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31 October 2005

Roy Hemmingway
Chair
Electricity Commission
PO 10041
WELLINGTON
New Zealand

Dear Roy

Proposals for approval under the Transitional Provisions

Please find enclosed a document containing additional grid development proposals for approval by the Electricity Commission under the transitional provisions of Part F of the Electricity Governance Rules.

The proposals submitted are:

- Upper North Island Reactive Support
- Enhancement of 220 kV Transmission Capacity between Otahuhu and Whakamaru
- Enhancement of the transmission network in the Bay of Plenty
- Replacement of the 220/110 kV Interconnecting Transformer at Kikiwa
- Kikiwa 220 kV Bus Security Upgrade
- Replacement of the 220/110 kV Interconnecting Transformer at Stoke
- Reconductoring 220 kV Aviemore – Waitaki – Livingstone circuits

Transpower is currently assessing additional projects that will increase the transfer capability into Auckland, including the establishment of a substation at Huntly East. Transpower expects to make a further submission on the latter under the transitional provisions before 18 November 2005.

I trust that the information provided is sufficient to allow the Commission to undertake a full assessment of the proposals provided. In the event that you need to clarify or seek further information, please do not hesitate to contact me.

Yours sincerely

Dr Ralph Craven
Chief Executive

TRANSPOWER

Grid Development Proposals

Grid Development Investment Proposals 2005

Table of Contents

1 Summary

This document contains additional proposed reliability investments that Transpower is seeking approval for under the transitional provisions of Part F of the Electricity Governance Rules.

Transpower seeks approval from the Electricity Commission under Rule F-III-16 (the "transitional provisions") of the Electricity Governance Regulations 2003 ("EGRs") for the following:

A. Approval of each of the interim grid projects set out in this submission in accordance with rule F-III-16; and

B. Approval for all actual project costs for the interim grid projects in accordance with rule F-III-17.

Transpower has determined that the expenditure described in this document is reasonably prudent or necessary to meet Transpower's current transmission security standards.

A summary of the transmission upgrade projects included in this submission is set out in Table 1-1.

Project	Cost Estimated $m (2005)[1]	Approval requested from EC $m[2]	Start	Finish
Reactive support in the Upper North Island	31.7	39.4	2005	2007
Thermal upgrade of the 220 kV Otahuhu-Whakamaru 1 and 2 circuits	10.0	13.5	2006	2008
Enhancement of the transmission network in the Bay of Plenty as follows: o New switching station at Hairini o New 25 Mvar capacitor bank at Tauranga o Reconductoring the 110 kV Hairini-Tauranga transmission line	13.5	15.8	2006	2008
Replacement of 220/110 kV interconnecting transformers at o Kikiwa and o Stoke	7.5	9.2	2006	2007
220 kV bus security upgrade at Kikiwa	3.6	4.2	2005	2007
Reconductoring the 220 kV Aviemore-Waitaki-Livingstone circuits	10.7	14.3	2006	2008

Notes:

1. Mid-range estimated cost, $m (2005), includes allowance for project contingencies but excludes allowance for financial (eg inflation) contingencies or Interest During Construction
2. Upper-range estimated cost includes allowance for financial (eg inflation) contingencies or Interest During Construction

Table 1-1: Projects for Approval

2 Introduction

This submission under the transitional provisions of Part F sets out seven additional investment proposals for Electricity Commission approval.

2.1 Planning

Much of the content contained within these proposals is dependent on outputs from Transpower's planning process. The specific inputs that are considered during the planning process are:

- The existing transmission system, its capacity, age and reliability
- The location, capacity and characteristics of generation plant
- The location, capacity and characteristics of load
- The security and reliability criteria which set out the level of security and reliability that is required to be delivered
- The economic robustness of the grid investments in relation to uncertainty in future generation developments and demand growth.

2.2 Regulatory Framework and Context

Establishing the processes and framework for transmission planning and investment is a key component of the Electricity Governance Regulations and Rules introduced in 2003. While the regulations set out the broader outline of the process and framework, details of what, how and when are presently being worked through in a constructive way between the Commission, Transpower and other key stakeholders.

2.3 Future Context

The nature of transmission investments is such that they represent a series of related investments that take place over time in order to enhance the grid capacity for reliably accommodating future load growth. Accordingly, the proposed investments mostly represent one aspect of an overall development strategy for meeting the load growth over an optimum time frame.

In cases where there is a future context of the investment, Transpower has set out this context to allow a better appreciation of the project. The future context of any proposal will naturally form part of future Grid Upgrade Plans, and are (where included) for information purposes only.

Within the above context, investments should be assessed as a group of investments, rather than individually, if they serve a common purpose.

2.4 Cost Estimation

Transpower has submitted cost estimates in good faith and expects to be able to recover actual costs reasonably incurred in relation to the approved project through the transmission pricing methodology.

If the actual project costs are greater than the estimated cost included in this submission and Transpower was unable to recover these costs, Transpower would incur an economic loss. Forecasting errors could lead to windfall losses and could deter efficient investment. While considerable effort is made to ensure estimated costs represent the expected efficient investment, inevitably such forecasts are subject to imperfect foresight.

Further information on Transpower's approach to cost estimation with particular reference to contingencies considered is provided in Appendix: A.

