,990**	**34,170**	**100.0%**

5. Transmission system analysis

5.1 Network requirement to accommodate renewables

5.1.1 SSG estimated the transmission investment options required to connect identified potential new renewable generation to the grid.[35] The transmission options were incorporated into the Commission's GEM model to help determine a conceptual co-optimised future generation-transmission build sequence.

5.1.2 The costs of all transmission investment options are indicative estimates only, based on line length and capacity and should not be used for actual transmission planning.[36]

5.1.3 There are two distinct transmission investment options identified:

(a) *Grid connection cost*—this is the cost required to build a new transmission line (if required) to connect new renewable generation to the existing transmission grid;[37] and

(b) *Inter-regional transmission upgrade, cost and capacity*—these costs and capacities identify the current grid and possible future upgrade options and costs.[38]

Grid Connection Cost

5.1.4 SSG has determined the cost of grid connection by sizing transmission lines from potential new generation locations to the existing grid, usually (but not always) by the shortest direct route. The cost of a high voltage switching station, if thought necessary, is also included but generator substation costs are assumed to be part of the generator's capital cost. Easement costs have been determined from Transpower's North Island Grid Upgrade Proposal approved by the Commission and all costs can therefore be considered approximate, using building-block cost estimates.

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35 The SSG report can be found in Appendix 5 of this report.

36 SSG has endeavoured to use the best available information within the time/cost parameters of the project. Information from previous Transpower reports (such as the 400kV and ODV documentation) has been used to help estimate line costs.

37 This cost essentially adds to the capital cost of the project, enabling GEM to distinguish between a highly economic renewable energy resource, geographically distant from the grid, to perhaps a less economic resource situated close to the grid, for example.

38 These transmission upgrade options essentially help GEM distinguish differences in regional generation, based on the cost of having to upgrade (or not) the main transmission grid between regions. This enables GEM choose between generation located close to major demand areas, to generation situated geographically distant from major demand centres.

5.1.5 In some circumstances additional nodes are required for the inter-regional model. This helps accommodate regions with multiple renewable generation potential sites and occurs in a number of regions throughout the country including, for example, the Upper Clutha where two possible future large hydro projects, Luggate and Queensbury could be built. It also occurs for many of the larger wind producing areas in both the North and South Islands. These additional nodes are identified in Figure 5.

5.1.6 Estimating indicative connection costs for possible future wind farm developments based on the information available has proven to be challenging. Connell Wagner provided regional potentials for the wind resource available which were very large. Where a wind farm is in the consenting stage, with a known location and size, this data has been used. In all other cases, SSG has had to estimate likely locations and sizes of possible future wind farms based on the information provided by Connell Wagner. The end result has been the development of a set of hypothetical wind farms with possible sizes (up to a certain size) and connection costs. Names of the closest town or geographic feature have been used to identify the approximate location of these sites.

5.1.7 The capacity assumed by SSG for existing and potential renewable generation is shown in Table 8 to Table 13.[39] The total capacity modelled is only that derived from Tranche 1 of the Connell Wagner report as there was not sufficient electricity demand in New Zealand to absorb Tranches 2 or 3 within the time horizon modelled, except the most apparently economic Tranche 2 resources in the upper North Island.

Table 8: Assumed geothermal capacity

Region	Location / Name of project (Owned by)	Capacity (MW)
Northland	Ngawha Top Energy	15
Bay of Plenty	Kawerau 2008: Stage 1 MRP	90
	Kawerau 2016: Stage 2 MRP	67
Taupo	Mokai Contact Energy	40

[39] The detailed tables are available in Appendix 5 of this Board paper.

Region	Location / Name of project (Owned by)	Capacity (MW)
	Pohipi Contact Energy	20
	Rotokawa 2009: Stage 1 MRP	130
	Rotokawa 2016: Stage 2 MRP	67
	Te Mihi Contact	60
	Tauhara 2010: Stage 1 Contact	20
	Tauhara 2012: Stage 2 Contact	180
	Ngatamariki MRP	67

Table 9: Assumed hydro capacity

Region	Location / Name of project (Owned by)	Capacity (MW)
Nelson / Marlborough	Wairau Trustpower	73
	Arnold Trustpower	46
Waitaki	North Bank Tunnel Meridian Energy	200 to 280
West Coast	Mokihinui River Meridian Energy	65 to 85
Clutha	Luggate Contact Energy	99

Region	Location / Name of project (Owned by)	Capacity (MW)
	Queensberry Hill Option 1 Contact Energy	180
	Tuapeka	340
	Beaumont	190

Table 10: Assumed wind capacity

Region[40]	Location / Name of project (Owned by)		Capacity (MW)
Northland	Northland 1 (NL1)	Kaitaia	200
	Northland 2 (NL2)	Cape Reinga	200
			900
	Northland 3 (NL3)	Dargaville - Kaipara Head	550
Auckland	Great Barrier Island 1 (GB1)	Great Barrier Island	420
	Coromandel 1 (COR1)	Coromandel	140
	Auckland 1 (AK1)	Wood Hill Forest	300
Waikato	Waikato 1 (WK1)	Central Eastland Area	560
Bay of Plenty	Bay of Plenty 1 (BoP1)	Central Eastland Area	400
	Bay of Plenty 2 (BoP2)	Puketawa	160
	Bay of Plenty 3 (BoP3)	Ruatoria / East Cape	200
Taranaki	Taranaki 1 (TK1)	Patea / Waverley	200
Taupo - Wanganui	Taupo - Wanganui 1a (TP1a)	Waiouru	200

[40] Regional definitions are based on the transmission network configuration not strictly on land region boundaries.

Region[40]	Location / Name of project (Owned by)		Capacity (MW)
	Taupo - Wanganui 1b (TP1b)	Ngamatea Station / Mangaohane Plateau	360
Hawkes Bay	Hawkes Bay 1a (HB1a)	HBWF / Te Waka / Titiokura	400
	Hawkes Bay 1b (HB1b)	Puketitiri	200
	Hawkes Bay 2 (HB2)	Mahia Peninsula	50
	Hawkes Bay 3 (HB3)	Makorori Beach	50
Manawatu	Manawatu 1a (M1a)	Eketahuna	800
	Manawatu 1b (M1b)	Pongaroa - Masterton - Castle Point region	1400
	Manawatu 1c (M1c)	Dannevirke - Porangahau - Pongaroa region	1000
Wellington	Wellington 1a (WLG1a)	Project West Wind - Mill Creek	210
	Wellington 1b (WLG1b)	Paekakariki	190
	Wellington 1c (WLG1c)	Belmont	200
	Wellington 1d (WLG1d)	Lake Wairarapa - Battery Hill - Wharekauhau	300
	Wellington 2a (WLG2a)	Windy Peak - Oterei	600
	Wellington 2b (WLG2b)	Riversdale Beach - Flat Point	600
Nelson - Marlborough	Nelson - Marlborough 1 (NM1)	Seddon / Lake Glassmere	500
North Canterbury	North Canterbury 1a (NC1a)	Highbank	300

Region[40]	Location / Name of project (Owned by)		Capacity (MW)
	North Canterbury 1b (NC1b)	Coleridge	300
	North Canterbury 2 (NC2)	Hawarden	200
	North Canterbury 3 (NC3)	Mt Cass / Hurunui Mouth (Black Hill)	200
Otago	Otago 1 (OT1)	Garvie Mountains / Old Man Range	200
	Otago 2a (OT2a)	Hayes	600
	Otago 2b (OT2b)	Rock and Pillar Range	100
	Otago 3a (OT3a)	Lammerlaw Range	100
	Otago 3b (OT3b)	Mahinerangi	200
	Otago 3c (OT3c)	Waitahuna Hill	100
	Otago 3d (OT3d)	Maungatua	100
	Otago 3e (OT3e)	Milton	100
	Otago 4 (OT4)	Dunedin	100
Southland	Southland 1a (SL1a)	Black Mount / Mount Nichols	150
	Southland 1b (SL1b)	Danby Hill / Burwood Forest	350
	Southland 2a (SL2a)	Orepuki / Riverton	300
	Southland 2b (SL2b)	Oreti Beach	100
	Southland 2c (SL2c)	Invercargill / Awarua	600
	Southland 2d (SL2d)	Fortrose / Otara / Tokanui	300
	Southland 3a (SL3a)	Kaiwera Downs / Slope Down Hill / Centre Hill	400

Region[40]	Location / Name of project (Owned by)		Capacity (MW)
	Southland 3b (SL3b)	Catlins Cone / Mt Rosebury / Brown Dome	150
	Southland 3c (SL3c)	Purakaunui	150

Table 11: Assumed hydro run of river capacity

Region	Location / Name of project (Owned by)		Capacity (MW)
West Coast	Arahura	Other	18
West Coast	Butler River	Other	23
North Canterbury	Clarence to Waiau Diversions	Other	70
Central Otago	Hawea Control Gate Retrofit	Contact Energy	17
Bay of Plenty	Kaituna Low Level	Other	38
West Coast	Kakapotahi	Other	17
North Canterbury	Lower Clarence River	Other	35
Manawatu	Mangawhero to Wanganui Div	Other	60
Bay of Plenty	Mohaka	Meridian Energy	44
Southland	Nevis River	Other	45
Bay of Plenty	Otoi Waiau	Other	17
Manawatu	Pohangina	Other	10
Southland	Pukaki Control Gate Retrofit	Meridian Energy	44
West Coast	Taipo	Other	33
Bay of Plenty	Tarawera at Lake Outlet	Other	14

Region	Location / Name of project (Owned by)		Capacity (MW)
Bay of Plenty	Tarawera at Te Matae Road	Other	10
Southland	Te Anau Control Gate Retrofit	Meridian Energy	40
West Coast	Toaroha	Other	25
Central North Island	Waihaha R West Taupo	Other	10
Central North Island	Wairehu Canal	Other	11
Auckland	Wairua Falls, Wairua River	Other	11
Hawkes Bay	Waitangi Falls Ruakiteri	Other	16
Manawatu	Whakapapanui Papamanuka	Other	16
Manawatu	Whangaehu	Other	20

Table 12: Assumed wave capacity

Region	Location / Name of project (Owned by)		Capacity (MW)
Bay of Plenty	Generic wave 1	Other	50
Manawatu	Generic wave 2	Other	50
Bay of Plenty	Generic wave 3	Other	50
Canterbury	Generic wave 4	Other	50
Southland	Generic wave 5	Other	50
Auckland	Generic wave 6	Other	50

