TRANSPOWER

NORTH ISLAND GRID UPGRADE PROJECT

AMENDED PROPOSAL

APPLICATION FOR APPROVAL

20 OCTOBER 2006

Contents

Attachments

Executive Summary

This document represents Transpower's Amended Proposal for the North Island Grid Upgrade Project, and updates (and replaces where defined), Transpower's original proposal that was submitted to the Electricity Commission as part of a full Grid Upgrade Plan in September 2005.

Amended Proposal - Works

The following works make up the Amended Proposal for which Transpower is now seeking approval:

The following works make up Transpower's Amended North Island Grid Upgrade Proposal (the Amended Proposal):

- Procure, construct, commission and operate a 220 kV switching station in the vicinity of Drury and upgrade the 220kV Otahuhu – Whakamaru C line by 2010.
- Procure, construct, commission and operate 350 MVAr of new static reactive plant at Otahuhu substation by 2010.
- Procure, construct, commission and operate a new double-circuit, steel lattice tower, overhead transmission line of approximately 190km from a new substation near the existing Whakamaru substation to a new transition station in the vicinity of the South Auckland urban boundary, that is capable of:
    - 220 kV operation
    - future 400 kV operation of around 2700 MVA, subject to later Commission approval of and Transpower commissioning of 220 kV-400 kV transformers and associated switchyards near the existing Whakamaru substation and in the vicinity of the South Auckland urban boundary.
- Procure, construct, commission and operate two underground cables from the new transition station in the vicinity of the South Auckland urban boundary to Pakuranga substation that:
    - are capable of 220 kV operation; and
    - have a continuous rating of around 660 MVA per set of cables
- Procure, construct, commission and operate the necessary substation / transition station facilities near the existing Whakamaru substation (Air Insulated Switchgear [AIS]), a transition station in the vicinity of the South Auckland urban boundary (AIS), and Pakuranga substation (Gas Insulated Switchgear [GIS]).
- Plan the works, including the acquisition of designations, consents and easements to allow for future upgrade to 400 kV operation through future addition of:
    - new 400/220 kV transformers and associated works near the existing Whakamaru substation to interconnect with the existing 220 kV system;
    - a new switchyard in the vicinity of the transition station with new 400/220 kV transformers and associated works; and
    - new overhead lines or underground cables to connect the new switchyard with the new transition station.

  - o new 220 kV underground cables to Otahuhu substation.
  - o extensions to the Otahuhu switchyard(s)
- Carry out the works necessary to convert and connect the existing 110 kV Otahuhu-Pakuranga line to 220 kV operation, for which it is already designed and consented;
- Dismantle the existing 110 kV Arapuni to Pakuranga transmission line
- Obtain designations, easements, resource consents and property purchases necessary for all the above works.
- Plan for a commissioning date for the major projects above of 2011 to prudently allow for potential delays due to delivery, designation, consenting and easement risks.

Amended Proposal – Cost

Transpower is seeking Electricity Commission approval for costs incurred by Transpower in the implementation of the Amended Proposal in accordance with the 90% limit of project costs in 2011 dollars, estimated at $824 million. The table below provides a breakdown of that cost:

Cost Category		Amended Project $ 2011 (million)
Investigations		27
Property		116
Environmental		8
Transmission Works:		
- Lines	*400 kV line*	203
	Up-rate OTA-WKM C	4
	OTA-PAK 110kV Circuits	1*
	Drury	2
- Substations	*Otahuhu*	12
	Whakamaru	13
	Pakuranga	55
	Drury	16
	Static Compensation	8
- Cable		110
Dismantling		5
Project Management		34
Subtotal		**614**
Contingency		105
Exchange Rate		25

Interest During Construction	80
TOTAL	**824**

*This cost will increase by between $7M and $10M if the Otahuhu diversity project does not proceed.

Rule Requirements
Transpower considers the Amended Proposal as described above meets the requirements of the Rules in that:

The Amended Proposal reflects good electricity industry practice in meeting grid reliability standards.
Specifically, the proposal and approach is consistent with international practice as being a prudent investment given the size, nature and importance of the Auckland load.

The Amended Proposal complies with the Rule processes
Transpower considers that the Amended Proposal follows the processes set out in Section III, Part F of the Electricity Governance Rules.

The Amended Proposal satisfies the Grid Investment Test
Under the Grid Investment Test, the Amended Proposal has a net market cost that is $10 million lower than the closest other option (220 kV into Pakuranga). Under sensitivity analysis across a wide range of assumptions, the Amended Proposal was better than other options in a significant majority.

Timing
Two methods for determining the actual timing of the proposed project – probabilistic and deterministic. The outcome from the timing analysis is as below:

Method	Requirement Date
Probabilistic (EC model): (combining the Grid Reliability Standards and Grid Investment Test)	2013
Deterministic: (using an n-g-1 security criteria and a prudent forecast)	2013

When delivery risk is included, the timing for the project is as below:

Project Delivery: (allowing for delivery risk)	2011

Recommendation

It is recommended that the Commission approve the Amended Proposal on the grounds that it:

- complies with the Rules;
- meets the GRS;
- passes the GIT; and
- is consistent with GEIP.

Further, it is the project that is most aligned with the draft changes proposed to the GPS, particularly with respect to an emphasis on renewable generation, provision of diversity of supply to Auckland and minimisation of the number of corridors required for transmission.

1 Introduction

1.1 Purpose of this project

1 The purpose of the North Island Grid Upgrade project is to maintain reliable bulk electricity supply for the upper North Island.

2 The purpose of this document is to obtain approval from the Electricity Commission for delivery of this upgrade, and for the recovery of the cost of doing so.

1.2 Background to this document

3 On 30 September 2005 Transpower submitted a Grid Upgrade Plan (the "Original GUP") to the Electricity Commission (the "Commission"), which included a proposal for a "reliability investment" to construct a new 400 kV double circuit line between Whakamaru near Tokoroa, and Otahuhu in South Auckland (the "Original Proposal").

4 The Commission commenced a consultation process on the Original Proposal on 27 April 2006 and also commenced consultation on its draft decision to decline approval.

5 On 31 May 2006 Transpower informed the Commission of its intention to amend the Original Proposal. Transpower also asked the Commission to suspend its consideration of the Original Proposal and the Commission agreed to such suspension.

1.3 Purpose of this document

6 This document is Transpower's submission to amend the Original Proposal contained in the Original GUP. The amendment relates solely to the Original Proposal and, except as set out in this submission, the Original GUP remains otherwise unchanged.

7 Transpower notes that the approval processes for the other investments contained in the original GUP are currently suspended, with the agreement of the Commission. Transpower confirms that it may submit amendments to those other investments in the Original GUP at appropriate times in the future.

8 Transpower suggests the timetable and process for consultation as outlined in Section 2.4 in relation to this amendment submission, for consideration by the Commission. Transpower also suggests that the consultation process which was suspended on 31 May 2006 be reinstated and continued.

9 Transpower notes that the Commission has withdrawn its draft decision to decline approval of the application for the Original Proposal as proposed in the Original GUP.

1.4 References to Original Grid Upgrade Plan

10 This proposal is an amendment to the Original GUP of September 2005. A full cross reference between the Original GUP and this Amended Proposal is provided in Appendix B, and is summarised below:

Volume of Original GUP	Section	Amended by this proposal
Vol I	Executive summary	Yes
	Asset Management Plan	No
	Contracted Investments	No
Vol II	400 kV Grid Upgrade Plan	Yes
Vol III	HVDC Inter Island Link	No
Vol IV	Grid Development Proposals	No

2 Approval sought

11 Transpower seeks approval from the Commission to recover the actual costs incurred in delivering the project through the transmission pricing methodology following commissioning of the project. Transpower will not exceed the amount approved for the project without further approval from the Commission. Costs are to include the accrued interest charged on works under construction.

2.1 The Amended North Island Grid Upgrade Proposal

12 The following works make up Transpower's Amended North Island Grid Upgrade Proposal (the Amended Proposal):

- Procure, construct, commission and operate a 220 kV switching station in the vicinity of Drury and upgrade the 220kV Otahuhu – Whakamaru C line by 2010.
- Procure, construct, commission and operate 350 MVAr of new static reactive plant at Otahuhu substation by 2010.
- Procure, construct, commission and operate a new double-circuit, steel lattice tower, overhead transmission line of approximately 190km from a new substation near the existing Whakamaru substation to a new transition station in the vicinity of the South Auckland urban boundary, that is capable of:
    - 220 kV operation
    - future 400 kV operation of around 2700 MVA, subject to later Commission approval of and Transpower commissioning of 220 kV-400 kV transformers and associated switchyards near the existing Whakamaru substation and in the vicinity of the South Auckland urban boundary.
- Procure, construct, commission and operate two underground cables from the new transition station in the vicinity of the South Auckland urban boundary to Pakuranga substation that:
    - are capable of 220 kV operation; and
    - have a continuous rating of around 660 MVA per set of cables
- Procure, construct, commission and operate the necessary substation / transition station facilities near the existing Whakamaru substation (Air Insulated Switchgear [AIS]), a transition station in the vicinity of the South Auckland urban boundary (AIS), and Pakuranga substation (Gas Insulated Switchgear [GIS]).
- Plan the works, including the acquisition of designations, consents and easements to allow for future upgrade to 400 kV operation through future addition of:
    - new 400/220 kV transformers and associated works near the existing Whakamaru substation to interconnect with the existing 220 kV system;
    - a new switchyard in the vicinity of the transition station with new 400/220 kV transformers and associated works; and
    - new overhead lines or underground cables to connect the new switchyard with the new transition station.
    - new 220 kV underground cables to Otahuhu substation.
    - extensions to the Otahuhu switchyard(s)
- Carry out the works necessary to convert and connect the existing 110 kV Otahuhu-Pakuranga line to 220 kV operation, for which it is already designed and consented;

- Dismantle the existing 110 kV Arapuni to Pakuranga transmission line
- Obtain designations, easements, resource consents and property purchases necessary for all the above works.
- Plan for a commissioning date for the major projects above of 2011 to prudently allow for potential delays due to delivery, designation, consenting and easement risks.

2.2 Transpower's Intended Approach to Project Management

13 On approval of the package listed in paragraph 12, Transpower intends to:

- Deliver the package listed in paragraph 12.
- Conduct for the Transpower Board independent periodic audits of its project management, procurement and commercial processes to demonstrate that cost controls are in place, with a demonstration of the process of business improvement in response to any issues identified.
- Report periodically to the Transpower Board on progress against both expected costs and cost with contingencies, and reasons for any divergence (e.g. foreign exchange), allowing for indexed escalation or deflation of linked costs.
- Transpower acknowledges that to manage the project risk it is essential that a high degree of quality assurance is applied in planning, design, manufacture, commissioning, testing and maintenance activities in accordance with good electricity industry practice.

14 Transpower recognises that, following approval, if it transpires that it cannot meet some aspect of the approved project above, such as the cost ceiling, it has the option to seek the Commission's agreement to an amendment under Rule 17.2.

2.3 Regulatory context, and structure, of this application for approval

15 This is an amendment to an application for approval of a reliability investment under Part F of the EGRs. Section 1 introduces the application, while section 2 specifies what Transpower is seeking Commission approval for. Section 3 sets out the need for investment while the options assessed to meet that need and Transpower's Amended Proposal are covered in sections 4 and 5 respectively.

16 Transpower acknowledges that in order to be approved, the proposed reliability investment must satisfy the following criteria:

13.4.1.1 "reflects good electricity industry practice in meeting grid reliability standards"; and

13.4.1.2 "complies with the processes set out in these Rules"; and

13.4.1.3 "meets the requirements of the Grid Investment Test".

17 The justifications of the Amended Proposal against these three criteria, respectively, are described in section 6.

18 This is followed by section 7 that addresses the timing of the investment.

19 In section 8 Transpower sets out a number of factors that it considers to be relevant to the Commission's assessment of the proposal.

20 Finally, section 9 sets out Transpower's recommendations to the Commission.

2.4 Suggested process and timetable for a draft decision

21 In order to make full use of the work already done by interested parties in making relevant submissions to date on the Original Proposal, Transpower requests that the Commission makes it clear to interested parties that they should indicate the extent to which of their earlier submissions or comments are to apply to the consultation and consideration by the Commission on the Amended Proposal. Transpower is of the view this will help make the consultation process more timely. If the proposal is to be built in time to minimise negative impact on grid security and reliability in the upper North Island, a draft decision is desired by the end of 2006. If a draft decision is not reached by Christmas 2006, this may have negative implications for the lodging of a Notice of Requirement and acquisition of easements by the deadline required by the project implementation timetable, which in turn will have knock on effects to the project management of the Amended Proposal, which may impact on Transpower's ability to implement the project in time to maintain reliability into the upper North Island.

3 Needs assessment

22 The needs analysis concludes that there is a risk of some electricity demand not being supplied to the upper North Island region at times of peak loading from 2013 and that new investment is required to maintain security of supply into that region. This date assumes that projects already approved by the Commission are commissioned by their target dates or, alternatively, no later than 2010. In particular, these projects include:

- Establishment of Ohinewai substation (Huntly East);
- Thermal upgrade of the 220 kV Otahuhu-Whakamaru A and B lines;
- Bombay bus split ; and
- The reactive power investments in the Upper North Island as approved by the Commission.

23 The September 2005 Grid Upgrade Plan, Volume 2, Part 2, “Establishing the Need for New Investment” provided details on how the need for the new investment is assessed.

24 The technical analysis of transmission options was carried out using the same assumptions as in the September 2005 GUP, with the exception of the items listed below:

Item	September 2005 GUP	Amended Proposal
Load forecast	2005 SoO with medium load growth scenario	2005 SoO with a ‘prudent’ high demand forecast
Security criteria	n-1 with allowance for reduced generation	Two assessments are made: o Grid Reliability Standard as applied in the draft decision on the 400 kV project; and o n-1 with allowance for the Otahuhu CCGT to be out of service

Table 3.1: Comparison of assessment assumptions

3.1 Load forecast

25 The Commission provided the load forecast used for this Amended Proposal. The load data is based on the 2005 Statement of Opportunities. This is the same as the September 2005 GUP but with a higher growth scenario. The growth scenario used was changed for the following reasons:

- experience gained from higher than predicted loads during winter 2006;
- alignment with good electricity industry practice (i.e. use of a high or ‘prudent’ rather than a medium forecast); and
- improvements in forecasting technology and methods.

26 The impact of these changes is that the load forecast used for the Amended Proposal is higher than used for the September 2005 GUP, as illustrated below:

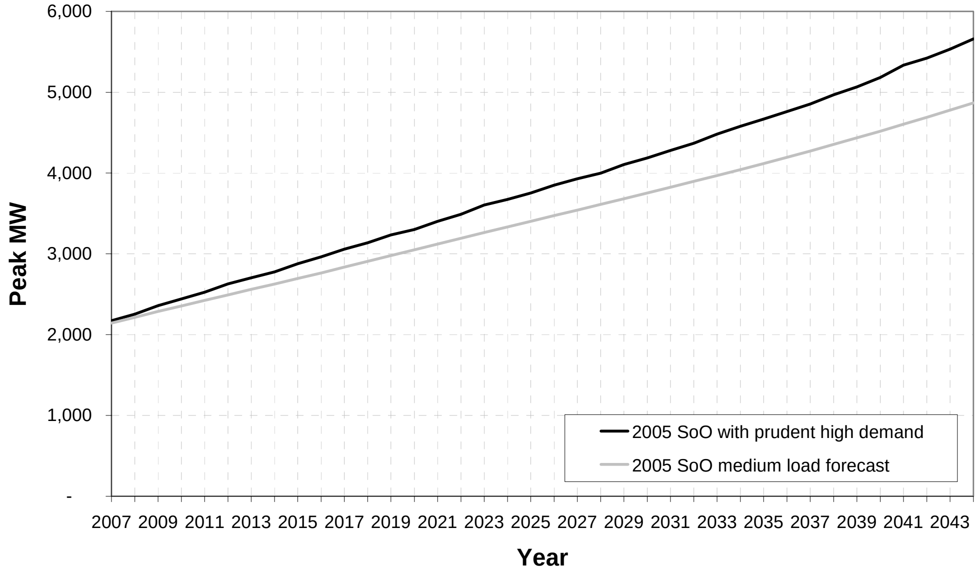

Figure 3-1: Comparison of load forecasts used for the Original and Amended Proposals

3.2 Reliability criteria and timing

27 The September 2005 GUP used a reliability criterion of n-1 with "an assessment of the likely level of actual generation that can be reasonably and prudently assumed to be available".

28 Two security criteria are used in this assessment:

- A probabilistic assessment using the Grid Reliability Standards and the Grid Investment Test together to determine the required timing of projects; and
- A deterministic criterion that, in Transpower's view, is consistent with the Grid Reliability Standards in that it makes the 'reasonable' allowance that the largest generator in the Auckland area may not be available at the same time peak demand occurs.

29 The probabilistic assessment is based on the methods outlined in the draft determination and calculates the required date for the project by assessing and balancing the cost of expected unserved energy (EUE) against the net cost of the proposed investment.

30 The deterministic security level applied to Auckland for the technical analysis in the Amended Proposal is n-g-1 where g is the Otahuhu CCGT generator and n is the worst single credible transmission line or generator contingency.

31 Both methods are used because Transpower, when it was preparing this application, had concerns that the probabilistic approach would not deliver an investment timing that was commensurate with the more widely used and historically proven deterministic standard.

32 Transpower agreed to provide both sets of results to inform a comparison of the outcomes. Transpower agrees with the Commission's conclusion in its draft decision that an outcome that meets n-g-1 is appropriate for a critical load centre like Auckland.

4 Options considered

4.1 Options considered by Transpower in the 2005 Grid Upgrade Plan

33 For the Original Proposal submitted as part of the Original GUP in September 2005, Transpower undertook an analysis of a number of transmission options and alternatives to transmission (including generation and demand side management) to meet the need for investment. These options included:

- 330 kV development
- 500 kV development
- Classic HVDC development
- HVDC Light development
- Under-grounding (either HVDC or HVAC)
- Peaking generation plant

34 The analysis carried out for the Original Proposal regarding these options concluded that they did not pass the assessment criteria. This conclusion remains unchanged and therefore these options (other than classic HVDC development and peaking generation plant) are not analysed further in this proposal.

4.2 Alternatives considered by the Electricity Commission

35 As part of their assessment of the 2005 Grid Upgrade Plan including the North Island 400 kV Upgrade Project, the Commission consulted widely on alternatives to the project.

36 The Commission narrowed the projects down to a short list and ultimately a set of alternatives to which the North Island 400 kV Upgrade Project was compared. These alternatives comprised 220 kV, 400 kV and HVDC projects[1].

37 This Amended Proposal builds off the analytical results obtained in the Commission's draft determination.

38 In their draft determination, the most cost effective alternative was the 220 kV project, with the HVDC and 400 kV (in 2010) being more costly.

39 Transpower, in considering alternatives for the Amended Proposal, has used the results of the draft decision and selected their best alternative – the 220 kV project – as the reference case for the economic analysis.

40 On the basis that both Transpower and the Commission analysis showed HVDC was not as cost effective, an HVDC alternative has not been considered in the economic analysis for the Amended Proposal.

41 Further discussion on the HVDC options is provided in Section 4.7.

4.3 Developing transmission augmentation projects - technology

42 The development of possible projects that would meet the demand is challenging because of the number of potential options that exist using various permutations and combinations of technologies, routes and forecasts.

[1] *http://www.electricitycommission.govt.nz/opdev/transmis/400kv/400kValternatives*

43 The choice of technology is of interest because, over the period of the analysis, it is likely that some new or refined technologies will emerge. In addition, the long life of the assets involved, and the staging of developments associated with those assets, means that there will be a number of decision points through the study period.

44 While there may be a high level of confidence that the first investment is a sound decision, technological and other change introduces uncertainties for all future decision points.

45 It is possible that at each of these decision points, the decision makers of the day could be faced with compelling reasons to change technologies or to depart from what today's decision makers would regard as a 'normal course of action'.

46 Unless the analysis period is short – say 10 years or less – most if not all possible projects to meet the need will be subject to the same uncertainties.

47 The approach taken by Transpower, and the Commission in their draft decision, is to select a project option based on a known technology and for future stages and development to be consistent with this technology. For example, choosing a 220 kV line of certain design characteristics would be followed by a similar development when required.

48 Changing technology at a decision point has been avoided in the analysis on the assumption that relative rankings of technologies do not change over time. For example, if 220 kV technology is less costly than HVDC for a comparative capacity, it is assumed this will remain true over the study period unless there is a compelling reason to believe otherwise.

49 The adoption of project staging delivers future opportunities to optimise investments to take account of actual outcomes and technological change. Staging thus provides opportunities to cap project downside while enabling upside.

50 The development of transmission augmentation projects has thus focused on providing:

- technology consistency through the study period; and
- staging to cap downside risks and provide opportunities to optimise future developments.

51 This approach in defining possible projects is based on using the best available information at the time of decision making and delivering a 'low regret' outcome.

4.4 Transmission Augmentation Projects

52 For the Amended Proposal, a total of eight transmission augmentation projects were analysed in terms of their technical feasibility. All projects share a common set of augmentations and are described in broad terms below:

4.4.1 Option 1: 220 kV into Pakuranga and Otahuhu.

53 This project involves:

- Building a new 220 kV double circuit transmission line between Whakamaru and the South Auckland urban boundary with 220 kV underground cables from the South Auckland urban boundary to Pakuranga;

- Building additional 220 kV cables from the South Auckland urban boundary to Otahuhu when required;
- Installing series compensation on the transmission line, when required, to increase the transfer capacity to the upper North Island; and
- Building an additional 220 kV double circuit transmission line between Whakamaru and Otahuhu when the transfer capacity to the upper North Island is exhausted.