3 Upper North Island Reactive Support

Proposal Summary

In order to securely meet the upper North Island (i.e. Auckland and North Isthmus regions) demand beyond 2007, Transpower proposes to install the following dynamic and static reactive power compensation in the area:

a) A new Static Var Compensator (SVC) of capacity ± 100 Mvar at Albany 220 kV
b) A new capacitor bank of capacity 100 Mvar at Albany 220 kV bus
c) Binary capacitor banks (2x12 Mvar blocks) at Kaitaia 33 kV bus
d) A reactive power controller

To ensure adequate reactive support in the area, Transpower has also assumed the following:

e) Installation of new distributed capacitor banks totalling 100 Mvar in the distribution systems (contracted with the distribution companies)
f) Up to +260/-150 Mvar's from synchronous condensers can be procured through the System Operator ancillary services procurement contracts by 2010.

If these assumptions do not eventuate, Transpower will be required to install the additional reactive support to make up the shortfall and will submit a proposal for these additional projects in future Grid Upgrade Plans.

This is the least cost transmission investment required for ensuring reliable supply to the region as per Transpower's current grid reliability standards.

The table below provides the estimated costs for the project:

Project	Cost Estimated $m (2005)[1]
+/- 100 Mvar SVC in Albany (including Reactive Power Controller	26.9
100 Mvar capacitor bank connected to the Albany 220 kV	2.7
24 Mvar binary capacitors (two blocks of 12 Mvar) at Kaitaia	2.1
Total	**31.7**

Notes:
1. Mid-range estimated cost, $m (2005), includes allowance for project contingencies but excludes allowance for financial (eg inflation) contingencies or Interest During Construction

3.1 Planning Assumptions

The planning assumptions are:

- All existing generation, reactive power support and other transmission assets are available beyond 2010.

- New distributed capacitor banks totalling 100 Mvar are installed in the distribution systems (contracted with the distribution companies).

- Up to +260/-150 Mvar's from synchronous condensers can continue to be procured through the System Operator ancillary services procurement contracts.

3.1.1 Generation Scenarios

Only existing generation and committed new generation has been considered in determining the level of security to the region.

It is also assumed that the following transmission and generation developments take place:

- New capacitor banks are installed at Hepburn Road and Penrose by winter 2006.
- The new combined cycle gas turbine (CCGT) unit (E3P) is commissioned and in service at Huntly by winter 2007.
- New cooling tower at Huntly is available by summer 2005/2006, enabling three units to be dispatched from Huntly during critical summer periods, generating a total of 410 MW (1x250 MW + 2x80 MW).

Recognising the uncertainty of generation availability in the region (e.g. prolonged outage of a generating unit due to an unplanned repair) it is assumed that the Otahuhu CCGT unit is not available in assessing the transfer capability into Auckland.

3.1.2 Load Forecasts

The power system studies were based on the winter peak load conditions and the 40 year load forecast developed by Transpower in 2005. Transpower utilised the Electricity Commission's 2005 national electricity consumption 40 year forecast as the basis for creating the necessary demand forecasts for the power system analysis[1].

3.1.3 Planning Criteria

The transmission system has been planned in accordance with Transpower's current Grid Reliability Standards[2].

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[1] For further information, please refer to the Grid Upgrade Plan 2005, Vol 2, Part II.

[2] Transpower Main Transmission Planning Criteria, Grid Upgrade Plan 2005, Vol 2, Supporting Document No. 6

The proposal deals with the adequacy of the capacity provided by the transmission network supplying the upper North Island. The following itemised list represents all the critical performance criteria used for this proposal:

- In the post-contingency steady state following a single contingency, the power transmission system has an adequate capacity for supplying a load equivalent to that connected to the power system in its pre-contingency state (i.e. n-1 security criterion).
- Steady state voltage levels are maintained within the tolerances specified in the Electricity Governance Rules and Regulations (EGRs),
- A voltage stability margin of at least 5% of the connected load is maintained for single credible contingencies at all times, including when the power system is in a transient state.
- The risk of loss of load during a power system disturbance is minimised by ensuring that the voltage at any point in the transmission system following a single contingency is controlled such that:
    i. voltage dip is less than 0.5 pu for any single “open circuit” contingency;
    ii. voltage at load busbars is restored to above 0.8 pu within 4 seconds;
    iii. voltage is restored such that no motor connected to the power system will draw current exceeding 3 pu for longer than 8 seconds;
    iv. the over-voltage is controlled to be less than 1.3 pu.

3.2 *Description of the Transmission Asset and the Present Capacity*

The voltage stability of the upper North Island region is significantly influenced by:

- the demand in the region;
- generation in Auckland and Huntly; and
- the grid supplying the above regions, including the transmission grid south of Auckland.

