TRANSPOWER

OTAHUHU SUBSTATION DIVERSITY PROJECT

PROPOSAL

ATTACHMENTS

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OTAHUHU SUBSTATION DIVERSITY PROJECT

PROPOSAL

ATTACHMENT A

DIVERSITY INTO THE UPPER NORTH ISLAND

Technical Analysis of Diversity Options for New Capacity into the Upper North Island

December 2006

Contents

1 Introduction

A recent event at Otahuhu Substation (June 12th 2006) that resulted in wide spread loss of supply to the Auckland area has lead to an increase in focus on the benefits of diversity, at all levels of the power system, including major substations such as Otahuhu.

This report analyses the effect on diversity into Auckland and Northland of locating the terminal point of the proposed new Upper North Island line at Pakuranga instead of Otahuhu substation. The results include an assessment of the benefits gained in terms of capacity available into Auckland and Northland, under each option, for various substation contingency scenarios.

This report is part of Transpower's application to the Electricity Commission seeking approval to recover costs for the building of a new switchyard at Otahuhu, aimed at improving diversity while catering for planned expansion at the substation. Implementation of the project will improve the resilience of Otahuhu substation so that it may withstand a single locational event such as that which occurred on June 12th from disrupting all supplies through Otahuhu.

2 Assumptions

2.1 Configuration and Development Options

Two basic configurations for the new Auckland to Whakamaru transmission line are assumed:

a) New line terminates into Pakuranga
b) New line terminates into Otahuhu

The diversity provided by each of these configurations is assessed with and without a new switchyard at Otahuhu.

Two new 220 kV cable connections are assumed to be installed between Pakuranga and Penrose for the Pakuranga option (a), along with the conversion of the existing 110 kV Otahuhu-Pakuranga line to 220 kV.

Two new 220 kV cable connections are assumed to be installed between Otahuhu and Pakuranga for the Otahuhu option (b), along with the conversion of the existing 110 kV Otahuhu-Pakuranga line to 220 kV.

2.2 Timing

A 'snapshot' of the system configuration as expected in 2013 is used as the basis for the analysis. This assumes that the first stage of the cross Auckland project is completed with one 220 kV cable connection between Penrose and Albany via Hobson Street and Wairau Road substations[1].

[1] Hobson Street and Wairau Road are presently zone substations that will converted to Grid Exit points when the first Penrose to Albany 220 kV cable is installed.

2.3 Circuit capacities

The capacities of all new circuits are assumed to be as follows:

Circuit	Type	Number of circuits	Capacity
Transition station[1] to Pakuranga	cable	2	660 MVA per circuit
Transition station to Otahuhu	cable	2	660 MVA per circuit
Pakuranga to Penrose	cable	2	660 MVA per circuit
Otahuhu to Penrose	cable	2	660 MVA per circuit
Penrose to Albany (via Hobson St and Wairau Rd)	cable	1	630 MVA per circuit

1. This is where the overhead line makes the transition to underground cables.

2.4 Existing System

2013 peak loads, calculated using a medium load growth scenario are used for this analysis. Note that the load figures used in this report are approximate and are for comparative purposes only.

The figure below provides an indication of the magnitude of these loads in 2013.

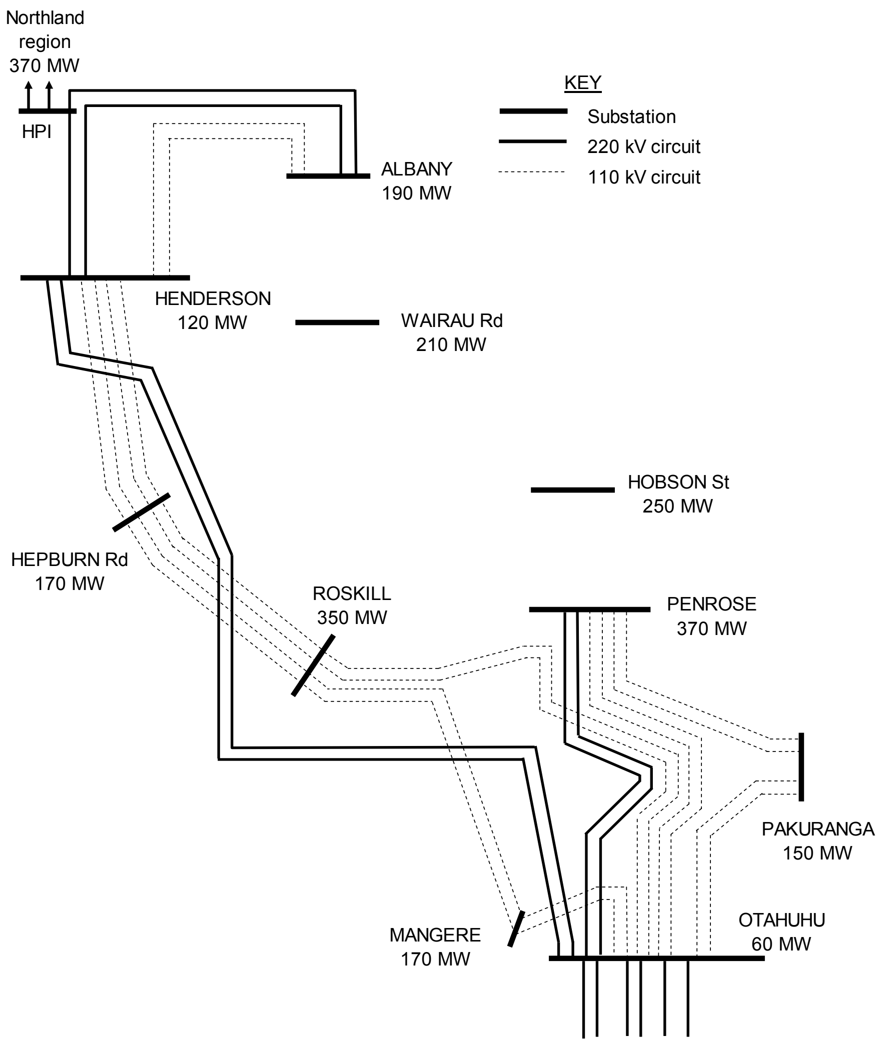

Figure 1 - Existing Transmission System in the Auckland region (simplified)

3 Diversity Analysis

For the purposes of assessing the diversity of this option, the low probability, high consequence contingency of the loss of an entire substation is considered. This type of contingency is rare, but as noted in the introduction, it is not unprecedented. The loss of either Otahuhu substation or Pakuranga substation is considered.

The assessment of the efficacy of the various configuration options is made through quantifying the percentage of Upper North Island load that can supplied following the loss of a substation under the different development options.

3.1 New Line terminated into Pakuranga

This involves terminating the new line at Pakuranga as illustrated in figure 2 below:

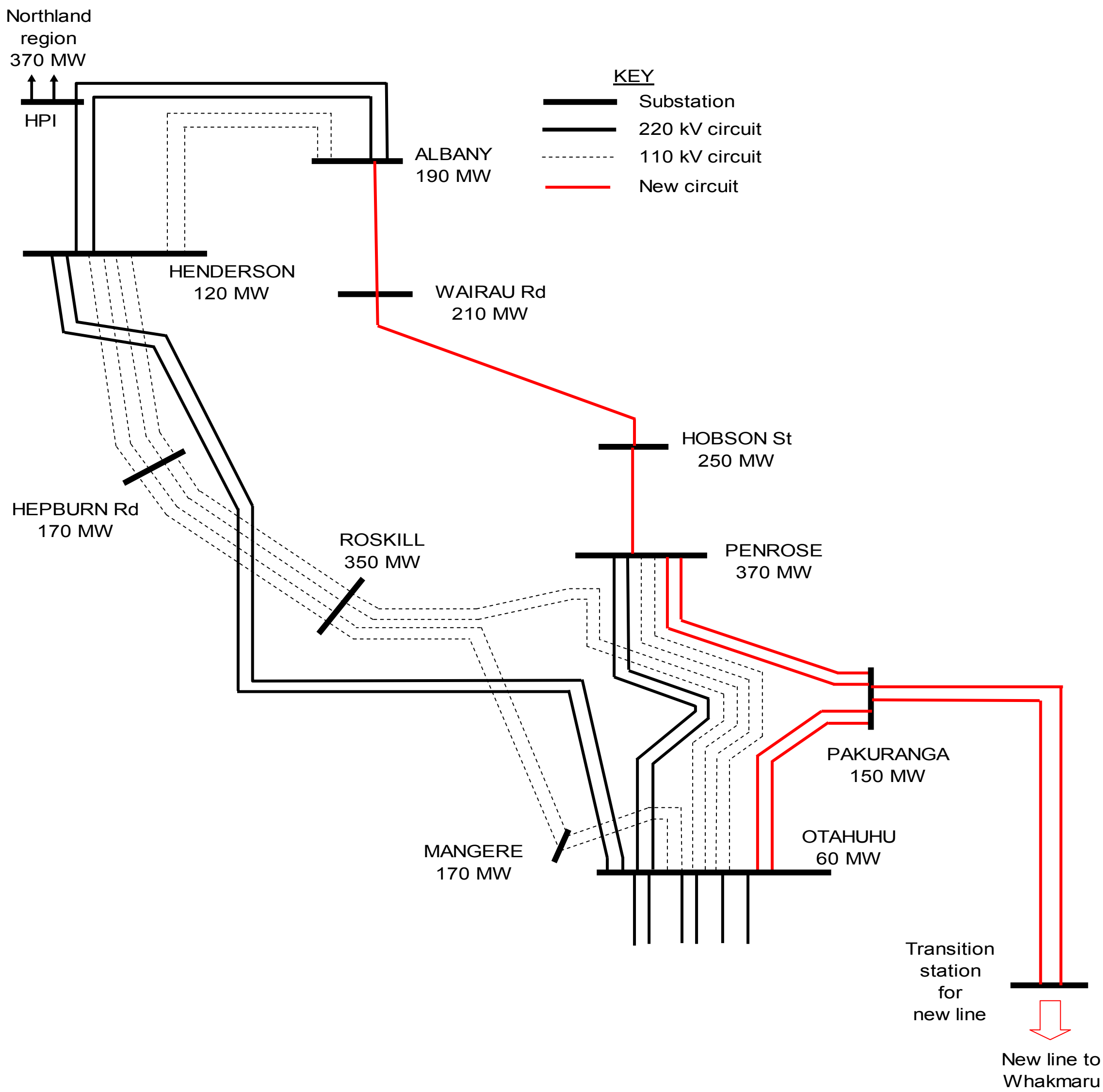

Figure 2 - New line from Whakamaru terminated into Pakuranga substation

3.1.1 Loss of Otahuhu Substation (Otahuhu NOT diversified)

The effect of loosing Otahuhu substation will be dependant on whether or not the substation is split. If there is only a single substation at Otahuhu, then a loss of Otahuhu substation will result in a loss of supply as illustrated in figures 3 and 4 below.

The remaining transmission capacity into Auckland is dictated by the maximum capacity of the cables between the transition station and Pakuranga substation, namely 2 x 660 MVA or 1320 MVA. This equates to about 50% of peak Auckland and Northland load in 2013.

Operators will have considerable flexibility as to how this power is distributed after an event. Possibilities include:

- Auckland CBD and the North Shore
- Auckland CBD and the Northland Region

In either configuration, approximately 50% of the total Auckland and Northland load in 2013 can be supplied following the loss of the entire Otahuhu substation. Two possible configurations that may result after the loss of Otahuhu substation are illustrated in figures 3 and 4 on the following pages.