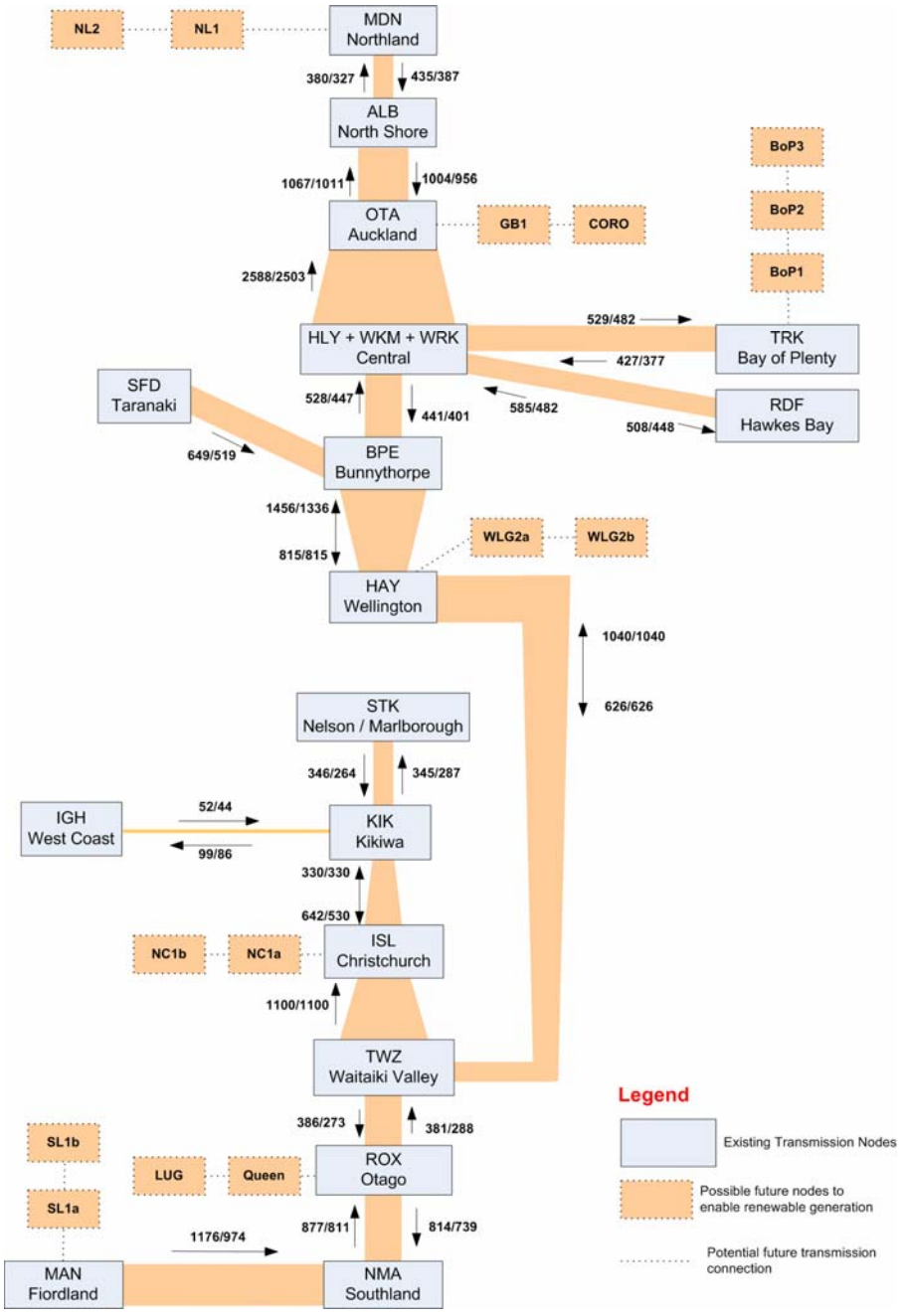
Table 13: Assumed biogeneration capacity

Region	Location / Name of project (Owned by)		Capacity (MW)
Bay of Plenty	Biomass Cogen, Kawerau	Other	30
Manawatu	Biomass Cogen, Central	Other	30
Hawkes Bay	Biomass Cogen, Whirinaki	Other	30
Waikato	Biomass Cogen, Kinleith	Other	30
Canterbury	Biomass Cogen, Ashley	Other	30

Inter-regional transmission upgrade, cost and capacity

5.1.8 In a previous report SSG identified a simplified inter-regional transmission network.[41] This simplified model is very approximate but gives a good overview of the *N – 1* capacity of New Zealand's current high voltage transmission grid.

Figure 5: Base-case Inter-regional transmission capacity model



[41] http://www.electricitycommission.govt.nz/pdfs/opdev/modelling/GPAs/SSG-inter-regional-transmission-capacity.pdf

5.1.9 Since the first report,[42] most of the inter-regional capacities have been found to be consistent with Transpower's views. Where advised, SSG has used the inter-regional capacity provided by Transpower.

5.1.10 Upgrade costs and capacities have been identified.[43] In general, lower cost transmission upgrades are identified first, such as thermal upgrades (re-tensioning) and/or duplexing of circuits,[44] followed by larger projects such as constructing new 220 kV or 400 kV transmission lines. Most transmission capacities are based on N – 1 transfer capacity.[45] All future transmission capacities assume balanced power flow between individual circuits making up the total inter-regional capacity.

5.1.11 An example is the inter-regional capacity between Twizel and Christchurch shown in Figure 6. The present capacity is around 1100MW, constrained by voltage stability (1). Adding capacitors and a static VAR compensator (**SVC**)[46] increases the capacity to around 1345 MW at a cost of around $19m, still constrained by voltage stability (2). Adding further SVCs at a further cost of $60m increases the capacity to the thermal limit of 1996/1813 MW (3). Finally, a new 220 kV double circuit line ($300m) increases the inter-regional capacity to 3448/3132 MW (4a).

[42] http://www.electricitycommission.govt.nz/pdfs/opdev/modelling/GPAs/SSG-inter-regional-transmission-capacity.pdf

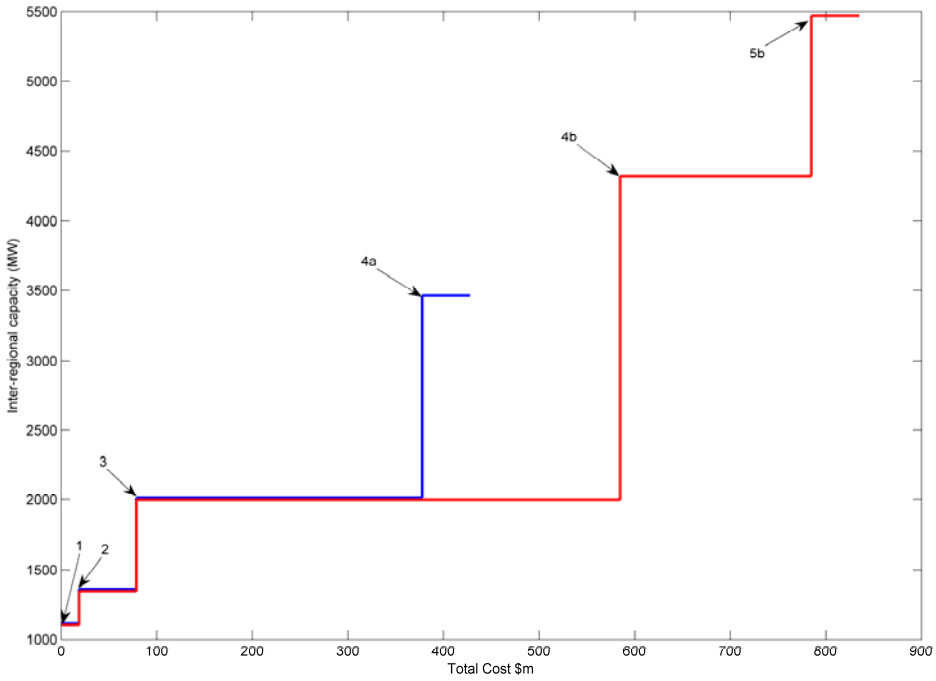
[43] SSG has also provided a set of inter-regional loss factors for input into GEM.

[44] Duplexing refers to the addition of an extra conductor, essentially doubling the capacity of the circuit/line.

[45] N – 1 refers to the loss of the single largest circuit and is a useful approximation to use in this type of analysis. Some transmission is assumed at N transmission with generation or HVDC runback.

[46] A SVC is an electrical device for providing fast-acting reactive power compensation on HVAC networks.

Figure 6: Inter-regional transmission capacity upgrade and cost between Twizel and Christchurch



5.1.12 Alternatively, the final step (4a) could be the installation of a 400 kV capable line run at 220 kV (step 4b, $506 m, 4320 / 3920 MW), before step (5b) which includes the upgrade of this line to 400 kV ($200m, 5470 / 4974 MW) if required. Hence, the logical transition for the Twizel to Christchurch inter-regional capacity upgrade is steps (1) through (3) followed either by step (4a) or step (4b) then (5b).

5.1.13 Obviously, the simplicity of the inter-regional transmission capacity model makes it rather approximate. It is only intended only as a high level guide to assist GEM to co-optimise regional generation builds (taking into account transmission investment option costs and inter-regional upgrade option costs).

6. Conclusion and next steps

Conclusion

6.1.1 The Commission through the TTER project has gathered information on the existing and potential size, type, costs and location of renewables.

6.1.2 This information has been used in developing the generation scenarios in the draft 2008 SOO which in turn will be used, as required by the GIT, to analyse transmission investments proposed by Transpower.

6.1.3 The Commission sought input from interested parties on the draft reports on hydro, wind and geothermal generation published in December 2007.

6.1.4 The key issues in respect of transmission access have also been considered, along with submitters' views on the issues. The Commission plans to investigate these issues further. The key issues were the Commission's approach to :

(a) identification of potential future renewable generation resources.

(b) power system analysis;

(c) GEM analysis;

(d) consideration of real options in justifying transmission investment;

(e) consideration of non-transmission alternatives to enhance interconnected grid capacity to better enable renewable connection; and

(f) the process for provision or upgrading of connection and deep connection assets.

6.1.5 This report presents:

(a) the finalised version of the hydro, geothermal and wind reports updated to reflect submissions received;

(b) the Commission's response to the comments received in submissions;

(c) policy issues identified by the Commission and submitters which require further consideration;

(d) the transmission augmentations which would be required to accommodate the potential renewable generation identified; and

(e) a high-level overview of the work undertaken by the Commission to analyse the impact of potential renewable generation investment by co-optimising transmission and generation investments.

Next steps

6.1.6 The Commission will, over the coming months, further explore a number of issues raised in submissions and in this report, in line with the objectives of the TTER project.

6.1.7 Those objectives are to:

(a) enable participants to better understand how the current framework (in particular, the rules) can be utilised to support the integration of renewables;

(b) provide an up-to-date "map" of potential renewable generation, its location and potential renewable fuel resource sizes (wind, hydro and geothermal) which can be factored into:

(i) the next SOO; and

(ii) Transpower's 2009 APR; and

(c) investigate the possible economic transmission investments for which Transpower could apply for approval under the rules to support the development of renewable generation.