The configuration of the existing network in the upper North Island is shown below.[3]

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[3] The transmission capacity of the present transmission system is described in detail in Part II of Volume II of the Grid Upgrade Plan

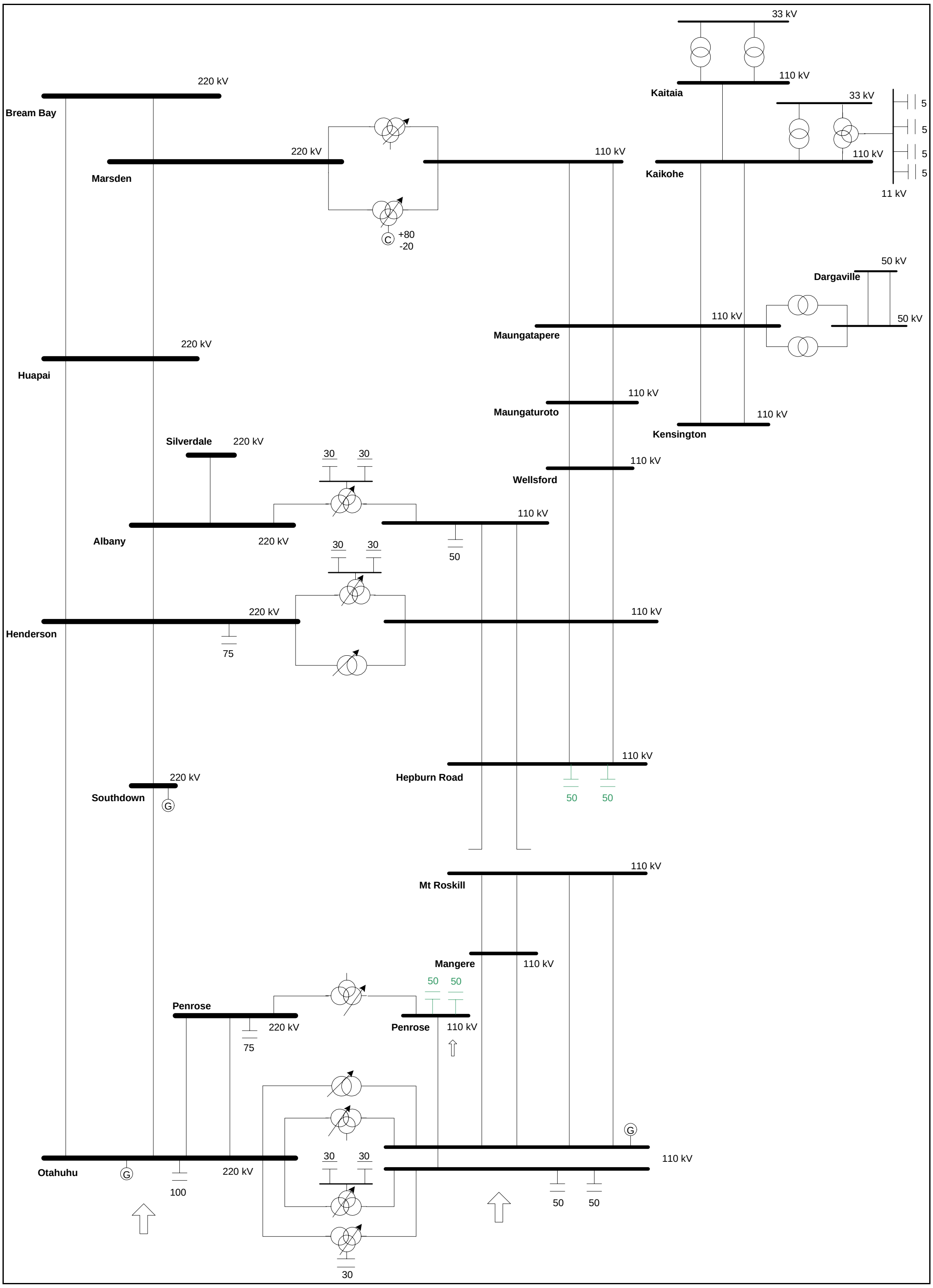

Figure 3-1: Upper North Island Transmission Schematic

3.3 Need Analysis

Loss of the Otahuhu CCGT plant and loss of the 220 kV Otahuhu-Whakamaru 3 circuit during critical summer and winter periods represent the worst generator and transmission contingencies respectively, which could push the system to voltage collapse. The capacity available in the transmission system following these contingencies governs the maximum demand that can be securely supplied in the region.

Analysis shows that with the assumed load growth and generation developments in the region beyond 2007, transmission capacity is likely to be constrained under winter peak conditions rather than under summer conditions. In addition, the load able to be supplied by the transmission system when it is in a transient state (immediately following a contingency) is less than that able to be supplied when the power system reaches a steady state (approximately 10 – 20 seconds after the disturbance).

Consideration of the performance of the load in a steady state as well as during transient periods following contingencies is critical in assessing the voltage stability of the power system. In order to better understand the characteristics of the connected load, a detailed survey was carried out in 2003 to estimate the composition of the load. From that work, the estimated composition of the load during the critical summer and winter periods could be classified into static and motor load as shown in Table 3-1:

Period	Static Load	Motor Load
Winter	62%	38%
Summer	35%	65%

Table 3-1: Composition of the load in the Upper North Island

The survey has also concluded that motor load can be subdivided into three groups, depending on performance during system disturbances:

- Group 1 - Those that are disconnected at or immediately after the time of the fault and remain disconnected throughout the event.
- Group 2 – Those that trip on over-current protection if they were drawing starting current (about 6 x rated) for 2-3 seconds, or re-acceleration current (about 3 x rated) for 8 seconds.
- Group 3 – Those that trip on either under-voltage protection if the voltage remains under 80% for 4-5 seconds, or on over-current protection as per group 2.