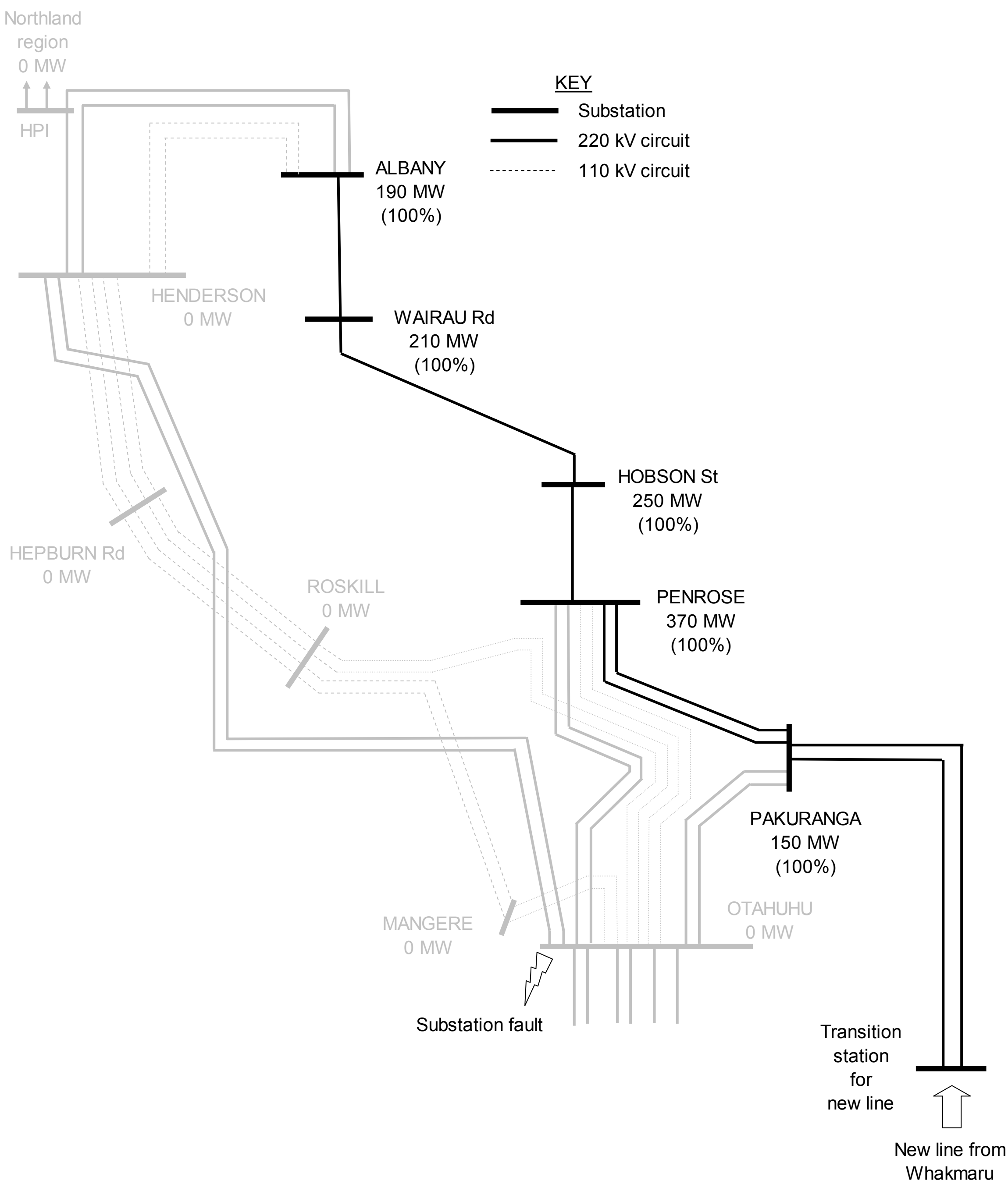

Figure 3 - New line into Pakuranga, following the loss of Otahuhu substation. Shown with supply retained to CBD and North Shore

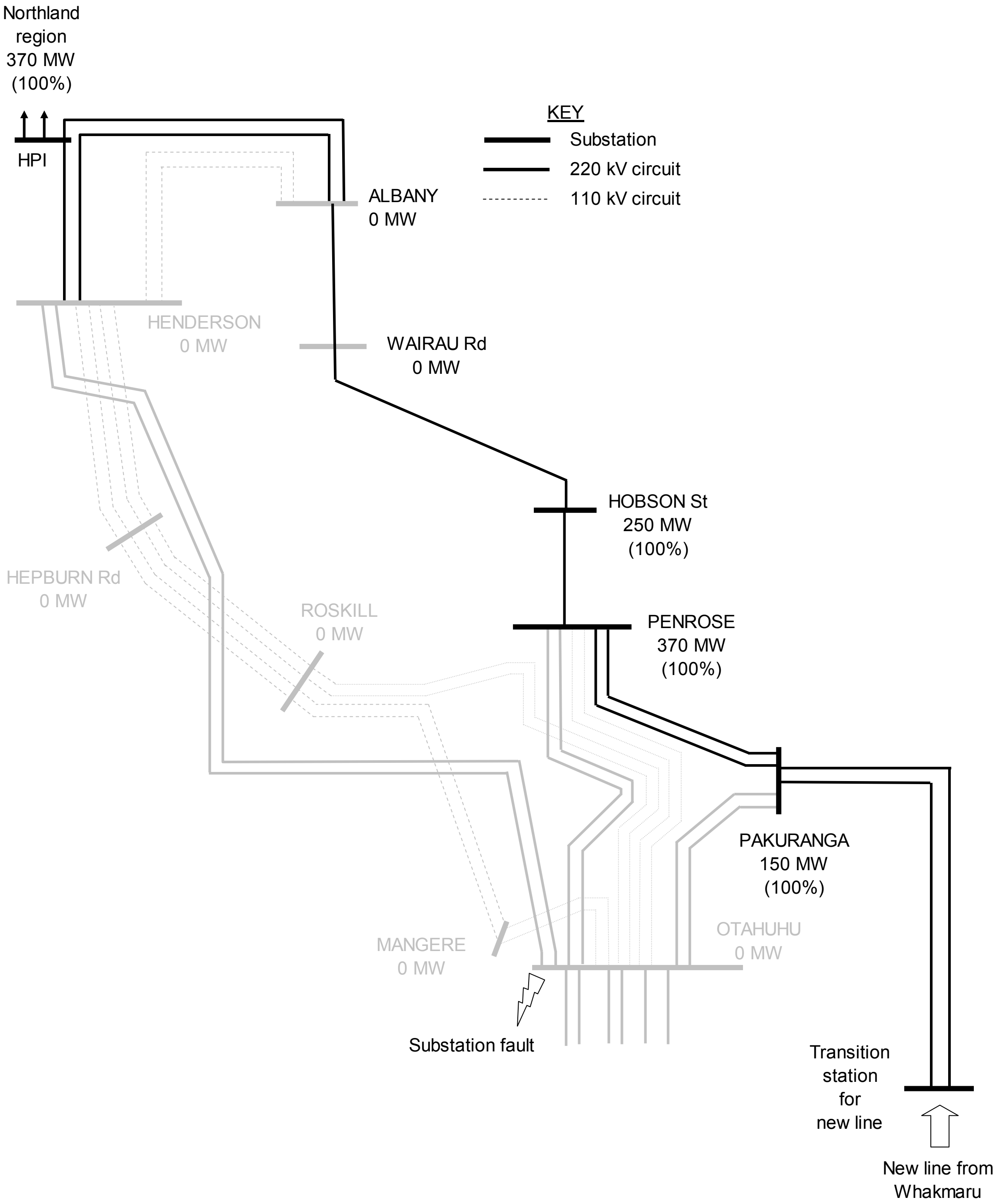

Figure 4 - New line into Pakuranga, following the loss of Otahuhu substation Shown with supply retained to CBD and Northland

3.1.2 Loss of Otahuhu Substation (Otahuhu diversified)

In this case, the remaining lines will be of sufficient capacity to supply the whole of the Upper North Island region, including Auckland CBD as illustrated in figure 5 below.

This scenario clearly demonstrates the benefits of diversification of Otahuhu substation – even with the new line terminated at Pakuranga. A comparison with the same scenario but without diversification at Otahuhu (section 3.1.1, figures 3 and 4) shows that 100% of loads can be supplied with Otahuhu diversified, as opposed to only 50% if Otahuhu is not diversified.

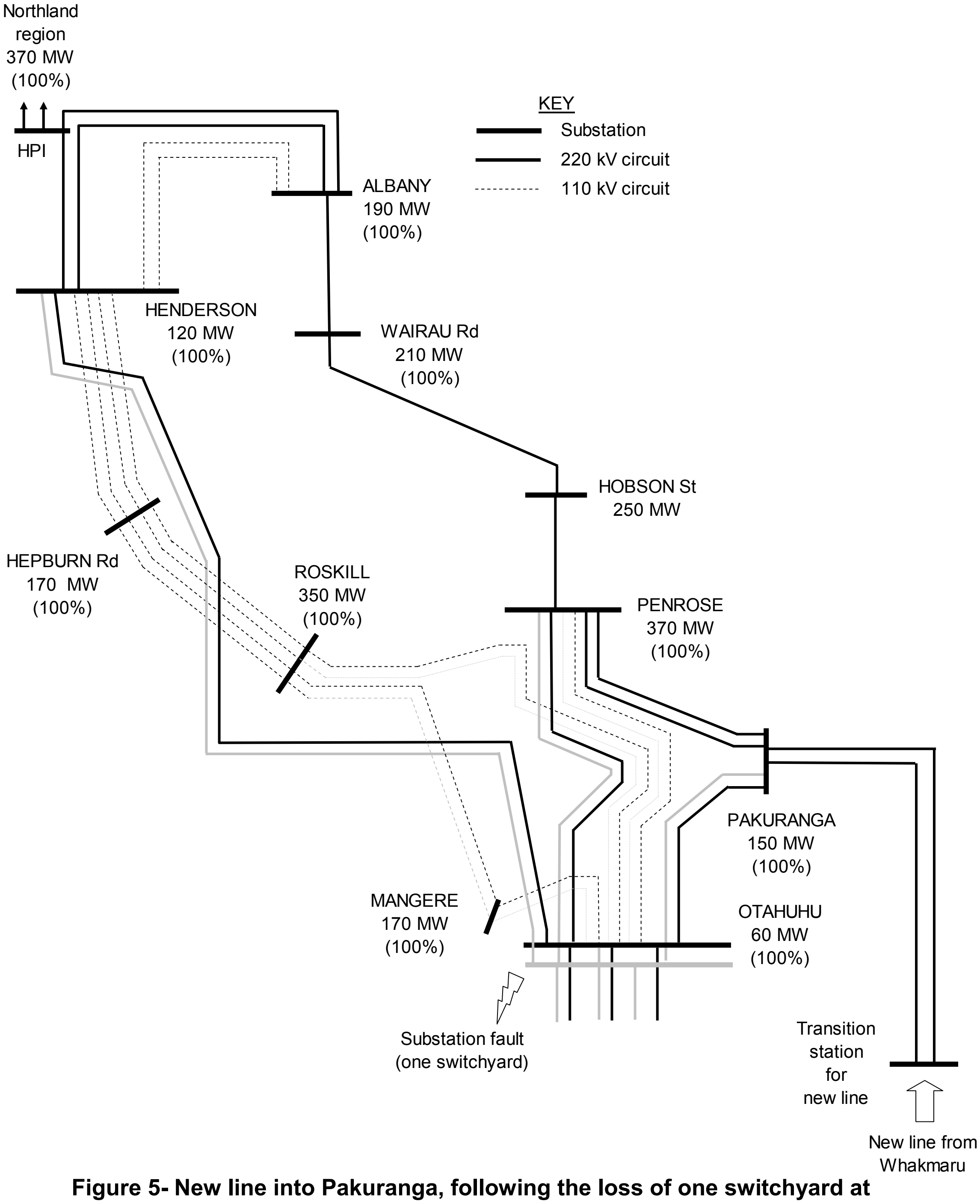

Figure 5- New line into Pakuranga, following the loss of one switchyard at Otahuhu substation. Otahuhu substation diversified

3.1.3 Loss of Pakuranga Substation

In this case, capacity into Auckland and Northland is dictated by the maximum capacity of the existing lines into Otahuhu. This equates to approximately 2000MW, which is sufficient to supply 90% of total load (excepting Pakuranga substation), or 85% of all loads if the loss of Pakuranga is included.