6.1.8 Consistent with this project's information provision objectives, the Commission will:

(a) publish the report commissioned in February 2008 into current and emerging marine energy technologies, both overseas and in New Zealand, and seek submissions on any implications for the TTER project;

(b) consider the development of a transmission renewables policy document to support Transpower's analysis of potential renewables-related transmission investments; and

(c) publish, when sufficiently advanced, GEM analysis that incorporates the renewables issues raised in this final report.

6.1.9 Further to the objective of facilitating the analysis of potential economic transmission investments, the Commission will:

(a) give further consideration to the issues raised in submissions regarding the use of special protection schemes, and will investigate the extent to which such arrangements might be pursued within the current regulatory provisions, and whether there are reasonable grounds for recommending changes to the existing regulatory arrangements to provide for such schemes;

(b) consider further the appropriateness of implementing some mechanism(s) to deal with the current pricing and contracting regime for connection assets where the regime is not resulting in the optimal outcome.

(c) consider further the possibility of implementing an arrangement for sharing the loss and constraint rentals with generators who invest in interconnection assets;

(d) further develop the GEM co-optimisation model to assist in identifying:

  (i) how much of the identified renewable capacity is likely to be economically rational to develop, and how sensitive that answer is to the assumptions around wind's potential contribution to meeting peak load and assumptions around generation and transmission plant costs;

  (ii) how much transmission infrastructure (at a high level) is justified; and

  (iii) how best to address issues concerning deep connection assets identified in the report; and

(e) further refine the application of real options analysis to potential investment decisions on renewables and encourage Transpower to consider incorporating the approach into their processes for formulating proposals for transmission investment.

Appendices

Appendix 1 Summary of submissions and Commission's response

Accuracy of data provided and modelling (includes responses to identification of future renewable generation resources, power system analysis and GEM analysis)		
Submitter	**Comment**	**Commission Response**
Contact	Contact considered the focus on the TTER works should be on improving the information on generation economics available to the Commission. However, it:	
	• noted that the LRMC of its geothermal projects are over estimated by 10% for Tauhara and 55% for Te Mihi	These are high level estimates and the Commission is unable to verify Contact's claim.
	• does not consider the de-rating factors for geothermal to be accurate and note that there could be an equivalent risk with other types of renewables (i.e. in the case of hydro example could be more sedimentation than expected). It added that among recent development most of their sites generates above or close to nameplate capacity	The Commission's response is set out in paragraphs 3.3.13 to 3.3.15.
	• considered the cost of wind to be understated (i.e. the $80 MWh and the average total capital expenditure of $2,600 kW are too low) and does not see any reason why turbine prices should abate in the near term as the underlying causes of the increase (steel price and high demand) look set to continue for sometime. This suggests to Contact that wind economics are overstated in the SSG analysis and more wind than is justified is being optimised by GEM into forecast generation supply.	The Commission notes that these comments are largely in agreement with the attached Connell Wagner report. As explained in body of the report, the basis of the $2,600/kW cost figure is historical. Connell Wagner has indicated that turbine prices are continuing to rise, with significant uncertainty on future prices due to exchange rate variation, raw material prices, and international demand for turbines.
	• considered the 7.87c /kWh for Tuapeka to be on the low-side (although it considers the hydro study to be a good piece of work with the ranking of projects to be accurate)	These are high level estimates and the Commission is unable to verify Contact's claim.
	• is concerned about inclusion of projects in the future generation supply stack if the overall costs per kWh imply a very high price of electricity or a very poor return on shareholders funds.	Noted. The Commission has attempted to define an overall merit order of investment for each scenario

Accuracy of data provided and modelling (includes responses to identification of future renewable generation resources, power system analysis and GEM analysis)		
Submitter	**Comment**	**Commission Response**
		and welcomes submitters' comments on this.
EECA	EECA commented that with regard to modelling deep connection assets serving multiple generators, the proportion of costs and benefits that lie with consumers or generators (distributional issues) should be considered (to help understand whether there is a case for existing grid consumers to fund these assets).	The Commission notes that wealth transfers are not relevant as the GIT is a net benefits test.
Federated Farmers	No comment.	
Genesis	Genesis suggested the TTER project does not seem to take any account of individual generators' portfolio economics but added that this is most probably appropriate. It is, however, an illustration of why a central-planning approach to 'enabling' grafted onto an otherwise market-based generation system is problematic. It also illustrates why an overly deterministic approach to generation modelling is likely to prove problematic. It suggested that the Commission should be cautious about the extent to which it treats resource consents and public announcements as indicators that a project is guaranteed to be built. Genesis suggested that the indicators really just mean that the generator has secured the option to build and noted that many generators will have multiple mutually exclusive development sites on their books. It noted that the Commission, in preparing the hydro report, did not contact Genesis Energy.	The Commission agrees. Attempting to do so in the absence of reliable information about how generators manage their portfolios would risk introducing unwarranted biases to the analysis. It provides a transparent basis for decision making on transmission or alternative investment. Individual company portfolio positions are unlikely to provide this adequately (also see Commission comments in paragraph 3.10.25). Noted.

Accuracy of data provided and modelling (includes responses to identification of future renewable generation resources, power system analysis and GEM analysis)		
Submitter	**Comment**	**Commission Response**
MEUG	No comment	
Meridian	Meridian considered that the Commission has not addressed the concerns raised in its February 08 submission, particularly in relation to generation cost estimates. It has general concerns with respect to: • +/- 30% accuracy range of the generation costs means – the margin of error is greater than the incremental cost of the transmission upgrades – it is difficult to accurately compare one renewable generation proposal on one side of a constraint to another on the other side of the constraint in order to determine which would provide the least market cost outcome • current GIT methodology does not capture generation investment drivers such as fuel supply availability, and other portfolio strategies. It is specifically concerned with PBA's estimates, because the costs reported by PBA represent a significant variance to the capital values Meridian has determined for Mokihinui and North Bank tunnel hydro proposals. In particular: • for the cost of construction of the Mokihinui Dam which have resulted in a output cost of 18 c/kWh. The main contributing factor is the cost of concrete being 80 – 90% higher than Meridian's estimates and the volume of mass concrete required (PB assumed a 80,000 cubic meters while Meridian assumed 1,250 cubic meters) • for the construction of the North Bank tunnel, the assumption of very poor ground conditions requiring full concrete tunnel lining is overly conservative and contrary to	Noted and substantially addressed in the amended PB report attached. The Commission considers that GIT provides a useful tool and that there is a need to balance materiality versus complexity. In addition, fuel supply is implicitly modelled in GEM via the price of gas assumed over time. Portfolio effects are not directly addressed. The Commission's response is set out in paragraphs 3.3.18 to 3.3.24.

Accuracy of data provided and modelling (includes responses to identification of future renewable generation resources, power system analysis and GEM analysis)		
Submitter	**Comment**	**Commission Response**
	currently available information. In addition, PBA has estimated a tunnel cost in the order of $400 to $600 million higher that the Meridian estimate for this item. It questioned the accuracy (and therefore predictability) of the Mesoscale model used by Connell Wagner to estimate the technical wind resources available: • the model predicts that the Manawatu Gorge is unsuitable. Meridian highlights that there are currently 26 turbines operating in the area. • its low resolution does not identify areas that may be of interest. • wind speed is not the only critical factor in the assessment of the resource. Other factors include: – physical access – contractual access	The modelling undertaken was necessarily low resolution to capture the geographical signals required by the scope of the study, whose purpose was to aid transmission planning. The study was not expected to identify individual wind farm sites but rather attempt to quantify the relative potential for wind generation on a regional basis. The validation referred to by Meridian suffers from limitations in the available database of information on building structures rather than the reliability of the mesoscale modelling. This is discussed in Section 2.9 of the CW report. Including the turbines in the blue zones indicating proximity to building structures at the Te Apiti site produces a result close to the 80% level suggested by Meridian as a minimum requirement. A similar level of prediction is achieved at the Tararua site. The Commission agree that these factors are important considerations for individual wind farms and further work could be done to incorporate these into the TTER findings.

Accuracy of data provided and modelling (includes responses to identification of future renewable generation resources, power system analysis and GEM analysis)		
Submitter	**Comment**	**Commission Response**
	– land use – land form – access to the grid – consentability	
	• absolute wind speeds are not solely used by developers to assess wind farm economics, but rather:	The scope of the study was not to assess economics of individual wind farms.
	– average wind speed, its distribution, turbulence and wind shear are all factors that influence turbine choice and each of these factors influence the relative economics of a wind farm. Therefore, Meridian notes that the Commission's report oversimplifies the choice of wind turbine that can be made based on wind speeds.	This was a necessary simplification, which Connell Wagner commented on in the footnote of page 4.
	– project scale	This is discussed in Appendix B of the wind report but was not practical to include in the main analysis as the modelling was not aimed at identifying individual sites.
	– lifecycle cost	Noted.
	It noted that the Connell Wagner report offers a range of break-even price bands for each tranche of wind speed but the Commission uses a single mid-point estimate in its GEM analysis which may distort the outcome of the analysis.	The Commission and most interested parties understood that there would be limitations to the study and opportunity to further refine the results. The Commission agrees with Meridian's observation and would note that the nature of the analysis being performed here necessitates making certain assumptions. Systematic sensitivity analysis will then be used to test the influence of those assumptions.
	It recommended that the Commission should not undertake significant resource	

Accuracy of data provided and modelling (includes responses to identification of future renewable generation resources, power system analysis and GEM analysis)		
Submitter	**Comment**	**Commission Response**
	mapping but rather identify transmission opportunities to match known generation development activities as private developers are already putting significant resources into mapping renewable energy opportunities. It recommended that the Commission should take great care not to place too much weight on scenarios involving wind development in areas that do not have project proponents. Considers that the Commission is using flawed assumptions in its analysis and suggests that the Commission consult with industry further.	Commission does not agree. The Commission has consulted with industry and sought input regarding data and assumptions.
MRP	It considered that it is inconsistent to derate potential geothermal generation capacity, to take into account uncertainties about actual generation capacity, but not potential hydro and wind generation. It noted generator expectations of generation capacity can be reasonably relied on without making such adjustments (the Rotokawa geothermal plant is an example and the announced capacity should be used). MRP suggested that Geothermal, hydro and wind have not been consistently assessed. MRP is concerned that consentability and distance from grid has not been included in Connell Wagner's assessment of potential wind farms. This has led to the situation where wind farms in Great Barrier Island and at the top of the Coromandel (which would require a 90km underwater cable) are included in the report as feasible prospects. It questioned how useful the wind resource report will be for the SOO given it does not take these matters into account.	The Commission's response is set out in paragraphs 3.3.13 to 3.3.15. Noted. The Commission's response is set out in paragraph 3.3.3 The Commission report explains how transmission costs to remote sites have been considered.