As a percentage of the total motor load, approximately 40% of the motors belong to group 1, 35% to group 2 and 25% to group 3.

During an under-voltage disturbance, while the tripping of group 1 motors is beneficial to voltage recovery, tripping could cause over-voltages in excess of 1.3 pu in the system. Deceleration and stalling of group 2 and group 3 motors draws a significant amount of reactive power from the system, deteriorating the voltage stability.

The following figure shows the risk associated with the operation of the power system. The risks associated are two fold:

(a). Voltage instability of the power system. Disconnection of some motors (i.e. Group-1 motors) following the disturbance is beneficial in improving system stability.

(b). Over-voltages in the power system. Following a power system disturbance, disconnection of a significant proportion of group 1 motors could cause over-voltage in the system greater than 1.3 pu.

(Note: in assessing the operational risk, it has been assumed that at least 25% and at most 90% of the group-1 motors will trip.)

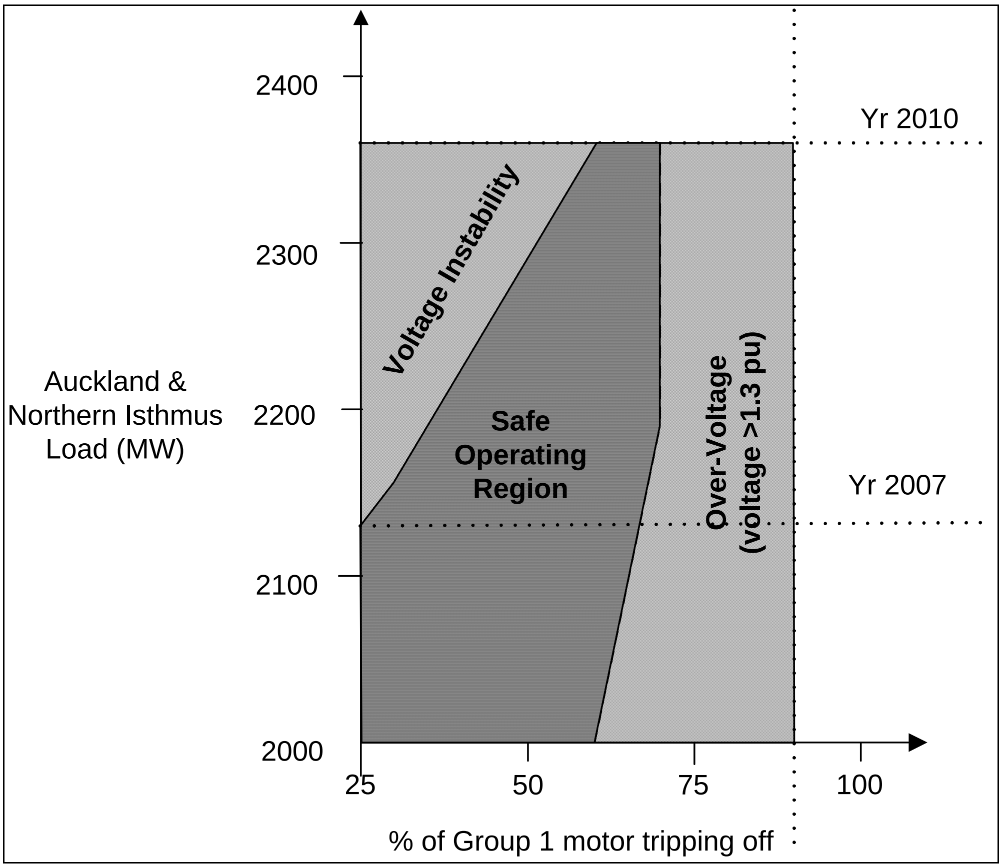

Figure 3-2: Variation of operation risk with different levels of Group-1 motor tripping before implementing the proposed grid upgrades.

Beyond 2005, when the upper North Island demand exceeds approximately 2000 MW, there is a significant risk that a power system fault could cause over-voltage in the region above 1.3 pu. Beyond the year 2007, when the upper North Island demand is expected to exceed approximately 2150 MW, there is a significant risk of voltage instability in the upper North Island region.

3.4 Investment Proposal

The proposed investment to meet the need is to increase reactive support in the upper North Island as per Table 3-2.

Reactive Source	Reactive Compensation (Mvar)		
	Present Level	**Needed By 2010**	**% Increase**
Synchronous Condensers	+126/-78[4]	+260/-150	106%
Capacitor Banks in Transmission System	730[5]	830	14%
Capacitor Banks in Distribution System	240	364[6]	52%
Static Var Compensators	0	+/-100	
Total	**+1096/-78**	**+1554/-250**	**42% / 220%**
Note: In the assessment of reactive requirements as indicated above, it has been assumed that all the generating units available in the Auckland area will provide reactive power output up to their declared reactive power capability limits.			

Table 3-2: Reactive support enhancement required for meeting supply security to 2010.

The proposed reactive power support developments as described will extend the safe operating region as shown in the following figure.