Diversifying Otahuhu substation does not affect this scenario.

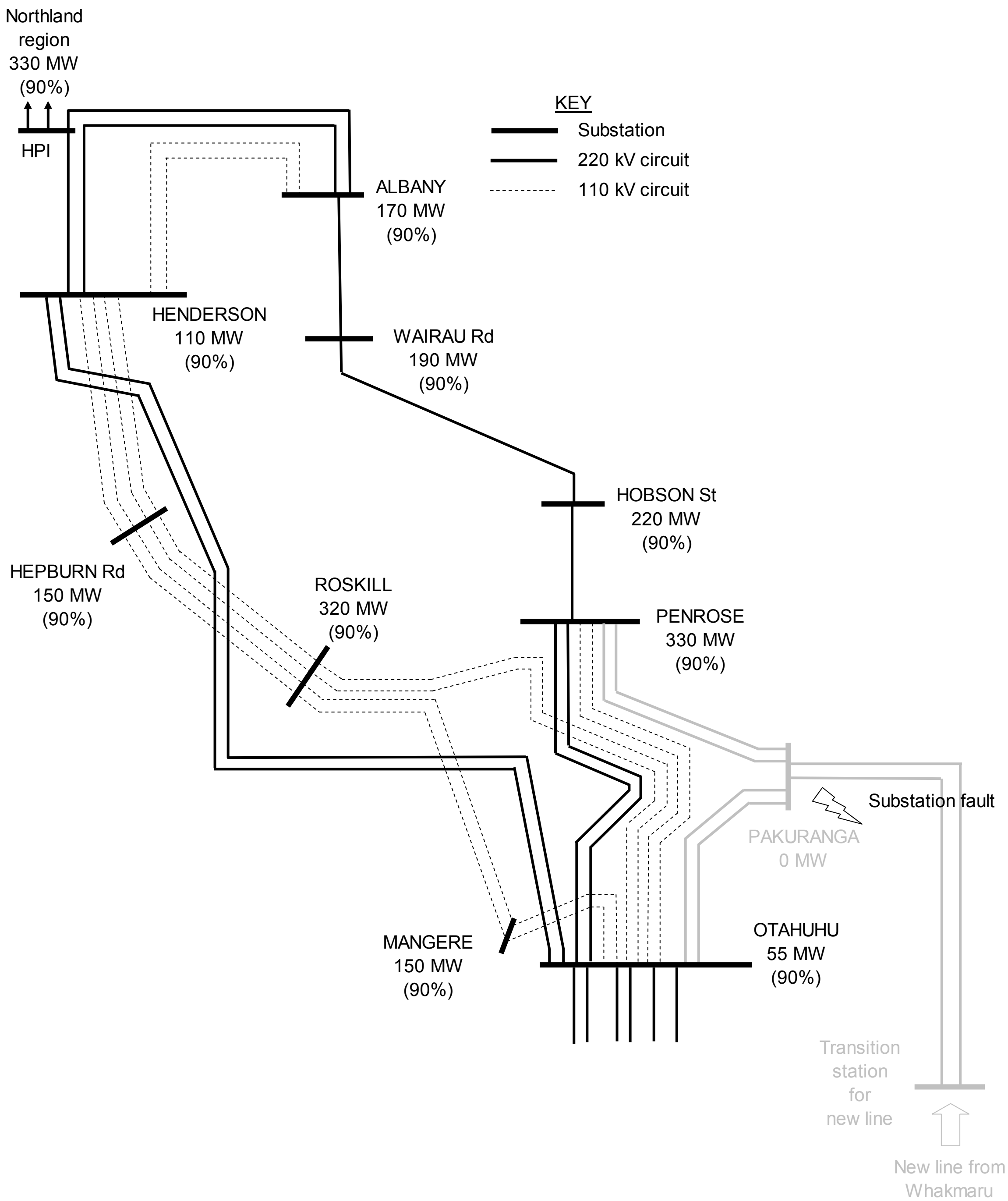

Figure 6 - New line into Pakuranga, following the loss of Pakuranga substation

3.2 New Line Terminated into Otahuhu

In this scenario, Pakuranga remains unchanged as a 110 kV substation supplied from both Otahuhu and Penrose. The arrangement is illustrated in figure 7 below.

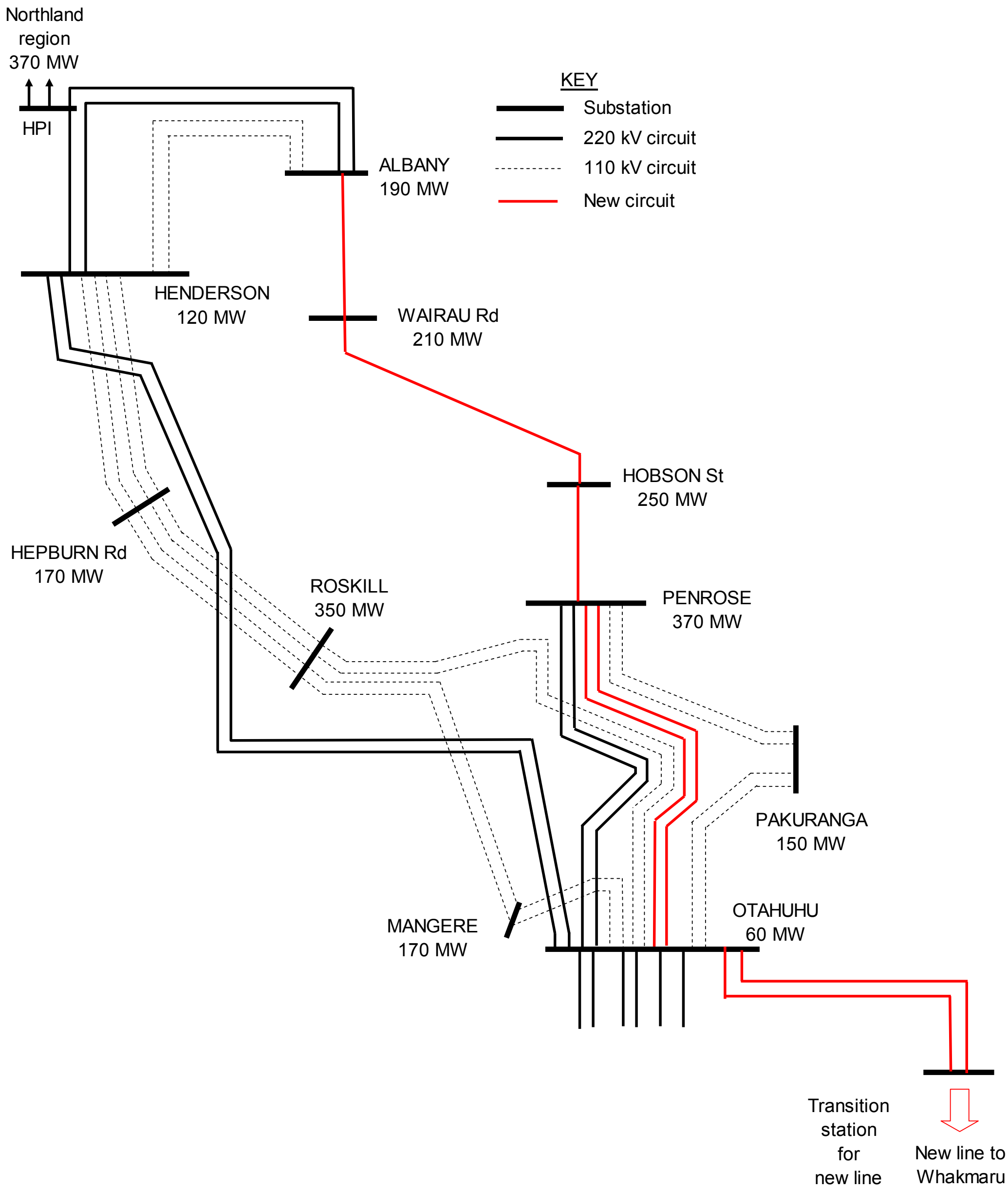

Figure 7 - New line from Whakamaru terminated into Otahuhu Substation

3.2.1 Loss of Otahuhu Substation (Otahuhu NOT diversified)

As there are no alternative transmission routes into Auckland or Northland, the loss of Otahuhu substation will result in a total loss of supply to Auckland and Northland.

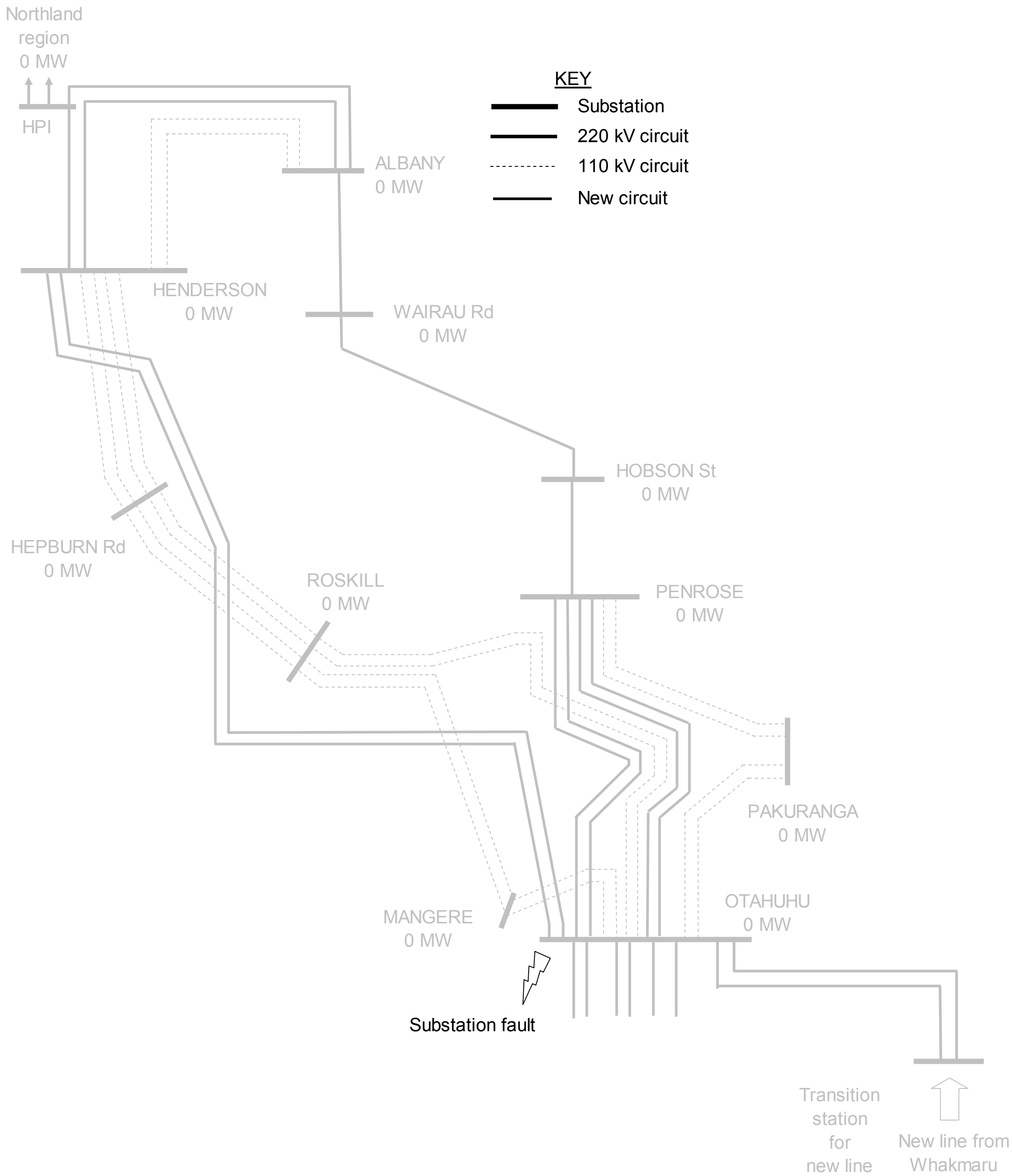

Figure 8 - New line into Otahuhu, following the loss of Otahuhu substation.