Accuracy of data provided and modelling (includes responses to identification of future renewable generation resources, power system analysis and GEM analysis)		
Submitter	**Comment**	**Commission Response**
Melhuish	Molly Melhuish noted that Windflow claims its generation costs are significantly lower than those of the 2-3 MW European turbines being used by the large retailer-generators. Its smaller turbines would be deployed in projects sizes on the order of 20 MW instead of 200 MW, involving less earthworks and less visual impact, hence more "consentable". Given access to high-grade wind resources - those giving a listed LRMC of 8c/kWh - the distributed wind alternative should be more than competitive. Molly Melhuish commented that a costing of 8c/kWh suggests that there are very good wind resources spread widely in the transmission-constrained regions in New Zealand, and adds that if these were developed through smaller wind farms embedded in the 33 kV lines, high transmission connection costs could be avoided. Also, if using synchronous generators of the Windflow turbine, they could provide valuable ancillary service support to distribution networks.	The Commission is unable to verify these claims. Noted.
NZWEA	It noted that wind modelling by Connell Wagner may not accurately depict the amount of wind generation realisable because of: • development constraints that exist that may not be captured by resource modelling and its assumptions, meaning that transmission investment may be pursued in an area where generation potential is lower than it appears. • application of a single factor (50%) to estimate the amount of suitable land that might be available by landowners. A change in this factor can lead to a significant change in the identified potential. • consentability issues. • spatial resolution of 3 km, which is likely to lead to a smoothing of the results. • the accuracy of 10 MW per square kilometre assumption.	Commission notes that the modelling has provided a reasonable approximation and agrees that identification of the consentability issues etc would further refine the results.

Accuracy of data provided and modelling (includes responses to identification of future renewable generation resources, power system analysis and GEM analysis)		
Submitter	**Comment**	**Commission Response**
	• land availability, financing problems and cumulative effects prevent large developments (300 – 500MW). It noted that the assumption that future policy changes will enable the potential development of all areas which have not been filtered for land use constraints, waterways and national park is a dangerous one as the NPS has not yet been tabled. It noted that the GEM co-optimisation is still under development and that the outcome will be dependent on the inputs/reasonably accurate cost assumptions. It noted the inconsistency between the wind resource that was identified in the Connell Wagner modelling and the generation projects that have been used in the transmission opportunities analysis. Projects considered in the GEM analysis need to be aligned with the resources that have been identified and not simply chosen as an interesting desktop exercise otherwise the true major potentials will be missed. It cautioned against assuming that policy changes will enable the potential development of areas assumed not to be accessible in the current modelling. It recommended that the Commission: • investigate the wind resource potential of priority regions more closely (i.e. higher resolution modelling, identification of development constraints, etc.) before the final decision is taken to ask Transpower to investigate transmission investment in that region. • discuss with potential wind energy developers the sites and regions that they see as having the greatest potential because developers are already likely to have spent some time and resources investigating resource potential and development constraints in a more detailed fashion than this modelling allows. NZWEA is willing	Noted. The Commission agrees and would note that this is true of any quantitative analysis. That is why the Commission has sought input from participants regarding inputs and cost assumptions. Noted. Noted. Recommendations noted.

Accuracy of data provided and modelling (includes responses to identification of future renewable generation resources, power system analysis and GEM analysis)		
Submitter	**Comment**	**Commission Response**
	to help to coordinate this if desired. • should undertake some sensitivity analysis (on both generation and transmission costs) while undertaking their co-optimisation exercise. • discuss with potential wind energy developers their understanding of generation costs and consider this in their modelling. • consider that upgrades as an option instead of new lines, given shorter lead times for upgrades.	
Powerco	Powerco noted that as the GEM analysis was not completed for the draft report, it is not clear whether all the confirmed and announced projects are included in the GEM analysis. It noted that the evidence presented in the report seems to provide a skewed view of the total estimated transmission connection costs due to the use of maximum power output, not the economically achievable output.	Noted. The Commission treats all consented and confirmed projects as committed. Projects that have been announced but not consented or confirmed are treated as potential projects that GEM may select but GEM is not required to do so. Relative economics will drive the decision by GEM whether or not to select a given potential project The Commission considers this to be an interesting point that needs to be further considered.
Transpower	Transpower considered the following to be issues with the modelling that may impact on data accuracy:	

Accuracy of data provided and modelling (includes responses to identification of future renewable generation resources, power system analysis and GEM analysis)		
Submitter	**Comment**	**Commission Response**
	• ranking of resource areas (exclusion of all tranche 2 and 3 areas as potential wind resource areas) may be inaccurate due to uncertainty about generation and transmission costs. Suggests that all tranches that may be commercially viable for generators to invest should be considered, and the impact of cost uncertainty on the ranking should be assessed.	The identified wind resource is many times what is needed for the next 30 or 40 years. But it needs to be broken up into wind farm investments of reasonable sizes, i.e nobody is going to install a 5000MW farm in a single development. There is little point in giving GEM even more potential wind farms to choose from as it doesn't even need to use all that it has now. Providing GEM with more to choose from and they were less desirable (i.e. greater cost/same capacity factor, or same cost/lower capacity factor) then GEM would never select them.)
	Importance of consenting likelihood (noting that automatic consenting cannot be assumed).Transpower considers that the parties that are most likely to build new generation are best placed to provide information on generation costs, the commercial drivers for investing at particular locations, and the associated uncertainties around these. For major generation projects, these parties are generally the incumbent generators.	Noted. The Commission will consider this comment further.
	Transpower noted that the simplicity of the analysis in which the transmission cost assumptions are intended to be used and the uncertainty in other critical assumptions limit the accuracy to which transmission costs are reasonably required.	Noted.

Accuracy of data provided and modelling (includes responses to identification of future renewable generation resources, power system analysis and GEM analysis)		
Submitter	**Comment**	**Commission Response**
	Transpower considered that GEM co-optimisation may deliver useful results, but is concerned that:	
	• generator costs that do not reflect what proponents are saying	Noted.
	• it may not reflect around generation uncertainties in regard cost and consentability	Noted.
	• a 18 regional radial model is a crude approximation of the full interconnected system	Agreed.
	• the assumption that all transmission circuits between regions are fully loaded at peak transfer is unrealistic as it will lead to significant underestimation of the transmission to support a healthy generation market.	The Commission considers that this comment needs to be supported by analysis as otherwise it appears to be generalised and not directly relevant.
	It suggested the Commission's modelling work should be labelled more accurately (for example, "expansion" rather than "co-optimisation") and that the impact of the simplifications inherent in the modelling be acknowledged and allowed for when drawing any conclusions from the analysis.	The Commission considers that either label is accurate. The point about acknowledging limitations and simplifications is relevant and will of course be addressed when the TTER GEM work is written up
	Transpower sought advice from ROAM Consulting on the proposed modelling approach, alternative modelling approaches and related issues.	The Commission notes the comments by ROAM Consulting and sees no need to do things differently based on the ROAM report.
	In relation to wind integration modelling, Transpower is concerned that models being used to form views on dependency and interdependency may contain significant assumptions on independence.	This issue is already addressed in the modelling
	Transpower suggested that the impact of the simplifications inherent in the modelling be acknowledged and allowed for when drawing conclusions from the analysis, and that extensive sensitivity analysis be conducted across the range of dependent and	Noted.

Accuracy of data provided and modelling (includes responses to identification of future renewable generation resources, power system analysis and GEM analysis)		
Submitter	**Comment**	**Commission Response**
	independent uncertainties in the assumptions to test the robustness of the results.	
TrustPower	The Report identified the most likely technical and economically viable options in the foreseeable future as hydro, wind and geothermal. TrustPower agreed with this assessment and that any investment in transmission to enable renewable generation should be focussed on these technologies only.	Noted.
Vector	Vector supported the identification of generation development potentials and the development of network scenarios to identify shortcomings in the grid and to develop grid solutions. It provided no detailed comment on accuracy of data provided.	Noted.

Real Option Analysis		
Submitter	**Comment**	**Commission Response**
Contact	Contact noted it was keen to engage with the Commission on the suggested real options approach. It considered that spending on transmission preparations in order to build option value for transmission routes is valuable, and that most of the value comes from truncating the time to commission new transmission lines. It considered investigating the extent to which costs incurred in development costs for new transmission can be recouped, should the forecast generation not materialise.	Noted. The Commission considers the current rules enable Transpower to recover easement and land purchase costs regardless of whether the transmission /generation is built.
EECA	It considered that real options analysis is likely to assist the Commission's understanding of the co-ordination problem, but noted its concern about the practical application of real options in the GIT process. For example, EECA suggested that it may not be practical or cost-effective for all projects, and it questioned how probabilities or probability distributions will be able to be assigned in a transparent or objective manner without inviting some degree of gaming. It stated that real options examples appear to imply that the probability of developing a renewable project will remain the same regardless of the level of transmission investment. It expected that as level of commitment to a transmission project increases, uncertainty around transmission capacity faced by renewable developers would be reduced and the probability of investment in the renewable resource would increase.	Noted. Noted.
Federated Farmers	No comment	

Real Option Analysis		
Submitter	**Comment**	**Commission Response**
Genesis	No comment	
Melhuish	No comment	
Meridian	It considered real options analysis would be suitable in terms of evaluating the benefits of early acquisition of easements prior to committing to developing new renewables areas, but notes that: • results of the analysis are dependent on the quality of the inputs used; and • the real options analysis needs to take into account the long lead time for developing the transmission.	Noted.
MEUG	No comment	
MRP	No comment	
NZWEA	No comment	
Powerco	It considered that a market-based approach should be explored in more detail in line with the action plan of the NZES.	Noted.
Transpower	It noted it generally supported use of real options analysis, and supported the acquisition of transmission corridors as a mechanism that may assist this. However, Transpower suggested that the outline in the draft report is not detailed enough to clearly show how the approach will be applied, and that: • there is more uncertainty associated with a range of relevant factors (such as fuel	Noted.