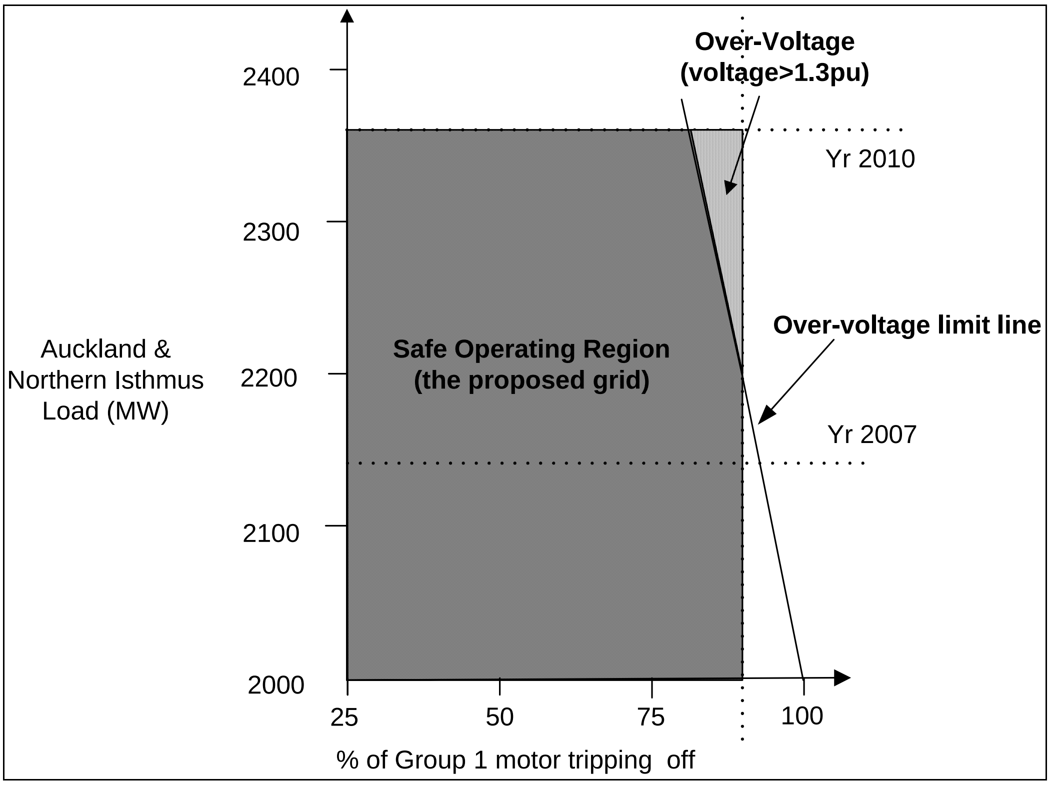

Figure 3-3: Extension of safe operating region with the proposed reactive power support in Auckland

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[4] Consists of 2x +33/-29 G4 & G6 condensers at OTA and 1x +60/-20 condenser at MDN. In the future OTA G1 &G2 may provide +50/-22 Mvar each and OTA G3 +33/-29 Mvar.

[5] This includes 2x50 Mvar capacitors committed to be installed by winter 2006.

[6] The additional 124 Mvar includes 2x12 Mvar binary capacitor blocks at Kaitaia 33 kV and 100 Mvar which may be installed at LV buses of TP's GXPs if it is not provided by distribution companies.

The increase in reactive power support will be made up of the following reactive capacities and locations:

Source	Size	Location
Static Var Compensators	+/- 100 Mvar	Albany
Capacitor Banks	100 Mvar	Albany
Capacitor Banks	24 Mvar	Kaitaia
Capacitor Banks	100 Mvar	(distribution systems)
Synchronous Condenser	+210/-150 Mvar	Contracted via System Operator Contract

Table 3-3: Proposed Reactive Power Support for Upper North Island

Increasing reactive power support in the upper North Island region as proposed will significantly reduce the risk of voltage instability and over-voltages in the system following a system disturbance. The proposed level of reactive power support will be sufficient for securely supplying the upper North Island demand until about 2010.

Figure 3-4 below shows the upper North Island transmission schematic subsequent to this investment.