3.2.2 Loss of Otahuhu Substation (Otahuhu diversified)

If the Otahuhu substation diversity project were approved and implemented, then the probability of losing the entire Otahuhu substation is greatly reduced.

The limiting factors in this case are the capacities of the existing 220 kV Otahuhu-Penrose line and the existing 220 kV Henderson -Otahuhu line at 400 MVA and 980 MVA per circuit respectively.

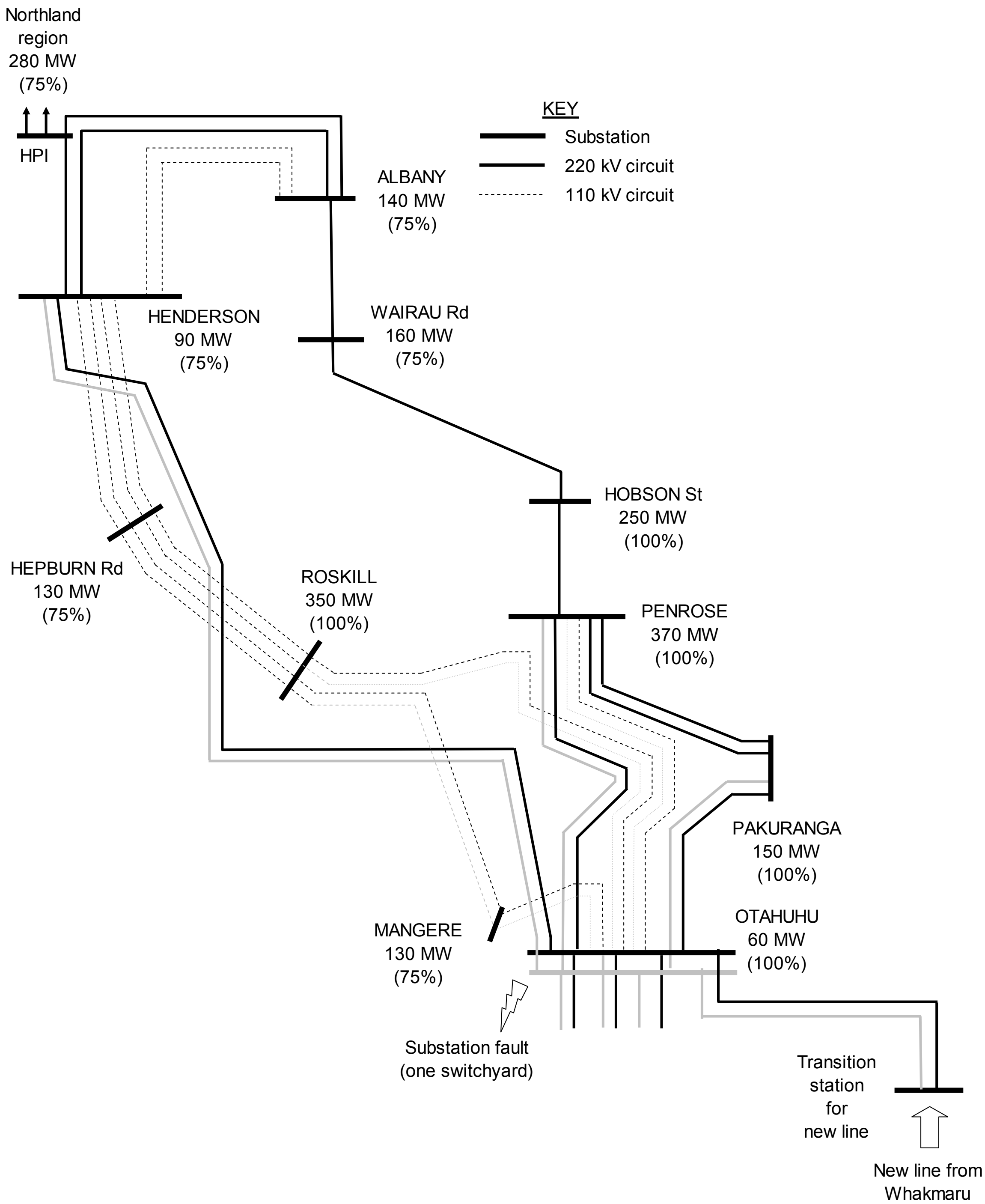

**Figure 9 - New line into Otahuhu, following the loss of one switchyard at Otahuhu substation.
Otahuhu substation diversified**

4 Summary of results

The results are summarised in the tables below:

Contingency	Otahuhu substation diversified	Proportion of Upper North Island load that can still be supplied
Loss of Pakuranga substation	Yes	85 %
Loss of Otahuhu substation (one switchyard)	Yes	100 %
Loss of Pakuranga substation	No	85 %
Loss of Otahuhu substation	No	50 %

Table 4-1. New line terminated into Pakuranga Substation

Contingency	Otahuhu substation diversified	Proportion of Upper North Island load that can still be supplied
Loss of Otahuhu substation (one switchyard)	Yes	85 %
Loss of Otahuhu substation	No	0 %

Table 4-2. New line terminated into Otahuhu Substation

These results show that significant gains in transmission reliability for the Upper North Island can be attained if the new line proposed by Transpower terminates into Pakuranga substation. If this were implemented, then the total loss of either Otahuhu or Pakuranga substation will, at worst, result in the loss of 50% of peak Auckland and Northland load in 2013.

These results are further improved if Otahuhu substation is diversified as well. In this case, at worst only 15% of Upper North Island load will be lost following a substation contingency, compared to 50% if Otahuhu is not diversified.

Terminating the new line into Otahuhu substation will only provide an improvement in diversity if Otahuhu substation is diversified as well. If this were done, then up to 20% of Upper North Island load would be lost following a switchyard contingency.

However, if a site wide event were to result in the loss of both switchyards at Otahuhu, or if Otahuhu substation is not diversified, then a total loss of supply will result.

5 Conclusions

There are two key opportunities available to provide diversity:

- Establish a separate substation at Otahuhu; and
- Terminate a new supply from the south at Pakuranga, establishing a new supply substation for Auckland.

If both steps are taken, a major problem at either Otahuhu or Pakuranga would still leave sufficient capability to supply the central business district and more than 80% of the Auckland load.

TRANSPOWER

Otahuhu Substation Diversity Project

Proposal

Attachment B

Revision 2

Economic Assessment

Application of the Grid Investment Test

December 2006

Executive Summary

This document forms part of a reliability investment proposal to the Electricity Commission (Commission), to ensure security of supply to the Auckland region and north. The Application for Approval document discusses the current non-compliance with the GRS and justifies the proposal as a reliability investment.

The Commission considers and assesses Transpower investment proposals in accordance with section III of Part F of the Electricity Governance Rules 2003. In particular, rule 12.3.3 requires that reliability investment proposals comprise:

"…justification…against the Grid Investment Test…"

and rule 13.4.1.3 provides that, in order to approve a reliability investment, the Commission must be satisfied that the proposed investment:

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

In order to pass the Grid Investment Test a reliability investment must:

"…maximise the expected net market benefit or minimise the expected net market cost compared with a number of alternative projects…"

and

"…if sensitivity analysis is conducted, a conclusion that a proposed investment…is sufficiently robust having regard to the results of that sensitivity analysis…"

This report describes the analysis undertaken by Transpower to justify the proposed reliability investment against the Grid Investment Test.

Of the transmission alternatives considered, the proposed project (to build a new GIS switchyard), has the lowest expected net market cost, robust over a range of sensitivities, and hence passes the Grid Investment Test.

The expected net market cost of the proposal is $1.8 million lower than the next lowest alternative, a new AIS switchyard option.

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1 Introduction

Transpower's proposal is to build a second switchyard at Otahuhu, using gas insulated technology, as soon as possible. The earliest feasible implementation date is 2009.

This analysis compares the proposal to two alternatives using the Grid Investment Test (GIT), as described in Schedule F4 of Part F. Although, in essence, the GIT is nothing more than a national cost-benefit analysis, there are several elements of Schedule F4 which require interpretation in order for it to be applied.

1.1 Simplified Approach

As discussed in the Application for Approval document, the existing Otahuhu substation does not comply with the GRS and investment is required as soon as possible. Consequently, a variable timing of investment analysis was not considered reasonably necessary and it is possible to include the demand uncertainty by means of a Load Probability Curve (LPC), rather than using Monte-Carlo analysis to average over individual generation and demand paths.

1.2 Alternatives considered

To pass the requirements of the GIT, the proposal must be compared with a number of alternatives.

The derivation of the alternatives is comprehensively discussed in the Application for Approval document. Briefly, the alternatives considered are:

- Transmission alternatives, namely:
  - Option 1: Modify and Extend Existing Substation
  - Option 2: Establish a Second AIS Switchyard
  - Option 3: Establish a New GIS Switchyard (the proposal)
- Non-transmission alternatives (NTAs)

A hypothetical NTA would have to lower the required transfer through Otahuhu sufficiently that the substation was no longer able to cause a single credible contingency event. This was not considered realistic in the immediate future.

1.3 Modelled projects

For the purposes of this analysis, it is assumed that a new transmission line between Whakamaru to Pakuranga is built and made operational from 2013. This new line is included as a modelled project. A sensitivity is conducted on the project being delayed until 2015.

2 Analysis framework

2.1 Analysis period

Clause 27 of Part F Section III Schedule F4 requires that in applying the GIT, market costs or benefits be assessed:

"…over a period of 20 years from the commissioning date (unless significant market benefits or costs are expected to arise from the proposed investment or alternative project after that time, in which case the then present-value of any future benefits may also be included…)"[1]

The planned commissioning date for the proposal and alternatives is 2009 and so 2029 is set as the end point.

, Future development plans for Otahuhu substation differ between the alternatives for a considerable period, with all alternatives having their last stages commissioned in 2041. Consequently, costs and benefits from 2030 to 2042 are present-valued back to 2006 and included as a terminal value. Operations and maintenance costs are approximately constant from one year after final commissioning and costs and benefits occurring after 2042 can be captured as terminal benefits and costs.

Transpower has included a terminal benefit calculation as used by the Commission in its draft determination of Transpower's 400kV investment proposal[2].Thus, in summary, costs and benefits from 2007 to 2029 are separated out by year, those from 2030 to 2042 are present-valued back to a single terminal value quantity, and a terminal benefit calculation is used for costs and benefits beyond 2042.

The development plans for all of the alternatives considered have been incorporated out until 2042 and the costs and benefits until 2042 included.

2.2 Commissioning date used in analysis

The commissioning dates used in this analysis for elements of the development plans are directly from the development plans.

As the existing switchyard fails to comply with the GRS, the proposal or an alternative should be built as soon as possible and no deliberate variation in the timing of the initial commissioning date is considered here.[3]

The dates when later components are required depend on the commissioning dates in the North Island Upgrade Development plan, and hence on demand growth until that time. Strictly, the full variability of demand growth paths should be considered. Here, however, the assumption is made that the average cost will be approximately equal to the cost for the average demand growth path. Sensitivities conducted on 10% and 90% probability of exceedance (POE) fixed demand growth curves show that the relativity of the options is insensitive to this assumption.

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[1] Transpower notes a discrepancy in the text of rule 27. The text notes that a longer analysis period can be applied if significant market <u>benefits or costs</u> arise after (20 years from commissioning date), but that only the significant <u>benefits</u> can be included. This is considered to be a drafting error in the rules and that significant <u>benefits or costs</u> should therefore be included.

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

[3] A sensitivity is included of commissioning in 2015.

2.3 Market development scenarios

Rule 6 of Part F Section III Schedule F4 requires that:

6. In applying this Grid Investment Test:

> *6.1. the market development scenarios must be the possible future scenarios outlined in the statement of opportunities unless the Board determines that market development scenarios proposed by Transpower, the proponent of a transmission alternative or the Board are more appropriate;*
>
> *6.2. the probability of occurrence of a market development scenario must be as set out in the statement of opportunities in respect of the relevant possible future scenario; and*
>
> *6.3. the number of market development scenarios used in applying this Grid Investment Test must be same as the number of market development scenarios set out in the statement of opportunities.*

For this proposal, the effects of market development scenarios only differ from each other in the amount of generation available north of Otahuhu, and consequent reduction in required transfer from the south. However, the generating stations are likely to under-voltage trip subsequent to the interruption of supply from two lines and be unavailable post-contingency, as considered in the Application for Approval. For this reason, no new generation north of Otahuhu is considered in the analysis of expected unserved energy that follows.