Real Option Analysis		
Submitter	**Comment**	**Commission Response**
	costs, demand growth etc) than described; • transmission should facilitate new generation rather than being initiated by it; • national value relates to the generation plant options rather than transmission; and • assumed independence between generation and transmission investment decisions is questionable. It suggested that because of the number of uncertainties associated with transmission investment there is little value in analysing real options for a single investment. Instead, Transpower proposes calculating an expected outcome based on the range of relevant assumptions and recognition of uncertainties. Transpower questioned the value calculated by using real options analysis will be sufficient to justify the purchase of easements and land while acknowledging that there will be option value in preserving investment options by, for example, securing designations and easements. It noted that real options analysis can be useful for considering the economic benefits of strategic transmission investment and the timing of an investment (eg. to bring forward or delay) to the extent that the choice to bring forward or delay can open up investment options. It concluded that option values should be considered, both for generation and transmission.	Noted. Noted. However, it may indicate there is no net benefit from purchasing the option. Noted.
TrustPower	No comment	
Vector	No comment	

Consideration of non-transmission alternatives to enhance interconnected grid capacity to better enable connection		
Submitter	**Comment**	**Commission Response**
Contact	Contact considered that Special Protection Schemes (SPS) should only be considered an immediate solution on the interconnection grid for specific temporary situations such as high HVDC south transfer. It noted the following issues with respect to SPS for other parts of the interconnected grid: • where the benefits and costs do no flow directly to the generator providing the runback there must be a commercial arrangement as per other ancillary services products. Contact notes that it would strongly oppose any mechanism to unilaterally use a generator as a transmission alternative based solely on technical feasibility and not by commercial agreement. • significant energy could be constrained versus the alternative of transmission upgrade to maintain N-1 • when the generator providing the runback service is not available because of a planned or forced outage, the benefits of the runback are lost • transmission upgrade provides a greater benefit as the runback scheme typically only provides a benefit for flow in a single direction • SPD relies on N-1 when scheduling reserves • restricted to fast start generation • requires run up generation as the circuit comes back into service. This would require regionally based reserves and consequential changes to the market system	The Commission's response is set out in paragraphs 3.6.24 to 3.6.42

Consideration of non-transmission alternatives to enhance interconnected grid capacity to better enable connection		
Submitter	**Comment**	**Commission Response**
EECA	No comment	
Federated Farmers	No comment	
Genesis	Genesis commented that the issue of generator run-back needs to be treated differently in different settings. and that for connection assets and for grid upgrades pursued via the contractual route, the use of run-back schemes is not a subject that EC needs to be overly concerned with. Genesis recommended that the following issues be considered with respect to the use of SPS: • technical feasibility and desirability • procurement • commercial arrangements for participating and affected generators Genesis recommended that until the Electricity Commission has worked through both of these issues, Transpower should not be obliged to analyse generator run-back as an option when applying for approval to recover the cost of upgrades to the core grid. The use of run-back schemes for connection assets and for grid upgrades pursued via the contractual route should be largely a matter for negotiation between the generation proponent and the transmission proponent.	The Commission's response is set out in paragraphs 3.6.24 to 3.6.42
MEUG	No comment	

Consideration of non-transmission alternatives to enhance interconnected grid capacity to better enable connection		
Submitter	**Comment**	**Commission Response**
Meridian	Meridian noted that SPS have been used to date for spur connections where only one generator will be affected by the transmission constraint that triggers the SPS. It also noted the following issues with respect to use of SPS for other parts of the interconnected grid: • may result in a weaker national grid over time (therefore, Meridian favours a more robust national grid in order to provide security of supply and facilitate retail and generation competition) • will require fast starting plant or spinning reserve to be located on the demand side of the constraint. Over time, if SPS become predominant on core grid then more fast ramping plant will be required, distributed about the grid. Since generation is generally more expensive than incremental transmission, it is unlikely that this would provide a least net market cost solution, and would be inefficient • will require complex location orientated coordination of instantaneous reserves and interruptible load and compensation for those generators not able to bid into the instantaneous reserves market • will have commercial implications on many parties. Runback generators would need to be compensated when they are runback to ensure commercial fairness. In the case where energy could be stored by the runback generator for later release, it could open the potential for gaming. • may increase the cost of ancillary services/instantaneous reserves and energy • may result in the spilling of renewable energy • should only be an interim measure until such time as a satisfactory	The Commission's response is set out in paragraphs 3.6.24 to 3.6.42

Consideration of non-transmission alternatives to enhance interconnected grid capacity to better enable connection		
Submitter	**Comment**	**Commission Response**
	transmission solution can be implemented. Meridian summarised its view by noting that: • generation runbacks in response to core grid overloads would have significant market impacts and add to the many unresolved complications of operating the market • SPS should not be implemented as a substitute for good system design or operating practices.	
MRP	MRP considered that widespread use of SPS such as intertrips and runback facilities on the core grid: • should not be considered as an alternative to transmission investment • can be considered as a permanent solution on spur lines where individual customers agree to the use of such schemes for commercial reasons • can provide a temporary solution on the non-core and core grid where transmission investment has not occurred in time, providing a safety margin for capacity rather than running the system to the limit • should always be via voluntary arrangements. Any mandated requirement for generators to install runbacks would amount to substantial interference with the competitive operation of the generation market. It considered that the widespread use of SPS would: • introduce considerable risk to the operation of the power system, as	The Commission's response is set out in paragraphs 3.6.24 to 3.6.42

Consideration of non-transmission alternatives to enhance interconnected grid capacity to better enable connection		
Submitter	**Comment**	**Commission Response**
	coordination of a large number of such schemes would be complex and if not done correctly, could potentially lead to cascade failure • have serious implications for the Instantaneous Reserves markets. Currently instantaneous reserves are chosen on the basis of offer price; location is not considered (other to the extent of which island). This methodology is possible as there is sufficient thermal headroom in the system such that instantly redistributed power flows would not cause circuits to trip – this would not necessarily be the case if runbacks/intertrips wee used	
Melhuish	No comment	
NZWEA	It noted that runbacks or inter-trips can provide a means to enable greater utilisation of a transmission asset but they may offer only a relatively short term solution, delaying the need for investment until the next generation connection is proposed or demand in that area of the grid increases. It recommended that: • long term use of that transmission asset should also be factored when considering SPS • the value of spill or lost generation should be considered as part of the economic assessment of the alternatives. • the value of that spill should be based on the value of the electricity that is dispatched in its place (i.e. the market price).	The Commission's response is set out in paragraphs 3.6.24 to 3.6.42

Consideration of non-transmission alternatives to enhance interconnected grid capacity to better enable connection		
Submitter	**Comment**	**Commission Response**
	NZWEA also noted that there may be complication with scheduling and compensation. For example, if there are several connections on an interconnected section of the grid where a runback is required, NZWEA asked how it would be determined which party would be runback, and whether they would compensated by the other parties accordingly?	
Powerco	It suggested that SPS needs to be considered carefully. The economic analysis of an upgrade needs to take these possibilities into account in the initial stages, and cost benefit of schemes needs to be evaluated. Powerco suggested that an auction of capacity rights may be a good way of providing certainty for both the transmission and generation.	The Commission's response is set out in paragraphs 3.6.24 to 3.6.42
Transpower	Transpower noted that runbacks and intertrips have their place in an efficient system, but they can have significant reliability implications and commercial complexities, especially on the interconnected system. Transpower considered that the Commission is overstating their role with regard to enabling renewables. Transpower noted it routinely investigates the use of non transmission alternatives, including both supply and demand side alternatives, when developing options for investment proposals. Generation inter-trips and runback schemes are two of the non transmission alternatives that appear in the long-list used for the assessment of transmission investments to relieve generation constraints. Transpower referred to its comments on the use of runbacks and intertrips in its revised Investment Proposal for the Central North Island Thermal Upgrades provided	The Commission's response is set out in paragraphs 3.6.24 to 3.6.42

Consideration of non-transmission alternatives to enhance interconnected grid capacity to better enable connection		
Submitter	**Comment**	**Commission Response**
	to the Commission in April 2008.	
TrustPower	TrustPower agreed that further studies into the use of Intertrip and runback schemes has the potential to allow the existing grid to be used more effectively to enable renewable generation remote from load centres.	Noted.
Vector	Vector supported consideration of non-transmission alternatives. Important that the process of formally seeking information from non-network providers as to possible non-network alternatives to a proposed network allows sufficient time for appropriate consideration and response. Vector considered it reasonable for the Commission /generators to be looking at intertrips/runback schemes to limit the requirement for (act as alternatives to) transmission upgrades (i.e. limit the generation injection at times of transmission constraints), as long as it does not place security of supply at risk over the longer term.	The Commission's response is set out in paragraphs 3.6.24 to 3.6.42

Process for provision of upgrading connection and deep connection assets		
Submitter	**Comment**	**Commission Response**
Genesis	It suggested that the Commission does not need to focus on the construction of connection assets, and that any signal that some proponents might receive 'free' connection assets would likely have a dampening effect on construction of connection assets. It noted that the suggestion that connection asset costs may be socialised may cause problems such as damaging competition, and considers that the Commission should leave it to market forces to influence those investment decisions. It suggested that if costs of shared connection assets were to be socialised, it would be better to fund multiple connection assets rather than one or two.	The Commission's response is set out in paragraphs 3.7.13 to 3.7.14.
MRP	It supported the Commission's chosen approach to monitor the way Transpower deals with parties requiring connection and deep connection assets as long as the Commission keeps a close watch on Transpower's conduct in this area and on whether regulation may be warranted in the future. It noted, with respect to transmission investment timing, that the problem with recovering costs of assets before they are used and useful is who to recover them from.	The Commission's response is set out in paragraphs 3.7.13 to 3.7.14
Powerco	It suggested that the provision of connection assets could be competitively sourced, and further, that competition may be the only way to meet the growth in the transmission grid that is required.	The Commission's response is set out in paragraphs 3.7.13 to 3.7.14

Process for provision of upgrading connection and deep connection assets		
Transpower	Transpower commented that the draft report did not make a distinction between two types of connection assets – those connected to the grid directly and those connected to the grid via a circuit breaker, and that they each have different affects on grid users. It also commented that a number of generation proponents have used non Transpower resources to undertake power system studies, and clarified some points of detail in relation to the way new connection asset investments are recovered under the TPM.	The Commission's response is set out in paragraphs 3.7.13 to 3.7.14.