54 The line design chosen for any new 220 kV line options was intended to meet the intent of the (draft) GPS requirement 88E for fewer corridors of high capacity. The heaviest conductor in use on 220 kV lines at present is Chukar and the line was optimised to give the greatest available capacity with this conductor for the lowest practicable implementation cost.

55 The resulting tower heights are up to 58m. Lower tower heights are possible but with a significant increase in the number of towers and therefore cost.

56 Transpower believes if the proposed project can be shown to have greater benefits than this optimised 220 kV line, it will also be superior to a sub-optimal and higher cost line.

4.4.2 Option 2: 400 kV into the South Auckland urban boundary, 220 kV into Pakuranga and Otahuhu

57 This project involves:

- Building a 400 kV double circuit transmission line between Whakamaru and the South Auckland urban boundary then 220 kV underground cables from the South Auckland urban boundary to Pakuranga;
- Building additional 220 kV cables from the South Auckland urban boundary to Otahuhu when required; and
- The transmission line would initially operate at 220 kV with series compensation to increase the transfer capacity to the upper North Island first and then convert to 400 kV operation when required.

58 The 400 kV line design is a result of optimisation and the requirements to meet technical guidelines relating to audible noise, electric and magnetic field strengths. Audible noise was a limiting factor and required the adoption of a triplex conductor configuration.

59 The conductor configuration provided a significant increase in the thermal capacity of the line, increasing from 1600 MVA of the original proposal to 2700 MVA for the current design.

60 The provision of a 400 kV substation in the South Auckland urban boundary region allows the full capacity of this line to be utilised in the proposal as 220 kV cables can be added as required to match the line capacity.

4.4.3 Option 3: Augmentation of existing 220 kV assets.

61 This project involves:

- Duplexing the 220 kV Otahuhu – Whakamaru A & B single circuit lines; and

- Re-terminating the Otahuhu-Whakamaru A and B transmission lines to Pakuranga from a point near the South Auckland urban boundary using 220 kV underground cables[2].
- Building additional 220 kV double circuit transmission lines between Whakamaru and Otahuhu when the transfer capacity to the upper North Island is exhausted.

62 The degree of strengthening required was determined using a factor representing the criticality of the line. Other factors affecting the degree of strengthening required were the age (40-50 years old) and design of these lines.

63 In this case, Transpower has used the same factors it would apply to any such significant 220kV (or indeed, 400kV) line. It is assumed the tower members are all in place and structurally competent when calculating the strengthening requirements.

64 Strengthening the towers to any lower level would imply some agreed programme to retire the towers and line before a typical line life of 40 (additional) years. This is in line with the (draft) GPS requirement to provide solutions that are consistent with good electricity industry practice (clause 87C) and provide long-term confidence in the reliability of supplies (clause 87 G).

65 A lower level of structural strength would create uncertainty about both the life of the line and its ability to withstand more onerous weather conditions, resulting in departures from good industry practice and provision of short-term rather than long-term solutions.

66 Transpower considered a variant to this option whereby the existing assets from the transition station would be utilised, saving the cost of one set of cables. This option would require additional space to effect the connection between one of the duplexed circuits and the two remaining sections of simplex construction extending into Otahuhu.

67 The first suitable location for this transition station would be at Redoubt Road, approximately 1 km further south than the currently proposed transition station.

68 Transpower considered there would be two primary effects of this variant:

- Reduction in cost gained by removing one cable, which would be offset by the additional costs of between $5M and $8M for the increased length of cable; and
- A reduction in diversity as only one cable, representing approximately 660 MVA of capacity, would terminate at Pakuranga.

69 Given the weight attributed in the (draft) GPS to the provision of diversity, Transpower did not consider this variant further.

4.4.4 Option 4: Augmentation of existing 220 kV assets using high temperature conductor

70 This project is a variant on Option 3 and involves

- replacing the conventional aluminium steel core conductor (ASCR) with high-temperature conductor (HTC) on the Otahuhu – Whakamaru A, B and C lines. This would permit higher transfer capacities over existing assets; and

*[2] The line section from Otahuhu to the South Auckland urban boundary would **not** be duplexed and would be disconnected but will remain in place.*

- building an additional 220 kV double circuit transmission line between Whakamaru and Otahuhu when the transfer capacity to the upper North Island is exhausted.

4.4.5 Option 5: 400 kV into Otahuhu.

71 This project involves:

- Building a new 400 kV double circuit transmission line between Whakamaru and the South Auckland urban boundary and 400 kV underground cables from the South Auckland urban boundary to Otahuhu.
- The transmission line would initially operate at 220 kV with sub options as follows:
  Sub option 5.1: Converting to 400 kV operation first and then installing series compensation to increase the transfer capacity into Upper North Island when required; or
  Sub option 5.2: Installing series compensation to increase the transfer capacity to the upper North Island first and then converting to 400 kV operation when required.

4.4.6 Option 6: 220 kV into Otahuhu.

72 This project involves:

- Building a new 220 kV double circuit transmission line between Whakamaru and the South Auckland urban boundary with 220 kV underground cables from the South Auckland urban boundary to Otahuhu.
- Installing series compensation on the transmission line, when required, to increase the transfer capacity to the upper North Island.
- Building an additional 220 kV double circuit transmission line between Whakamaru and Otahuhu when the transfer capacity to the upper North Island is exhausted.

4.4.7 Option 7: 400 kV into Pakuranga and Otahuhu.

73 This project involves:

- Building a 400 kV double circuit transmission line between Whakamaru and the South Auckland urban boundary and 400 kV underground cables from the South Auckland urban boundary to Pakuranga.
- Building additional 400 kV cables from the South Auckland urban boundary to Otahuhu when required.
- The transmission line would initially operate at 220 kV with sub options as follows:
  Sub option 7.1: Converting to 400 kV operation first and then installing series compensation to increase the transfer capacity into the upper North Island when required; or
  Sub option 7.2: Installing series compensation to increase the transfer capacity to the upper North Island first and then converting to 400 kV operation when required.

4.4.8 Option 8: 400 kV into the vicinity of the South Auckland urban boundary, 220 kV into Pakuranga and Otahuhu – early conversion to 400 kV.

74 This project involves:

- Building a 400 kV double circuit transmission line between Whakamaru and the South Auckland urban boundary with 220 kV underground cables from the South Auckland urban boundary to Pakuranga.
- Building additional 220 kV cables from the South Auckland urban boundary to Otahuhu when required.
- The transmission line would initially operate at 220 kV and convert to 400 kV operation early-on and then install series compensation when required to increase the transfer capacity into the Upper North Island.

4.4.9 Common augmentations

75 A number of augmentations are common to all of the projects. These common projects are drawn from the Annual Planning Report 2006 (Sections 5 to 13). The common projects are listed in the technical report (Attachment D).

4.5 Non-transmission alternatives

76 Three non-transmission alternatives were identified and analysed:

- 155 MW OCGT, 3 shaft, peak load option;
- 240 MW CCGT, single shaft, base load option;
- 380 MW coal fired steam turbine, single shaft, base load option.

77 Transpower specified the capital, fuel and other assumptions used in the analysis. The approach was to bias assumptions towards the generation option to ensure any close options would be identified.

4.6 Limiting the options

78 An assessment of the projects was carried out in order to limit the number of projects against which the Grid Investment Test (GIT) would be applied, in accordance with schedule F4, item 11 of the Electricity Governance Rules (EGR's).

79 The criteria used to assess and limit the number of projects were:

- Diversity; and
- Capital cost.

4.6.1 Diversity

80 Following the 12 June 2006 event in which approximately half of the Auckland load was lost due to earth-wire conductors dropping across busbars, concerns were raised about the dependence of the Auckland load on a single substation.

81 A review of the Auckland supplies indicated a lack of diversity in relation to:

- Substation switchyards;
- Substation locations; and
- Transmission line corridors.

82 Options to address the lack of diversity in relation to each of the three points above were documented in the aftermath of the 12 June 2006 event. A more detailed discussion on the benefits of diversity is provided in Attachment A.

83 The draft GPS has an objective to provide adequate alternative supply routes to larger load centres and to be resilient against low probability but high impact events (Clause 80).

84 Transpower decided to terminate options at Pakuranga but to assess the cost differential of providing this diversity against the Original Proposal of initially terminating the options at Otahuhu.

Item	New line terminates at Pakuranga ($2006 million)	New line terminates at Otahuhu ($2006 million)
Lines	215	215
Cables	104	104
Substations	102	53
Property	96	96
Consenting	7	7
Investigation	23	23
Project management	34	34
Dismantling	5	4
Total	**586**	**535**

Table 4-1. Capital cost comparison of terminating the new line at Pakuranga and Otahuhu

85 Table 4-1 shows that the proposal, including a new line terminating at Pakuranga in 2011, has a total substation capital cost of approximately $102 million. This provides improved diversity of supply for Auckland consumers by reducing reliance on the Otahuhu substation.

86 Alternatively, the new line could terminate at Otahuhu in 2011, which would reduce the total substation capital cost to approximately $53 million, but without any improvement in diversity.

87 Good Electricity Industry Practice (GEIP) requires reducing reliance on Otahuhu substation in the future and this is reflected in the long term development plans for Auckland, which show that Pakuranga substation would be developed by 2021 under all scenarios.

88 The cost of providing diversity of supply now, by terminating the new line at Pakuranga instead of Otahuhu is $15 million. This is the difference in present value terms between spending $102 million in 2011, or spending $53 million in 2011 followed by a further $49 million in 2021.

89 It should also be noted that Pakuranga substation may be upgraded to 220 kV sooner than 2021, regardless of where the new line is terminated. This is due to the way in which Penrose substation may be reinforced as part of the North Auckland and Northland project.

90 One of the possible options identified in the recent North Auckland and Northland request for information (RFI) for reinforcing supplies into Penrose is to go via Pakuranga at 220 kV. The estimated cost for this option is the lowest of the five possibilities presented in the RFI.

91 If this lowest cost option were to be selected then Pakuranga would have to convert to 220 kV by around 2013. Under this scenario, the cost of diversity that could be attributed to the North Island Grid Upgrade project is the cost of bringing the Pakuranga substation conversion works forward by two years, which is approximately $7m.

92 Based on the above analysis, Transpower believes that terminating future options at Pakuranga rather than Otahuhu is sensible, prudent and consistent with the (draft) GPS (Clause 80). Therefore options 5.1, 5.2 and 6 should be discarded.

4.6.2 Capital Cost

93 Option 7.1 and option 7.2 (400kV into Pakuranga and Otahuhu) although technically feasible, are more costly due to their requirement for two 220/400 kV substations in Auckland, one each at Otahuhu and Pakuranga.

94 The capital cost of option 8 (early conversion to 400kV) is higher than for option 2 due to the comparative costs of building the 220/400 kV substations earlier.

95 Therefore, options 7.1, 7.2, and 8 should be discarded because they are more costly than equivalent options

4.7 Non-qualifying alternatives

96 The Grid Investment Test defines an 'alternative' in clause 19. Transpower believes the options defined in section 4.4 meet the requirements of clauses 19.1, 19.4 and 19.5.

97 As discussed below, Transpower concludes that HVDC options and the High Temperature Conductor option (Option 4) are not likely to proceed (Clause 19.3) and not reasonably practicable (Clause 19.2) and therefore do not qualify as alternatives.

4.7.1 HVDC alternatives

98 Based on Tables 8.1 and 8.3 in the Commission's draft determination, the HVDC alternative in 2017 is more costly than either their 220 kV or 400 kV alternatives in 2017. On this basis, Transpower has concluded that the 220 kV alternative considered in this Amended Proposal is a reasonable surrogate for the HVDC option. In other words, if the Transpower proposal is shown to be more cost effective than the 220 kV proposal, then it will also be better than the HVDC proposal.

99 Transpower has, as part of its Grid Vision[3] considerations, assessed the options of relocating the Haywards HVDC converter station to Bunnythorpe or Auckland and found HVAC options to be more cost effective.

100 Transpower has also submitted an HVDC upgrade project in the September 2005 GUP. It has been suggested that there could be synergies between this project and the North Island Upgrade project.

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[3] The summarised finding of the Grid Vision considerations were published in the Transpower documents 'Future of the National Grid' December 2003 and October 2004.

101 Moving one pole of the existing HVDC link to a point further north of Haywards, including Auckland, would require the construction of a new HVDC line or conversion of existing 220 kV lines to HVDC operation.

102 The time taken to consent a new HVDC line and the comparative costs of building a line from Wellington to Auckland, in Transpower's view, rule this option out.

103 Converting existing 220 kV lines to HVDC operation is costly, would increase congestion on the 220 kV grid and potentially restrict the ability to provide for both southward transfers and the Wellington load.

104 In addition to the cost based arguments, Transpower has considered the implications of the (draft) GPS. Clause 34A of the (draft) GPS requires that the national transmission grid should be planned in such a way as to facilitate the potential contribution of renewables to the electricity system and in a manner that is consistent with the Government's climate change and renewables policies. Clauses 87A and 87B refer to facilitating renewables and requirements for consistency with government policy relating to renewable generation and climate change.

105 There is potential for significant development of renewables – mainly wind and geothermal – in the central and southern North Island. Converting existing 220 kV lines for HVDC operation would reduce the options for renewables to connect to the 220kV grid because of the reduced capacity. Connection to HVDC is expensive because of the cost of the converter stations.

106 HVDC links are generally point-to-point solutions and multi-terminal HVDC installations are rare and not considered a mature technology, as indicated by the following[4]:

> *"… the adoption of a three terminal dc link of the conventional type for the Whakamaru-Auckland system would be a very costly solution with limited flexibility for future transmission expansion. On the other hand, …, the more flexible PWM multi-terminal alternative is not really a contender for the large power rating involved. Apart from the components (particularly the cable) costs, the switching (due to high frequency) and transmission (due to the high current) losses would be extremely high. "*
>
> *"New Zealand's previous commitment to dc (with the Cook Strait scheme), was an obvious decision, as there was no practical economic ac alternative at the time. However, the case for further dc, and particularly the multi-terminal option, is far from obvious at the moment and I would suggest a prudent "wait and see" policy in this respect."*

107 Transpower has concluded that even if the proposed project does not proceed, it is unlikely that this option would be built. The option is thus classed under Rule 19.3 as not qualifying as an alternative for formal comparison with the proposal.

[4] "Use Of HVDC Multi Terminal Options For Future Upgrade Of The National Grid?" Jos Arrillaga Emeritus Professor, FIEE, FIEEE, MNZM, 24-May-2006.

4.7.2 Option 4: Duplexing of Whakamaru-Otahuhu A&B lines with high temperature conductor

108 This involves:

- duplexing the Otahuhu – Whakamaru A & B single circuit lines with high temperature conductor and connecting to Pakuranga from a transition station in the vicinity of the South Auckland urban boundary through 220 kV cables. The line section from Otahuhu to transition station will **not** be duplexed and will be disconnected but not dismantled;
- re-conductor other existing circuits (for example, the Otahuhu - Whakamaru C double circuit line) with high temperature conductor as required;
- utilising series compensation to maximise the sharing of transmission flows and extend transmission capability; and
- details of the project and the sequencing of modelled projects are provided in Attachment D.

109 Although Transpower considers this a non-qualifying alternative, Transpower decided to undertake a comparative economic analysis because of the interest shown in the option by some landowners and interest groups. The economic analysis shows the option is not competitive and reasons for this are discussed later in this document.

110 Aside from the economic results, Transpower has no experience with this type of conductor and is not aware of any transmission lines of comparable length where the conductor is relied on to operate for extended periods at high temperatures.

111 Transpower is therefore concerned at the potential risks of conductor failure, particularly where the lines in question – the Otahuhu -Whakamaru A, B and C lines – all have significant levels of residential under-build.

112 An increase in magnetic field of between two and three times is associated with the substantial increase in current that is required to deliver the deferral benefits. Transpower believes that ‘prudent avoidance’ of such substantial increases in magnetic fields is appropriate, particularly where there are significant levels of under-build.

113 Transpower has concluded that even if the proposed project does not proceed, it is unlikely that this option would be built. The option is thus classed under Rule 19.3 as not qualifying as an alternative for formal comparison with the proposal, although analysis in this application allows this comparison to be made to demonstrate the economic cost of the project.

4.8 Electric and magnetic fields: transmission design issues for the options

114 Transpower has adopted the ICNIRP Guidelines[5] in designing 400 kV and 220 kV options. Transpower expects the current standards to be relatively stable in the long term but is aware that some utilities are voluntarily adopting lower standards for magnetic field levels.

[5] International Commission on Non-Ionizing Radiation Protection; “Guidelines For Limiting Exposure To Time-Varying Electric, Magnetic, And Electromagnetic Fields (Up To 300 Ghz)” – 1998.

115 Transpower notes that Option 3 and 4 involve duplexing and increasing the current flow in the Otahuhu-Whakamaru A and B lines. These lines have many dwellings and other buildings located directly under the lines and within the easement boundaries.

116 While the electric field strength does not change (as the operating voltage remains in the same range), the current related magnetic field will increase (almost double) from existing levels. Nevertheless, the resulting magnetic field strengths remain below the ICNIRP guidelines.

117 For the options in new corridors, the magnetic field strengths at the corridor boundaries are well below those experienced directly under existing lines or Option 3 or 4.

118 A further safeguard is provided for new lines through the purchase of easements which ensure that the construction of dwellings or other substantial buildings are prohibited within the easement boundaries.

4.9 Alternatives for further analysis

119 Limiting the options has resulted in three alternative projects that will be compared against each other using the GIT with the aim of selecting a proposed investment.

120 The projects are:

Option	Description
1	220 kV into Pakuranga and Otahuhu
2	220 kV – 400 kV staged to Pakuranga 400 kV into the South Auckland urban boundary and 220 kV cables to Pakuranga and Otahuhu (deferred conversion to 400 kV)
3	220 kV augmentation – duplexing of Otahuhu -Whakamaru A&B lines

Table 4-2. Alternative projects for further analysis

121 Each of these projects is, with respect to the Grid Investment Test Rule 19:

- Technically feasible;
- Reasonably practicable; and
- Reasonably expected to provide similar benefits.

122 These projects are therefore considered as alternatives for the purposes of applying the GIT. The alternative projects are summarised below.

4.9.1 Option 1: 220 kV into Pakuranga and Otahuhu

123 This involves

- Building a new high capacity 220 kV double circuit transmission line between Whakamaru and a transition station in the vicinity of the South Auckland urban boundary, which will be series compensated when required.
- Installing 220 kV cables from the transition station to Pakuranga substation.

- Building an additional 220 kV double circuit transmission line between Whakamaru and Otahuhu (on a new route and preferably providing corridor diversity) when the transfer capacity to the upper North Island is exhausted.
- Details of the project and the sequencing of modelled projects are provided in Attachment D.

4.9.2 Option 2: 220 - 400 kV staged to Pakuranga:

124 This involves

- Building a 400 kV double circuit overhead line between a new substation (Whakamaru North) located near the existing Whakamaru substation and a transition station in the vicinity of the South Auckland urban boundary. Initially the transition station will be connected to Pakuranga using 220 kV underground cables.
- Subsequently, additional 220 kV cables will be used to transmit power from the transition station to Otahuhu. The overhead transmission circuits will initially operate at 220 kV and convert to 400 kV operation when required by building 400 kV/220 kV switchyards at the South Auckland urban boundary transition station and also at Whakamaru North.
- The overhead transmission circuits will be series compensated when required to increase the transfer capacity to the upper North Island as long as possible before conversion to 400 kV. When the transfer capacity is exhausted, the transmission circuits will convert to 400 kV operation.
- Details of the project and the sequencing of modelled projects are provided in Attachment D.

4.9.3 Option 3: Duplexing of Whakamaru-Otahuhu A&B lines

125 This involves

- duplexing the Otahuhu – Whakamaru A & B single circuit lines and connecting to Pakuranga from a transition station in the vicinity of the South Auckland urban boundary through 220 kV cables. The line section from Otahuhu to transition station will not be duplexed and will be disconnected but not dismantled;
- building a 220 kV line and subsequent investments after the capability following the duplexing is exhausted; and
- details of the project and the sequencing of modelled projects are provided in Attachment D.

4.10 Selecting the Proposed Investment

126 The three alternative projects identified above as well as the High Temperature Conductor variant, were compared against each other using the GIT.

127 Transpower notes that there has been a considerable amount of discussion on the GIT and its interpretation. In light of these discussions, Transpower has agreed to use the GIT calculation tool designed by the Commission for selecting the Amended Proposal on the understanding that the tool is still evolving. Transpower hopes to continue to develop the GIT calculation tool with the Commission over time.

128 A detailed description of how the GIT was applied and the results of the analysis is provided in Attachment E, which describes how the proposed investment was selected as being Option 2: 220 - 400 kV staged to Pakuranga.

5 Transpower's Amended Proposal

129 Transpower is seeking approval for the reliability investment as defined in paragraph 12. This project is Option 2, 220 kV - 400 kV staged to Pakuranga, as described in the previous section.

130 Many of the final design details will depend on, amongst other factors (and subject to this approval):

- The outcomes of the RMA approval process and requisite consultation phase;
- The availability of property and easements;
- Detailed design of substations, towers and cable routes; and
- Commercial negotiations with suppliers and contractors.

131 The purpose of this section is to set out a likely form that the proposal would take at a more detailed level, for the purposes of public information and the Commission's approval process. Transpower does not seek approval at the level of detail set out in this section, and Transpower confirms that it seeks approval for the project as defined and described in paragraph 12.