2.4 Definition of the Reference Case

The definitions in Part F Section III Schedule F4 define a base case as follows:

"Base case" means the market development scenarios developed for the reasonable future state of the electricity industry without the proposed investment or any alternative project.

As noted by both the Commission and Transpower in analysis of the North Island Upgrade, it is difficult to identify a suitable base case for the analysis when the proposal is required to meet the GRS. In the same manner as the Commission, Transpower has used one of the alternatives as a reference case for this analysis. Option 1 (Modify and Extend Existing Substation) is the lowest cost alternative considered and is set as the reference case.

2.5 NPV v Real Options analysis

Part F Section III Schedule F4 rule 13 requires that:

"Either standard net present value analysis or real options analysis must be applied in assessing the expected net market benefit of a proposed investment or alternative project."

As noted by the Commission in their draft determination on the original North Island 400 kV Grid Upgrade Proposal, a textbook treatment of real options is not tractable for transmission investment analysis. Integration of the power systems analysis required to compare transmission alternatives with the economic modelling would not be practicable.

Also, as noted above, uncertainties in market development scenarios and load can be reduced for the purposes of this analysis to use of a load probability curve.

Thus a deterministic NPV calculation is used in the analysis.

2.6 Discount rate

Part F Section III Schedule F4 requires that:

14. The discount rate used in all present value calculations must be:

14.1. the discount rate determined by the Board, from time to time, for the purposes of this Grid Investment Test; or

14.2. if the Board has not determined a discount rate for the purposes of clause 14.1, a discount rate of, or equivalent to, a pre-tax real rate of 7%.

Transpower has conformed to this requirement in calculating expected net market benefit or cost, but has also received advice from Castalia[4] that there is a strong argument for use of a discount rate in the range of 2.72 – 4.18% in the GIT.

The rationale for such an approach is:

- the GIT is essentially a social cost benefit analysis, not a private investment analysis;
- the appropriate discount rate for a social cost benefit analysis is the Social Rate of Time Preference plus a factor to account for social risk aversion;
- the best estimate of the real Social Rate of Time Preference is the post-tax real rate on long term government bonds. Government bonds currently yield 5.8 percent as a pre-tax nominal return, meaning the real return in investors' hands post-tax is around 1.25 percent;
- the best estimate of social risk aversion for the project is derived from the asset beta of companies which invest in and operate electricity and gas transmission companies in other OECD countries, multiplied by a market risk premium;
- tax is simply a transfer in a social cost benefit analysis, and therefore the discount rate should not be "grossed up" for tax.

Transpower considers Castalia's arguments to be compelling and although the analysis has been undertaken with a 7% discount rate, as required by Part F Section III Schedule F4, rule 14, a 4% sensitivity is included and Transpower urges the Commission to consider the results of that sensitivity with some weight.

2.7 Sensitivity analysis

Part F Section III Schedule F4, Clause 17 requires that:

17. In applying sensitivity analysis, a number of alternative reasonable scenarios should be developed for each of the market development scenarios using reasonable variations in all of the following variables, with the exception of those variables in respect of which sensitivity analysis is either not reasonably practicable or not reasonably necessary:

17.1. forecast demand;

17.2. the size, timing, location, and operating and maintenance costs of:

17.2.1. the proposed investment or alternative project; and

17.2.2. existing assets, committed projects and modelled projects;

[4] "Discount Rate for the Grid Investment Test", Castalia, August 2006

17.3. the capital cost of:

17.3.1. the proposed investment and the alternative projects; and

17.3.2. modelled projects;

17.4. the timing of decommissioning, removing or de-rating decommissioned assets;

17.5. the value(s) of unserved energy (which varied value or values will be the value or values published by the Board for this purpose from time to time or, if no such value or values is published by the Board, $10,000/MWh and $30,000/MWh);

17.6. the discount rate used in all present value calculations;

17.7. the discount rate used in present value calculations in relation to a particular alternative project that is a transmission alternative;

17.8. a range of consistent hydrological inflow sequences, as defined in the statement of opportunities and centralised data set;

17.9. generator and demand-side bidding strategies;

17.10. key input variables in the calculation of competition benefits;

17.11. the forecast amount of carbon charges associated with operating the proposed investment, alternative projects, existing assets, committed projects and modelled projects; and

17.12. the probability of occurrence of a market development scenario.

Considering these individually:

Forecast demand

Uncertainty in the demand forecast is incorporated in the Load Probability Curve. Two sensitivities are performed by assuming that the load grows at the 10% and 90% POE values only.

Variations in the size, timing, location, and operating and maintenance costs

Variations in the size of the proposal and alternatives have not been considered in the economic analysis. The size of the proposal was considered in the technical analysis and hence a GIT sensitivity is not considered reasonably necessary.

As noted above the current substation configuration does not meet the GRS, hence the build timing should be "as soon as possible" and a timing sensitivity is not considered reasonably necessary.

The location of the proposal has also been considered as a part of the technical analysis and hence is not reasonably necessary as a sensitivity in the GIT analysis.

A sensitivity on operating and maintenance costs has not been undertaken because the difference in operating and maintenance costs between the proposal and alternatives is small, hence variations in such costs would not be material to the GIT outcome. Such a sensitivity is therefore not considered reasonably necessary.

Capital cost

The capital costs of the proposal and alternatives have been considered as a sensitivity, over a range of +20% to -5%. The sensitivities undertaken inflate the capital cost of all capital expenditure in the analysis, including modelled projects.

Timing of decommissioned assets

Assets being decommissioned are functional and will be replaced. Hence the decommissioning will be just in time for replacements and a sensitivity is not considered reasonably necessary.

Value of unserved energy

The base value of unserved energy in that analysis is $20,000 per MWh, as required by the GIT and sensitivities using $10,000 as a lower bound and $30,000 as an upper bound are undertaken.

$20,000 is a 2004 value. This is equivalent to $21,200 in 2006 dollars, inflating at 3%. Similarly the sensitivities inflate to $10,600 and $31,800 respectively.

Discount rate

The discount rate has been sensitised to values of 4% and 10%. The reason for the choice of 4% is discussed in Section 2.6. 10% is used as an upper bound merely because of its symmetry with the use of 4% as a lower bound.

Discount rate for alternatives

The discount rate has not been varied for the alternatives compared to the proposal. The rationale for requiring such a sensitivity is not clear, but may relate to the situation where a transmission alternative is compared to a non-transmission alternative such as generation. In that case there may be an argument for the use of different discount rates, on the basis of the different redundancy risk of transmission compared to generation. As none of the three alternatives considered in this GIT analysis are non-transmission alternatives, such a sensitivity was not considered reasonably necessary.

Variation in hydrological inflow sequences

Variations in hydrological inflow sequences will not have a significant impact on the total power transfers in and out of Otahuhu and so are not considered reasonably necessary in the sensitivity analysis.

Generator and demand side bidding strategies

Generator and demand-side bidding strategies have not been considered in the analysis.

Competition benefits

Transpower has not currently quantified competition benefits in this analysis and therefore it is not necessary to consider such a sensitivity.

Carbon Charges

Carbon charges have not been sensitised separately in this analysis. Loss values are not required, hence a separate sensitivity is not reasonably necessary.

Probability of occurrence of market development scenarios

As noted above, the analysis is relatively insensitive to differing market development scenarios. Thus a separate sensitivity is not considered reasonably necessary.

In addition the following sensitivities are also considered:

$2009

The Commission's preferred approach is to discount all costs to the year in which the proposal is commissioned and to express the GIT result in commissioning year dollars.

This sensitivity expresses the result using the Commission's preferred approach, which is in $2009, being the commissioning date for the proposal.

PAK 2015

The unserved energy results are dependent on the commissioning date of the modelled project of new lines into Pakuranga. A sensitivity is conducted on the possibility that the lines will not be completed until 2015, rather than 2013 as assumed in the base case.

2.8 List of sensitivities included in analysis

Summarising the discussion above, the following sensitivities have therefore been undertaken and are reported in Section 5:

- 10% POE demand path only
- 90% POE demand path only
- Capital cost +20%
- Capital cost -5%
- Value of unserved energy at $10,600 per MWh
- Value of unserved energy at $42,400 per MWh
- Discount rate of 4%
- Discount rate of 10%
- $2009
- Lines to PAK built 2015

3 Costs and market benefits for this analysis

3.1 Definition of costs and market benefits

Transpower has adopted the Commission's cost definition for the purpose of this analysis. The costs used in the analysis are called "expected costs", and they 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. The scope accuracy used in this analysis is:

- +10% for lines works;
- +10% for cables works;
- +10% for substation works.

In this respect, the costs are more than a P50 estimate and represent the maximum cost of the project excluding financial contingencies. Financial contingencies are variations in price quotations, commodities, exchange rates, inflation, etc. Financial contingencies are calculated separately and are added to the expected cost to arrive at the cost Transpower is seeking cost recovery for, as described in the Application for Approval document.

The benefits are P50 values. A scope accuracy, or equivalent, is not added to derive expected benefit values. This is a conservative approach which will tend to underestimate the value of the benefits and hence favour the reference case.

3.2 Inflation

The expected cost of the projects have been derived in real ($2006) terms and the results are presented in $2006. The Commission's preferred GIT approach requires the results to be calculated and reported in dollars related to commissioning year of the proposal, which is 2009 in this case. These results are also reported, as a sensitivity. $2006 are inflated into future dollars using a 3% per annum inflation rate.

3.3 Interest During Construction

The cash flows used for present value calculations in this analysis reflect the capital costs of projects being streamed according to expected outlays and these vary according to the type of project. For the building of new lines, costs are streamed over five years prior to commissioning. For minor projects (eg installation of static capacitors) costs are spread over periods between two and four years prior to commissioning. To convert costs into commissioning date dollars, interest during construction costs are calculated and are added to the capital cost in the expected year of commissioning.

3.4 Costs included in the analysis

Investigation costs

Investigation costs have been included in the economic analysis to reflect the costs of:

- investigating the need for a project;
- identifying the alternatives that should be considered;
- considering the alternatives;
- developing a Grid Upgrade Plan (Application for Approval) for the Commission.

These costs include Transpower employee costs and external consultant costs, as required. Significant costs are incurred for external consultants in developing alternatives to a point where they can be meaningfully compared.

Although investigation costs would be incurred for all projects, including modelled projects, they have been included for major new lines projects only. Investigation costs for other modelled projects would be small and there are similar numbers of such projects in the alternatives, so in that respect they could be considered common costs.

Capital Costs

Substation costs

The substation costs are based on a preliminary engineering design for the proposal and alternatives.

The capital cost included in the analysis includes estimates for detailed engineering design, surveys, procurement, delivery, construction, project management, testing and commissioning.

Consenting costs

Consenting costs reflect the costs of satisfying the requirements of the Resource Management Act 1991, the Electricity Act 1992, the Public Works Act 1981 and other relevant legislation. Such costs are incurred obtaining designations, resource consents and other permissions necessary to construct a new project.

Project management costs

Project management costs reflect the cost of Transpower employees managing the design, construction and commissioning of new projects. They are estimated at a standard 8% of capital plus property cost. All new builds will be constructed using third parties, who will have their own project managers on-site, but these costs are included in the capital cost estimates.

Operating and Maintenance costs

Operating and maintenance costs have been included for all projects. These costs have been estimated from historical operating and maintenance costs for various sorts of electrical equipment and are consistent with Transpower's budgeted costs for operating and maintenance costs.