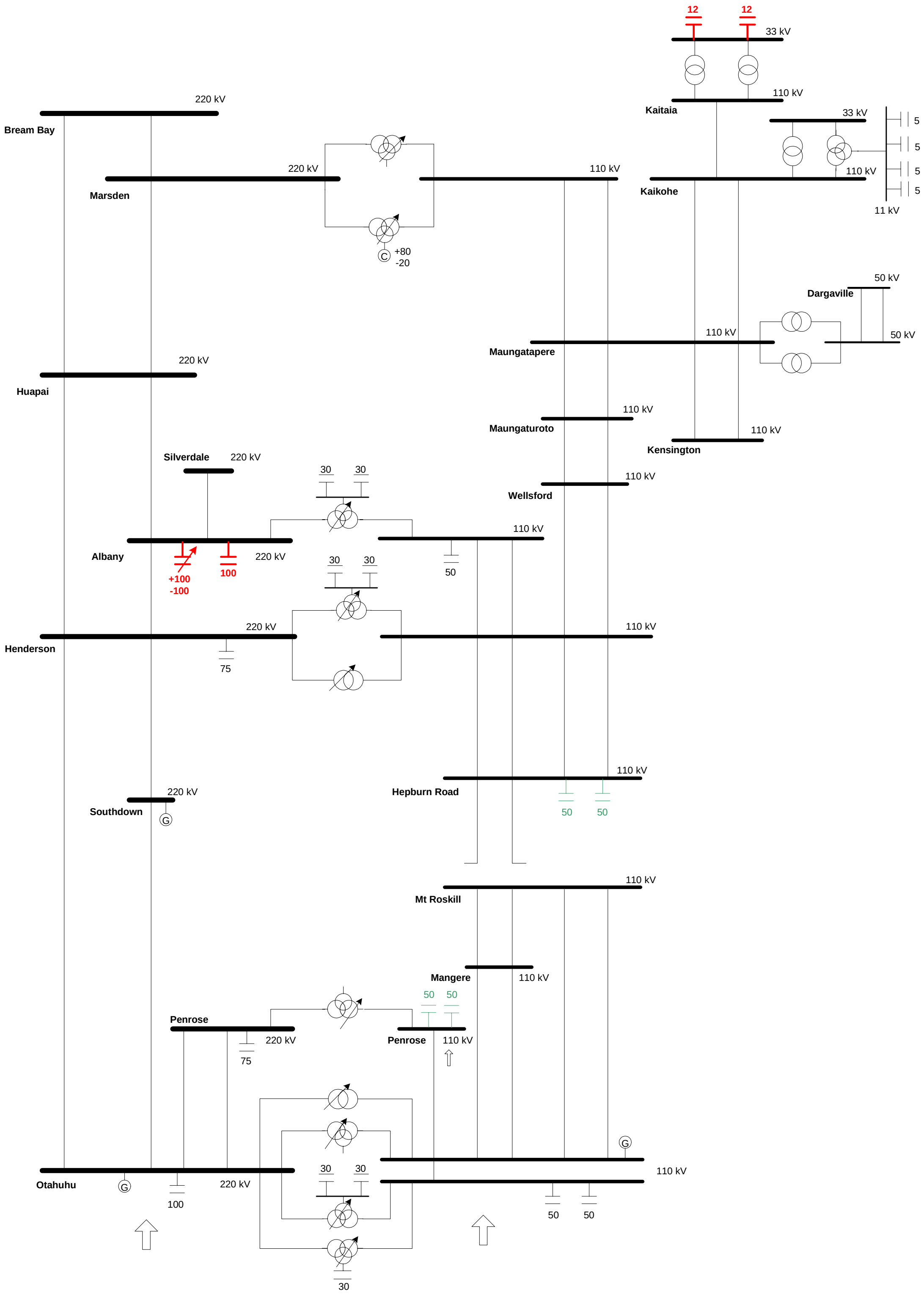


Figure 3-4: Upper North Island Transmission Schematic Post Investment

3.5 Future Context

The present proposal identifies the reactive power requirements for meeting the upper North Island load up to 2010, assuming all generation in the local region is available for dispatch during peak load periods.

However, past experience has shown that a major generating unit (e.g. Otahuhu combined cycle gas turbine plant) in the region could be unavailable for a considerable time for unplanned repairs. Accordingly, there is a significantly high risk that not all the installed generation in the local region is available for dispatch and transmission planning needs to take this risk into account.

In order to ensure reliable supply to the region, taking into account the uncertainty of generation available for dispatch, it is likely that further reactive power compensation is required as follows:

- 100 MVAR Static Var Compensator at Otahuhu by 2007;
- 100 MVAR of capacitors at Otahuhu by 2008;
- 50 MVAR of synchronous condensers at Albany by 2008;
- 50 MVAR of synchronous condensers at Henderson by 2008; and
- 100 MVAR of capacitors at Otahuhu by 2009.

These developments will also be required, in order to ensure supply reliability to the region, if there is a delay in the planned 400 kV transmission from Whakamaru to Otahuhu.

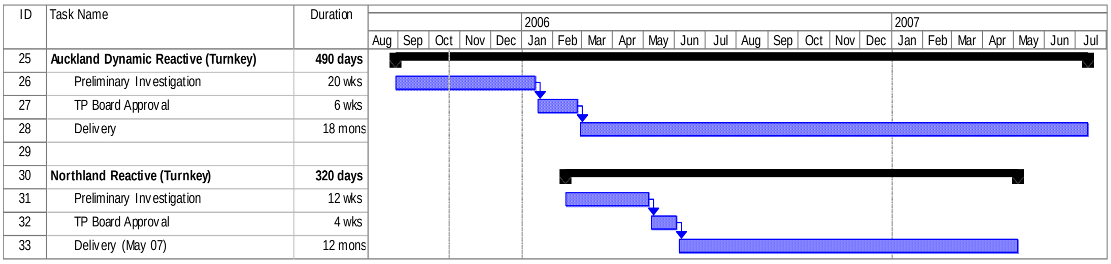
Investigations confirming the need for the above future developments are being presently completed. Approval for these future grid developments is not sought as a part of this submission but will form a part of a future Grid Upgrade Plan.