5.1 Proposal description and timetable

132 The proposed investment is for a 400 kV overhead transmission line from Whakamaru North into the transition station, with 220 kV cables into Pakuranga and Otahuhu substations (option 2 as described above).

133 This option comprises building the new 400 kV transmission line, along with the projects identified as 'common' augmentations listed in Attachment D.

134 The 400 kV transmission line has a system need date of 2013 and will be initially operated at 220 kV increasing the transfer limit to the Upper North Island to approximately 3,400 MW.

135 In 2022, the new line may be 55% series compensated, which along with other developments, increases the transfer limit to approximately 4,500MW. A further cable connection into Auckland will be provided at this stage.

136 By 2034, the line needs to be upgraded to 400 kV operation, by commissioning new 400 kV sub-stations at Otahuhu and Whakamaru. Along with other developments, the transfer limit increases to approximately 5,500 MW.

137 The thermal and the reactive development plans for the proposed investment are shown in the tables below and as well as pictorially in Figure 5.1.

138 The 'Year' column represents the year in which the 'Augmentation' is required to be commissioned for a high load growth scenario. Lower load growth would result in these augmentations being deferred. With respect to dates, 2013 means the augmentation must be commissioned by winter 2013.

139 Table 5.1 shows the development plan in terms of system needs dates. These dates represent the absolute latest that the augmentations must be commissioned by and ***it provides no allowance*** for risks caused by such events as delays in procurement or obtaining consents etc.

140 Project risk and its effect on the timing in relation to the proposal is discussed in section 7.

Year	Augmentation
2009	**Install 250 MVAr static reactive plant at Otahuhu**
2010	**Decommission the 110 kV Arapuni - Pakuranga line**
	Install 100 MVAr static reactive plant at Otahuhu
2012	**Establish Drury switching station and implement thermal upgrade for Otahuhu-Whakamaru C line**
2013	**New substation at Whakamaru North**
	2 x 400 kV Whakamaru North – Transition Station circuits operated at 220 kV
	2 x 220 kV Cables, Transition Station - Pakuranga
	Cable Transition Station in the vicinity of the South Auckland urban boundary
	220 kV sub station at Pakuranga
	Increase operating voltage of Otahuhu -Pakuranga to 220 kV *
	Install 3 x 120 MVA supply transformers at Pakuranga
	First 220 kV Pakuranga-Penrose Cable
2014	Reconductor 110 kV ARI-HAM 1 & 2 to Nitrogen 75°C conductors.
2016	Install 100 MVAr static reactive plant at Otahuhu
2017	Install 100 MVAr static reactive plant at Otahuhu
2018	Second Pakuranga-Penrose cable
	Install 100 MVAr dynamic reactive plant at Otahuhu
2020	Install 100 MVAr static reactive plant at Huntly
2022	2 x 55% compensation on Whakamaru -Transition Station circuits
	Install 110 kV OTA-WIR cable; close the WIR bus breaker
	1 x 220 kV Penrose- Otahuhu cable
	Commission switching station at South Auckland urban boundary
	1 x 220 kV Transition Station - Otahuhu cable
2024	Install 200 MVAr static reactive plant at Otahuhu
	Second 220 kV Otahuhu - Transition Station cable
2025	Install 100 MVAr dynamic reactive plant at Otahuhu
	Second Roskill 220 / 110 kV transformer
2027	Re-conductor HAM-BOB 110 kV circuits to Nitrogen Conductors.

Continued on next page

2028	Install 100 MVAr static reactive plant at Huntly
	Thermal upgrade of HLE- Whakamaru section of Otahuhu - Whakamaru C line
	Second 220 kV Penrose - Roskill cable
2029	Install 150 MVAr static reactive plant at Otahuhu
	Install 20 Ohm reactor on Otahuhu - Whakamaru A&B lines
2031	Install 100 MVAr static reactive plant at Huntly
2032	Install 300 MVAr dynamic reactive plant at Otahuhu
	Forced cooling on Transition Station -Pak cables
2033	Install 150 MVAr static reactive plant at Otahuhu
	Third Roskill 220 / 110kV transformer
2034	Forced cooling on 220 kV Transition Station - Otahuhu cables
	400 kV sub station at Whakamaru North
	400 kV sub station at the transition station in the vicinity of the South Auckland urban boundary
	Operate Whakamaru - Transition Station at 400 kV
	6 x 400/220 kV 600 MVA transformers at Transition Station
	6 x 400/220 kV 600 MVA transformers at Whakamaru
	Reduce series compensation on the 400 kV line to 45%
	Second 220 kV Penrose-Otahuhu cable
2038	New Otahuhu 220/110 kV transformers in parallel with T3 and T5
	1 x 75 MVA phase shifting transformer on Arapuni-Bombay circuit
2042	Install 300 MVAr static reactive plant at Otahuhu
	Post contingency Operational Measures to reduce Transition station - Otahuhu loading

* Transpower will consult on both AIS and GIS switchyard at Pakuranga. Only if there is a clear public preference for a GIS switchyard at Pakuranga will the designation be limited to this option, and thus the GIS referred to above would have to be built.

** This list excludes augmentations that are common to all of the alternatives. For the common projects, refer to Attachment D (Technical Assessment of Modified Options)

Table 5-1: System need dates under the proposed investment, showing projects included in this proposal in bold.

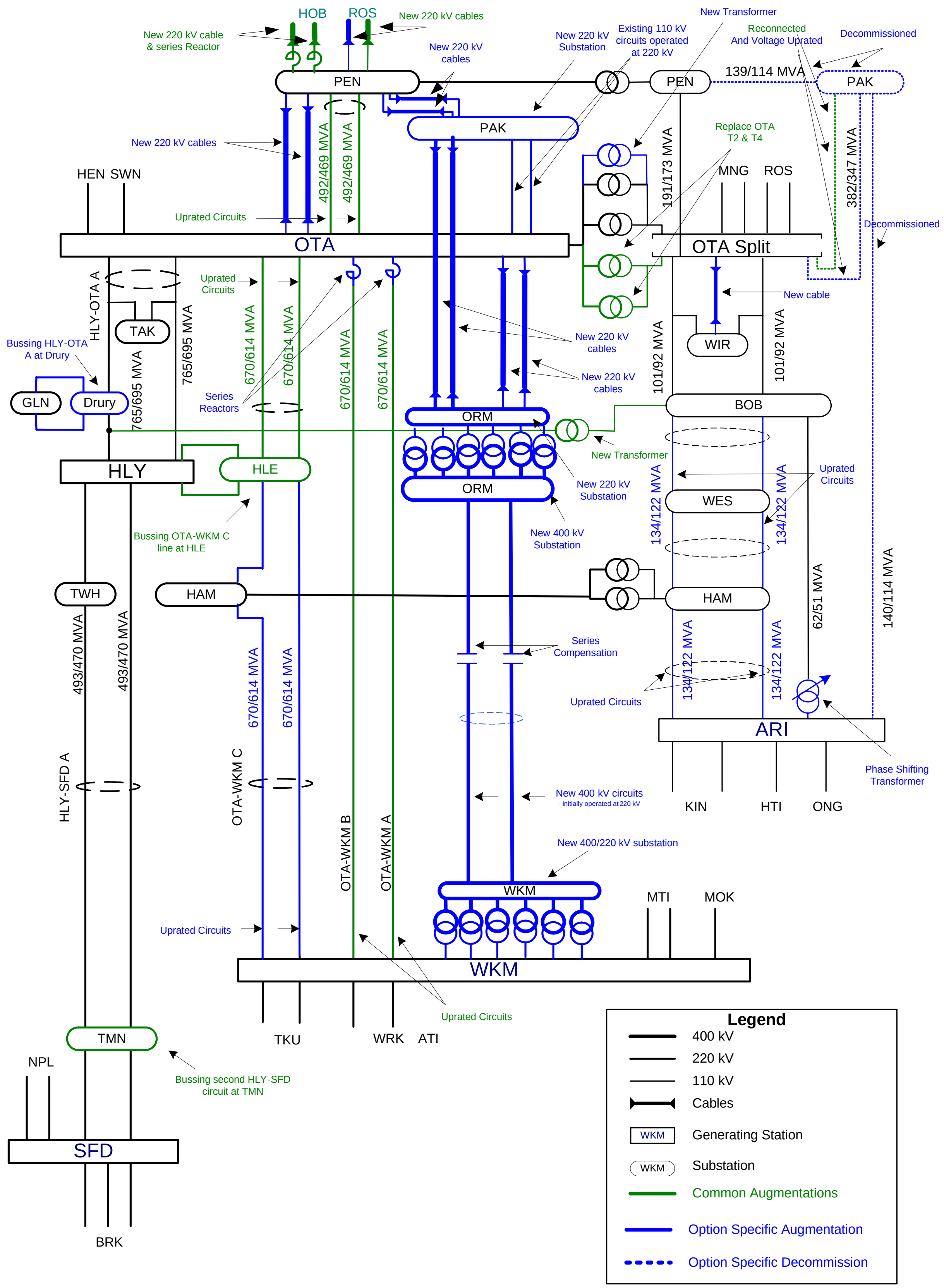

Figure 5-1. Single Line Diagram for Proposed Investment

5.2 Proposal costs

141 Transpower is seeking Commission approval for costs incurred by Transpower in the implementation of the Amended Proposal. The estimated capital cost for the Amended Proposal is $585m in $2006, including contingencies ($509m excluding contingencies).

Category	Item	Estimated Cost $m (2006)	Estimated Cost including Contingencies $m (2006)
Investigations	Preliminary engineering, environmental and property work.	22	22
Property	Acquisition of property rights	96	96
Environmental	Acquisition of designations and resource consents.	7	7
Transmission Works	2x400kV circuits from Whakamaru to a transition station in the vicinity of the South Auckland urban boundary operated at 220kV	168	210
	Other Lines Works	6	7
	Substation Works	87*	101*
	Cable	91	104
Dismantling	Arapuni to Pakuranga Line	4	5
Project Management		28	33
Total		**509**	**585**

*This cost will increase by between $7M and $10M if the Otahuhu diversity project does not proceed.

Table 5-2. Estimated Costs for Proposal
(The projects included in these cost estimates are those described in Table 7-2.)

142 To determine an amount for its approval request Transpower has estimated the mid-point and 90% limit of project costs using a simulation technique (see detail in 5.2.1) on commissioning of the first major stage of the proposal.

143 The mean project cost estimate in December 2011 dollars is $764M. The 90% limit of project costs has been estimated at $824M. The chart below shows the distribution of project costs.

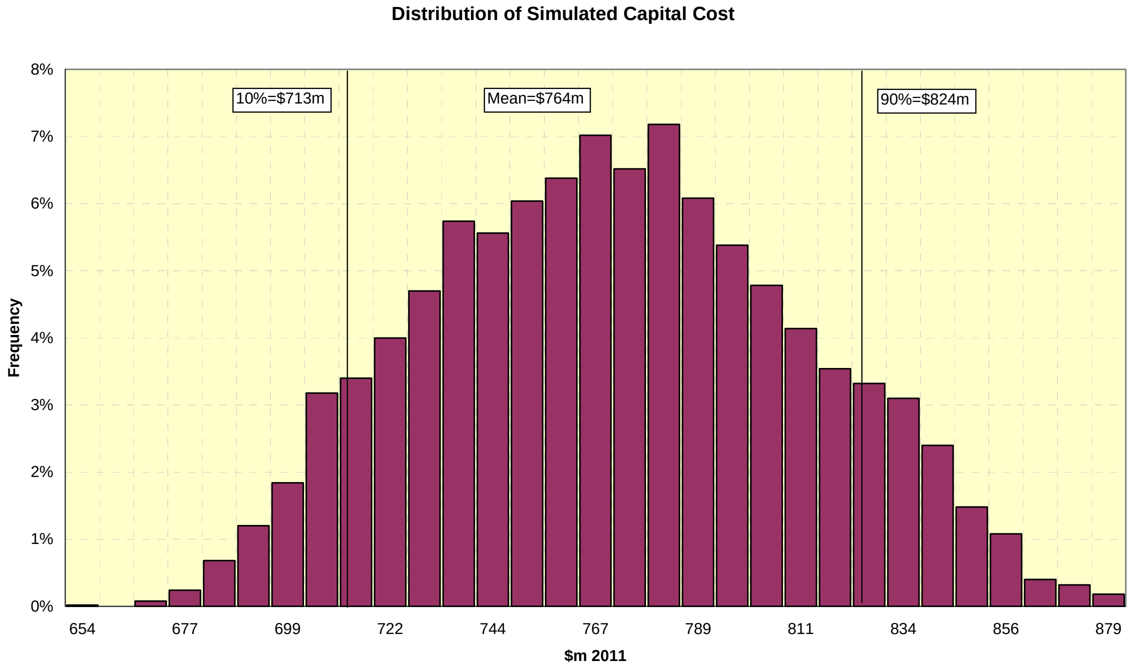

Figure 5-2. Distribution of project costs

144 The following table shows the Amended Proposal costs without simulation. The total cost is expected to equal $764M, in $2011, which includes a $117M inflation adjustment.

Category	Cost $m (2006)	Contingencies	Exchange Rate Variation	Interest During Construction	Fully Adjusted Cost $m (2006)	Inflation	Fully Adjusted Cost $m (2011)
Investigations	22	0	0	0	22	5	27
Property	96	0	0	12	108	20	128
Environmental	7	0	0	2	9	2	11
Lines	174	43	0	29	246	44	290
Substations*	87	13	0	4	104	18	122
Cable	91	13	0	8	112	21	133
Decommissioning	4	1	0	0	5	1	6
Project Management	28	6	0	7	41	6	47
Total	509	76	0	62	647	117	764

*These costs will increase by between $7M and $10M if the Otahuhu diversity project does not proceed.

Table 5-3. Proposal costs without simulation

145 Including simulation, a 90% upper limit on project cost is expected to equal $824 M, in $2011, which includes a $141M inflation adjustment.

Category	Cost $m (2006)	Contingencies	Exchange Rate Variation	Interest During Construction	90% Cost Limit $m (2006)	Inflation	90% Cost Limit $m (2011)
Investigations	22	0	0	0	22	5	27
Property	96	0	0	13	109	23	132
Environmental	7	0	0	2	9	2	11
Lines	174	46	14	30	264	52	316
Substations*	87	18	4	5	114	22	136
Cable	91	16	3	9	119	27	146
Decommissioning	4	1	0	0	5	1	6
Project Management	28	6	0	7	41	9	50
Total	509	87	21	66	683	141	824

*This cost will increase by between $7M and $10M if the Otahuhu diversity project does not proceed.

Table 5-4. Proposal costs with simulation

5.2.1 Method for Estimating 90% Cost Limit

146 The Monte Carlo technique was used to estimate the mid-point and 90% limit on project costs. The cost of the Amended Proposal is simulated a large number of times, and the frequency of simulation results is used to establish costs for a given level of likelihood.

147 Costs for projects and other elements of the proposal are broken down into components including:

- Costs denominated in New Zealand dollars
- Costs denominated in other currencies
- Property costs

148 The projects occur on a staggered basis and costs have been streamed over various dates to reflect project timing, and to allow calculation of interest during construction[6].

149 The model takes into account the following variables:

- Exchange rates
- Inflation
- Real interest rates
- Property cost escalation
- Price accuracy
- Scope contingencies

150 Cost estimates also include an allowance for interest during construction.

[6] For property purchases it has been assumed that if the proposal is approved the cost of land and easements can be included in Transpower's revenue base once route acquisition has been completed. Interest during construction costs will be higher if these costs must be incurred until completion of the transmission line, and lower if Transpower can recover these costs from the time of the land acquisition.

5.2.2 Assumptions for Key Variables

Exchange Rates

151 Point estimates of capital cost were based on 10 year average exchange rates. These were subsequently adjusted to smoothed spot rates using the average exchange rate 20 business days either side of 30 June 2006. For the simulation runs exchange rates have been sampled from daily exchange rates over the period 1 July 1996 to 30 June 2006. This approach ensures that the simulated exchange rates and cross-rates have a similar mean and variance to historical rates. Over a large number of simulations the exchange rate will be close to the 10-year average rate.

Inflation

152 Inflation is modelled by drawing from a uniform distribution in a range from 2% to 4%.

Real Interest Rates

153 The real interest rate is modelled by drawing from a uniform distribution in a range from 6% to 8%. The nominal interest rate is the real interest rate plus the inflation rate.

Property Cost Escalation

154 Real property cost escalation (i.e. price escalation over and above the inflation rate) is modelled by drawing from a uniform distribution in a range from 2% to 4%.

Price Accuracy

155 As regulatory approval occurs prior to the issuing of tenders, there is uncertainty over the price of equipment to be installed. This has been modelled by expressing the accuracy of estimates as a triangular distribution. The point estimate of costs is given as the most likely outcome, and lower and upper bounds are expressed as percentages of the midpoint.

Price Accuracy Parameters	Lower Limit	Upper Limit
Static compensation	-12.5%	12.5%
Decommission 110kV ARI-PAK Line	-5.5%	5.5%
Drury Switching Station	-12.5%	12.5%
OTA-WKM C thermal upgrade	10.0%	10.0%
2x400kV WKM-ORM ccts operated at 220kV	-5.5%	5.5%
WKM & WKN Sub work	-11.5%	11.5%
OTA Enabling Work	-10.0%	10.0%
OTA Subs Work	-10.0%	10.0%
2x220kV ORM-PAK cables	-10.0%	10.0%
Cable Termination at ORM	-11.5%	11.5%
220kV substation at PAK	-9.5%	9.5%
Convert OTA-PAK 110kV ccts to 220kV	-10.0%	10.0%

Table 5-5. Price accuracy

Scope Contingency

156 Scope contingencies have been included to cover two distinct categories of costs: Costs for works which are planned, but which have not been included in the cost estimates except through a general allowance, and costs for works not anticipated at the time costs were estimated.

157 For the purpose of simulation modelling, scope contingencies have been treated as fixed percentages, i.e. scope contingencies as a percent of costs do not vary between simulations. They may vary in dollar terms because of changes in other input variables. This is consistent with the definition of expected costs used in the economic analysis.

5.2.3 Comparison of Costs with September 2005 GUP

158 This subsection compares the approval cost estimates in Transpower's original April 2005 submission, and September 2005 GUP[7] with the new approval cost estimates for the Amended Proposal. A straight comparison is meaningless as the GUP cost estimates were expressed in nominal terms and the amended project costs are in December 2011 dollars, consistent with the Commission's approach in its Draft Decision.

Cost Category		April 2005 Submission/ Sept 2005 GUP			Amended Project Sept 2006	
		$2005	Nominal	$2011	$2006	$2011
Investigations		20		25	22	27
Property		97		121	96	116
Environmental		11		14	7	8
Transmission Works						
- Lines	*400kV Line*	120		150	168	203
	Uprate section of Ota-Wkm C				3	4
	Ota-Pak 110kV Circuits				1*	1*
	Drury Switching Station				2	2
- Subs	*Otahuhu*	66		82	10	12
	Whakamaru	33		41	11	13
	Pakuranga				46	55
	Drury Switching Station				13	16
	Static Compensation				7	8
- Cable		84		105	91	110
Dismantling		4		5	4	5
Project Management		25		31	28	34
Subtotal		**460**	**460**	**575**	**509**	**614**
Inflation			39	104*		141*
Contingency		60	65	75	87	105
Exchange Rate		-6	-6	-7	21	25
Interest During Construction		59	64	74	66	80
Total		**573**	**622**	**716**	**683**	**824**
Adjustment for difference in Limits**				-7		
Total		**573**	**622**	**709**	**683**	**824**

*This cost will increase by between $7M and $10M if the Otahuhu diversity project does not proceed.

Table 5-6. Cost summary

[7] *Volume 2, Section 5, Tables 6.1 and 7.2.*

Note that for the orange columns inflation figures are included to show the scale of the price adjustments made to the original estimates. They are not included in the summation.

** The April 2005 estimates were 95% upper limits compared to the 90% limit Transpower is now using. Analysis of the September 2005 GUP calculations suggest that the difference between 95% and 90% cost limits would have been $7m in $2011.

159 Table 5-6 shows both sets of figures adjusted to December 2011. These are the orange columns. The other columns show the amounts in dollars at other points in time so that they can be compared to costs in the September 2005 GUP, and this proposal.

160 The important differences between the costs for the original proposal and those for the Amended Proposal are:

- Lines costs rise $60m – reflecting the higher carrying capacity of the line, and costs to convert the Otahuhu – Pakuranga 110kV lines to 220kV, and to up-rate sections of the Otahuhu-Whakamaru C line to 80˚C.
- Substation costs drop $19m. This would be more but the 2005 GUP submissions did not include short term augmentation projects, or static compensation costs prior to the major project. These costs amount to $26m.
- Contingency allowances rise $30m. This reflects the use of fixed “Scope” contingencies in the estimates for the Amended Proposal. In preparing the 2005 GUP estimates these were assumed to be variable with a mean of zero.
- Exchange rate allowances rise $32m. This reflects an alternative treatment of exchange rate volatility. The original estimates covered Transpower for relatively modest exchange rate swings.

5.3 Proposal is a reliability investment

161 Part A of the Electricity Governance Rules defines a reliability investment as “investments by Transpower in the grid, or alternative arrangements by Transpower, the primary effect of which is, or would be, to reduce **expected unserved energy**”. Expected unserved energy is defined in Part A as meaning “a forecast of the aggregate amount by which the demand for electricity exceeds the supply of electricity at each grid exit point as a result of likely planned or unplanned outages of primary transmission equipment”.