Delay

Options 1 and 2 both include an estimated 50% chance of delay in the 2009 commissioning. The assumptions made in this case are

- statistical expectation of unserved energy (SEUE) remains at the pre-diversified level for a further year.
- Capital and property costs are unchanged. This is a conservative assumption that the extra costs associated with the delay will no more than cancel out the savings in present value of those that can be deferred.
- Increases in operations and maintenance costs are deferred a year

Substation equipment costs are dependent on the equipment to be installed and have been derived project by project.

3.5 Benefits included in this analysis

Reliability benefits or savings in statistical expectation of unserved energy costs

The increase in diversity of options 2 and 3 over option 1 (the reference case) results in a lower SEUE. The net present value of this difference represents a benefit.

Terminal benefits

The Commission's approach to valuing terminal benefits for a line investment has been adapted for a substation investment in this analysis.

Methodology for a Line Investment

In the context of a line investment here are two main elements to the approach:

- a reflection of remaining, unutilised, thermal capacity at the end of the analysis period, and;
- a summation of ongoing costs and benefits of all available thermal capacity at the end of the analysis period

The approach is described in detail in the Commission's economic analysis report included in their draft determination on the 400kV upgrade, but in brief, four cost/benefit streams covering up to 25 years after the end of the analysis period are calculated and added together.

1. Remaining, unutilised thermal capacity is a benefit, valued at the long run marginal cost of transmission, calculated as being the cost of the amended proposal divided by the ultimate thermal capacity of the amended proposal.
2. However, utilising that thermal capacity will incur a "thermal unlocking" cost, being the cost of other developments, including reactive support, needed to access that capacity. This is added as a cost.
3. Loss savings, relative to the losses associated with the amended proposal, are an additional benefit or cost. These are assumed to be constant for 25 years from the end of the analysis period, at the loss cost difference that applied at the end of the analysis period.
4. Operating and maintenance costs are also assumed to be constant for 25 years from the end of the analysis period, at the level incurred at the end of the analysis period.

Adaptation for a Substation Investment

Taking the four cost/benefit streams from the line investment analysis in turn

1. The remaining unused capacity here is the residual value of the new substation components, which varies amongst the different options due to different build times. The residual value is calculated as

   Residual value = build cost * remaining life / expected total life
2. There is no cost to unlock this capacity.
3. Analogous to loss savings are savings in the statistical expectation of unserved energy. In principle these are assumed to be constant for 25 years from the end

of the analysis period. In practice, none of the options has significant SEUE beyond the commissioning of the new lines into Pakuranga.

4. As for the lines investment, operating and maintenance costs are also assumed to be constant for 25 years from the end of the analysis period, at the level incurred at the end of the analysis period.

3.6 Costs and Benefits not separately included or excluded from the analysis

Testing and commissioning costs

Testing and commissioning costs for the proposal and the alternatives are included in the capital cost estimates.

Statutory compliance costs and benefits

For the purposes of this analysis, the only statutory compliance cost which has been costed and included is consenting costs, which are the costs of satisfying the requirements of the Resource Management Act 1991, the Electricity Act 1992, the Public Works Act 1981 and other relevant legislation. These are included as a separate line item in the cost estimates.

No other statutory compliance costs have been included.

Fuel cost benefits

Fuel cost benefits arise if a proposed transmission investment or alternative enables lower fuel cost generation to be dispatched. A transmission constraint which constrains generation from the south being dispatched to the Auckland region, could result in higher cost thermal generation in the Auckland region being dispatched, to meet demand. If new transmission into the Auckland region avoids such out-of-merit dispatch, the generation fuel cost saving is a benefit to the new transmission.

It is assumed that generation dispatches would not vary between the alternatives considered in this analysis, hence it is not necessary to consider fuel cost benefits.

Demand-side management costs and benefits

Demand-side alternatives have not been considered in this analysis and hence their costs and benefits do not arise. Transpower is not aware of any feasible demand-side alternatives which could materially defer the need for the new transmission investment proposed in this application. It is acknowledged that this is a relatively unexplored and undeveloped area amongst industry participants, but is potentially promising in terms of providing transmission alternatives.

Ancillary service costs and benefits

The ancillary service cost difference considered in this analysis, is any cost in the amount of voltage support contracts which the System Operator may need to hold in order to ensure security of supply in the Auckland region.

The analytical approach taken by Transpower assumed the same contracted voltage support was utilised over the analysis period. Some dynamic compensation was added into the development plans as required, but the analysis determined that each of the alternatives required essentially the same level of new voltage support. Therefore, ancillary service benefits were not considered further in this analysis.

Distribution costs and benefits

Distribution costs and benefits were not considered in this analysis. Such costs and benefits could arise if the level of service differed significantly to distribution companies in the Auckland region, between the alternatives, but this is not the case. In this proposal.

4 Calculation of Costs and Market Benefits

Transpower has calculated the expected net market benefit or cost of transmission alternatives in a manner which is similar to that use by the Commission in its draft determination of Transpower's original 400kV investment proposal[5]. However as noted above a number of simplifications can be made in this simpler proposal which lead to a straight-forward deterministic net present value calculation of benefits minus costs.

Costs, as detailed above, include capital expenditure, property and noise abatement costs, and operations and maintenance.

The major benefit of the alternatives over the reference case is the reduction in SEUE. The SEUE is calculated by assuming the probabilities of double bus bar failures in the various different scenarios as discussed in the Application for Investment.

In the event of a failure, demand is determined randomly from the Load Probability Curve for the appropriate region and any excess of demand over post-contingent capacity is counted as unserved energy. A statistical expectation is taken over events and demand values for each year of the analysis period and a net present value is calculated.

Terminal Benefits are also included, as discussed above.

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

5 Calculation of Unserved Energy

5.1 Number of Events

The existing 220kV switchyard as shown in figure 5-1 is vulnerable to the consequences of four failure events:

- CB 598 (bus tie)
- CB 528 (bus section)
- CB 538 (bus section)
- Bus section A

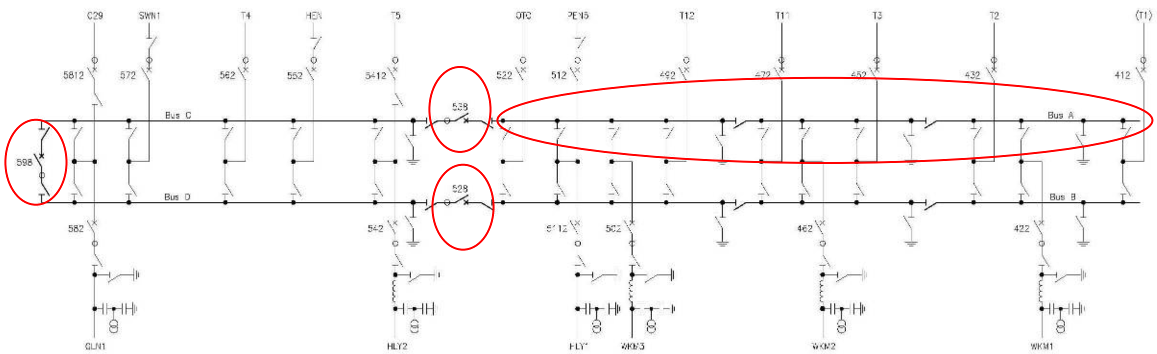

Figure 5-1: Existing 220kV switchyard – single points of failure

The failure of any one of these elements will result in the loss of two feeder circuits from the south, with subsequent loss of load as discussed in section 6 of the proposal.

The installation of additional bus coupler circuit breakers in 2009 is common to all options and will provide compliance with the GRS by eliminating the possibility of a single bus fault event (trip of bus section A) as a single contingency that would result in the loss of two feeders from the south.

Installing bus coupler circuit breakers will not however reduce the vulnerability of the switchyard to bus section and bus tie circuit breaker faults. Figure 5-2 shows that there are still four events that could result in the loss of two feeders from the south. This situation is retained under the reference case until 2013, at which time the switchyard extension will be built and the feeders from the south are diversified. Under options 2 and 3 however, feeders from the south are diversified in 2009 when the new switchyards at Otahuhu are commissioned.

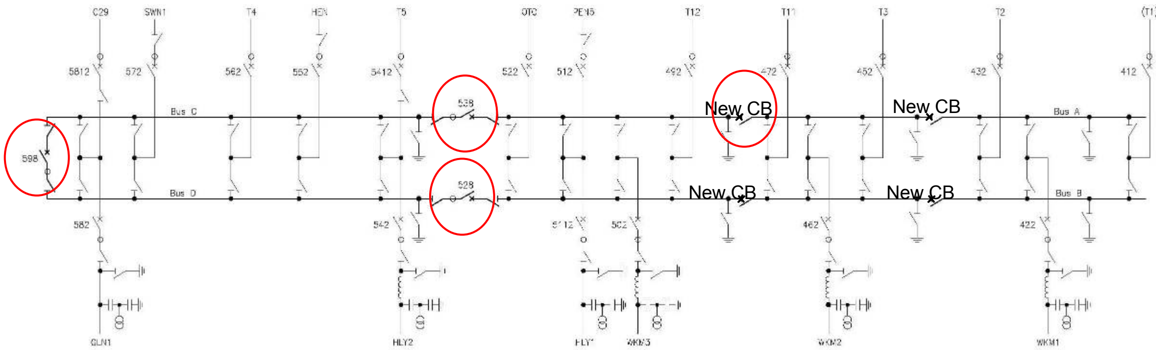

Figure 5-2: Existing switchyard with new bus section circuit breakers

5.2 Effects of a failure

Several scenarios were developed to calculate the amount of unserved energy at risk following a failure.

Ref	Description
A	The fault results in lost load north of Otahuhu which includes all of Auckland and Northland
B	The fault results in voltage instability causing the subsequent loss of all load in the top of the North island, north of Whakamaru

Table 5-1: Loss of load scenarios prior to diversification of feeder circuits into Otahuhu

The above two scenarios apply to all options prior to the diversification of south feeder circuits as described in table 6-3 of the proposal (i.e. reference case until 2013, option 2 until 2009, with 50% chance of delay until 2010, and option 3 until 2009). The assumption is made that half of the fault events will result in scenario A, and half in scenario B. Estimated outage durations are derived from table 6-1 in the proposal and are:

- 6 hours for scenario A
- 9 hours for scenario B

The load probability curves used for the above two scenarios were derived from the Electricity Commissions 2005 load duration curves using the prudent methodology. These are the same curves as those used for the Upper North Island Grid Development Amended Proposal. The load probability curves are shown in figures 5-3 and 5-4.