3.6 *Project Timeline*

A project of this magnitude is expected to take approximately two years from approval to final commissioning

Transpower has identified that the earliest date the proposed investment can be in place is mid 2007, provided investigation and planning commences now.

A tentative timeline for the project is shown below:



ID	Task Name	Duration
25	**Auckland Dynamic Reactive (Turnkey)**	**490 days**
26	Preliminary Investigation	20 wks
27	TP Board Approval	6 wks
28	Delivery	18 mons
29		
30	**Northland Reactive (Turnkey)**	**320 days**
31	Preliminary Investigation	12 wks
32	TP Board Approval	4 wks
33	Delivery (May 07)	12 mons

Figure 3-5: Indicative Timeline

Any delay in project commencement will result in delay through the project and consequently, extending the period of reduced security for the upper North Island beyond 2007.

3.7 Property Requirements

The proposed developments will take place mostly within the Albany and Otahuhu sites owned by Transpower. It is unlikely that new property acquisition is required.

3.8 Environmental Impact

Albany is a designated site, but any noticeable increase in noise may become an issue. Kaitaia substation is designated and in a rural area. Otahuhu substation is not a designated site and therefore noise will need to comply with the District Plan.

Provided works at all three sites can be contained within the land owned by Transpower, and the impacts of any additional noise investigated and where necessary remediated, then the required environmental approvals/consents should be able to be gained for the proposed works.

3.9 Estimated Cost

Cost estimates have been prepared using the approach described in Appendix: A Note that the project costs exclude costs for approximately 360 Mvar of reactive support that may be provided by contract.[7]

Table 3-4 below summarises the cost estimates for the major components of the project.

Category	Cost Estimated $m (2005)[1]
Line capital costs	0.0
Substation capital costs	30.8
Property	0.0
Dismantling Costs	0.0
Project Management costs	0.9
Approval Costs	0.0
Total	31.7

Notes:
1. Mid-range estimated cost, $m (2005), includes allowance for project contingencies but excludes allowance for financial (eg inflation) contingencies or Interest During Construction

Table 3-4: Estimated Capital Expenditure for Stage 1 of the Auckland Reactive Support Project

The timing of capital expenditures is shown in Figure 3-6.

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[7] Consisting of 100 Mvar distributed capacitors and 260 Mvar from rotating plant

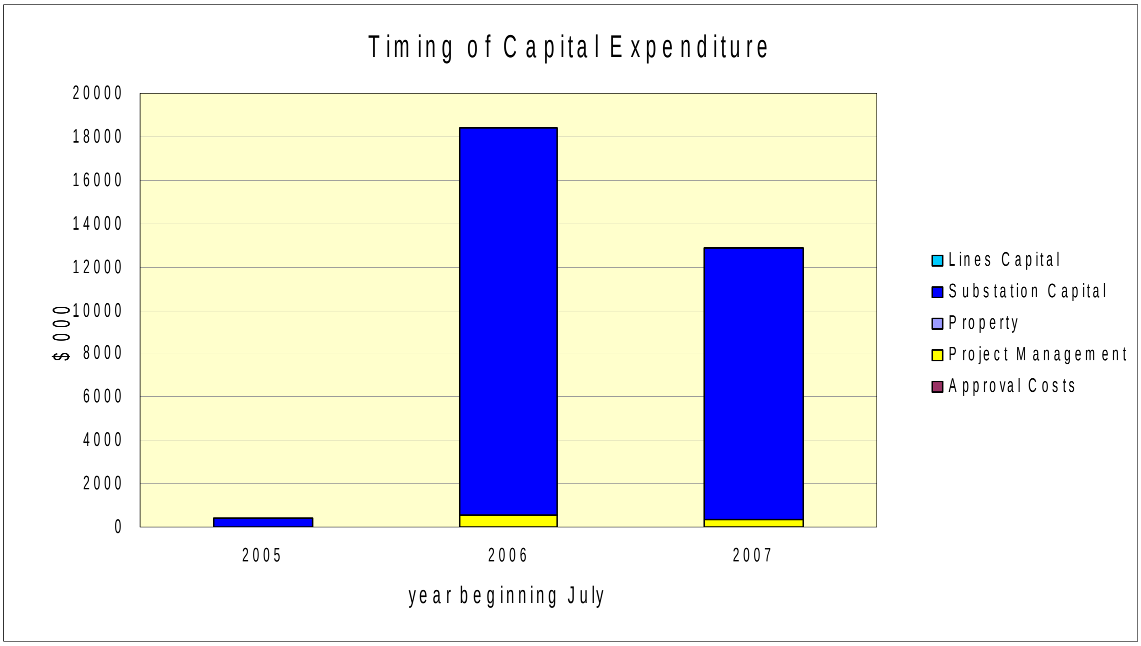

Figure 3-6: Anticipated Incidence of Expenditure on the Proposed OTA-WKM A&B Thermal Upgrade

3.9.1 Contingent Amounts

Table 3-5 provides a summary of the various contingent amounts that have been discussed in this section.