162 The need for new investment to reduce expected unserved energy in the upper North Island is demonstrated in Part II, Volume II of Transpower’s September 2005 GUP and in section 3 of this proposal. The “needs analysis” in the original Volume II of the GUP concluded that “there is some risk of electricity demand not being supplied into the upper North Island at times of peak loading from 2010 and that new investment is required to maintain security of supply into the region.”[8] The Commission, in paragraph 5.1.6 of its draft decision on the original Volume II proposal, stated it was “satisfied … that the proposal would have the primary effect of reducing unserved energy and therefore it is appropriate to consider it as a reliability investment under rule 13.”

163 The Amended Proposal outlined in this application is also designed to reduce the expected unserved energy identified in the needs analysis referred to above, therefore the Amended Proposal is, in Transpower’s view, also a reliability investment.

[8] *P5, Volume II, Transpower GUP, September 2005*

164 The Amended Proposal is for a new transmission link between Pakuranga/Otahuhu and Whakamaru. The Commission's determination on the Core Grid defines this line as being included within the Core Grid. Because the line is part of the Core Grid both parts of the Grid Reliability Standards (GRS) , as defined in the glossary of this application, are relevant to this Amended Proposal. That is both the probabilistic (identified in rule 4.1 of Schedule F3) and the deterministic (identified in rule 4.2 of Schedule F3) standards are applicable to the assessment of the Amended Proposal.

5.4 Proposal is an amendment

165 On 31 May 2006 Transpower informed the Commission of its intention to amend the 400 kV Project in response to, among other things, various requests for information from the Commission. This current application, of an amendment to the 400 kV Project in the Original GUP, has been agreed with the Commission.

166 A salient difference between the Original Proposal and the Amended Proposal is that the new line initially terminates into Pakuranga substation, with a termination into Otahuhu being provided in the future. This is illustrated in the diagram below. The Original Proposal included the termination of the new line into Otahuhu only.

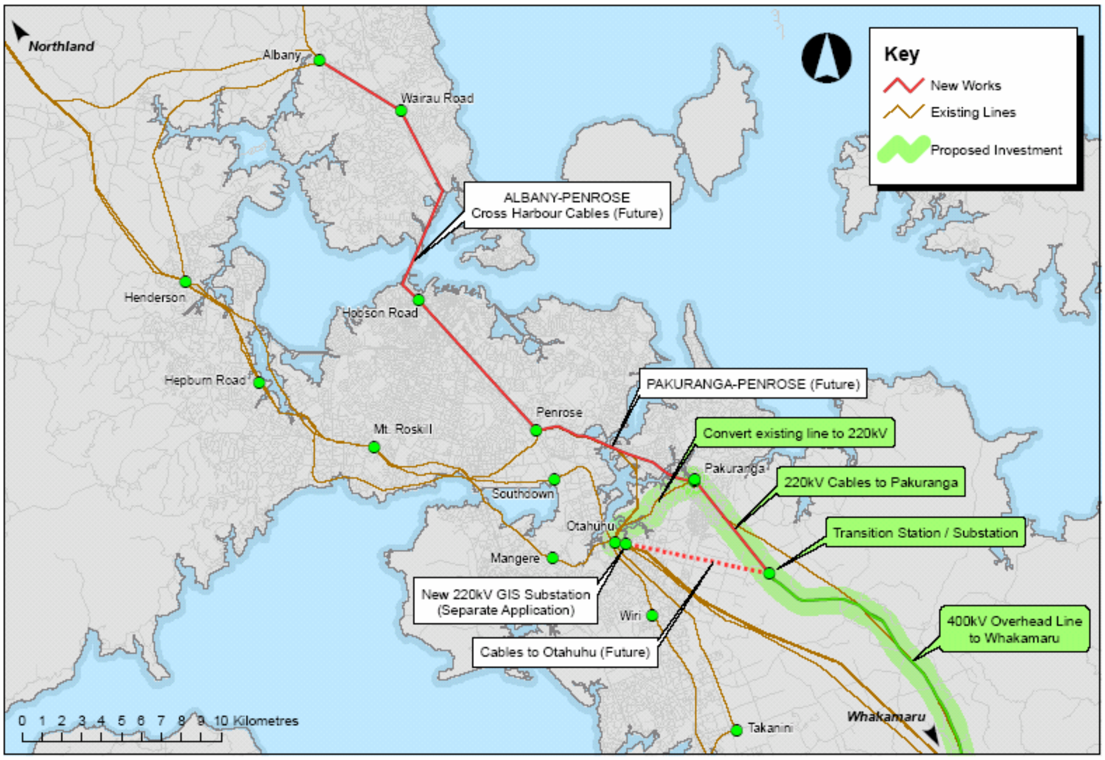

Figure 5-3. New line into Auckland (indicative only)

167 Other principal ways in which the Amended Proposal varies from the Original Proposal include:

- The overhead line component is amended such that it will be staged. Rather than operate at 400 kV from commissioning, it will operate initially at 220 kV. When it becomes economic to do so, approval will be sought for installation of the 220/400 kV transformers to enable 400 kV operation;

- The transmission capability of the overhead line has been increased to 2700 MVA to improve the utilisation of the transmission corridor and defer the need for a further corridor;
- The underground cable components are amended to operate at 220 kV rather than 400 kV;
- Short term projects are included in the proposal to defer the need for the major project to 2013 (details in paragraph 12); and
- Commissioning of the short term projects is targeted for 2010 with the major works in 2011; and
- A new 220kV substation is required at Pakuranga.

168 This application presents for approval this Amended Proposal by reference to the Asset Management Plan and information on investment contracts contained in the Original GUP.

6 The Amended Proposal meets the requirements of the Rules

169 Rule 13.4 sets out three criteria that a proposed reliability investment must meet in order to gain approval from the Commission. These criteria, and a discussion as to why Transpower's Amended Proposal meets these criteria, are set out in the following subsections.

6.1 Rule 13.4.1.1: The Amended Proposal demonstrates GEIP in meeting the GRS

170 The first criteria for approval under Rule 13.4.1 requires that the proposed reliability investment:

> *13.4.1.1 "reflects good electricity industry practice in meeting grid reliability standards"*

171 In its draft decision, the Commission considered that Rule 13.4.1.1 is not entirely clear, but took a view that in determining whether the Rule has been complied with, the Commission must turn its mind to whether it is satisfied that the proposed investment both:

- meets the GRS; and
- in so doing, reflects good electricity industry practice (GEIP).

172 Transpower agrees that the proposed investment must meet both of these criteria. Transpower's view is that this GEIP applies in addition to <u>how</u> one interprets the GRS, i.e. that under this Rule GEIP and the GRS are not independent. In other words, this rule is more than two independent rules "reflect good electricity industry practice" and "meet grid reliability standards".

173 The following three sections are therefore ordered to cover in turn:

- the GRS
- reflects GEIP; and
- reflect GEIP in meeting the GRS

6.1.1 The GRS

174 The GRS are contained in Schedule F3, which states that:

> *4 "For the purpose of clause 3, the grid satisfies the grid reliability standards if:*
>
> *4.1 the power system is reasonably expected to achieve a level of reliability at or above the level that would be achieved if all economic reliability investments were to be implemented; and*
>
> *4.2 with all assets that are reasonably expected to be in service, the power system would remain in a satisfactory state during and following any single credible contingency event occurring on the core grid."*

175 Rule 4.1 is the so-called "probabilistic limb of the GRS", and Rule 4.2 the "deterministic limb of the GRS". On a case by case basis, whichever limb provides the higher standard drives the reliability standard.

176 Transpower notes that on occasion the terms "economic limb" and "standards limb" of the GRS have been used instead. This is potentially misleading, as both limbs have economic and standards-based components in their formulation and application.

177 The deterministic limb provides a safety net for the probabilistic limb for contingencies on the core grid.

The probabilistic limb of the GRS

178 As defined in the GRS:

> *"Economic reliability investments" means investments in the grid and transmission alternatives that would satisfy the Grid Investment Test:*
>
> *8.1. reading each reference to a proposed investment in the Grid Investment Test as a reference to the grid investment or transmission alternative (as the case may be); and*
>
> *8.2. having regard to part C of these rules including the policy statement set out in schedule C4.*

179 The proposal (and the alternatives under the GIT being considered) is for a grid investment. For the proposal, clause 4.1 of the GIT therefore implies:

> *the power system is reasonably expected to achieve a level of reliability at or above the level that would be achieved if:*
>
> - *all investments in the grid that would satisfy the GIT were to be implemented,*
> - *having regard to part C of these rules including the policy statement set out in schedule C4.*

180 The proposal satisfies the GIT, as detailed in section 6.3 "Rule 13.4.1.3: The Amended Proposal satisfies the Grid Investment Test", so the first part of the test would be achieved were the proposal to be implemented.

181 The relevant components of Part C including C4 of the Rules detail the manner in which security is maintained for contingent events. In essence, the system is operated in real time to a security level of n-1 with all assets made available to the System Operator. It is the asset owners, principally the grid owner and generators, who determine what assets are made available.

182 These are not reasons not to use the GIT as part of the reliability standards. However they are relevant factors in considering how to interpret the deterministic "safety net" limb of the GRS.

183 For example, if one had total confidence in the accuracy and applicability of the GIT, one would not need a deterministic safety net. This is not the case in New Zealand, nor anywhere to Transpower's knowledge. The Rules accept that this is the case, as did the Commission in recommending those Rules:

184 Limitations of a pure probabilistic approach and a similar Grid Investment Test have been recognised by VENCorp, the transmission planner for Victoria, Australia:

> *"This 25 year vision indicated:*
>
> *• The long term economic benefits of efficient high capacity infrastructure such as the 500 kV electricity transmission network established by Victoria three decades ago.* ***It is not clear that this***

> ***backbone network would have emerged if current transmission planning approaches had been used at the time**.*[9]

The deterministic limb of the GRS

185 The "deterministic limb" of the GRS requires that

> *The grid satisfies the grid reliability standards if, with all assets that are reasonably expected to be in service, the power system would remain in a satisfactory state during and following any single credible contingency event occurring on the core grid."*

186 This is akin to the manner in which the system is operated, as described above.

187 Transpower has interpreted this deterministic limb to mean n-1 (the power system would remain in a satisfactory state during and following any single credible contingency event occurring on the core grid) with one generator out of service (with all assets that are reasonably expected to be in service). This standard is known as n-g-1, being short-hand for n-1 with the largest generator out of service.

188 The Commission, in its draft decision, appears to have misinterpreted Transpower's position, stating that:

> *"[Transpower considers it] reasonable to expect that a generating unit (eg a unit at Otahuhu B) will always be out of service. The Commission accepts that generating plant will be out of service from time to time, but does not consider it reasonable to assume that one generating unit will always be out of service"*

189 For clarity, Transpower does not consider it reasonable to expect that a generating unit will always be out of service. Transpower does consider it reasonable and prudent to plan on being able to maintain n-1 security when a generating unit (e.g. a unit at Otahuhu B) is out of service.

190 The Commission, in its draft decision, argues that its interpretation of the GRS delivers the same outcome as Transpower's interpretation of the deterministic limb of the GRS:

> *"As it happens, while Transpower's and the Commission's interpretation of the GRS is different, there is no practical difference in this case: in analysing the need for investment in respect of providing supply into Auckland, both approaches result in the same n-g-1 supply security outcome"*

191 Transpower does not fully agree with this assessment, as Transpower believes that GEIP in meeting the GRS requires meeting n-g-1 at a prudently high demand forecast, whereas Transpower understands that the Commission's assessment of the alternative proposals that it used in its draft decision met n-g-1 at a medium growth forecast.

192 Notwithstanding this, Transpower agrees that this potential difference is not relevant to approving this proposal under Rule 13.4.1.1, because if the proposal meets n-g-1 at a prudently high demand forecast it will certainly meet n-g-1 at a medium growth forecast.

[9] *"Vision 2030 – 25 year vision for Victoria's Energy Transmission Networks" October 2005, VENCorp, Australia.*

6.1.2 Definition of "Good Electricity Industry Practice"

193 Good electricity industry practice or GEIP is not a defined term in the Rules. In its draft decision, the Commission developed a definition of GEIP through reference to Transpower's definition in its posted terms and conditions, and the Australian definition, as:

> *"the exercise of that degree of skill, diligence, prudence, foresight and economic management, as determined by reference to good international practice, which would reasonably be expected from a skilled and experienced asset owner engaged in the management of a transmission network under conditions comparable to those applicable to the relevant grid assets consistent with applicable law, safety and environmental protection. The determination is to take into account factors such as the relative size, duty, age and technological status of the relevant transmission network and the applicable law."*

194 The Commission in its draft decision considered that this definition is appropriate for the purposes of the application of Rule 13.4.1.1, with some additional factors including:

- Performance criteria such as voltage stability margins, steady state bus voltage ranges and transmission asset loading limits. The Commission considers that many of the performance criteria detailed in Transpower's "Main Transmission Planning Guidelines"[10] are sufficient to ensure that the grid is planned to GEIP.
- Reliance, for substantial power system investments, on the use of equipment and designs whose performance can be directly related to proven service experience.
- A high degree of quality assurance applied in planning, design, manufacture, commissioning, testing and maintenance activities.
- In its draft decision, the Commission considered that for a proposed investment to meet GEIP, the following would be required:
  - a robust design process, with consultation and involvement of customers and stakeholders;
  - well developed specifications and design documents;
  - high-quality manufacturing and software development processes;
  - extensive co-ordination and testing before and after system integration phase;
  - as far as possible, full factory testing of complete finished control and protection systems;
  - thorough checking and testing at site/commissioning; and
  - ongoing validation and diagnostic maintenance.

195 Transpower agrees that the Commission's definition provides a useful working basis, and that the above factors are relevant considerations of GEIP. However, Transpower's view is that for transmission planning, there is more to GEIP than included in these factors.

[10] This report is available as a supporting document to the Proposal on Transpower's website: www.transpower.co.nz.

6.1.3 GEIP in meeting the GRS

196 In particular, GEIP requires amongst other things prudence as determined by reference to good international practice. In the case of the proposal, GEIP also would require consideration of the size, nature and importance of the Auckland load.

197 Transpower maintains that for a critical load like Auckland, the minimum acceptable standard for reliability would be one where peak demands could be reliably supplied even with a critical generator, such as the Otahuhu CCGT, out of service.

198 This approach is consistent with the short- and medium-term operational planning processes used by the System Operator to ensure supply adequacy and reliability. The System Operator has used this approach historically and has demonstrated its efficacy over many years.

199 International references confirm the n-g-1 approach, or a standards-based equivalent, to be consistent with international practice[11,12] and therefore an important indicator of GEIP.

200 In the Australian National Electricity Market, supply adequacy is treated separately from grid reliability by means of a minimum reserve margin (in MW) that must be maintained. For regions at the ends of the NEM power system (Queensland and South Australia), the minimum reserve margin is at or greater than the size of the largest unit. The approach is therefore consistent with an n-g-1 approach for Auckland.

201 Transpower maintains further that, even if the Commission disagrees with Transpower's interpretation of the GRS and interprets it as n-1, assuming all generation is available at 100% of its rated capacity, the requirement to consider GEIP would necessitate taking into consideration international practice described above.

[11] *PJM CETL process described at http://www.pjm.com/planning/downloads/cetlproc.pdf*

[12] *http://www.electricitycommission.govt.nz/pdfs/opdev/transmis/400Kv/supdocs/memoreport04.pdf*

6.2 Rule 13.4.1.2: The Original GUP complies with Rule processes

202 The second criterion for approval under Rule 13.4.1 requires that the proposed reliability investment:

13.4.1.2 "complies with the processes set out in these Rules".

203 In its draft decision, the Commission considered that this Rule should be interpreted as requiring Transpower to comply with the processes stipulated by Section III of Part F in relation to the submission of a proposed investment under a GUP. The relevant processes are summarised by the Commission in its consultation paper on the draft decision, in paragraph 6.3.5. Table 6.1 below re-states these processes, and the actions Transpower undertook to meet the process requirements:

Processes required by Rules 12 and 13	Transpower fulfilled these requirements:
• submitting a GUP to the Commission within three months of receiving a written request from the Commission, or such other date as the Commission agrees (Rule 12.2);	On 23 May 2005 the Commission sent a written request to Transpower to prepare a GUP, and to submit this by 24 August 2005. Following discussions between the Commission and Transpower, in August 2005 this deadline was extended to 30 September 2005. The Original GUP was submitted on this date.
• providing such content in the GUP as required by Rule 12.3;	Rule 12.3 requires a GUP to include: 12.3.1 a comprehensive plan for asset management and operation of the grid 12.3.2 information on investment contracts 12.3.3 the proposed reliability and / or economic investments, with supporting information 12.3.4 such other information as prescribed by the Commission Board. The Original GUP submitted on 30 September 2005 included Transpower's most recent Asset Management Plan (Vol. I), a list of bi-lateral investment contracts that had been entered into up to September 2005 (Vol I), the proposed 400 kV upgrade into Auckland as a reliability investment (Vol. II), and the proposed upgrade to the HVDC link as an economic investment (Vol. III). Two other investment proposals were included as economic investments in Vol. IV, which was submitted on 31 October 2005. There was no extra content prescribed in writing from the Commission Board, under rule 12.3.4.
• complying with the timetable for consultation and approval of the investment under consideration as agreed by the Commission and	In its consultation paper on its draft decision, the Commission summarised the development of the consultation timetable, including extensions to this timetable. In paragraph 7.2.8 of the consultation paper the Commission confirmed it was satisfied Transpower had complied with the extended

Transpower or stipulated by the Commission (Rule 13.2); and	timetable.
• answering the Commission's questions and carrying out investigations and evaluations as required by the Commission under Rule 13.3.3.	Appendix 2 of the draft decision consultation paper lists in a table key relevant events and processes, up to the publication of the consultation paper itself. This table includes the various requests for information made by the Commission under Rule 13.3.3. In paragraph 7.2.10 of the consultation paper the Commission stated it believed Transpower had endeavoured to respond to these requests to the extent practicable.

Table 6.1: Compliance with the Rule processes ('Commission' refers to the Commission'

204 Transpower notes that in its draft decision, with respect to Transpower's Original Proposal, the Commission determined that:

> *"On balance, the Commission is … satisfied that Transpower has complied with the processes set out in the relevant Rules."*

205 That the Amended Proposal follows the Rules process for an amendment by Transpower to a reliability proposal is demonstrated in this section of the application.

206 The Original Proposal and the amendment of it to form this Amended Proposal therefore comply with the processes set out in the Rules.

207 Transpower considers that the Original GUP submitted on 30 September 2005, and the Amended Proposal which is the subject of this application, demonstrate compliance with the Rules for amending the Original Proposal, and hence meet the requirements of Rule 13.4.1.2 that the "proposed reliability investment … complies with the processes set out in these Rules".

6.3 Rule 13.4.1.3: The Amended Proposal satisfies the Grid Investment Test

208 The third criteria for approval under Rule 13.4.1 requires that the proposed reliability investment:

> *13.4.1.3 "meets the requirements of the Grid Investment Test".*

209 Clause 4 of the GIT states that a proposed investment that is necessary to meet the reliability standard[13] satisfies the Grid Investment Test if the Board is reasonably satisfied that:

> *4.1.1. the proposed investment maximises the expected net market benefit or minimises the expected net market cost compared with a number of alternative projects; and*
>
> *4.1.2. if sensitivity analysis is conducted, a conclusion that a proposed investment satisfies clause 4.1.1 is sufficiently robust having regard to the results of that sensitivity analysis;*

210 The purpose of this section is therefore to satisfy the Commission that the Amended Proposal maximises the expected net market benefit, or minimises the expected net market cost, compared with a number of alternative projects, in a robust manner with respect to sensitivity analysis[14].

211 The remainder of the GIT consists of the methodology for applying the GIT (clauses 5 to 17) and the definitions to be used (clauses 18 to 32).

212 Table 6-2 presents the summarised rankings of the proposal and alternatives as a result of the application of the Grid Investment Test.

213 The results in table 6-2 show that the proposed investment (Option 2) passes Clause 4.1.1 of the GIT by having the lowest expected net market cost of the three alternatives. The results in table 6-2 are in 2006 dollars; results in 2011 dollars are presented in Attachment E.

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[13] *Different GIT clauses apply to economic investments. The Amended Proposal is a reliability investment, and hence clauses 4.1.1 and 4.1.2 apply. See section 5.3.*

[14] *Assuming that, given the size of the proposal, sensitivity analysis is conducted. Transpower has conducted sensitivity analysis, and the Commission conducted sensitivity analysis in its draft decision.*

Item	Option 1 220kV WKM-PAK	Option 2 400kV WKM-PAK	Option3 Duplex OTA-WKM A&B
	PV $ 2006 (millions)		
Mean capital cost (A)	687	682	737
Mean O&M costs (B)	24	25	21
Mean unserved energy cost (C)	0	0	0
Mean relative loss cost (D)	0	-1	60
Mean terminal benefit (F)	12	13	4
Strategic benefit (G)	0	-5	0
Mean NPV cost (A+B+C+D-F+G)	**698**	**688**	**813**
Difference v 220kV	**-**	**-10**	**115**

Table 6-2: Ranking of the Transpower proposal and alternatives with the 220 kV alternative as the reference case.

214 Table 6-3 presents a summary of the sensitivity studies used to confirm the rankings of the proposal and the alternatives for a variety of changes to key parameters.