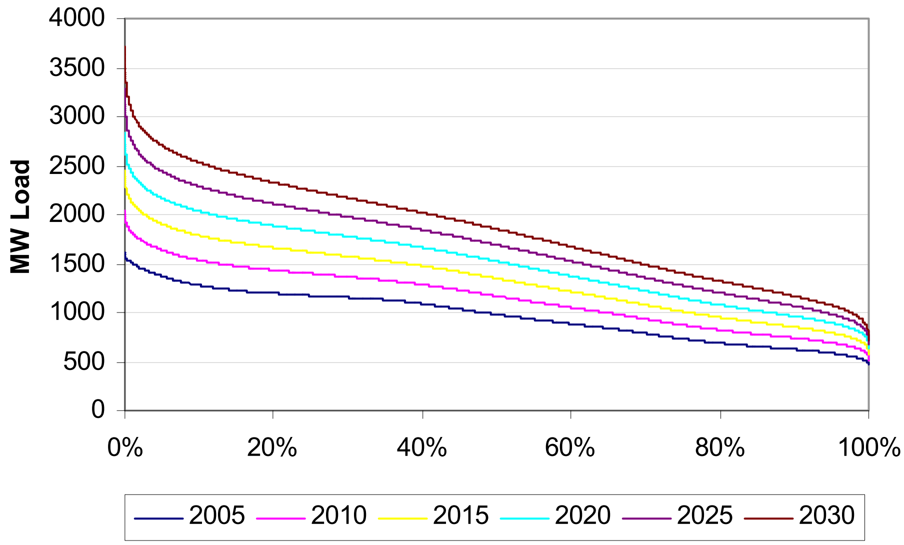

Figure 5-3: Load Probability Curve for the area north of Otahuhu

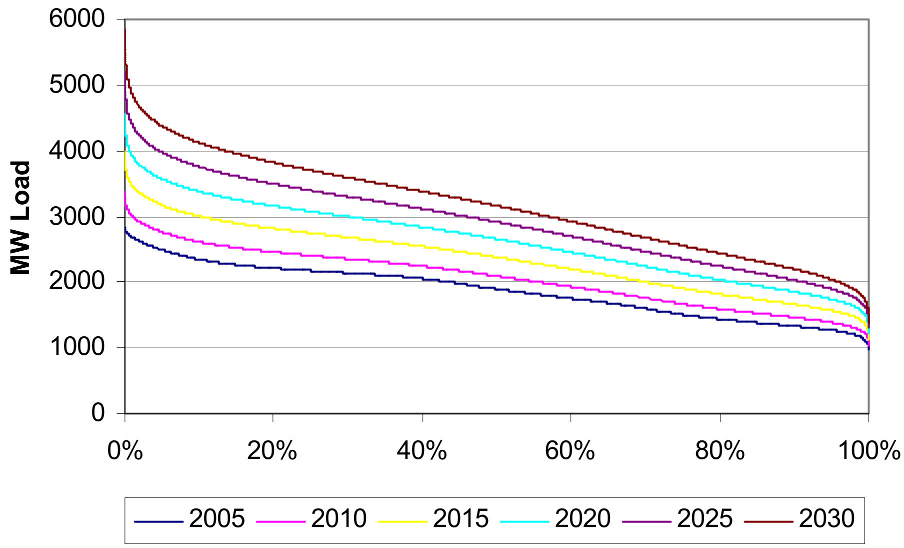

Figure 5-4: Load Probability Curve for the area north of Whakamaru

The following three scenarios apply only to the case where no further improvements are made to the reliability of the Otahuhu substation following the installation of the bus coupler circuit breakers. Also assumed are two south feeder circuits into Pakuranga substation which provide 1300MW of capacity into the region independently of Otahuhu. This case was developed in order to provide a measure against which the reference case and the options could be compared with respect to the unserved energy calculations.

Ref	Description
C	This assumes a single switchyard at Otahuhu following the commissioning of the Upper North Island Development Project. Refer to Attachment A for details. Supply to Auckland and north is restricted to the 1300 MW through Pakuranga.
D	A fault causes voltage instability and the subsequent loss of all load north of Whakamaru. This is similar to scenario B above, but restoration of supply is expected to be quicker
E	Restoration of the fault in scenario D includes a stage where supply is restored to all points south of Otahuhu.

Table 5-2: Loss of load scenarios following commissioning of feeders into Pakuranga

An assumption is made that there is a 50% probability of the Upper North Island Development Project proceeding by 2013, with a 50% probability of a fault causing voltage collapse.

The estimates for supply restoration times under the above scenarios are:

- 4 hours for scenario C,
- 2 hours for scenario D, followed by 2 hours for scenario E (i.e. staged restoration of supplies)

The reference case and options 1 and 2 all have no chance of a major outage through this failure mode following the commissioning of the Upper North Island Development Project.

5.3 Calculations

A copy of the spreadsheet that details the calculation of unserved energy for the reference case and the options is summarised below. A more detailed version is attached to the end of this report.

Assumptions	
VoLL ($/MWh)	21200
NPV years	20
Discount rate	7%
Load probability curve	EC 2005 growth data using prudent methodology
MTBF per CB (years)	250
No. events (CB's)	4

Cost of USE under various scenarios

Lost load scenario	**Load limited to (MW)**	**Hours at reduced load**	**MTBF Total**
A	0	6	62.5
B	0	9	62.5
C	1300	4	62.5
D	0	2	62.5
E	0	2	62.5

Cost of USE under each option	**2007-2009**	**2009-2012**	**2013+**	**NPV (USE)**
No improvements (note 1)	0.5*(A+B)	0.5*(A+B)	0.5*(C+(D then E))	$30,466,510.57
Reference case	0.5*(A+B)	0.5*(A+B)	0	$20,178,418.96
Option 2 (AIS)	0.5*(A+B)	0	0	$8,940,850.02
Option 3 (GIS)	0.5*(A+B)	0	0	$7,227,536.10

Savings in USE	
Reference case	$ 10,288,092
Option 2 (AIS)	$ 21,525,661
Option 3 (GIS)	$ 23,238,974

Notes
1. Assumes no work is undertaken to address reliability issues at Otahuhu

Figure 5-5: Summary of USE calculation results

6 Results and Sensitivity Analysis

Results from Transpower's economic analysis for the proposal and alternatives are presented below.

The results include sensitivities to significant inputs, as discussed in Section 2.7 above.

The following results are presented.

- GIT comparison of transmission alternatives, namely:
  - Option 1: Modify and Extend Existing Substation
  - Option 2: Establish a Second AIS Switchyard
  - Option 3: Establish a New GIS Switchyard
- GIT comparison of transmission alternatives

6.1 Assumptions

The following assumptions summarise those used in applying the GIT to the transmission alternatives:

- the July 2005 SoO demand forecast has been used;
- the GIT analysis has been conducted over a total 36 year period, from 2007 to 2042;
- a 7% discount rate is used, although a 4% discount rate sensitivity is included, as Transpower has received advice that there is a compelling argument for use of a social discount rate in GIT analysis, which would be around 4%;

6.2 Cost of transmission alternatives

The GIT analysis was completed using a grid development plan for the substation upgrade for each transmission alternative, as described in the Application for Approval document. The costs used in the GIT analysis reflect the costs of the entire development plan to 2042.

These costs are consistent with the Commission's definition of "expected costs", being estimated capital costs, plus an allowance for scope contingencies (estimated at 10%). They exclude financial (eg exchange rate, commodity) contingencies and thus differ from the amount Transpower would actually seek approval for. Calculation of the cost Transpower would actually seek approval for is described in the Application for Approval document.

Note, for clarity, that use of the term "expected" in this context, is different from use of the term "expected", with respect to net market costs discussed in Section 1 above.

6.3 GIT Results

In summary, the GIT results comparing the proposal and transmission alternatives are

	Extend Existing Switchyard	2nd AIS Switchyard	GIS Switchyard
	2006 dollars (millions)		
Capital cost (A)	75.8	80.0	82.2
Consenting and noise abatement costs (B)	0.0	0.5	0.0
Operations and maintenance costs (C)	1.9	3.0	2.6
Saving in Expectation of Unserved Energy (D)	10.3	21.5	23.2
Terminal value (E)	2.9	1.7	3.0
Terminal Benefit (F)	4.0	4.0	4.1
Mean NPV cost* (A+B+C-D-E-F)	60.5	56.1	54.3
Difference v Reference Case		-4.4	-6.2

Table 6-1: Grid Investment Test Results

The expected net market cost of the proposal is the lowest of the alternatives considered.

6.4 Sensitivities

In order to pass the second requirement of the GIT, the expected net market cost of the proposal must be sufficiently robust to sensitivity analysis.

A range of sensitivities have been considered, as derived in Section 2. The results of the sensitivity analysis are presented in Table 6-2 and the significance of each is the further discussed below.

-$2006 million-	Extend Existing Switchyard	2nd AIS Switchyard	GIS Switchyard	ENMC Diff GIS – E.E.
Base results	**60.5**	**56.1**	**54.3**	**-6.2**
Sensitivity:				
10% POE demand path only	58.7	53.9	52.4	-6.3
90% POE demand path only	61.7	57.5	55.2	-6.4

Capital cost +20%	75.7	72.1	70.8	-4.9
Capital cost -5%	56.7	52.1	50.2	-6.5
Value of unserved energy $10,600/MWh	65.7	66.9	66.0	0.3
Value of unserved energy $31,800/MWh	55.4	45.3	42.7	-12.7
Discount rate of 4%	52.1	45.2	42.8	-9.3
Discount rate of 10%	60.0	57.9	56.4	-3.5
$2009	66.1	61.3	59.4	-6.8
Lines to PAK built 2015	57.2	49.9	48.6	-8.7

Table 6-2: Sensitivity of expected net market cost of proposal and transmission alternatives to various parameter changes

10% POE demand path only

A sensitivity is calculated for the demand being always equal to the prudent forecast. This results in increased SEUE savings and increased costs after 2013, due to an acclerated build plan. However, the relativity between the options is not significantly altered.

90% POE demand path only

For symmetry a low demand path is also used. Again the relativities amongst the options are not significantly altered.

Capital cost +20%, -5%

As a significant part of the overall expected net market cost is the capital cost of the development plan, a sensitivity is undertaken to evaluate the effect of uncertainty in the capital costs. A higher positive variance is used to reflect the fact that it is more likely costs have been left out (as a detailed design has not been undertaken at this time) than it is that the proposal has been over-designed.

The expected net market cost difference between the AIS option and the proposal does not change over this range because the present values of the capital costs are almost identical.

Value of unserved energy $31,800/MWh

This sensitivity is included as required under the GIT. The value of the diversity of the second and third alternatives over the reference case is increased.

Value of unserved energy $10,600/MWh

This sensitivity is included as required under the GIT. The advantages of options 2 and 3 over the reference case are much less than in the base case, but still favour the GIS option.

Discount rate 4%

Castalia, on Transpower's behalf, has considered the appropriateness of using 7% as a discount rate for GIT analysis. In brief, they believe that because the GIT is a national cost-benefit analysis, the discount rate should reflect a social rate of time preference. Castalia have derived an appropriate range of discount rate for GIT analysis to be 2.72% to 4.18%.

This sensitivity covers the upper end of Castalia's appropriate range and demonstrates that the proposal has a significantly lower expected net market cost than the reference case using this discount rate. With higher discount rates, costs and benefits that occur further out in time make a smaller contribution to the result.

The reference case has greater change in SEUE values to partially cancel out future capital costs and so is less sensitive to variations in the discount rate.

Discount rate 10%

This sensitivity is provided for symmetry with the 4% discount rate sensitivity, although there appears little rationale for discounting transmission investment streams at such a discount rate.

$2009

This sensitivity is provided to show the effect of undertaking economic analysis in commissioning year dollars, as preferred by the Commission. The rankings of alternatives does not change, but as might be expected, the difference between the proposal and reference case increases in line with inflation.

Lines to PAK built 2015

A two year delay in the construction of the new lines into Pakuranga would increase the SEUE in the reference case, but not options 2 or 3, both of which give greater diversity into Auckland from 2009. The delay would reduce the NPV of costs in all three options. Thus options 2 and 3 have the greatest reduction in net cost. The gap between 2 and 3 closes slightly as option 2 has more "just in time" build, but 3 still has the lowest net cost.

7 Conclusion

The results in Section 5.3 demonstrate that the proposal has the lowest expected net market cost of the alternatives considered in the GIT analysis.

It is concluded therefore that the proposal passes the first requirement of the GIT, under which the proposal must:

"…maximise the expected net market benefit or minimise the expected net market cost compared with a number of alternative projects…"

The results in Section 5.4 provide the GIT results for the sensitivities considered in this analysis, as derived in Section 2.7.

The expected net market cost of the proposal is lower than the alternatives considered over the majority of sensitivities undertaken and it is only in extreme and in Transpower's view, relatively unlikely situations, that the proposal does not have the lowest expected net market cost.

It is concluded therefore, that the proposal passes the second requirement of the GIT, in that the "proposed investment…is sufficiently robust having regard to the results of …sensitivity analysis…"

Since the proposal passes the first and second requirements of the GIT, it is concluded that the proposal passes the GIT.