Feasibility of the Commission approach to parties such as generators contracting with Transpower for upgrades to the existing interconnected grid		
Submitter	**Comment**	**Commission Response**
Contact	Contact considered that the GIT process would need to be reviewed if there were significant benefits for renewable generation from a proposed transmission investment, but the net benefits of the proposed transmission investment fell short under the GIT process. It regards it as a logical step in such instances for the Board to make a discretionary call and approve the investment.	The Commission's response is set out in paragraphs 3.8.34 to 3.8.47
EECA	It noted that the report suggests that a generator (or a group of generators) could fund Transpower to invest in an interconnection asset that did not pass the GIT if it saw significant benefit in doing so. EECA noted that such an investment may also provide economic benefits to consumers. If so, it would be reasonable that these benefits should be able to be recovered by the generator. It recommended that the Commission consider other options for recovery of benefits gained by consumers besides redistribution of loss and constraint rentals.	The Commission's response is set out in paragraphs 3.8.34 to 3.8.47
Federated Farmers	No comment	
Genesis	Genesis recommended that the issue of securing rights to private investment in the interconnected grid should be a priority area for the Commission to focus much of its further efforts on. Commission's approach to operationalising the SOO and the GIT could be improved to avoid problems with what it considers is an overly deterministic approach. Genesis considered that, (while it would be premature to do so at present), ultimately, there would be merit in revisiting the grid investment test to see whether its workability could be improved.	The Commission's response is set out in paragraphs 3.8.34 to 3.8.47

Feasibility of the Commission approach to parties such as generators contracting with Transpower for upgrades to the existing interconnected grid		
Submitter	**Comment**	**Commission Response**
MEUG	MEUG considered that the Commission's suggestions relating to this issue have considerable merit. It used an example in the draft report (paragraph 2.2.15) to illustrate how it was possible for Meridian to fund the $37m needed to upgrade the Otago to Waitaki transmission line. MEUG does not believe there is any barrier to Meridian bi-laterally contracting with Transpower to build that line for $37m. If as claimed this $37m is holding back investment of $1.5 billion renewable generation, then perhaps Meridian would willingly pay the $37m as it would only be another 2.5% on the capital cost to unlock that investment. That would be a better outcome than socialising the $37m cost across all consumers and allowing Meridian to receive a wind fall gain of the same amount.	The Commission's response is set out in paragraphs 3.8.34 to 3.8.47
Meridian	Meridian did not directly comment on the Commission's suggestion but it did comment on related issues: • that the relieving of constraints is important for enhancing competition and this should be factored into the Commission's transmission investment decision making • transmission upgrades should be considered in the context of the fraction of their cost relative to generation. The final process must be practical, pragmatic, and commensurate to cost • incremental upgrades should be given a priority and a more appropriate and accurate methodology should be used for dealing with incremental grid upgrades.	Noted
MRP	It did not specifically comment but recommended locational-based pricing be adopted	Noted

Feasibility of the Commission approach to parties such as generators contracting with Transpower for upgrades to the existing interconnected grid		
Submitter	**Comment**	**Commission Response**
Melhuish	No specific comment.	
NZWEA	It did not specifically comment on the Commission's suggestions but referred to a process (Location Constrained Resource Interconnection Facility (LCRIF)) that the Californian ISO is developing with the same objective as the TTER project. The LCRIF requires that developers either be in a connection queue, sign a declaration of intent or take part in a "open season" (a process where projects can be put forward for consideration) and pay a deposit. A transmission project cannot then proceed until a certain level of subscription or commitment from generators is reached (which might fit with the "real optons" approach for justifying transmission investment being discussed by the Commission). The proposed investment must also serve more than one new generator, and there is a cap on the size of investment (to ensure that costs to consumers – who initially fund the investment – are not excessive). It suggested that other features of the LCRIF that may be worth considering in the TTER projects are: • an "open season" in which any market participant can request that a specific transmission process be pursued (i.e. a means by which developers can identify the transmission investments that would be of most value to them). The process also allows for parties other than the grid owner to put forward investment proposals (that will still be controlled operationally by the System Operator). • Investment is only possible in identified "Energy Resource Areas" (ERAs), identified and approved by a broad panel of stakeholders based on presence of the energy resource itself as well as other constraints such as planning and environmental effects that could influence its use. Accordingly the potential transmission investments can be pursued with greater certainty that they will be able to be completed.	The Commission's response is set out in paragraphs 3.8.34 to 3.8.47

Feasibility of the Commission approach to parties such as generators contracting with Transpower for upgrades to the existing interconnected grid		
Submitter	**Comment**	**Commission Response**
Powerco	It recommended that the Commission or a similar entity run an auction on capacity for any proposed upgrade to ascertain demand and price. Suggests that this would indicate if there was sufficient demand to justify the expansion and if any shortfall was required to be covered by a subsidy.	The Commission's response is set out in paragraphs 3.8.34 to 3.8.47
Transpower	It noted that the draft report states that "loss and constraint rentals are allocated to those that pay for transmission assets, and that these are the financial equivalent of capacity rights, given that whenever a transmission constraint occurs the difference in the value of the electricity that flows through the constraint link is refunded as a constraint rental." States that this is correct only for radial connection assets, not for the core grid. Comments that radial generation connection assets are rarely constrained and that rentals on connection assets amount to under three per cent of total rentals. Notes that connection rentals are also often negative.	The Commission's response is set out in paragraphs 3.8.34 to 3.8.47
TrustPower	TrustPower recommended that property rights are allocated to generators who pay for interconnection asset investments. It also agreed that if generators pay for new interconnected grid investment then those generators should receive the loss and constraint rentals. It recommended that the Commission consider the allocation of capacity rights to those prepared to pay for interconnection asset investments. It supported the provision of sufficient modelling information and the ability for other suitably qualified parties to undertake grid connection studies on behalf of Transpower.	The Commission's response is set out in paragraphs 3.8.34 to 3.8.47

Feasibility of the Commission approach to parties such as generators contracting with Transpower for upgrades to the existing interconnected grid		
Submitter	**Comment**	**Commission Response**
Vector	Vector noted that there are minimal locational signals for generation as long as generation does not pay for use of system (interconnection) under the transmission pricing methodology. In section 2.2.14, Meridian states that by Transpower spending $37 million, about $1500 million of new generation investment can be unlocked. Vector believes that this is a clear signal for a review of appropriate counterparties to transmission agreements. If generators were counterparties for interconnection (and therefore paid for use of system), their decisions would reflect all costs and provide strengthened incentives to influence transmission upgrades. It supports the Commission's intention to undertake further work on locational pricing for transmission in the near future.	The Commission's response is set out in paragraphs 3.8.34 to 3.8.47

Consideration of confidential information on renewable energy		
Submitter	**Comment**	**Commission Response**
Contact	Contact is supportive of the process regarding confidential information that has been used for the renewables project as generators have the most accurate up-to-date information, as the inputs into the information changes with time. Suggests that rather than have the Commission try to second-guess generator information, the Commission should give credence to generator information if the information falls within the estimated upper and lower bounds of its analysis. If generator information is not within the upper and lower bounds, then discussion and consultation can occur on these bands.	The Commission's response is set out in paragraphs 3.9.8 to 3.9.15
EECA	No comment	
Federated Farmers	No comment	
Genesis	No comment	
MEUG	No comment	

Consideration of confidential information on renewable energy		
Submitter	**Comment**	**Commission Response**
Meridian	Suggests the parties with the best information on the costs of generation development and the technical issues are the developers themselves. Developers may have considerable intellectual property (IP) on specific wind, water or geothermal resources, development processes and technologies that are not generally available to the consultants that are engaged by the Electricity Commission. This IP (e.g. 80m wind data, geothermal well data etc) is a source of competitive advantage to the particular developer. Meridian is happy to share information with the Commission or Transpower's consultants under an appropriate confidentiality agreement.	The Commission's response is set out in paragraphs 3.9.8 to 3.9.15
MRP	No comment	
Melhuish	No comment	
NZWEA	No comment	
Powerco	No comment	
Transpower	Transpower believes the Commission's concerns, regarding generators understating costs because of commercial drivers, can be substantially mitigated by other means including: • Obtaining agreement on assumptions by multiple generators. This would substantially mitigate the risk of a distorted outcome, and allow the generators' significant experience to be injected effectively into the process. • Testing information provided by generators through consultation. This would allow other interested parties to comment on any distortions they perceive in the	The Commission's response is set out in paragraphs 3.9.8 to 3.9.15

Consideration of confidential information on renewable energy		
Submitter	**Comment**	**Commission Response**
	generators' provision of information. Transpower notes: • that it is in the generators' best long-term interests to be open with this information • it is not clear who could provide a useful, independent verification or testing that added value to the generators' estimates of their development costs	
TrustPower	Although it is desirable that information provided to the Commission is able to be released as public information to enable public scrutiny, in practice this will mean that prospective generators are going to be reluctant to release information that could disadvantage a commercial position. Confidential Information should be verified without releasing the details into the public arena and can be summarised or combined such that sensitive information is not identified separately.	The Commission's response is set out in paragraphs 3.9.8 to 3.9.15
Vector	No comment.	

Other issues		
Submitter	**Comment**	**Commission's response**
Contact	It noted its concern that the generation economics in the co-optimised GEM may not accurately reflect competition in the wholesale market Contact suggested that the HVDC charges/Transmission Pricing Methodology discriminates against renewable generation from new market entrants in the South Island – requests that the Commission take this into account when it next considers the TPM and when it considers feedback on the draft TTER report.	The Commission's response is set out in paragraph 3.10.25. The Commission's response is set out in paragraph 3.10.4
Federated Farmers	It is concerned about the need for productive land to be taken out of productive use to accommodate the renewable energy source and the transmission links to connect the renewable energy generation to the national grid. It suggested annual payment for the use of land by Transpower as compensation for the burden of transmission infrastructure on the land.	Noted. The Commission's response is set out in paragraph 3.10.16

Other issues		
Submitter	**Comment**	**Commission's response**
Meridian	It argued that an inadequate core grid is proving to be a significant barrier at Environment Court hearings where project opponents claim that renewable projects will not be able achieve the benefits in net additional renewable energy production and reduced carbon emissions that they claim, due to transmission constraints. In Meridian's view there is a risk that generation competitors will be able to block new generation through the RMA process, as a result of inadequate transmission infrastructure. This is counter to the desire to have a competitive market for building generation and offering it into the real time market for efficient dispatch, and is likely to impact achievement of the 90% renewables by 2025. It suggested the Commission and Transpower should put greater weight on projects that have or are in the process of gaining resource consent when preparing SOO scenarios or market development scenarios used in the GUP. Meridian considered that the HVDC charge disincentivises generation investment in the South Island and is not consistent with the beneficiary pays approach or a user pays principle.	Noted. Noted. Meridian has not presented any new information not previously considered by the Commission and the Commission's responses set out in earlier consultations remains valid
MRP	It supported the Commission's investigation of possible future generation solutions as a necessary part of the development of the SOO and the GIT, but noted it is sceptical as to its potential role in any "generation follows transmission" policy development.	