-$2006 million-	Option 1 220kV WKM-PAK	Option 2 400kV WKM-PAK	Option 3 Duplex OTA-WKM A&B	Difference 400kV-220kV
Mean NPV costs	698	688	813	-10
Sensitivity:				
$2011	1112	1096	1296	-16
Capital cost +20%	835	824	961	-11
Capital cost -5%	664	654	777	-10
System SRMC	698	687	827	-11
Loss cost +30%	698	687	834	-11
Loss cost -30%	698	689	793	-9
Discount rate 4%	934	883	1159	-51
Discount rate 10%	545	553	602	8
Property escalation 0%	682	680	784	-2
Property escalation 6%	724	697	857	-27
Exchange rate 10 yr average	691	687	807	-4
Hydro/Renewable scenarios - 0 new generation	750	722	903	-28
Reduced demand scenario - 1 new generation	714	701	846	-13
Coal scenario – 2 new generation	674	674	776	0
Gas scenario - 3 new generation	629	640	688	11
Gas scenario only, rated up – 6 new gen	-	-	-	41
40%, 20%, 20%, 20%, 0,2,4,6 new gen	-	-	-	2
New generation prior 2030 only	680	675	793	-5
20 year analysis period	613	634	696	21
Urban sprawl 10km	701	688	813	-13
Upper 50% runs	747	721	882	-26
Lower 50% runs	653	658	753	5
Risk adjusted timing	758	753	839	-5
10% POE Demand path only	769	737	924	-32

Table 6-3: Sensitivity of expected net market cost of the Transpower proposal and alternatives and expected net market cost difference between the proposal and 220kV reference case

215 The sensitivity studies show that the benefit of the proposed option is even greater under a social discount rate of 4% and for the renewable and hydro scenarios. The proposal also improves under a lower demand scenario with only one generator going into the upper North Island area.

216 The proposal is less economic under scenarios with high levels of generation in the upper North Island (gas scenario with 3 or more new generators).

217 The result is robust to changes in capital cost as all projects are similarly affected.

218 Re-running the GIT calculation tool with the risk adjusted project timing described in section 7 does not change the ranking of alternatives. Refer to Attachment E for further details.

6.3.1 Discussion on Options 1 & 2: new line WKM-PAK

219 From a GIT perspective, even though Option 2 passes the GIT, there is very little separating Option 1: 220 kV and Option 2: 400 kV WKM-PAK (Proposed) given that the cost estimates are limited to 20-25% accuracy and the number of assumptions made with respect to costs generally.

220 Given the closeness of the comparison, Transpower believes it is appropriate to examine the sensitivity studies and the ranges in outcomes that they provide. Transpower also believes the two projects can be differentiated by considering non-quantified benefits that are discussed below.

221 Another significant differentiator between these two projects is the requirement in the 220 kV option for an additional corridor in later years.

222 The maximum ‘corridor capacity’ for the 220 kV option is 1200 MVA compared with 2700 MVA for the 400 kV proposal. This latent capacity may provide additional comfort to potential investors that there is a greater likelihood, in the longer term, for capacity to be readily available from the 400 kV option. The lead time for establishing substations is of the order of 2 years and designation, consenting and easement issues are less likely because only substation works will be required. The 220 kV option will face significantly more challenges in this area as a new easement will be required.

6.3.2 Discussion of the potential ranges of outcomes

223 The sensitivity studies show there is a range of possible outcomes.

224 In view of the closeness of the results between the proposal and the next best alternative, the 220 kV Option 1, Transpower has considered other factors to inform the selection of the preferred alternative.

Demand Analysis

225 The demand analysis using the lower and upper 50% of runs shows that the range of outcomes can be considered to be in the range of $5M to -$26M. The GIT analysis was carried out using the 2005 SoO load forecasts and observations in the 2006 winter were on the high side of the 2005 SoO load forecasts. Transpower’s view is that there is no basis to assume that future load outcomes will be on the low side and that 2006 observations suggest outcomes are more likely on the higher demand side of the range (i.e. more in favour of the proposal). If demand is in the lower range (<50%), it is likely there will be less generation and this will have a compensating effect.

Renewable energy sources

226 The (draft) GPS makes it clear that it is the Government's intention to facilitate and promote renewable energy sources, as per clauses 34A, 87A and 87B. The range of potential outcomes are for three new thermal generators in Auckland to zero new generators under the renewables scenario, giving possible outcomes in the range $11M to -$28M.

227 Further analysis has considered up to six new thermal generators in Auckland (Refer to Attachment E) which expands the range to approximately $41M to -$28M. Arguments have been raised about the need for 'conventional' generation to 'back-up' intermittent renewable generation (such as wind). Transpower notes the initiative by Genesis and Contact to seek consent for a potential LNG terminal in Taranaki.

228 If additional thermal generation is required, as argued, the prospect of all this generation going into Auckland is unlikely, given the requirement for gas pipeline capacity into Auckland.

229 Furthermore, unless the HVDC inter-island link is downgraded, an obvious choice for providing back-up to intermittent renewables is hydro generation, available in both the South and North Island.

230 Transpower therefore argues that the prospect of many new generators in Auckland is low and that the higher probability outcome, particularly in the light of the (draft) GPS, is at the lower end of the thermal generation outcomes in Auckland.

231 Transpower believes the appropriate range of outcomes thus lies in the range -$13M to -$28M, representing up to one new thermal generator in Auckland.

Property escalation

232 The property escalation range is from -$2M to -$27M depending on whether property is escalated at 0% or 6% relative to CPI. The base results use 3% escalation.

233 The 200 km line route passes through a range of land usage types from rural to developed. The actual escalation will vary between land usage types with rural being closer to 0% and developed being closer to 6%.

234 The increasing popularity of 'lifestyle' blocks south of Auckland, together with increasing urbanisation, add weight to a higher escalation rate. Transpower notes that there is already significant development up to the '40 year urban boundary' in the vicinity of the proposed transition/substation.

235 If the South Auckland urban boundary is revised, as would appear likely, development further south would necessitate future corridors to terminate further from Otahuhu or Pakuranga substations. The increased cost of cabling from these termination points would significantly increase net project costs.

236 Considering the cost of the corridor for the proposal is approximately $80M and the cost per km of underground cable is in the order of $5-8M/km per circuit, cost escalation at the higher rates would seem, on average, to be justified.

Discount rates

237 Varying the applicable discount rates shows a range of outcomes between $8M and -$51M.

238 Transpower believes the discount rate for long-term investments with an element of 'social good' requires a lower discount rate than the standard 7% used in the base case. The argument for a discount rate in the vicinity of 4% is supported by advice from independent consultants[15]

239 Transpower believes that the adoption of a lower discount rate would favour the proposal.

6.3.3 Other non-quantified benefits favouring the proposal

240 There are a number of other benefits that Transpower believe additionally favour the proposal and which if quantified, would be included in the GIT results.

241 They are difficult benefits to defensibly quantify. Work is underway to quantify these benefits and the results of this work will be advised once available.

242 They are broadly grouped as competition benefits and capacity benefits, further described below.

Competition benefits:

243 In its draft determination of Transpower's original 400kV investment proposal[16], the Commission argued that since the 400kV proposal and the alternative projects provided similar levels of unconstrained transmission capacity, competition benefits would be equal for each alternative, therefore making it unnecessary to quantify them as they would net out in the economic analysis.

244 In a recent paper, The Energy Centre[17] point out that:

"…this argument is based on the mistaken assumption that the intensity of competition in an electricity market can be improved by transmission investment only if an absolute transmission constraint is relieved. Under the Commission's reasoning, a transmission line that had 1000MW of unused capacity…would not generate any additional competition benefits over and above those generated by a transmission line that…had 1MW of spare capacity…"

245 They go on to show that recent economic research supports an argument that since the 400kV project provided more actual capacity than the alternatives it would be expected to generate greater competition benefits.

"The key idea is that a transmission line provides a threat of competition to generators located in different areas…[provided] the line has sufficient capacity that generators do not find it profitable to ignore the possibility of output expansion by a rival…".

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[15] *"Discount Rate for the Grid Investment Test" Report to Transpower, August 2006, Castalia Strategic Advisors. Refer to Attachment L*

[16] *"Economic assessment of Transpower's Auckland 400kV grid investment proposal", May 2006.*

[17] *"Submission to the Electricity Commission and the Minister of Energy on: Transpower's Auckland 400kV investment proposal draft decision", 22 June 2006*

246 Transpower agrees with The Energy Centre's analysis and consider that the same arguments will apply to the Amended Proposal in this Application for Approval. The Amended Proposal has significantly more thermal capacity than the alternatives and this capacity can be released at relatively short notice compared to the alternatives. This becomes particularly noticeable in the years leading up to the need for a second new 220kV line in the reference case, and the years leading up to the need for new 220kV lines in the duplexing alternative. Therefore, Transpower believes the proposal does have a competition benefit compared to the alternatives.

247 The benefits that arise from such a situation are categorised into two groupings:

- benefits which reduce the overall supply cost of electricity. These arise because heightened intensity of competition forces generators to become more efficient operationally.
- benefits which reduce the price of electricity to consumers. These also arise because of heightened intensity of competition, but are differentiated from the previously discussed benefits because they are wealth transfers between generators and consumers and cannot be included in the GIT.

248 Transpower is working to quantify both types of benefit, because even though only the first can be included in the GIT, the Commission are required under the GPS to *"…promote and facilitate retail competition…",* hence Transpower would expect the Commission to take into account information which demonstrates the extent to which limited competition is affecting consumers.

249 The GIT requires Transpower to estimate the direction and magnitude of non-quantifiable benefits.

250 Competition benefits accrue in a direction that favours the proposal, because of the higher latent capacity. Transpower is unable at this stage to quantify the magnitude of this benefit. Accounting for the competition benefits arising from the latent capacity is also consistent with the requirements of the (draft) GPS.

Capacity benefits

251 As discussed above, the Amended Proposal has significant amounts of unused thermal capacity, particularly in the earlier years, compared to the alternatives. Although there is a cost in investing in such a large line (the initial capital costs of the Amended Proposal are higher than the alternatives) Transpower believes there are capacity benefits associated with having large amounts of surplus capacity, compared to alternatives which provide smaller amounts, or just sufficient, capacity. These are categorised into three different potential benefits. The Energy Centre paper[18] discusses two aspects of transmission investment analysis, categorised as capacity benefits:

1) The first relates to the interdependence between transmission and generation investments. The paper points out that, in general, transmission investments drive generation investments. Potential investors in generation pay considerable attention to (expected) decisions on transmission investment and these decisions *"…influence the profitability of different generation investments (technology as well as location) differently. More specifically the signal not to build a new transmission line, will stimulate…generation investments near Auckland…"*. Such an outcome may or may not be

[18] *"Submission to the Electricity Commission and the Minister of Energy on: Transpower's Auckland 400kV investment proposal draft decision", 22 June 2006*

economic for New Zealand. It will only be economic if building generation near Auckland is the cheapest option. If building generation in Taranaki (say) is cheaper, but the possibility of being able to exercise market power, at least for a short time, leads to a generator building in Auckland instead, then the outcome is sub-optimal for New Zealand.

Transpower agrees with this assessment and considers that the Amended Proposal and reference case are similar in this regard and that both have a capacity benefit over the duplexing alternative until 2020. However, the higher latent capacity of the proposal favours this option. The duplexing alternative, which limits transmission capacity into Auckland prior to a new 220kV being built in approximately 2020, may stimulate (sub-optimal) generation investment in the Auckland region.

2) The second capacity benefit relates to the impact of uncertainties on transmission and generation investments. In their draft determination, the Commission have correctly identified that postponing major transmission investment decisions creates more time for clarity to emerge with respect to future generation investment. This is termed transmission option value and if correctly identified, may be added as a benefit in GIT analysis. The Energy Centre paper points out however, that creating an option value for transmission investment may do so at the expense of option value for generation investment i.e. where options for transmission are kept open, uncertainties increase for new generation investors, thereby increasing their risks/costs.

   The Amended Proposal has significantly more latent thermal capacity than the alternatives (two years as opposed to seven years for a new line) and this capacity can be released at relatively short notice compared to the alternatives. Whilst this may mean the Amended Proposal has less transmission option value than the alternatives, it reduces the uncertainty for generation investors compared to the alternatives and thereby gives a higher generation option value.

   Considering the relative capital intensity of generation and transmission investments, Transpower believes it is better to provide higher generation option value through certainty of transmission investment. In this context, Transpower believes the direction of the benefit favours the proposal. Transpower has not been able to estimate the size of this benefit at this stage.

3) The third capacity benefit relates to the flow-on effect to the economy from having good infrastructure in place. Transpower has a view that "just-in-time" infrastructure development creates, at the very least, a perception of uncertainty to potential investors in New Zealand. Castalia was commissioned to consider an approach for quantifying such effects and their paper is attached to this application as Attachment N – Foreign Direct Investment Effects[19]. Quoting from that paper:

   "*Because it is difficult to predict the likely increase in Foreign Direct Investment (FDI) that the Upgrade will generate, we have cast the proposition as the following question:*

[19] *At Transpower's request, Castalia focussed on foreign investment in New Zealand, but it should be noted that similar arguments could be developed for local investment.*

What increase in investor confidence and FDI would result in the Earlier Option delivering $100m more welfare than the Later Option (in present value terms, taking into account only the different effects on investor confidence of the two options)?

We chose $100m as the order of magnitude of the cost differences being debated in the Auckland Supply Upgrade.

We find that an increase of about $2.3m in the annual flow of FDI would generate the additional $100m in welfare. To put this in perspective, the $2.3m figure represents a 0.09 percent increase in FDI."

Castalia's reference to Earlier and Late Options is a reference to the Commission's draft determination where a comparison was made between building a new transmission line in 2010 (Earlier Option), or by using incremental investments, deferring the new line until 2017 (Later Option).

Castalia go on, in their paper, to acknowledge that there is no way of knowing what the FDI effect of one transmission investment versus another will be.

"Rather, we think the assessment can be left with the Electricity Commission and the Government. To decide to save some tens of millions of dollars by opting for a just-in-time transmission upgrade plan—rather than a plan with more surplus capacity, decision makers have to be confident that the increase in FDI from an earlier upgrade will be less than one tenth of one percent."

Clearly, the Amended Proposal, with its large amount of surplus capacity, will enable a significantly higher level of investor confidence with respect to Auckland infrastructure and will therefore encourage higher levels of FDI.

Transpower believes the direction of this benefit favours the proposal, because of the investor confidence provided by the higher latent capacity than the 220 kV reference case. Transpower believes that any long term investor would appreciate the availability of this latent capacity. The discussion above shows this is a significant benefit for even very small changes in FDI.

6.3.4 Discussion on Option 3: Duplex WKM-OTA A and B

252 This option has high initial costs that offset the initial attraction of a medium-term remedial measure.

253 The Otahuhu-Whakamaru A and B transmission lines are over 50 years old and require substantial refurbishment and tower replacement works in order to reliably support double the conductor weight and increased wind loading.

254 The physical works are $97.7M of the of the total project cost estimate.

255 The property costs for this line are estimated to be $83.0M. Transpower is satisfied that this is a reasonable estimate and consistent with costs assessed for options 1 and 2.

256 Even if, in an extreme case, the property costs for this option were considered to be zero, the GIT analysis shows that the project would still lag options 1 and 2 by approximately $40M.

257 Similarly, if the variant discussed in Section 4.4.3 were adopted – using only one cable into Pakuranga and retaining in service the existing lines – the cost savings of around $50M would, on its own, be insufficient to warrant adoption of this variant.

258 A significant cost for this option is attributable to the relatively high losses incurred on the line. This arises initially in the first ten years prior to the construction of a new greenfield 220 kV line. During this period, Options 1 and 2 both benefit from having two low-loss circuits delivering energy to the Auckland environs.

259 Given that losses quadruple when current doubles, the generally higher loading on all the parallel transmission lines in the initial years, and in later years before a second 220 kV line is required, accumulate loss costs that prejudice this project against Options 1 and 2.

260 In addition, the lower latent capacity in the initial years would not provide the same level of confidence to investors (GPS clause 87G and benefits described in 6.3.3) than would Options 1 and 2.

261 It is also arguable that the lower latent capacity would reduce competitive pressures in the generation sector and provide less to renewable generation in central and southern North Island access to upper North Island markets.

262 Further suggestions to reduce cost include the use of high temperature conductor (HTC) for those components of the Otahuhu-Whakamaru line that would require easements. This constitutes about one third of the line length, or 70 km, on the current assumptions for consenting and easements.

263 The use of HTC for one third of the line would increase capital costs by approximately $31M, being the difference between the cost of duplexed conventional conductor and simplex HTC. Further increases in cost would be required to install 13 extra strain towers (at a cost of $1.6M) plus a fund of $5M to cover the expected increase in Environment Court costs.

264 It is not clear that avoiding duplexing these sections will, of itself, be sufficient to avoid having to obtain easements. Factors that might trigger a requirement to obtain easements are not clear but could include consideration of:

- Conductor Diameter;
- Conductor Swing;
- Electric and Magnetic Fields;
- Temperature; and
- Conductor Sag/Tower heights.

265 Even if easements were not required over these sections, Transpower believes at least $18M would still be required for the removal of structures under the line.

266 The higher losses on these sections of the line would offset cost savings, with an estimated loss component rising from $60M to approximately $80M, based on interpolation of the Option 3 and Option 4 loss costs.

267 In addition, the higher reactance of the resulting composite line would increase the net reactance and therefore the reactive losses. This would require additional reactive compensation in the Auckland area, increasing costs further.

268 In addition to all the above considerations, Transpower, in section 4.7 has indicated its concerns about using a relatively new conductor technology, with limited international application, in precisely those locations of under-build where concerns of conductor failure are the greatest.

6.3.5 Discussion on Option 4: Duplex WKM-OTA A and B with HTC

269 This option is virtually identical to Option 3 in the initial years prior to the need for the next major augmentation.

270 The initial capital cost is affected by the costs of:

- remedial and refurbishment works ($80M);
- the high temperature conductor ($179M); and
- easements ($83M).

271 Comparative results for this option are provided in Table 6.4.

Item	Option 1 220kV WKM-PAK	Option 4 HTC on OTA-WKM A,B,C
	2006$ (Millions)	
Mean capital cost (A)	687	808
Mean O&M costs (B)	24	20
Mean unserved energy cost (C)	0	0
Mean relative loss cost (D)	0	126
Mean terminal benefit (F)	12	-9
Strategic benefit (G)	0	0
Mean NPV cost (A+B+C+D-F+G)	**698**	**963**
Difference v 220kV	**-**	**265**

Table 6-4: Comparative assessment of the non –qualifying alternative Option 4 with the 220 kV alternative as the reference case.

272 Sensitivity results for option 4 are given in Table 6.5.

$2006 million	Option 1 220kV WKM-PAK	Option 4 HTC OTA-WKM A,B,C	Difference HTC-220kV
Base results	698	963	265
Sensitivity:			
$2011	1112	1534	422
Capital cost +20%	835	1124	289
Capital cost -5%	664	922	258
System SRMC	698	1011	313
Loss cost +30%	698	1009	311
Loss cost -30%	698	917	219
Discount rate 4%	934	1438	504
Discount rate 10%	545	694	149
Property escalation 0%	682	941	259
Property escalation 6%	724	997	273
Exchange rate 10 yr average	691	955	264
Hydro/Renewable scenarios - 0 new generation	750	1092	342
Reduced demand scenario - 1 new generation	714	1010	296
Coal scenario – 2 new generation	674	903	229
Gas scenario - 3 new generation	629	784	155
New generation prior 2030 only	680	937	257
Urban sprawl 10km	701	963	262
Upper 50% runs	747	1044	297
Lower 50% runs	653	890	237
10%POE demand path only	769	1141	372

Table 6-5: Sensitivity of expected net market cost of the non-qualifying alternative Option 4 and 220kV reference case

273 Subsequent to 2017, series capacitors will be required on these lines to ensure sharing between the six parallel 220 kV circuits. This will have the effect of directing more flow to these HTC circuits, increasing losses accordingly.

274 The subsequent re-conductoring of the Otahuhu - Whakamaru C line (double circuit, duplex) would require a similar outlay for the conductors and potentially for easements and/or cable entries into Otahuhu.

275 As the re-conductoring does not change the line impedance (of the C line), further series capacitors are required to direct flow onto these circuits, with the flow increasing the losses markedly on this circuit.

276 The loss costs in Table 6.4 reflect the significantly higher losses incurred in this option.

277 Transpower believes the high loss costs are contrary to the climate change imperatives outlined in the (draft) GPS clauses 34A, 87A and 87 B as these losses all require greater production from thermal generation that could otherwise be avoided.

278 The higher flows also incur very high reactive losses which necessitate the installation of additional reactive support for voltage control. This is reflected in the project capital cost.

279 The conclusion drawn from the economic analysis is that even in the extremely unlikely case where property costs were zero and the conductor was supplied for the same cost as conventional conductor, the project would still not be economically viable.

6.3.6 Comparison with non-transmission alternatives

280 Attachment K shows the non-transmission alternatives are generally not as cost effective as transmission options 1 and 2.

281 The exception appears to be the case where an existing peak load unit were moved to the Auckland region from elsewhere in New Zealand (e.g. Whirinaki). This is because the fixed annual costs of the plant may be treated as zero since they would have been incurred irrespective of the move.

282 In the case of Whirinaki, for a relocation cost of $30 million this would give a net market benefit of $39 million. This however needs to be considered in light of the draft GPS which states that when considering non-transmission alternatives, the Commission should:

> *"not consider alternatives which are only likely to proceed if they are assisted by the government…."*

283 A general finding with respect to base load generation is that even if adjusted for transmission deferral benefits, there are options with lower long run marginal costs (LRMCs) that are lower and should, in an efficient market, be built before Auckland base load plant.

284 This finding does not include differences in reliability between transmission and generation (in favour of transmission).