Appendix: Unserved Energy Calculation with NPV projections to 2030

Calculation of the cost of unserved energy for Otahuhu substation diversity project.
This is an excerpt of a larger spreadsheet, and gives a summary of the USE results.
Transpower December 2006

Assumptions

VoLL ($/MWh)	21200
NPV years	20
Discount rate	7%
Load probability curve	EC 2005 growth data using prudent methodology
MTBF per CB (years)	250
No. events (CB's)	4

MW lost load (average using LPC as above)

Lost load scenario	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017
A	1042	1080	1117	1154	1190	1225	1261	1298	1334	1370	1405
B	1882	1944	2006	2065	2123	2181	2239	2297	2355	2411	2468
C	23	34	50	67	85	106	127	149	172	196	221
D	1882	1944	2006	2065	2123	2181	2239	2297	2355	2411	2468
E	1042	1080	1117	1154	1190	1225	1261	1298	1334	1370	1405

Lost load scenario	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
A	1440	1475	1510	1546	1581	1615	1650	1684	1717	1751	1784	1817
B	2524	2580	2636	2690	2744	2799	2851	2905	2956	3008	3061	3111
C	246	272	298	326	353	381	409	437	465	494	522	551
D	2524	2580	2636	2690	2744	2799	2851	2905	2956	3008	3061	3111
E	1440	1475	1510	1546	1581	1615	1650	1684	1717	1751	1784	1817

Cost of USE under various scenarios

Lost load scenario	Load limited to (MW)	Hours at reduced load	MTBF Total	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017
A	0	6	62.5	$2,121,295	$2,198,182	$2,273,097	$2,348,014	$2,420,958	$2,493,901	$2,566,846	$2,641,760	$2,714,705	$2,787,649	$2,858,622
B	0	9	62.5	$5,745,495	$5,933,966	$6,122,436	$6,305,196	$6,482,243	$6,659,292	$6,836,338	$7,013,387	$7,190,435	$7,361,772	$7,533,108
C	1300	4	62.5	$30,668	$46,417	$67,477	$90,708	$115,997	$143,634	$171,815	$202,198	$233,904	$266,339	$299,405
D	0	2	62.5	$1,276,777	$1,318,659	$1,360,541	$1,401,155	$1,440,498	$1,479,843	$1,519,186	$1,558,531	$1,597,874	$1,635,949	$1,674,024
E	0	2	62.5	$707,098	$732,727	$757,699	$782,671	$806,986	$831,300	$855,615	$880,587	$904,902	$929,216	$952,874

Lost load scenario	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
A	$2,931,567	$3,002,539	$3,073,511	$3,146,455	$3,217,429	$3,286,430	$3,357,404	$3,426,405	$3,495,405	$3,564,406	$3,631,436	$3,698,466
B	$7,704,446	$7,875,781	$8,047,118	$8,212,744	$8,378,369	$8,543,995	$8,703,911	$8,869,535	$9,023,739	$9,183,653	$9,343,567	$9,497,771
C	$333,888	$369,017	$404,025	$441,709	$478,907	$516,537	$554,464	$592,295	$631,168	$670,145	$708,313	$748,073
D	$1,712,099	$1,750,174	$1,788,248	$1,825,054	$1,861,860	$1,898,666	$1,934,202	$1,971,008	$2,005,275	$2,040,812	$2,076,348	$2,110,616
E	$977,189	$1,000,846	$1,024,504	$1,048,818	$1,072,476	$1,095,477	$1,119,135	$1,142,135	$1,165,135	$1,188,135	$1,210,479	$1,232,822

Cost of USE under each option	**2007-2009**	**2009-2012**	**2013+**	**NPV (USE)**	**2007**	**2008**	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**
No improvements (note 1)	0.5*(A+B)	0.5*(A+B)	0.5*(C+(D then E))	$30,466,510.57	$3,933,395	$4,066,074	$4,197,766	$4,326,605	$4,451,600	$4,576,596	$ 1,273,308	$ 1,320,658	$ 1,368,340	$ 1,415,752	$ 1,463,151
Reference case	0.5*(A+B)	0.5*(A+B)	0	$20,178,418.96	$3,933,395	$4,066,074	$4,197,766	$4,326,605	$4,451,600	$4,576,596	$0	$0	$0	$0	$0
Option 2 (AIS)	0.5*(A+B)	0	0	$8,940,850.02	$3,933,395	$4,066,074	$2,098,883	$0	$0	$0	$0	$0	$0	$0	$0
Option 3 (GIS)	0.5*(A+B)	0	0	$7,227,536.10	$3,933,395	$4,066,074	$0	$0	$0	$0	$0	$0	$0	$0	$0

Cost of USE under each option	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**
No improvements (note 1)	$ 1,511,588	$ 1,560,018	$ 1,608,388	$ 1,657,791	$ 1,706,621	$ 1,755,340	$ 1,803,901	$ 1,852,719	$ 1,900,789	$ 1,949,546	$ 1,997,570	$ 2,045,755
Reference case	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Option 2 (AIS)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Option 3 (GIS)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0

Savings in USE

Reference case	$ 10,288,092
Option 2 (AIS)	$ 21,525,661
Option 3 (GIS)	$ 23,238,974

Notes
1. Assumes no work is undertaken to address reliability issues at Otahuhu

TRANSPOWER

OTAHUHU SUBSTATION DIVERSITY PROJECT

PROPOSAL

ATTACHMENT C

CAPITAL COST BREAKDOWNS

December 2006

These costs represent the capital cost elements of the project only, and they exclude:

- Project management
- Contingencies
- Interest during construction
- Foreign exchange risk

Reference Case

Description	Total CAPEX	CAPEX														
		2007	2008	2009	2010	2011	2013	2018	2022	2024	2025	2028	2032	2034	2038	2042
Enabling Works	$10,602		$8,266				$1,191						$1,145			
AIS Substations	$38,992		$2,091	$10,808		$7,702	$9,436	$521	$2,207	$669	$521	$529	$1,042	$1,191	$521	$1,753
220 kV Transmission Lines																
HEN-OTA & OTA-SWN				$8,930												
OTA-HEN (Stage 2)							$2,875									
OTA-PEN 5 & 6				$4,482												
WKM 1 & WKM 2							$5,482									
HLY 2 & WKM 3							$6,265									
PAK 1 & 2							$10,242									
Subtotal 220 kV lines	$38,275			$13,412			$24,864									
Total	$87,869		$10,357	$24,220		$7,702	$35,491	$521	$2,207	$669	$521	$529	$2,187	$1,191	$521	$1,753

Option 2 (AIS)

Description	Total CAPEX	CAPEX														
		2007	2008	2009	2010	2011	2013	2018	2022	2024	2025	2028	2032	2034	2038	2042
Enabling Works	$10,126		$10,126													
AIS Substations	$42,147		$2,091	$20,709			$9,004	$521	$2,207	$1,538	$521	$877	$2,430	$669	$521	$1,059
220 kV Transmission Lines																
OTA-SWN				$2,852												
OTA'C' Tie-line				$4,135												
WKM 1				$4,073												
WKM 2													$4,038			
Tie-lines 4 & 5				$6,743												
HLY 2 & WKM 3				$10,792												
PAK 1 & 2							$5,291									
Subtotal 220 kV lines	$37,923			$28,595			$5,291						$4,038			
Total	$90,197		$12,217	$49,304			$14,295	$521	$2,207	$1,538	$521	$877	$6,469	$669	$521	$1,059

Option 3 (GIS)

Description	Total CAPEX	CAPEX														
		2007	2008	2009	2010	2011	2013	2018	2022	2024	2025	2028	2032	2034	2038	2042
Enabling Works	$9,916	$3,484	$3,532			$2,209						$691				
AIS Substations	$21,536		$1,045	$6,164		$3,646	$1,129	$521		$803	$521	$4,237	$1,042	$803	$566	$1,059
GIS Substations	$35,246			$28,771			$541		$5,935							
220 kV Transmission Lines																
OTA-SWN				$2,727												
HEN-OTA				$2,113												
OTA'C' Tie-line				$2,276												
WKM 1 (deleted)																
Tie-lines 4 & 5				$6,656												
HLY 2 & WKM 3				$10,221												
PAK 1 & 2							$2,906									
Subtotal 220 kV lines	$26,898			$23,992			$2,906									
Total	$93,596	$3,484	$4,577	$58,927		$5,855	$4,576	$521	$5,935	$803	$521	$4,928	$1,042	$803	$566	$1,059

OTAHUHU SUBSTATION DIVERSITY PROJECT

PROPOSAL

ATTACHMENT D

LIST OF ASSUMPTIONS

As discussed by Transpower and the Electricity Commission as at 10 November 2006

November 2006

Issue	Transpower view
Demand Forecasts	
Demand forecast to be used for determining reliability of investment	EC's new peak demand methodology assuming 2005 energy forecast – supplied by EC in September Applied to the LDCs to produce forecast LPCs
Options	
Extending bus section	• Extend existing switchyard to north and south as required to remove 'double-ups' and accommodate additional circuits and reactive support
AIS substation	• Build new AIS 1.5 cb switchyard • Remove over crossings • Remove double-ups in existing yard • Extend new AIS and existing switchyard as required to accommodate additional circuits and reactive support
GIS substation	• Build new GIS 1.5 cb switchyard for lines • Build new AIS SBDB switchyard for reactive support and transformers • Remove over crossings • Remove double-ups in existing yard • Extend as required to accommodate additional circuits • Build a second GIS when required • Move all remaining circuits from existing AIS to new GIS • De-commission old AIS

Issue	Transpower view
Technical Assumptions	
Security level to apply	N-1. The critical contingency will be where a cb failure takes out two or more feeders from the south. This usually means the failure of a bus section cb.
Transmission investment assumptions: Committed projects	The following transmission investments will be assumed to be commissioned (i.e. committed projects): • Ohinewai (Huntly East) switching station • Temperature upgrade of the OTA-WKM A and B lines; and • Bombay (BOB) bus-splitting scheme and capacitor bank.
Transmission investment assumptions: modelled projects	As per amended proposal, i.e.: • New 400kV line terminated (at 220kV) in to Pakuranga. • New PAK-PEN link and existing OTA-PEN line operated at 220kV • Reactive requirements as per amended proposal
Cost	
Date for which proposal and all alternatives are costed	Transpower will provide its cost estimates referenced against two years: the year of the submission of its proposed investment for approval, and the expected year of commissioning of the first major component of the proposed investment.
Exchange rate	Spot rate average ±20 business days either side of 30 June 2006
Accuracy	Wherever practicable, all costs to +/-20% Where reasonably possible, costs to +/-10%
Use of expected and with contingent costs	Project costs will be submitted as: • Expected cost with scope contingencies but not financial contingencies for economic (GIT) analysis; and • Cost with contingencies at “P90” level for approval. Use the expected cost, along with expected costs of alternative(s), in the GIT analysis

Issue	Transpower view
GIT analysis	
Analysis period	20 years from commissioning of proposal; and If significant market benefits or costs are expected to arise after that time, a sufficiently long further time to capture the differences between proposal and alternatives
Discount rate	7%, but with 4% (social discount rate) as credible and relevant alternative, and 10% as sensitivity
NPV modelling approach	Calculate EUE from reliability modelling
Analysis in current or future $	Transpower will prepare its analysis in commissioning year dollars, but provide costs in both current year and commissioning year dollars
Contingencies	Use expected cost with scope contingencies but not financial contingencies for GIT analysis.
Loss modelling	N/A
Loss value	N/A
Uncertainty analysis wrt demand	Taken into account in reliability modelling of LPCs
Uncertainty analysis wrt new generation	N/A
Reliability differences – calculation of unserved energy	Use forecast LPCs based on EC's 2005 energy forecast Use CIGRE survey data and / or TP historical data
Terminal benefits	
Dispatch cost differences	N/A
Competition benefits	N/A
Capacity benefits	N/A

Issue	Transpower view
Strategic benefit	These should be measured against a system vision and additional costs/benefits of a particular project to the system vision as a whole included in GIT analysis.
Diversity benefits	Where quantifiable, should be included in reliability benefit analysis. Where not quantifiable, the direction of the market benefit or cost and likely magnitude of the market benefit or cost must be identified (clause 9 of GIT). May be able to be included in the approval criterion "good electricity industry practice in meeting the grid reliability standard" (rule 13.4.1.1)
Managing project risks	
Uncertainties related to designations, consents and easements	The impact of uncertainties related to Project timing, easement costs, and capital cost, cash flows will be evaluated through sensitivities that will examine the potential range of impact on the proposed project and alternatives. With respect of project evaluations: • the first step 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.