Other issues		
Submitter	**Comment**	**Commission's response**
Melhuish	Molly Melhuish noted the potential for embedding of small scale wind generation (to reduce transmission losses). Molly Melhuish suggested that distributed wind generation should be compared from a national-interest perspective with the large-scale remote projects, before TTER offers any further subsidy of costs or risks of the latter.	The Commission's response is set out in paragraphs 3.10.18 to 3.10.20.
NZWEA	NZEA suggested there is potential for greater stakeholder involvement in development of project outcomes beyond consultation process currently being followed. Suggests the next stage of the project should include a greater level of discussion on potential funding and investment arrangements.	Noted.
Transpower	It strongly disagreed with the TTER project's purpose to present the transmission augmentations required for the identified potential generation identified. Transpower was concerned that if the Commission expresses a view on "optimal" transmission investments prior to reviewing investment proposals by Transpower, it may look like predetermined approval by the Commission Transpower commented that the draft TTER report states that the HVDC charge promotes efficient uptake of renewable generation by signalling the locational cost of connection in the South Island. It noted that this is true only to the extent that the charge influences investment in new HVDC capacity (and, that even then, it cannot be claimed that the charge in any way accurately reflects the LRMC of investment in HVDC capacity).	The Commission's response is set out in paragraph 3.10.22
TrustPower	TrustPower considered that the HVDC charges disadvantage new entrants and is inefficient.	The Commission's response is set out in paragraph 3.10.1(a)(i)

Other issues		
Submitter	**Comment**	**Commission's response**
Vector	Vector suggested that further clarity is required around the respective roles of small scale versus large scale renewable.	

Appendix 2 Final geothermal report "Transmission to enable renewables - Existing and potential geothermal generation in New Zealand" prepared by the Electricity Commission

Appendix 3 Final hydro report “Transmission to enable renewables – Potential NZ Hydro schemes” prepared by Parsons Brinckerhoff Associates

Appendix 4 Final wind report “Transmission to enable renewables – Economic wind resource study” prepared by Connell Wagner

Appendix 5 “Transmission to enable renewables project: Transmission network reinforcement – Inputs for GEM” prepared by System Studies Group

Appendix 6 "A possible real options framework to support transmission to enable renewables" prepared by the Electricity Commission

6.1.1 Many investment decisions are made based on Net Present Value (NPV) analysis, where investment strategies are compared and the strategy that is most NPV positive is preferred and carried out if it appears to make a sufficient return.

6.1.2 However, standard NPV analysis has its drawbacks. While it is a well-proven analytical tool when the investment model contains parameters with values that are virtually certain, it may not prove so useful in the presence of uncertainty. With standard NPV analysis investment based decisions, uncertainty may introduce conservative assumptions, and investment strategies that at the outset looked unpromising may be discarded but over time may prove worthwhile strategies.

6.1.3 Investment decisions made in the present may both create and eliminate options to do something in the future. In some cases, particularly when there are uncertainties, it is often of value to make decisions today that preserve decision options in the future. Real options analysis is a method of determining the value associated with future decision options.

6.1.4 The real options framework allows decision makers to quantify the value of various investment strategies in the presence of known risks. The decision-maker can then re-visit the analysis model at a later date when issues become clearer and risks lessen, i.e. uncertainty reduces as time passes and new information becomes available. In this way decision risk is reduced. Also it permits a large degree of flexibility to be factored into the investment decision framework.

6.1.5 This note presents two examples of real options analysis that may be applied to the Transmission to Enable Renewables (TTER) project. For this purpose it is assumed that a large wind resource has been identified in a region, and to accommodate this wind resource, some transmission investment (transmission works and easement purchase) will be required on the grid. Given the disparity in development timeframes when generation and transmission project lead times are compared, there are many questions regarding when transmission investment would be justified and to what extent it is justified based on the information available.

6.1.6 Two examples are presented that model both certain and uncertain information at different stages of the wind resource development. The examples employ the

expected NPV rule based options analysis, creating a decision tree based on the likelihood of events occurring, their costs and investment timing[47].

Example 1 – Delay transmission investment until wind resource consented and notionally committed (easements secured immediately)

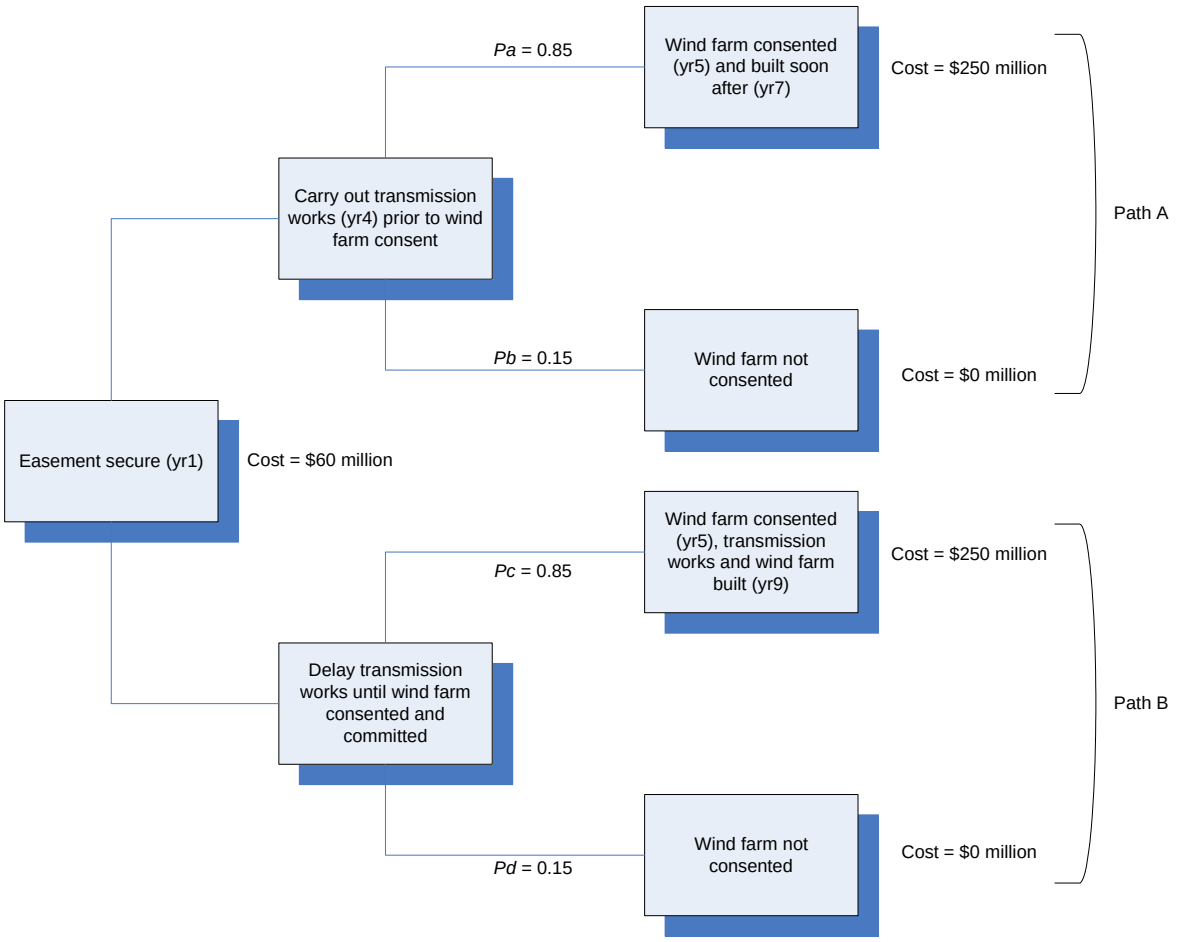
6.1.7 In the first example, it is assumed that a 1000MW wind resource has been identified in a region and the decision to purchase easements associated with the transmission works to accommodate the full potential capacity of the wind resource, is made immediately.

6.1.8 The analysis then attempts to ascertain whether there is any value in delaying the transmission works until the wind resource has been consented and committed for construction.

6.1.9 Figure 7 presents the decision framework for this real options analysis. The easements are assumed secured and paid for by year 1. The two paths that can then be followed are to either have the transmission works completed by year 4, or to wait until the development of the wind farm becomes more certain.

[47] From “Mycogen as a Case Study in Real Options”. Turvey, Calum G., Review of Agricultural Economics, Volume 23(1):2001, pp. 243-264.

Figure 7: Decision tree for example 1 – easement purchase immediately



6.1.10 Figure 7 illustrates the two identified investment paths. Path A is the early transmission investment option, while Path B is the investment delay option. The investment paths are probability weighted based on the certainty of each outcome. In the early stages of the wind farm development the likelihood of it being developed is probably very low, while Figure 7 shows a situation where it is almost certain to be built.

6.1.11 In this analysis investment timing is important as the various investment paths are compared on an NPV basis and weighted by the probability of that outcome. In the case where the wind farm has an 85% chance of being built (as is Figure 7), the NPV analysis yields an expected value of $39.5 million. This is the sum of each possible outcome on a probability weighted NPV basis (see Appendix A for spreadsheet), even the case where the transmission works are carried out yet the wind farm is not consented (in this case this is assigned a likelihood of 15%).

6.1.12 At the early stages where the wind farm is not so certain of being developed the decision maker may place a low probability for a positive wind farm development

outcome, say 30%. If this is assumed then the expected NPV would be -$190.9 million.

6.1.13 On the basis of these results there appears to be some value associated with waiting for the wind developer to notionally commit to the project before carrying out the transmission works (based on the modelling cost, timing and probability assumptions made). Nothing has changed in the analysis framework except that investment postponement has revised outcome probabilities as the information becomes more certain. In real options theory terms this investment flexibility is called an investment timing option.