285 This finding does not necessarily take into consideration all the factors that a prospective generator may wish to consider before investing. The analysis is based on costs and benefits that would normally be considered in a centrally planned power system.

6.3.7 Impact of the draft GPS

286 The (draft) GPS is discussed in Section 8. The changes proposed by the Government effectively add weight to the renewable and hydro energy futures. As such, Transpower believes these sensitivities should be weighted higher than the coal and gas scenarios. This favours the proposal as the renewable, hydro and low Auckland generation (low growth) scenarios deliver improved economies over the 220 kV alternative as illustrated in table 6-3.

287 The(draft) GPS specifies two requirements in relation to diversity:

- [Clause 80] … where practical, the transmission grid should provide adequate alternative supply routes to larger load centres having regard to the load which could otherwise be disrupted and the duration of any disruption; and
- [Clause 88E] … to the extent the Commission considers the environmental effects of new lines, it should also take into account any longer term benefits that larger capacity lines may provide by avoiding multiple smaller lines.

288 Transpower has given effect to these requirements by:

- Specifying Pakuranga as the termination point of the proposal and alternatives, providing the first stages of a longer term establishment of an 'eastern corridor' to supply Auckland; and
- Adopting high capacity designs for both the proposal and the alternatives to maximise the corridor utilisation.

289 Transpower recognises the tension between the requirements of (draft) GPS clauses 80 and 88E in that higher corridor capacity reduces the level of diversity. That is many low capacity lines provide more diversity than fewer high capacity lines.

290 Transpower believes in this instance the requirements of clause 88E take precedence over clause 80 because the current concentration of supplies in one substation – Otahuhu – and limited corridors, will benefit from having a reliable alternate supply (corridor and substation) of equivalent rating to the current supply arrangements. This will balance the supply capability of the two corridors and ensure at least half of the load can be supplied for a low probability event causing the failure of a corridor.

291 Transpower considers that in the first stage of the proposal, with operation at 220 kV, there is little difference in the diversity of the 220 kV Option 1 and the proposal, other than the proposal retains the ability to deliver greater capacity with a shorter lead time than Option 1.

292 Once converted to 400 kV operation, and well into the analysis period, loss of the corridor (for example a tower failure causing loss of both circuits) will have a higher impact than loss of a tower on a 220 kV double circuit line.

293 However, the higher capacity of the 400 kV line also provides a degree of resilience for the failure of one of the existing 220 kV double circuit lines, considered a higher probability as the age of these lines would be approaching 80 years.

294 Analysis of this high impact, low probability event is provided in Attachment A (Diversity into the Upper North Island).

295 On balance Transpower acknowledges the higher impact of losing a heavily loaded 400 kV circuit, but believes the impacts can be contained using special protection systems and having fast response repair strategies in place.

6.3.8 Conclusion of the GIT analysis

296 Transpower has demonstrated that the Amended Proposal satisfies the Grid Investment Test because:

- as a reliability investment, it maximises the expected net market benefit when compared with the alternative projects;
- it is robust having regard to the results of a sensitivity analysis; and
- satisfies the intentions outlined in the GPS.

297 Of the three alternatives, Transpower believes the non-quantified benefits identified in 6.3.3 all act in a direction to favour the proposal and some of these benefits are potentially very significant.

298 In meeting all of the above criteria, the proposed project satisfies the third criteria for approval under Rule 13.4.1 that the proposed reliability investment "meets the requirements of the Grid Investment Test".

7 The Amended Proposal is appropriately sequenced and timed

299 As previously mentioned (section 5), the GIT calculation tool was used to 'rank' the alternative projects in order to select the proposed project, in accordance with rule 13.4.1.3.

300 Once the proposed project is selected, two different methods of determining the timing of its implementation may be applied:

- the probabilistic method, combining the GRS and GIT; or
- the deterministic method using n-g-1 and a prudent forecast.

7.1 Probabilistic method of determining project timing

301 The GIT calculation tool is used to balance the cost of expected unserved energy resulting from delaying the proposed project against the deferral benefits. This is the approach used by the Commission in its draft decision. Details of how this was applied to the proposed and alternative projects are provided in Attachment E and H1.

7.2 Deterministic method of determining project timing

302 Power system analysis tools are used to determine the point at which the grid is no longer able to provide a secure supply in accordance with a predefined security criteria. Deferral of the project beyond this date may result in unserved energy. A discussion of the criteria used and its justification is provided in section 6.1.

303 The deterministic method is preferred by Transpower as it aligns with GEIP as discussed in Section 6.1.

7.3 Grid Development Projects

304 Transpower has undertaken to implement a series of grid development projects in order to maximise the use of available capacity on the grid. These projects are regarded as 'common' projects, as they are required regardless of which major project is implemented. The Grid Development projects include:

- Establishment of Ohinewai substation (Huntly East); and
- Thermal upgrade of the 220 kV Otahuhu-Whakamaru A and B lines; and
- Bombay bus split; and
- The reactive power investments in the Upper North Island as approved by the Commission

305 Each of these projects carries a delivery risk and the dates mentioned are subject to revision. Late delivery on any of these projects may have a bearing on the short term and major projects.

7.4 Short-term projects

306 In addition to the common projects there are also projects that may be cost-effective to pursue (e.g. new switching station, transmission line upgrades; phase-shifting transformers) in the short-term prior to the major upgrade. Transpower accepts that such cost-effective short-term projects would form part of the proposed upgrade and alternatives in this application.

307 Some short-term projects may assist in meeting regional demands and delay the need date for the major upgrade to the core grid but may not be cost-effective to pursue. These types of projects should be regarded as contingency projects.

308 Short-term projects may assist in meeting regional demand and delay the need for a major upgrade to the core grid. There are two types of short-term projects:

- Cost-effective (or economic) projects that are justified on the basis that their cost is lower than the unserved energy that would otherwise occur; and
- Projects that are not cost-effective (ie they would not normally be implemented) but could be implemented to manage unexpected (contingency) events.

309 Transpower also accepts that cost-effective short-term projects will not be held back for risk management purposes, which could result in the need-date for the major upgrade project being brought forward.

310 The actual timing and final commitment to short-term projects may be subject to revision in the future as uncertainties around the designation, consenting and easement risks are resolved or as they impact the need and value of the short-term projects.

311 Appendix D lists 11 sets of short-term projects that have been considered and gives:

- A description of the project;
- the improvement in transfer capability if the project is implemented;
- the approximate cost of the project; and
- Transpower's classification of the project.

312 The amount of deferral available from the short term projects in appendix D takes into account the impact and need for ON constraint of generation. It then compares the deferral benefits from each option against its cost. The economic projects are:

- Option 5: 110kV phase shifting transformers
- Option 7: Drury switching station
- Option 8: Drury switching station + upgrade of OTA-WKM C line

The greatest benefit to cost ratio is from short term project 8.

313 In the case of short term project 8, the theoretical maximum deferral is three years, however in order to achieve this, Huntly power station must be constrained on to nearly 100% of its output (1314 MW) along with full output from New Plymouth and Stratford power stations (320 and 360 MW respectively). This amount of on-constraint is required by the System Operator to cover for the loss of a major generating unit and a transmission line (n-g-1). Reliance on this amount of on-constraint is considered impracticable, especially in light of New Plymouth power station having a long 'warm-up' time, therefore a deferral of three years is not recommended.

314 A deferral of two years could possibly be achieved using option 8, but it still relies on near maximum Huntly output however this time without New Plymouth power station being constrained on.

315 One year of deferral is possible without New Plymouth and without a major Huntly unit having to be constrained on. This is considered to be a reasonable condition in light of the potential market distortions that any amount of on-constraint may cause.

7.4.1 Arapuni-Pakuranga 110 kV line

316 The proposed route for a new 220 kV or 400 kV transmission corridor into Auckland follows much of the route of the existing 110 kV Arapuni to Pakuranga Line (ARI-PAK line).

317 Transpower has advised that the construction of the proposed new lines would require the retirement of the ARI-PAK line approximately 18 months prior to the in-service date of the new lines which would effectively bring the need date for the new lines ahead by up to two years. Analysis presented in Appendix D indicates that the benefit of retaining the ARI-PAK line is only one year.

318 Various methods of maintaining the ARI-PAK line in-service were suggested as part of the Commission's draft decision.

319 It has been suggested that significant capital carrying costs could be saved if there were a means of keeping the ARI-PAK line in-service or finding alternative ways of mitigating the effect of their absence though the construction phase of the new line.

320 Appendix E indicates the deferral benefits that could be captured by keeping the ARI-PAK line in service. It is only economic to undertake the works required to keep the line in service if the costs are lower than the deferral benefits.

321 Given that the costs of keeping the ARI-PAK line in service are estimated to be $35M and the benefits are in the range of $15-$22M, Transpower has concluded that this project is not economic.

322 There are operational, safety, easement and RMA issues which must be considered in determining the feasibility of concurrent operation of the ARI-PAK line during the construction of the new line.

323 These implementation risks are further valid reasons why the ARI-PAK line retention is neither economic nor practicable in the sense that it would introduce significant risk and potentially prejudice the major project if delays are incurred with the retention works.

7.5 Appropriate timing

324 Transpower proposes a two step process in determining project timing, namely that:

- the first step of the project evaluations should be done based on a system that reflects the direct system needs (i.e. free of designations, consents and easements and other delivery risk); and
- the second step is to explicitly and transparently consider such risks in relation to project timing so that Transpower can adequately manage those risks.

325 In completing the first step of the timing process, Transpower has calculated the timing for the direct system need using both the probabilistic and deterministic approach.

326 Transpower's assessment of the capacity of cost-effective short-term projects is that they could provide a project deferral of up to two years under an ideal generation dispatch scenario, but only one year for normal dispatch scenarios. Transpower considers it prudent to allow for one year of deferral.

327 The set of short-term projects selected to provide an economic deferral of the major project is contained within Option 8 of Appendix D. This option including a Drury 220 kV switching station and upgrade of the OTA-WKM C line provides cost effective deferral of the major project by one year as previously mentioned.

7.5.1 Probabilistic approach - Transpower

328 For this approach, Transpower engaged ROAM Consulting to analyse the unserved energy that could be expected as a result of generation contingencies in the Auckland region, including Huntly. The results of this analysis are reported in Attachment H2.

329 Transpower used the unserved energy as a function of peak load from the ROAM report as an input into the GIT model. The GIT model is discussed in Attachment E.

330 The major project was moved back one year at a time in the GIT model and the calculated expected unserved energy was added as a cost. The need-date for the project was found as the year that minimised the total cost, or equivalently, gave the optimum balance between deferral benefits and unserved energy cost

331 Attachment H1 indicates the required service date for the major project using this analytical approach is around 2017.

7.5.2 Probabilistic approach – Electricity Commission

332 The Commission provided an analytical model for an alternative approach to that adopted by Transpower.

333 The alternative approach considers a similar load probability curve but the assessment of the unserved energy is extended to consider a wider range of demand outcomes.

334 The rapid increase in unserved energy with increasing demand results in very high unserved energy for peak demands. This weights the average unserved energy and can result in higher levels of expected unserved energy.

335 The timing as set by this alternative approach results in a project need of 2013 – the same outcome as the deterministic approach discussed below.

336 This result is consistent with the Commission's finding in their draft decision that the probabilistic approach yields similar results to the deterministic approach.

7.5.3 Deterministic analysis

337 This section describes the deterministic analysis used to set the need-date for the projects based on an n-g-1 criterion and the Commission's 'prudent' forecast, The approach requires the determination of the n-g-1 capacity of the transmission system and the consequential demand that could be supported in the Auckland and Northland areas.

338 The supportable demand was then compared with the 'prudent' forecast. The need-date is set at the year that supportable demand would be exceeded if the project were not implemented.

339 Figure 7-1 shows the need-date for the proposal and alternatives using the deterministic approach, with short term projects included. Details are provided in Attachment D.

340 Using this analysis, the proposed major project is thus required in 2013.

7.5.4 Conclusion on timing

341 Transpower has concluded that, based on the Commission's probabilistic approach and Transpower's deterministic approach, the appropriate timing for the proposed major project is 2013.

7.6 Accounting for delivery risk

342 Figure 7-1 below shows the timing of the short-term projects and the major project as determined by the probabilistic and deterministic approaches. These dates align with those provide in table 5-1 "System need dates for proposed investment".

343 The dates shown in the diagram refer to the required commissioning dates based on need. Late delivery would result in significant levels of expected unserved energy, as shown in Attachment H1 and H2..

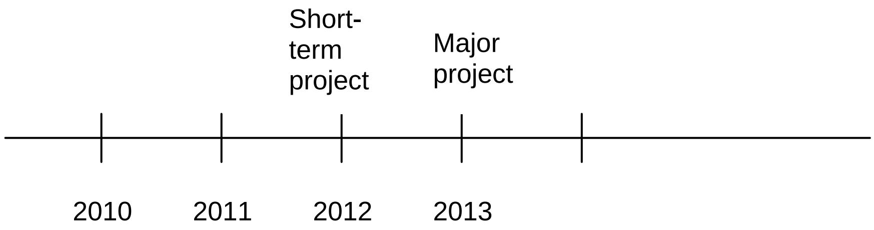

Figure 7-1. Project timing based on need but excluding delivery risk

344 The above analysis has considered only the technical need and neither method has made any allowance for the risk of delays in delivering the project. These risks include delays due to:

- designations ,consents and / or easements
- project and/or construction issues.

345 Transpower has assessed a range of project delivery scenarios for each of the four projects. The outcome of this analysis, assuming approval is obtained this year (2006) is shown in Table 7-1. The supporting analysis is presented in Attachment C.

Project	Earliest completion	Probable completion	Latest completion
Base (220 kV)	2011	2012	2014
Proposal (400 kV)	2011	2012	2014
Duplexing	2012	2013	2016
High temperature conductor	2012	2013	2016

Table 7-1: Potential delivery dates taking account of designation, consenting and easement risks (assuming project commencement early 2007)

346 The approach taken was to explicitly and transparently recognise delivery risks. The most appropriate way of doing this is to :

- Work towards an earlier completion date with a view to increasing confidence that the project will be available by the need-date;
- Adjust, where possible, the delivery date as project risks are avoided or mitigated to avoid an unnecessarily early delivery date if risk do not transpire.

347 Transpower believes that as this is the first major greenfield transmission project to be built under the Resource Management Act 1991 it would be prudent to take a risk averse position regarding delivery risk. In all cases this indicates that a two year advancement should be applied to the major project need-date.

348 Note that some of the short-term projects described in Appendix D also have designation, property and easement risks – e.g. requiring a thermal upgrade of the Whakamaru-Otahuhu 'C' line, which could result in issues under the RMA.

349 Using the Commission's model and approach to determining expected unserved energy, the consequences of not delivering the major project in 2013 would be of the order of $32M (Attachment H1 and H2), equivalent to just under two year's deferral benefit (Appendix E). A delay beyond 2014 would result in expected unserved energy rising rapidly to $89M, equivalent to more than 3 years deferral benefit.

350 This is the first greenfield transmission line built under the RMA and will require the involvement of 7 councils, two regional councils and over 300 land owners. Given the lack of precedent for Transpower, the risks of delays are therefore considered to be high.

351 For both the probabilistic and deterministic approaches, Transpower proposes that the explicit risk allowance should be to bring forward the need-date for the various projects. This is shown diagrammatically in figure 7-2 below with a two year advancement for both the short-term projects and the major project.

352 Transpower considers the proposed approach and resultant timing for the Amended Proposal to reflect good electricity industry practice and reasonable and prudent management of risk.

353 A revised project timing comparison is provided in figure 7-2 below.

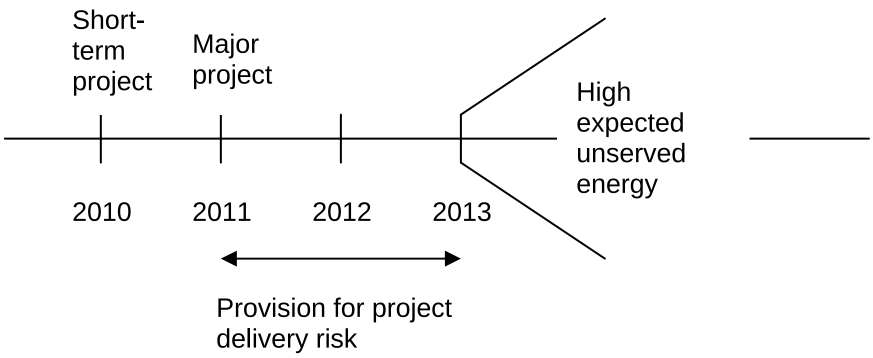

Figure 7-2. Revised project timing diagram – including risk allowance

7.7 Timing of the Proposal

354 The revised timing of the proposal, including the short term projects and accounting for delivery risk is shown in table 7-2 below.

Proposal Timing (includes risk allowance)	Augmentation
2009	Install 250 MVAr static reactive plant at Otahuhu
	Decommission the 110 kV ARI-PAK line
2010 (short term projects)	Establish Drury switching station Implement thermal upgrade for Otahuhu-Whakamaru C line Install 100 MVAr static reactive plant at Otahuhu
2011 (major projects)	Establish 220 kV substation adjacent to existing Whakamaru substation (Whakamaru North)
	Cable Transition Station, South Auckland
	400 kV double circuit line from Whakamaru to cable transition station in South Auckland. Circuits operated at 220 kV.
	2 x 220 kV cables from transition station to Pakuranga substation
	220 kV sub station at Pakuranga
	Install 3 x 120 MVA supply transformers at Pakuranga substation
	Increase operating voltage of existing 110 kV OTA-PAK line to 220 kV

Table 7-2. Timing of proposal

8 The Amended Proposal is consistent with wider policy objectives

355 Transpower notes the application is being submitted within the context of a wider regulatory framework. As such, points of reference within that wider framework that can reasonably be assumed to be relevant are:

- The purpose of Section III of Part F of the Electricity Governance Rules;
- The Government Policy Statement on Electricity Governance (GPS); and
- The Commission's objectives

356 These factors are considered further in the following subsections.

8.1 The purpose of Part F

357 Transpower submits that the following factors are relevant to the Commission's consideration of the Amended Proposal:

	Purpose of Part F	Would approval of the proposal contribute to this purpose?
1	"facilitate Transpower's ability to develop and implement long term plans (including timely securing of land access and resource consents) for investment in the grid"	Yes The proposal is a component of Transpower's long term plans.
2	"assist participants to identify and evaluate investments in transmission alternatives"	Yes, albeit that any proposal following the Part F process will achieve this.
	"facilitate efficient investment in generation"	Yes The proposal will provide assurance of releasable capacity into the Upper North Island from the Lower North Island and the South Island. This will provide both capacity and confidence to generation investors, particularly North Island investors in renewable generation.
	"facilitate any processes pursuant to Part 4A of the Commerce Act 1986"	Yes, albeit that any proposal following the Part F process will achieve this.
	"enable the cost of approved investments to be recovered through the transmission pricing methodology applied in transmission agreements"	Yes, albeit that any proposal following the Part F process will achieve this.

Table 8-1. Alignment of Proposal with Part F of the Electricity Governance Rules

8.2 The GPS

358 Transpower submits that the Government Policy Statement (GPS) provides useful context for this Amended Proposal. At the time of submitting this application, there is an extant 2004 GPS, and a draft 2006 GPS, which places additional emphasis on for example:

- Facilitating renewables;
- Resilience against low probability but high impact events
- Diversity
- Facilitating competition
- Early corridor acquisition
- Avoiding multiple low-capacity lines

359 Table 8-2 considers how the proposal and alternatives address these wider policy issues by commenting on both the extant GPS and August 2006 Draft GPS.

	Government policy statement 2004 (extant)	Government policy statement 2006 (draft)	Would approval of the proposal contribute to this purpose?
Renewable Energy			
34A	-	Encouraging the development of renewable energy resources is a key part of the Government's strategy for managing climate change and long term energy security. To further this aim the Government's objectives in relation to renewable energy, are that: • Undue barriers to investment in renewables should be reduced or removed • The efficient uptake of renewable generation should be promoted and • The national transmission grid should be planned in such a way as to facilitate the potential contribution of renewables to the electricity system and in a manner that is consistent with the Government's climate change and renewables policies.	Construction of the proposed project or the 220 kV alternative would make the grid more robust through the provision of, or ability to provide, spare capacity. This is required to better withstand the specific characteristics and stresses placed on the system by intermittent generation such as wind power.
Transmission			
Background			
79	The way in which transmission services are provided and priced impacts directly and indirectly on all parts of the electricity industry, the economy and the environment. Transmission has strong natural monopoly characteristics, which makes it important that the Government sets out its policy expectations as	No change	

	Government policy statement 2004 (extant)	Government policy statement 2006 (draft)	Would approval of the proposal contribute to this purpose?
	to how transmission services should be provided and priced and how Transpower should operate. Poorly designed policies may, for example, encourage inefficient investment in generation, which would waste scarce capital resources and cause unnecessary environmental effects.		
Objectives for the provision of transmission services			
80	The Government's objectives for the provision of transmission services are that:	The Government's objectives for the provision of transmission services are that:	
	• the services are provided in a manner consistent with the Government's policy objectives for electricity	• the services are provided in a manner consistent with the Government's policy objectives for electricity and in particular that security of supply should be maintained at a level required by residential, commercial and industrial users and the Government's economic development objectives	It is Transpower's view that the construction of the proposed project would improve grid security and reliability into the upper North Island to a level consistent with prudent planning standards. As a region, the upper North Island has a significant proportion of the residential as well as commercial and industrial customer base in New Zealand.
	• the services should be provided at the standards of power quality and grid reliability required by grid users and consumers as determined by the Commission	-	
	-	• the transmission grid should be adequately resilient against the effects of low probability but high impact events having regard to the load which could be disrupted and the duration of any disruption	The proposal – and Transpower's wider development plan in which the proposal sits – is designed to cover, to the extent technically and economically feasible, low probability but high impact events. In addition, the flexibility provided by the eastern corridor, the Otahuhu substation development and the termination point at

	Government policy statement 2004 (extant)	Government policy statement 2006 (draft)	Would approval of the proposal contribute to this purpose?
			Pakuranga will provide flexibility that will: o place less load at risk of a major substation failure; and o improve recovery times because of the ability to transfer loads.
	-	• where practical, the transmission grid should provide adequate alternative supply routes to larger load centres having regard to the load which could otherwise be disrupted and the duration of any disruption	The proposal and the 220 kV alternative both provide alternative supply routes (corridors) to Auckland. All three projects considered facilitate a new supply point – Pakuranga- for Auckland.
	-	• competition in generation is facilitated and transmission constraints are minimised	The proposal and 220 kV alternative both provide sufficient capacity initially to facilitate competition. The proposal has a slight advantage in that in later years there is an ability to readily release significant additional capacity whereas the 220 kV option will require the construction of a further line along the proposed or a new corridor.
	-	• the transmission grid should be planned and operated in a way which helps achieve the government's climate change and renewable energy objectives	As mentioned above, a strong grid is required to allow for significant development of wind power and other intermittent generation. The proposal is part of a wider plan to upgrade the backbone of the national grid. An anticipated outcome of this wider upgrade plan is that future renewable energy projects will be able to be incorporated into the country's generation portfolio on a larger scale than is currently possible.

	Government policy statement 2004 (extant)	Government policy statement 2006 (draft)	Would approval of the proposal contribute to this purpose?
	• the efficiency of transmission services should be continuously improved so as to produce the services grid users and consumers want at least cost, and	No change	
	• the services are priced in a manner that:	No change	
	o is transparent	No change	
	o fully reflects their costs including risk	No change	
	o facilitates nationally efficient supply, delivery and use of electricity	No change	
	o promotes efficient investment in transmission or transmission alternatives	No change	
	o promotes nationally efficient use of transmission services by grid users and consumers.	No change	
	-	• stakeholders and the public are kept well-informed about how security of supply is to be maintained throughout the development and consideration of any grid upgrade plans.	
Investment in and maintenance of the transmission network			

	Government policy statement 2004 (extant)	Government policy statement 2006 (draft)	Would approval of the proposal contribute to this purpose?
86	As part of its modeling and forecasting work, the Commission should provide for the development of statements of opportunities relating to transmission. These should:	No change	
	i. incorporate electricity demand and supply forecasts	No change	
	ii. enable identification of potential opportunities for:	No change	
	o efficient management of Transpower's transmission network including investment in system expansions, replacements and upgrades	No change	
	o transmission alternatives (notably investment in local generation, demand-side management, and distribution network augmentation)	No change	
	iii. facilitate long term planning for timely securing of easements and resource consents	No change	
	iv. be prepared at least biennially.	No change	
87	Transpower should submit grid upgrade plans to the Commission for approval. The grid upgrade plans should be consistent with statement of	Transpower should *develop and* submit grid upgrade plans to the Commission for approval.	Transpower has developed and analysed the options from which the proposal and alternatives have been derived.

	Government policy statement 2004 (extant)	Government policy statement 2006 (draft)	Would approval of the proposal contribute to this purpose?
	opportunity forecasts and demonstrate the rationale for all expenditure (operation, maintenance and capital), taking into account the prescribed reliability standards. The plans should demonstrate that the proposed expenditure is required to meet reliability standards and/or deliver the greatest net benefit after taking into account transmission alternatives. The Commission should ensure that affected parties are fully consulted.		
87A	-	Except where urgency is required for individual projects, any grid upgrade plan submitted by Transpower should be as comprehensive as possible, ideally covering short, medium and longer term proposals. This will better enable consideration of the interrelationships between projects and the wider synergies from the grid, including facilitating renewables, least-cost provision of new generation and increased competition between generators. It will also enable consideration and approval of proposed expenditure for the grid as a whole over an appropriate timeframe (for example, five years) within a longer term framework.	The submission of Transpower's GUP on 30 September 2005, and the submission of this amendment, is consistent with this objective.
87B	-	The grid upgrade plan should also be consistent with statement of opportunity forecasts and wider government energy policy including applicable policies on renewable generation and climate change.	The 30 September 2005 GUP, and this amendment, meet with this requirement, including being consistent with the wider government energy policy, beyond Part F of the EGR's.

	Government policy statement 2004 (extant)	Government policy statement 2006 (draft)	Would approval of the proposal contribute to this purpose?
87C	-	Grid upgrade plans should demonstrate the rationale for all expenditure (operation, maintenance and capital), taking into account the prescribed reliability standards and good industry practice for power system operation. The plans should demonstrate that the proposed expenditure is required to meet reliability standards and/or deliver the greatest net benefit after taking into account transmission alternatives and government energy policy requirements.	The 30 September 2005 GUP, and this amendment, are consistent with this requirement
87D	-	In the development of grid upgrade plans, the Government's objective is that Transpower should undertake the detailed planning role (including the assessment of transmission alternatives) and the Commission should assess and approve grid upgrade plans that satisfy the required standards and evaluation criteria and reject applications that fail them.	Transpower, as grid planner, favours the Amended Proposal as it is part of a wider plan to develop the national grid, which is expected to strategically place the grid in a position where it is best able to meet the future challenges of growth (both demand and in renewables) and uncertainty, while optimising the utility of the assets involved, including transmission corridors.
87E	-	The Commission should make available to Transpower and other stakeholders clear and specific criteria on how any grid upgrade plans in general and any particular plan specifically will be assessed.	From Transpower's perspective the Interim Working Phase has contributed significantly to meeting this requirement.
87F	-	The Commission should ensure that affected parties are fully consulted on grid upgrade plans	Transpower supports transparency in the transmission planning process.

	Government policy statement 2004 (extant)	Government policy statement 2006 (draft)	Would approval of the proposal contribute to this purpose?
87G	-	In developing and considering grid upgrade plans, Transpower and the Commission should seek to maintain business confidence by making it clear that adequate security of supply will be maintained.	In Transpower's view the Amended Proposal will achieve levels of grid security and reliability in the upper North Island, required to maintain business and investor confidence in the region. The latent capacity of the proposal to meet projected demands for many years to come should engender confidence.
88	Where the Commission approves investment by Transpower, the cost of that investment should be recoverable by Transpower in accordance with the pricing methodology determined by the Commission.	No change	Transpower has proposed a process for cost recovery as part of its application of the Amended Proposal, that ensures Transpower recovers its full economic cost, while at the same time allowing for monitoring of and reporting on Transpower's management of costs incurred.
Planning ahead			
88A	-	The current pressing need for a number of major upgrades on the transmission system reflects, in part, insufficient planning and securing of consents (or designations) and land access rights in the past. Government is concerned to ensure that this situation is not repeated in the future.	A timely decision to approve the proposal, and the future implementation of Transpower's wider strategic plan to develop the national grid of which this Amended Proposal is a part, will meet the concerns addressed in this point. Transpower's Annual Planning Report provides clear indications of future augmentation needs.
88B	-	The Government therefore expects Transpower and the Commission to ensure that Transpower identifies and secures the necessary land corridors and, to the extent possible, resource consents (or designations) well in advance of urgent need. Transpower should be able to	A timely decision to approve the proposal will meet the concerns addressed in this point. Rule changes to allow corridor designation well in advance of project approval and delivery would assist in this regard by providing the basis for a designation and resource consents..

	Government policy statement 2004 (extant)	Government policy statement 2006 (draft)	Would approval of the proposal contribute to this purpose?
		recover the reasonable costs of doing so.	
88C	-	This should help the essential process of maintaining stakeholder confidence in ongoing security of electricity supply even if, at times, there is some loss of flexibility around investment choices and some additional cost for electricity consumers.	A timely decision to approve the proposal will meet the concerns addressed in this point. Transpower is of the view construction of the Amended Proposal will minimise future costs, including among other things the costs and risks associated with the acquisition of further transmission corridors, in maintaining an adequate level of grid security and reliability.
Environmental effects			
88D	-	Final environmental requirements are determined by consenting authorities under the Resource Management Act which provides the statutory framework for dealing with environmental effects.	Transpower is of the view that the Amended Proposal is the best alternative when considering the trade-offs between cost, grid reliability, security, and other benefits, and environmental impacts, including impacts on residential areas. It is recognised that the proposal is subject to review through the RMA processes.
88E	-	To the extent the Commission considers the environmental effects of new lines, it should also take into account any longer term benefits that larger capacity lines may provide by avoiding multiple smaller lines.	The proposal has been designed to optimise the trade off between costs, benefits and environmental impacts, including optimising the number of transmission corridors required for the grid as a whole, going forward into the future. Transpower's proposal only requires one new overhead line corridor as opposed to two for the alternatives.
	Transmission alternatives	*Non-transmission alternatives to transmission*	

	Government policy statement 2004 (extant)	Government policy statement 2006 (draft)	Would approval of the proposal contribute to this purpose?
89	As part of its consideration of transmission investments, the Commission should ensure that transmission alternatives are properly considered to the extent practicable	As part of the consideration of transmission investments, the Commission should ensure that, in addition to considering transmission alternatives, non-transmission alternatives are considered to the extent practicable subject to the following conditions:. • the Commission should only consider alternatives which have a high probability of the alternatives proceeding and the Commission has determined that on-going security of supply can be maintained if the alternative is delayed or does not proceed • the Commission should not consider alternatives which are only likely to proceed if they are assisted by the government or an agency acting on behalf of the government unless and until the government has explicitly authorised or agreed to provide such assistance.	Transpower has cooperated with the Commission to develop generic generation projects as alternatives to transmission investments. These have been assessed and compared with the transmission proposal and alternatives. The best of these options, relocation of Whirinaki to Auckland, is a government owned generator and is the lowest cost generation option only because of the sunk capital cost of the plant.
90	As part of its consideration of transmission pricing, the Commission should consider whether there would be net benefits in providing for a mechanism whereby investments in transmission alternatives receive payments reflecting some or all of the value of avoided transmission investment. This is a complex subject, and the Commission will need to take into account, among other things, practicalities,	No change	

	Government policy statement 2004 (extant)	Government policy statement 2006 (draft)	Would approval of the proposal contribute to this purpose?
	effects on incentives to invest in alternatives, and the extent of assurance that grid reliability standards will be met.		

Table 8-2. Alignment of Proposal with Government Policy Statement

8.3 The Commission's objectives

360 Transpower submits that Commission's two principal objectives under the Electricity Act 1992 provides useful context. How approval of the proposal will contribute to each of these is summarised below:

Commission's objectives	Would approval of the proposal contribute to this purpose?
ensure that electricity is produced and delivered to all classes of consumers in an efficient, fair, reliable, and environmentally sustainable manner and	**Yes** ***Production***: the increased capacity of the proposal will enable efficient competition between generators, leading to productive efficiencies. Over time, the increased capacity of the proposal will enable efficient investment in generation, including renewable generation, leading to dynamic efficiencies also. ***Delivery***: the increased capacity of the proposal will enable efficient competition between and dispatch of generation, leading to allocative efficiencies. ***Efficiency***: the proposal will provide the efficiencies noted above, reduce transmission losses, and is the most economic means of delivering required reliability, as measured by the GIT. ***Fairness***: the increased capacity of the proposal will avoid tilting the "level playing field" towards particular producers or consumers. ***Reliability***: the proposal will significantly increase reliability of electricity supply for consumers in the Upper North Island. ***Environmental sustainability***: the increased capacity of the proposal will: enable more efficient dispatch of existing renewable energy; reduce transmission losses; enable greater investment in renewable generation in the Lower North Island and South Island; In consequence, reduce greenhouse gas emissions relative to alternatives; and Minimise the requirement for additional transmission corridors into the Upper North Island over time.
promote and facilitate the efficient use of electricity.	Yes, albeit that any proposal following the Part F process will achieve this.

Table 8-3. Alignment of Proposal with the Commissions objectives

361 Transpower considers that the Amended Proposal is consistent with wider policy objectives and hence is likely to satisfy the Commission's exercise of any discretion required in approving the proposal.

9 Recommendation

362 It is recommended that the Commission approve the Amended Proposal on the grounds that it:

- complies with the Rules;
- meets the GRS;
- passes the GIT; and
- is consistent with GEIP.

Further, it is the project that is most aligned with the draft changes proposed to the GPS, particularly with respect to an emphasis on renewable generation, provision of diversity of supply to Auckland and minimisation of the number of corridors required for transmission.

Appendix A Glossary of Terms

Term	Description
AIS	**A**ir **I**nsulated **S**witchgear
Alternative Project	Projects that are reasonable to consider as alternatives to the proposed investment in applying the Grid Investment Test (GIT), in accordance with rule 19, Schedule F4, Part F Section III, Electricity Governance Rules (EGRs).
Amended Proposal	The proposal, for a new line between Auckland and Whakamaru, which is outlined in this application for approval, dated 30 September 2006. (the “North Island Grid Upgrade project”).
North Island Grid Upgrade Project	The project, for a new line between Auckland and Whakamaru, which is outlined in this application for approval, dated 30 September 2006 (the “Amended Proposal”).
Commission	The Commission, a Crown entity set up under the Electricity Act to oversee New Zealand’s electricity industry and markets.
deterministic limb of the GRS	The deterministic limb of the GRS defines that the grid satisfies the grid reliability standards if, with all assets that are reasonably expected to be in service, the power system would remain in a satisfactory state during and following any single credible contingency event occurring on the core grid. (Refer rule 4.2, Schedule F3, Part F Section III, Electricity Governance Rules (EGRs)).
Draft Decision	The Commission’s consultation paper explaining its draft decision on the Original 400 kV Project, dated 27 April 2006.
economic investment	Investments in the grid that can be justified on the basis of the Grid Investment Test under section III of part F, Electricity Governance Rules (EGRs), and are not reliability investments.
EGRs	**E**lectricity **G**overnance **R**ules. In the context of this document, it generally refers to Part F Transport, Section III Grid Upgrade and Investments, 16 February 2006.
expected project costs	Expected project costs (or expected costs) represent the estimated (P50) cost plus a contingency for scope accuracy. Scope accuracy allows for unexpected variations in the design scope and a standard allowance, based on experience, for items not considered in the design.

expected unserved energy	A forecast of the aggregate amount by which the demand for electricity exceeds the supply of electricity at each grid exit point as a result of likely planned or unplanned outages of primary transmission equipment.
GEIP	**G**ood **E**lectricity **I**ndustry **P**ractice. Refer section 6.1.2 of this document.
GIS	**G**as **I**nsulated **S**witchgear
GIT	**G**rid **I**nvestment **T**est. A test for reliability investments and economic investments in the grid developed in accordance with rule 6 of section III of Part F, Electricity Governance Rules (EGRs). The specific rules defining the Grid Investment test, as developed according to the process in rule 6 of section III, are set out in Schedule F4 of section III of Part F.
GPS	**G**overnment **P**olicy **S**tatement on Electricity Governance. Refer section 8.2 of this document.
GRS	**G**rid **R**eliability **S**tandards. Standards for reliability of the grid developed in accordance with rule 4 of section III of part F, Electricity Governance Rules (EGRs), including variations, but does not include interim grid reliability standards. The standards themselves as currently developed are detailed in rule 4 of Schedule F3, section III of Part F.
GUP	**G**rid **U**pgrade **P**lan. A plan for grid expansions, replacements and upgrades, developed in accordance with rule 12 of section III of part F, Electricity Governance Rules (EGRs).
HTC	**H**igh **T**emperature **C**onductor. A type of overhead transmission line conductor that is capable of sustained operation up to temperatures around 200 degrees Celsius
HVDC Upgrade Project	The proposal to upgrade the HVDC inter-island link between Benmore in the South Island and Haywards in the North Island, as detailed in Volume III of the Original GUP, submitted to the Commission on 30 September 2005.
LRMC	Long Run Marginal Cost
modelled projects	Transmission augmentation projects and non-transmission projects, other than the proposed investment and alternative projects, which are likely to occur in a market scenario, are reasonably expected to occur in that market development scenario within the time horizon for assessment of the market benefits and costs of the proposed investment and alternative projects, and the likelihood, nature and timing of which will be affected by whether the proposed investment or any alternative project proceeds.

N-G-1	System security standard which is achieved when the power system remains in a satisfactory state during and following any single credible contingency event occurring on the core grid (defined as N-1 security standard), whether Otahuhu 'C' generator is in or out of service.
Original GUP	Transpower's first GUP, submitted to the Commission on 30 September 2005, containing a number of projects including the Original 400 kV Project and the HVDC Upgrade Project.
Original 400 kV Project	The original proposal to build a 400 kV line between Otahuhu and Whakamaru, as detailed in Volume II of the Original GUP, submitted to the Commission on 30 September 2005.
probabilistic limb of the GRS	The probabilistic limb of the GRS defines that the grid satisfies the grid reliability standards if the power system is reasonably expected to achieve a level of reliability at or above the level that would be achieved if all economic reliability investments were to be implemented.
reliability investment	Investments by Transpower in the grid, or alternative arrangements by Transpower, the primary effect of which is, or would be, to reduce expected unserved energy.
Transition station	A site where the transition is made from an over-head transmission line to underground cables.
Transpower	Transpower New Zealand Limited, owner and operator of New Zealand's high-voltage electricity network (the national grid).
UNI or Upper North Island	Includes the Auckland and Northland regions. The Auckland region is the area bordered by and including Bombay 110 kV Substation in the south, and Penrose 220 kV Substation and Mount Roskill 110 kV Substation in the north. The Northland region covers the area north of and including Hepburn Road 110 kV Substation.

Appendix B Cross Reference with September 2005 GUP

Section of September 2005 GUP	Part of 400 kV GUP or HVDC GUP?	If 400 kV GUP, has it been superseded by this application?	If yes or in part, which sections of this application?
Volume 1			
Executive Summary			
Section 1	Both	Part	Executive Summary
Sections 2 to 6	Both	No	-
Section 7	400 kV	All	Executive Summary
Section 8	HVDC	No	-
Section 9	Both	Part	Executive Summary
Comprehensive Plan for Asset Management and Operation of the Grid	HVDC	No	-
Contracted Investments	HVDC	No	-
Volume 2			
Executive Summary and Introduction			
Section 1	400 kV	Part	Section 1
Section 2	400 kV	All	Section 2
Section 3	400 kV	No	Section 3 Section 4
Section 4	400 kV	Part	Section 5.1
Section 5	400 kV	All	Section 7
Section 6	400 kV	Part	Section 3
Section 7	400 kV	No	Section 4
Section 8	400 kV	All	Section 5
Section 9	400 kV	All	Section 5
Section 10	400 kV	No	-

Section of September 2005 GUP	Part of 400 kV GUP or HVDC GUP?	If 400 kV GUP, has it been superseded by this application?	If yes or in part, which sections of this application?
Appendix A	400 kV	All	Attachments
Part 1			
Section 1	400 kV	Part	Section 5
Section 2	400 kV		
Section 2.1	400 kV	All	Section 5
Section 2.2	400 kV	Part	Section 5
Section 2.3	400 kV	Part	Section 5
Section 2.4	400 kV	Part	Section 5
Section 3	400 kV	No	-
Section 3.1	400 kV	No	-
Section 3.2	400 kV	No	-
Section 3.3	400 kV	No	-
Section 3.4	400 kV	Part	Section 2.4
Section 3.5	400 kV	All	Section 7
Appendix 1A	400 kV	All	Section 5
Appendix 1B	400 kV	No	-
Appendix 1C	400 kV	All	Section 5
Appendix 1D	400 kV	All	Section 7
Part 2			
Section 1	400 kV	All	Section 3
Section 2	400 kV	All	Section 3
Section 3	400 kV	All	Section 6
Section 4	400 kV	All	Section 6
Section 5	400 kV	Part	Attachment D
Section 6	400 kV	Part	Attachment D
Section 7	400 kV	All	Section 7
Appendix IIA	400 kV	All	Attachment D
Appendix IIB	400 kV	No	Attachment D
Appendix IIC	400 kV	All	Section 5
Appendix IID	400 kV	No	-

Section of September 2005 GUP	Part of 400 kV GUP or HVDC GUP?	If 400 kV GUP, has it been superseded by this application?	If yes or in part, which sections of this application?
Part 3			
Section 1	400 kV	No	-
Section 2	400 kV	Part	Section 3
Section 3	400 kV	No	-
Section 4, 4.1, 4.2	400 kV	No	-
Section 4.3	400 kV	All	Section 4 Attachment D
Section 4.4	400 kV	Part	Section 6
Section 4.5	400 kV	All	Section 5 Section 6 Attachment D
Section 4.6	400 kV	No	-
Section 4.7	400 kV	No	-
Section 4.8	400 kV	No	-
Section 4.9	400 kV	No	-
Section 4.10	400 kV	No	-
Section 4.11	400 kV	No	-
Section 4.12	400 kV	No	-
Section 4.13	400 kV	Part	Section 6
Section 5	400 kV	Part	Section 6
Appendix IIIA	400 kV	No	-
Appendix IIIB	400 kV	All	Section 7 Appendix D
Part 4	400 kV	All	Section 6 Appendix E Attachments
Part 5	400 kV	All	Section 5 Appendix C
Supporting Documents			
1. Request for Information	400 kV	No	-