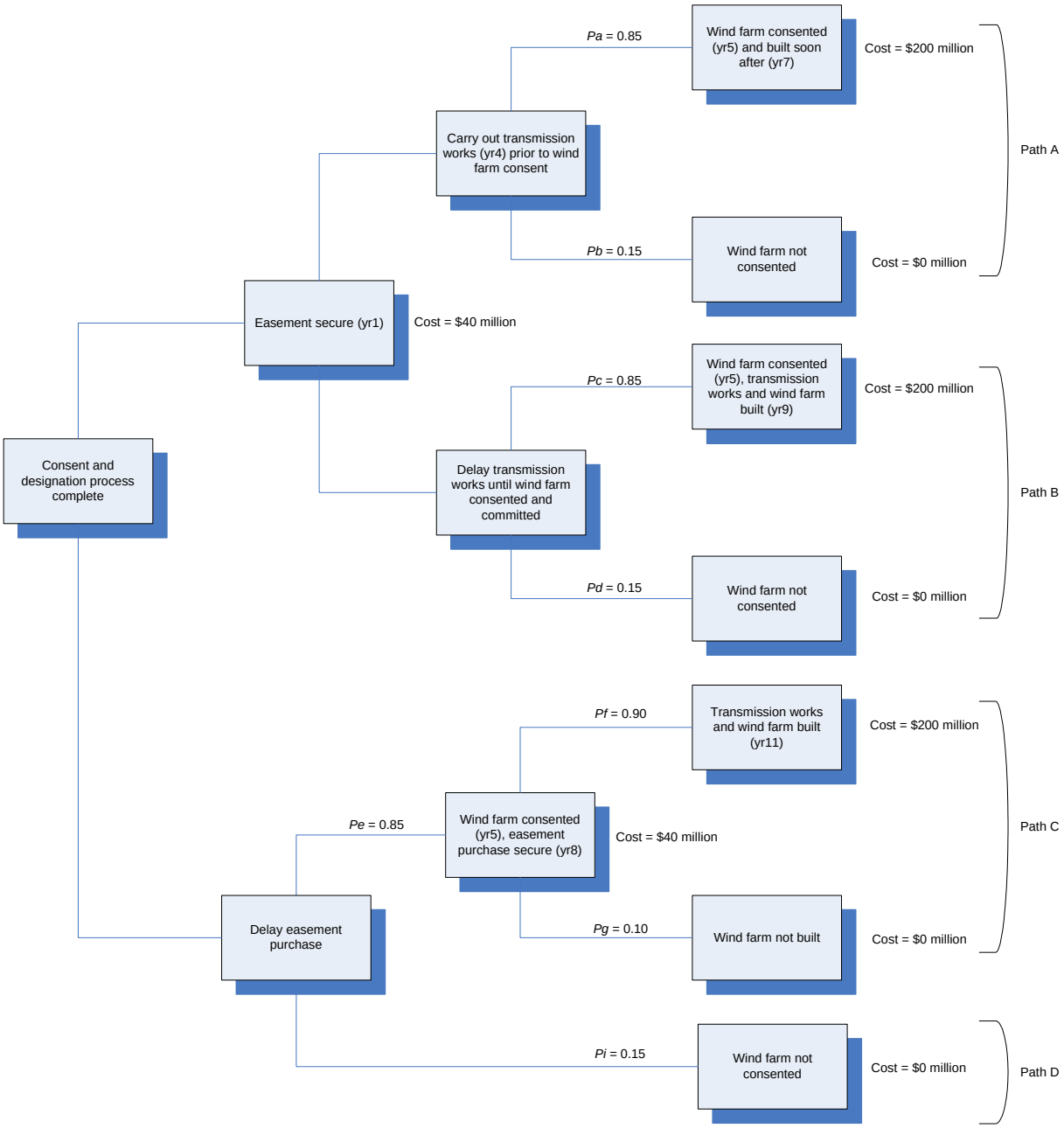
Example 2 – Delay easement purchase until wind resource consented

6.1.14 In this example, it is assumed that as soon as a 500MW wind resource has been identified the resource consent and transmission works designation process begins and is completed by year 1. There are then two investment paths to consider.

6.1.15 The first is to purchase the easements immediately then make choices about the transmission works or not at an early stage as in Example 1. The second path is to delay the easement purchase until the wind resource is consented. In the second path there may be delays associated with the wind farm being built as a consequence of the delay to easement purchase and transmission works. This possible delay needs to be reflected into the probability weighted NPV analysis as cost savings due to capital deferral may not always prove to be the most economic investment path.

6.1.16 Figure 8 illustrates a possible decision tree for this example for the case where the wind farm is virtually certain of being developed to its 500MW potential (85% chance of being built).

Figure 8: Decision tree for example 2 – easement purchase delay



6.1.17 If the transmission investment decision-maker at the early stage of the investment process assigns a 30% probability to the wind resource being developed to 500MW, then the expected NPV would be -$162.7 million (based on an easement cost of $40 million and transmission investment cost of $200 million). However, if this wind farm development has a 85% chance of being built (as shown in Figure 2) then the expected NPV becomes positive at $19.4 million (see Appendix 2 for the spreadsheet).

6.1.18 As in the first example, and on the basis of the assumptions made, there appears to be some value in waiting for the wind developer to secure consent for the project before securing the easements and then carrying out the transmission works. However this value appears to be only marginal even on the basis that the easements are secure within 3 years and the wind farm is generating by year 12 rather than in year 9 as in Path B.

6.1.19 Clearly the decision to delay any early easement purchase will have to be made on a case by case basis once a wind resource has been identified, and the various parameters that affect the NPV results, varied to ascertain the robustness of the expected NPV results.

Next steps

6.1.20 This analysis has been presented not so much a basis for justifying any easement or transmission investment at this stage. Rather it is to promote discussion about the ways and means to put an analytical framework around what transmission investment may be justified and when, once a renewable resource has been identified.

6.1.21 The logical extension to the analysis presented in this note is to apply some form of Monte Carlo risk modelling to the options analysis variables, namely for:

(a) easement and transmission upgrade costs;

(b) thermal generation plant displacement benefits (this will be fully correlated with the size of the consented generation project);

(c) consented generation capacity vs possible generation capacity;

(d) easement and transmission investment timing;

(e) wind farm consent timing; and

(f) outcome probabilities.

6.1.22 Additionally, once the TTER project identifies the renewables resource regions, and the possible upgrades and costs associated to develop these, a real case study of this analytical approach can be carried out.

Appendix A

Examples 1a and 1b – Easements secured by year 1 (only costs/benefits to yr 12 reproduced but analysis carried out to yr 20)

Scenario	NPV ($m)	yr1	yr2	yr3	yr4	yr5	yr6	yr7	yr8	yr9	yr10	yr11	yr12
A - Easement by yr 1, transmission works by yr 3, wind farm built by yr 7													
Easement	-56.07	60.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Transmission line works	-204.39	0.00	83.33	83.33	83.33	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Thermal plant displacement benefit	320.51	0.00	0.00	0.00	0.00	0.00	0.00	55.00	55.00	55.00	55.00	55.00	55.00
Total	**60.05**												
B - Easement by yr 1, transmission works by yr 8, wind farm built by yr 9													
Easement	-56.07	60.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Transmission line works	-155.93	0.00	0.00	0.00	0.00	0.00	83.33	83.33	83.33	0.00	0.00	0.00	0.00
Thermal plant displacement benefit	254.25	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	55.00	55.00	55.00	55.00
Total	**42.25**												
Path A													
WF built	$51.04												
WF not built	-$39.07												
Path A NPV	**$11.97**												
Path B													
WF built	$35.91												
WF not built	-$8.41												
Path B NPV	**$27.50**												
Probability weighted NPV	**$39.47**												

Scenario	NPV ($m)	yr1	yr2	yr3	yr4	yr5	yr6	yr7	yr8	yr9	yr10	yr11	yr12
A - Easement by yr 1, transmission works by yr 3, wind farm built by yr 7													
Easement	-56.07	60.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Transmission line works	-204.39	0.00	83.33	83.33	83.33	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Thermal plant displacement benefit	320.51	0.00	0.00	0.00	0.00	0.00	0.00	55.00	55.00	55.00	55.00	55.00	55.00
Total	**60.05**												
B - Easement by yr 1, transmission works by yr 8, wind farm built by yr 9													
Easement	-56.07	60.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Transmission line works	-155.93	0.00	0.00	0.00	0.00	0.00	83.33	83.33	83.33	0.00	0.00	0.00	0.00
Thermal plant displacement benefit	254.25	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	55.00	55.00	55.00	55.00
Total	**42.25**												
Path A													
WF built	$18.02												
WF not built	-$182.32												
Path A NPV	**-$164.31**												
Path B													
WF built	$12.67												
WF not built	-$39.25												
Path B NPV	**-$26.58**												
Probability weighted NPV	**-$190.88**												

Example 2a – Easements delay and 30% chance of wind farm being developed

Scenario	NPV ($m)	yr1	yr2	yr3	yr4	yr5	yr6	yr7	yr8	yr9	yr10	yr11	yr12
A - Easement by yr 1, transmission works by yr 3, wind farm built by yr 7													
Easement	-37.38	40.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Transmission line works	-163.51	0.00	66.67	66.67	66.67	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Thermal plant displacement benefit	229.28	0.00	0.00	0.00	0.00	0.00	0.00	30.00	30.00	30.00	30.00	30.00	30.00
Total	**28.38**												
B - Easement by yr 1, transmission works by yr 8, wind farm built by yr 9													
Easement	-46.36	40.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Transmission line works	-124.74	0.00	0.00	0.00	0.00	0.00	66.67	66.67	66.67	0.00	0.00	0.00	0.00
Thermal plant displacement benefit	193.13	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	30.00	30.00	30.00	30.00
Total	**22.03**												
C - Easement by yr 8, transmission works by yr 11, wind farm built by yr 11													
Easement	-24.95	0.00	0.00	0.00	0.00	0.00	13.33	13.33	13.33	0.00	0.00	0.00	0.00
Transmission line works	-101.83	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	66.67	66.67	66.67	0.00
Thermal plant displacement benefit	147.31	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	30.00
Total	**20.54**												
Path A													
WF built	$8.51												
WF not built	-$140.62												
Path A NPV	**-$132.11**												
Path B													
WF built	$6.61												
WF not built	-$32.45												
Path B NPV	**-$25.84**												
Path C													
WF built	$1.23												
WF not built	-$5.99												
Path C NPV	**-$4.76**												
Probability weighted NPV	**-$162.71**												

Example 2b – Easements delay and 85% chance of wind farm being developed

Scenario	NPV ($m)	yr1	yr2	yr3	yr4	yr5	yr6	yr7	yr8	yr9	yr10	yr11	yr12
A - Easement by yr 1, transmission works by yr 3, wind farm built by yr 7													
Easement	-37.38	40.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Transmission line works	-163.51	0.00	66.67	66.67	66.67	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Thermal plant displacement benefit	229.28	0.00	0.00	0.00	0.00	0.00	0.00	30.00	30.00	30.00	30.00	30.00	30.00
Total	**28.38**												
B - Easement by yr 1, transmission works by yr 8, wind farm built by yr 9													
Easement	-46.36	40.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Transmission line works	-124.74	0.00	0.00	0.00	0.00	0.00	66.67	66.67	66.67	0.00	0.00	0.00	0.00
Thermal plant displacement benefit	193.13	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	30.00	30.00	30.00	30.00
Total	**22.03**												
C - Easement by yr 8, transmission works by yr 11, wind farm built by yr 11													
Easement	-24.95	0.00	0.00	0.00	0.00	0.00	13.33	13.33	13.33	0.00	0.00	0.00	0.00
Transmission line works	-101.83	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	66.67	66.67	66.67	0.00
Thermal plant displacement benefit	147.31	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	30.00
Total	**20.54**												
Path A													
WF built	$24.13												
WF not built	-$30.13												
Path A NPV	**-$6.01**												
Path B													
WF built	$18.73												
WF not built	-$6.95												
Path B NPV	**$11.77**												
Path C													
WF built	$15.71												
WF not built	-$2.12												
Path C NPV	**$13.59**												
Probability weighted NPV	**$19.36**												