Section of September 2005 GUP	Part of 400 kV GUP or HVDC GUP?	If 400 kV GUP, has it been superseded by this application?	If yes or in part, which sections of this application?
2. Grid development Plan – 400 kV – Part 1	400 kV	All	Attachment D
3. Grid development Plan – 400 kV – Part 2	400 kV	All	Attachment D
4. Grid development Plan – 2200 kV – Part 1	400 kV	All	Attachment D
5. Grid development Plan – 220 kV – Part 2	400 kV	All	Attachment D
6. Main Transmission System Planning Criteria	400 kV	Part	Section 6
7. Planning Assumptions – Demand and generation forecasting	400 kV	All	Section 6 Attachment D
8. Security of supply into Upper North Island – Comparison of High Voltage Direct Current and High Voltage Alternating Current Grid Upgrade Alternatives	400 kV	No	-
9. 300/400 kV Transmission Line Upgrade Study	400 kV	No	-
10. Monte Carlo Analysis of Auckland Area thermal Plant Availability	400 kV	No	-
11. Comparison of reliability of 400 kV underground cable with an overhead line for a 200 km circuit	400 kV	No	-
12. peer review of choice of voltage for development of the New Zealand Grid	400 kV	No	-
13. Security of supply into Auckland – review of system capacity limitations	400 kV	All	Attachment D
14. Methodology to calculate lower bound of competition benefits	400 kV	All	Attachments

Section of September 2005 GUP	Part of 400 kV GUP or HVDC GUP?	If 400 kV GUP, has it been superseded by this application?	If yes or in part, which sections of this application?
Volume 3	HVDC	No	-
Volume 4	Grid Development Proposals	No	-

Appendix C Cost breakdowns of alternative projects

Option 1: 220 kV into Pakuranga and Otahuhu

Year	Augmentation	Total -Expected Cost ($,000)
2009	350 MVAR Static compensation	9,185
2010	Upgrade OTA-WKM C	4,615
	Decommission 110kV ARI-PAK Line	5,032
	Drury Switching Station	21,227
	Drury Switching Station - Lines	2,047
2012	220kV Line (2 Chukar @ 75C) WKM-ORM	277,068
	WHN 220 kV Substation	10,688
	WKM Subs Work	3,807
	OTA Subs Work	5,242
	OTA Enabling Work	3,417
	ORM Cable Termination Station	10,755
	2x220kV cables ORM-PAK	117,888
	220kV Sub Station at PAK	54,231
	Shift existing OTA-PAK 110kV circuits to operate at 220kV	688
	1st PAK-PEN cable	61,159
	PEN GIS Sub	40,033
2013	Reconductor ARI-HAM 1&2 to Nitrogen 75C conductor	12,324
	BOB Interconnector	9,479
	100 MVAr Static compensation	4,297
2017	ORM Civil Works	8,532
	100 MVAr Dynamic compensation	25,159
	2nd PAK-PEN cable	61,159
	PAK Subs Work	6,866
	PEN Subs Work	3,271
2019	100MVAR Static compensation	4,282
2021	110kV OTA-WIR cable; close the WIR bus breaker	35,223
	50% series compensation on the ORM-WKM 1&2 ccts	42,021
	Switching station at ORM	12,478
	One ORM-OTA 220kV cable	69,018
	1st OTA-PEN cable	60,949
	PEN Subs Work	3,271
	OTA Subs Work	6,122
2022	200 MVAR Static compensation	6,541
2024	2nd ORM-OTA Cable	67,916
	OTA Subs Work	779
	ORM Subs Work	1,747
2026	100 Mvar Static compensation-	4,277
	Series current limit reactor - 20 Ohm	18,874
2027	100 MVAR Dynamic compensation	25,164
2029	100 MVAR Static compensation (HLY)	4,277
	250 MVAR Static compensation (OTA)	7,422
2031	2nd 220kV Double Circuit between WKM-ORM	262,782
	WHN Subs work	4,386
	ORM Subs Work	4,318
	1st 220kV cable between SAD-PAK	107,555
	PAK Subs Work	610

Continued next page

2032	2nd OTA-PEN cable	60,949
	PEN Subs Work	3,271
	OTA Subs Work	1,444
2035	250 MVAR Static compensation	7,422
2036	PST on ARI-BOB	9,318
2037	1st cable SAD-OTA Cable	96,485
	ORM Subs Work	2,381
	OTA Subs Work	6,639
2038	150 MVAR Static compensation	5,535
2040	Series Compensate WKM-ORM 3&4 circuits by 50%.	42,016
2042	400 MVAR Static compensation	10,698

Option 1 - 220 kV into Pakuranga and Otahuhu

Option 2: 220 – 400 kV Staged to Pakuranga (Proposed Investment)

Year	Augmentation	Total - Expected Cost ($,000)
2009	350 MVAR Static compensation	9,088
2010	Uprate HLE-HAM-WKM section of OTA-WKM C line to twin Goat @ 80C	4,573
	Decommission 110kV ARI-PAK Line	4,979
	Drury Switching Station	21,227
	Drury Switching Station - Lines	2,047
2012	2x400kV WKM-ORM ccts operated at 220kV	335,219
	WHN 220 kV Substation	10,578
	WKM Sub work	3,770
	OTA Enabling Work	3,381
	OTA Subs Work	5,192
	2x220kV ORM-PAK cables	116,700
	Cable Termination at ORM	10,719
	220kV substation at PAK	57,233
	Convert OTA-PAK 110kV ccts to 220kV	680
	1st PAK-PEN cable	60,529
	PEN GIS	39,615
2013	Reconductor ARI-HAM 1&2 to Nitrogen 75C conductor	12,217
2015	BOB Interconnector	9,380
	100 MVAr Static compensation	4,232
2017	ORM Civil Works	9,092
	100 MVAr Dynamic compensation	24,896
	2nd PAK-PEN cable	60,529
	PAK Subs Work	1,115
	PEN Subs Work	3,237
2019	100MVAR Static compensation	4,232
2021	1x220kV ORM-OTA cable	68,329
	ORM Subs Work	13,305
	2x55% compensation on WKM-ORM ccts	45,684
	Install 110kV OTA-WIR cable - close the WIR bus breaker	34,855
	1x220kV PEN-OTA cable	60,316
	PEN Subs Work	3,237
	OTA Subs Work	6,058
2022	200 MVAR Static compensation	6,473
2023	100 MVAr Dynamic compensation	24,896
	2nd 220kV OTA-ORM cable	67,239
	OTA Subs Work	771
	ORM Subs Work	1,724
2026	100 Mvar Static compensation	4,232
2027	150 MVAR Static compensation -reactive plan of 25/9	5,477
2028	Install 20 Ohm reactor on OTA-WKM A&B line	18,672
2029	ORM Civil Works	10,391
	100 MVAR Static compensation	4,232

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2030	300 MVAR Dynamic compensation	48,179
2031	150 MVAR Static compensation	5,477
	Install cable cooling ORM-PAK cables	8,465
2033	400kV sub at WKM	112,295
	400kV sub at ORM	115,690
	2nd PEN-OTA cable	60,316
	PEN Subs Work	3,237
	Install cable cooling ORM-OTA cables	8,465
2037	PST on ARI-BOB	9,221
2040	300 MVAR Static compensation	8,216
2042	300 MVAR Static compensation	8,216

Option 2: 220 – 400 kV Staged to Pakuranga (Proposed Investment)

Option 3: Duplexing of Whakamaru – Otahuhu A&B

Year	Augmentation	Total - Expected Cost ($,000)
2009	300 MVAR Static compensation	8,290
	100 MVAR Dynamic compensation	25,123
2010	BOB Interconnector	9,465
	Drury Switching Station	21,227
	Drury Switching Station - Lines	2,047
2011	Uprate HLE-HAM-WKM section of OTA-WKM C line to 2xGoat 80C	4,473
2012	PAK 220kV sub station	58,242
	Convert existing OTA-PAK 110kV to 220kV	687
	OTA Enabling Work	3,412
	OTA Subs Work	4,208
	1st PAK-PEN cables	61,071
	PEN GIS Sub	39,965
2014	Duplex OTA-WKM A&B ccts, deviate line from Sth Auckland to PAK	221,666
	PAK Subs Work	2,247
2015	South Auck Sub	3,357
	Redoubt Rd - PAK cables	136,488
	100 MVAR Static compensation	4,271
2016	Second PAK-PEN cable	61,071
	PAK Subs Work	6,856
	PEN Subs Work	3,326
	200 MVAR Static compensation	6,537
	Reconductor ARI-HAM 1&c ccts to Nitrogen 75C	12,309
2017	Bussing of OTA-WKM A&B lines at HLE	10,541
2019	OTA-WIR 110kV Cable	35,172
	110kV ARI-PAK line decommissioned	5,025
2020	220kV D/C WKM-ORM line (twin Chukar 75C)	274,791
	WKM Subs Work	2,865
	2x220kV cables from ORM-PAK	146,655
	PAK Subs Work	609
	3rd PAK-PEN cable	61,071
	PEN Subs Work	3,266
	Cable transition at ORM	10,600
2025	200 MVAR Static compensation	6,532
	PST on ARI-BOB	9,305
2027	100 MVAR Static compensation	4,271
2029	250 MVAR Static compensation	7,411
2031	50% Series Compensation on ORM-WKM 1&2 ccts	41,960
	Switching Station at ORM	15,898
	1st and 2nd ORM-OTA cables	128,974
	OTA Subs work	7,984
2033	50 MVAR Dynamic compensation	16,581

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2035	220kV Double Circuit between WKM-Sth AKL	272,882
	WKM Subs Work	2,609
	ORM Subs Work	4,488
	1st OTA-PEN cable	60,862
	OTA Subs work	7,233
	PEN Subs Work	3,266
	3rd OTA-Sth Akl cable	106,213
2042	450 MVAR Static compensation	10,682

Option 3: Duplexing of Whakamaru – Otahuhu A&B

Option 4: High Temperature Conductor

Year	Augmentation	Total – Expected Cost ($,000)
2009	250 MVAr static compensation	7,405
	100 MVAr Dynamic compensation	24,840
2010	BOB interconnector	9,359
2011	Drury Switching Station	21,227
	Drury Switching Station - Lines	2,047
	Thermal Uprating of sections of OTA_WKM C south of HLE with Goat 80 C	4,564
	150 Mvar static compensation	5,047
2012	PAK 220kV substation 3x120MVA supply transformers at PAK	57,105
	1st PAK-PEN cable	60,394
	Convert existing 110kV OTA-PAK circuits to 220kV operation	679
2014	OTA-WKM A and B lines - HTC Duplex Disconnect OTA-WKM A and B sections between SAK and OTA OTA-WKM A and B lines redirected from SAK to PAK with 1 cable per line	436,225
	SAK Cable transition station	3,417
	2x220 cable SAK-PAK	135,001
2015	Second PAK-PEN cable	60,394
2016	Reconducting ARI-HAM 1 and 2 circuits to Nitrogen at 75C	12,194
	100 MVAr static compensation	4,274
2017	OTA-WKM A and B lines 40% Series Capacitance	45,766
2019	110kV cable from OTA to WIR	34,776
	Switching station at SAD	13,275
	150 Mvar static compensation	5,451
2021	200 Mvar static compensation	6,477
2022	350 Mvar static compensation	9,063
2023	200 Mvar static compensation	6,477
	OTA_WKM C – Duplex HTC (all sections but HLE to HAM)	275,388
	OTA-WKM C installed with 25% series capacitance on OTA-HLE, and HLE-WKM sections and 30% series capacitance on HAM-WKM section.	80,730
	OTA_WKM A and B bussed at HLE	10,461
	1st Cable from OTA to PEN	60,181
2025	PST on ARI-BOB	9,305
2027	450 MVAr static compensation	10,537
2028	Decommission ARI_PAK 110kV line	4,968
	1 Ohm series reactor on OTA_SAK bonded pair	2,484
2029	Construction new 2 duplex Chukar circuits from WKM to ORM	272,637
2030	2nd Cable from OTA to PEN	60,281

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2032	Cable transition Station at ORM	10,712
	New cable from ORM to OTA	68,183
2035	150 Mvar static compensation	5,451
2039	2nd cable from ORM to OTA	68,183
	450 MVAr static compensation	10,537
	150 Mvar dynamic compensation	31,050
2040	30% series compensation on ORM_WKM circuits	45,581
	3rd Cable from PAK to PEN	60,394
2041	250 MVAr Dynamic compensation	43,470
	500 Mvar static compensation	11,178

Option 4: High Temperature Conductor

Appendix D Short Term Augmentation Projects

Assumptions:

- 2010 High demand used as base and the loads scaled to obtain transfer limit (Huntly Generation re-dispatched to get maximum limit)
- Arapuni Generation dispatch at180 MW
- Huntly East (Ohinewai) switching station commissioned
- OTA-WKM A&B lines thermally upgraded to 75 degrees
- HVDC dispatch at 1400 MW
- PSTs set to have 95% flow post contingency where possible on 110 kV circuits out of ARI, phase shift range +/-30°
- PSTs set to have 100% flow post contingency on 220 kV circuits
- Transfer Limits quoted are approximate values and the accuracy may vary slightly due to the numerical algorithms used

No	Description	ARI-PAK in	ARI-PAK out	Comment	Cost ($m) [2]	Deferral benefit (years) [3]	Deferral benefit ($m) [4]	Benefit - Cost ($m)
		Upper North Island Transfer Capacity(MW)						
1	Base	2668	2510*					
2	PSTs on HLE-OTA 1 & 2 Circuits	Minimal	Minimal	By itself, this project has marginal impact on the transfer capacity	-	0	-	No benefit
3	Thermal upgrade of OTA-WKM C line upgrade to 80 deg	Minimal	Minimal	By itself, this project has marginal impact on the transfer capacity.	-	0	-	No benefit
4	PSTs on HLE-OTA 1 & 2 + OTA-WKM C line upgrade.	2753*	2667*	700 MVA PSTs required (Phase shift requirement to be ascertained). Lower HVDC dispatch is likely to	64.6	1	31.9	-32.7

		ARI-PAK in	ARI-PAK out		Cost ($m) [2]	Deferral benefit (years) [3]	Deferral benefit ($m) [4]	Benefit - Cost ($m)
				reduce the transfer limit, but is not quantified.				
5	PSTs on ARI-HAM, ARI-BOB AND ARI-PAK+OTA-WKM C line upgrade	**2711**	**2618**	With ARI-PAK in the circuits into ARI from the south particularly KIN-LFD will overload for a HAM-WKM outage. Overloading (up to approx 165%) as far back as TRK ICTs, no overloading without ARI-PAK in service	32.8	1	31.9	-0.9
6	Re-conductoring of HAM-BOB circuits+PSTs+OTA-WKM C line upgrade	**2707**	**2623**	With ARI-PAK in the circuits into ARI from the south particularly KIN-LFD will overload for a HAM-WKM outage. Overloading (up to approx 165%) as far back as TRK ICTs, no overloading without ARI-PAK in service	57.2	1	31.9	-25.3
7	Drury switching station	**2665***	**2659***	Increases transfer from Taranaki and Huntly However, if the generation south of Whakamaru is replaced from the Central North Island generation then the transfer limit drops substantially. Low Huntly generation will also have a similar effect,	23.3	1	31.9	+ 8.6

		ARI-PAK in	ARI-PAK out		Cost ($m) [2]	Deferral benefit (years) [3]	Deferral benefit ($m) [4]	Benefit - Cost ($m)
8	Drury switching station+ OTA-WKM C line upgrade	**2764***	**2736** [1]	Increases transfer from Taranaki and Huntly as well as from Whakamaru. However, if the generation south of Whakamaru is replaced from the Central North Island generation then the transfer limit is likely to reduce.	27.9	1 to 2 [5]	31.9 to 61.7	+ 4.0 to + 33.8
9	Re-conductoring of ARI-PAK+PST on ARI-PAK +OTA-WKM C line upgrade	**2751**	**-**	The 110 kV circuits between Kinleith and Tarukenga and inter connector at Tarukenga overload up to approx 160% and needs augmentation	-	0	-	No benefit
10	OTA-WKM C line upgrade, Drury switching station, Recondutor ARI-PAK and HAM-BOB, PSTs on all 110 kV circuits north of ARI	**2805**	**2724**	The 110 kV circuits between Kinleith and Tarukenga and inter connector at Tarukenga overload up to approx 200%, where ARI-PAK is in service and needs augmentation	Over 80	1	31.9	< - 48.1
11	OTA-WKM C line upgrade, Drury switching station, Recondutor ARI-PAK and HAM-BOB, PSTs on all 110 kV circuits north of ARI, PSTs on HLE-OTA circuits	**2879**	**2803**	The 110 kV circuits between Kinleith and Tarukenga and inter connector at Tarukenga overload up to approx 205%, where ARI-PAK is in service and needs augmentation	Over 140	2	61.7	< - 78.3

Notes:
1. BOB-WIR-OTA circuit breakers are open at BOB to prevent overloading on the HAM-BOB circuits reducing the transfer limit
2. Costs are provided only for those options that provide more than one year of deferment of the major project.
3. Deferment is assessed only for options with ARI-PAK out. Years of deferment is assessed on the basis of likely generation dispatch scenarios.
4. Refer to Appendix D of this report “Assessment of the value of deferring investments”
5. Option 8 provides at least one year of deferral, with possibly more under favourable generation dispatch scenarios. It also provides benefit during summer peak periods when Huntly generation is often constrained down.

Appendix E Assessment of the value of deferring investments

Delaying the need for an investment may have a benefit if the cost of delaying the investment is less than the deferral benefit.

The value of money to be spent now is higher than money that can be spent later as you could alternatively invest the money (e.g. in governmental bonds – considered a risk free investment) and get a return. Thus, the later an investment is made, the more other benefits (such as return of investments) could have been achieved in the meantime. Therefore, money spend in years to come are lowered by a discount rate to adjust for the benefits the capital can provide in the meantime. This is the origin of the deferral benefit.

The deferral benefit arises from applying the discount rate on the given investment for a longer period of time. For example, if using a discount rate of 7%, delaying an investment by one year will cause the present value of the costs to be lowered by 1/1.07 = 93.4%. For an investment with a present value of $100 million being delayed a year, the deferral benefit would then be $6.6 million.

In the context of the Auckland Transmission Upgrade proposal, two types of deferral are of interest. They are explained below.

Deferral of part of the investment

In the economic analysis of the transmission alternatives, several short term options (see Appendix D) for deferring the need of the first major part of the proposed investment one or two years are analysed.

The analysis is based on the year 2010 – i.e. the project need date in 2012 brought forward two years to reduce risks. The costs of those options are to compared with the deferral benefits, which are:

400 kV in 2010	Defer 1 year	Defer 2 years
Benefits in $million 2006	31.9	61.8

Table E-1. Project deferral benefits

The values arise from delaying the investments from the table below, which are all due in 2010 if no deferral projects are committed.

Description
2x400kV WKM-ORM ccts operated at 220kV
WHN 220 kV substation
WKN Sub work
OTA Enabling Work
OTA Sub Work
2x220kV ORM-PAK cables
Cable Termination at ORM

220kV substation at PAK*
Convert OTA-PAK 110kV ccts to 220kV*
1st PAK-PEN cable*
PEN GIS*

** These projects are needed in 2012 at latest for the strengthening of the across harbour capacity. Hence, the can only be deferred two years.*

Table E-2. Deferral components

The costs of those sum up to $559 million. This includes the associated property costs as well as the costs of investigations, project management and consenting. To this, scoped contingencies (between 15% and 25%) have been added to capital costs and project management costs. This gave a total of $642 million.

Looking at the change of the net present value (NPV) of investing in either 2010, 2011 or 2012, the following benefits NPV of delaying the investments are found:

- One year deferral: $29.9 million
- Two years deferral: $58.0 million

To this is added the change in NPV of the operations and maintenance costs, which is $2.0 million for one year and $3.8 million for two years. Hence, the value presented in the table for a one year deferral is $31.9 million and the value of two years of deferral is $61.8 million.

Deferring the project more than two years adds around $19 million per year. This is lower than the value of each of the two first years, but is due to the fact than certain components are due in 2012 latest.

Deferral of the full investment stream

When analysing the generation alternatives, it has been assumed that these options delay all projected investments from the initial and on to 2042 (i.e. the full development plans presented in Appendix C). This might not be the case, either because parts of the investments may have been committed before an investor commits itself to building a generator (or potentially a contract can be signed with a supplier of a DSM initiative) – or because some of the components in the development plans will be needed anyway. However, to bias the analysis towards generation, this has been the assumption.

The deferral benefits include both investments and operations and maintenance costs. The table below shows the deferral value of delaying the transmission reference case (building 220 kV lines) a different number of years.

220 kV reference case *$million 2006*	**Year of commissioning** 2011	2013
NPV of capital costs and O&M costs	770	710
Benefits – 1 year delay	50	46
Benefits – 2 years delay	97	90
Benefits – 3 years delay	141	130
Benefits – 4 years delay	183	168
Benefits – 5 years delay	221	204
Benefits – 6 years delay	257	237

Table E-3. Deferral value of delaying the transmission reference case

A NPV of the capital costs and operation and maintenance costs (O&M) are based on the GIT model runs presented in Attachment E (Economic Analysis of Alternatives report). For the reference case, this states a mean NPV of the capital costs if the first part is commissioned in 2013 of $687 million while mean O&M costs is $24 million giving $710 million in total. A sensitivity analysis of this run was made when the first part of the investment, in general the parts due up to 2013, was moved advanced two years to a 2011 commissioning date. This gave $770 million in total based on $743 million in mean capital costs and $27 million in O&M costs.

It can be seen that the deferral benefits are quite a lot higher than in the previous example, but here the full investment stream is deferred while it in the earlier case only the building of the first line was deferred.