Cost Category	Estimated Cost $k (2005)[1]	Inflation $k	Exchange Rate $k	IDC $k	Expected Cost $k[2]	Cost Contingency $k	Approval Requested from EC $k[3]
Lines	0	0	0	0	0	0	0
Substations	30842	1300	0	3635	35777	2552	38329
Property	0	0	0	0	0	0	0
Dismantling	0	0	0	0	0	0	0
Project Management	880	36	0	109	1025	0	1025
Approvals	0	0	0	0	0	0	0
Total	31723	1336	0	3743	36802	2552	39354

Notes:
1. Mid-range estimated cost, $m (2005), includes allowance for project contingencies but excludes allowance for financial (eg inflation) contingencies or Interest During Construction
2. Mid-range estimated cost in nominal $ including allowances for financial (eg inflation) contingencies and Interest During Construction
3. Upper-range estimated cost in nominal $ including allowances for financial (eg inflation) contingencies and Interest During Construction

Table 3-5: Relationship between Project Costs in Real and Nominal Terms.

The difference between estimated capital costs and nominal costs including contingencies is approximately $7.6 million. Interest during construction and inflation (which do not affect the economic merits of the project) represent $5.1 million of this difference. Cost contingencies are 8% of real capital costs.

Transpower wishes to recover the actual costs of the proposed investment. The nominal cost estimate including contingencies represents a good faith estimate of what those actual costs might be.

3.10 Transmission Alternatives

3.10.1 Building a new transmission line

Building a new transmission line (as proposed under the 400 kV North Island Grid Upgrade project – refer to Volume 2 of Transpower's GUP 2005), would increase transmission capacity into Auckland but it will require a significant lead time for project completion and, accordingly, will not provide a timely solution.

3.10.2 Installing series compensation between Whakamaru and Otahuhu

Installing series compensation of the lines between Whakamaru and Otahuhu would provide reactive support, but this will cause load sharing issues between the lines leading to overloading of some of the circuits before 2010.

4 Enhancement of 220 kV Transmission Capacity between Otahuhu & Whakamaru

Proposal Summary

To increase the transmission capacity into Auckland so that the existing circuits can meet the predicted upper North Island load until 2010, Transpower proposes to re-tension the Otahuhu – Whakamaru 220 kV A and B transmission lines for 75^0 C operation. This will increase their rated capacity to 293/323 MVA (summer/winter)

This is a core grid reliability investment and the proposal is justified against Transpower's current Grid Reliability Standards.

The table below provides the estimated cost of the project:

Category	**Cost Estimated $m (2005)**[1]
Line capital costs	6.8
Substation capital costs	0.2
Property	1.5
Dismantling Costs	0.0
Project Management costs	0.8
Approval Costs	0.4
Investigations	0.4
Total	10.0

Notes:

1. Mid-range estimated cost, $m (2005), includes allowance for project contingencies but excludes allowance for financial (eg inflation) contingencies or Interest During Construction

The project costs above assume that a designation of the whole route would not be required. In the event this is not correct, Transpower reserves the right not to proceed with this project.

4.1 Planning Assumptions

4.1.1 Generation Scenarios

Only existing generation and committed new generation has been considered in determining the level of security to the region.

It is also assumed that the following transmission and generation developments take place:

- New capacitor banks are installed in Hepburn Road and Penrose by winter 2006.
- The new combined cycle gas turbine (CCGT) unit (E3P) is commissioned and in service in Huntly by winter 2007.

- The new cooling tower in Huntly is available by summer 2005/2006, enabling three units to be dispatched from Huntly during critical summer periods, generating a total of 410 MW (1x250 MW + 2x80 MW).

Recognising the uncertainty of generation availability in the region (e.g. prolonged outage of a generating unit due to an unplanned repair), it is assumed that the Otahuhu CCGT unit is not available in assessing the transfer capability into Auckland.

Winter peak conditions reflect a wet Waikato generation dispatch, and summer peak conditions reflect a normal Waikato generation dispatch.

4.1.2 Load Forecasts

The power system studies were based on the winter peak load conditions and the 40 year load forecast developed by Transpower in 2005. Transpower utilised the Electricity Commission's 2005 national electricity consumption 40 year forecast as the basis for creating the necessary demand forecasts for the power system analysis[8].

The half hour average medium growth regional load forecast is as shown in Table 4-1 below:

Year	Winter load (MW)		Summer load (MW)	
	Auckland/Isthmus	North Island	Auckland/Isthmus	North Island
2005	1918	4188	1681	3743
2006	1984	4309	1739	3849
2007	2053	4434	1798	3959
2008	2124	4562	1860	4070
2009	2196	4689	1922	4182
2010	2265	4811	1982	4289

Table 4-1: Load forecast for Auckland and North Isthmus compared to total North Island Load

4.1.3 Planning Criteria

The transmission system has been planned in accordance with Transpower's current Grid Reliability Standards[9].

The proposal deals with the adequacy of the capacity provided by the transmission network supplying the upper North Island. The transmission network is considered to provide adequate capacity and reliability if the entire connected load can be supplied during and following any single credible contingency event occurring in the transmission network.

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[8] For further information, please refer to the Grid Upgrade Plan 2005, Vol 2, Part II.

[9] Transpower Main Transmission Planning Criteria, Grid Upgrade Plan 2005, Vol 2, Supporting Document No. 6

4.2 Description of the Transmission Asset and Present Capacity

The configuration of the existing network between Otahuhu and Whakamaru is illustrated in the diagram below:

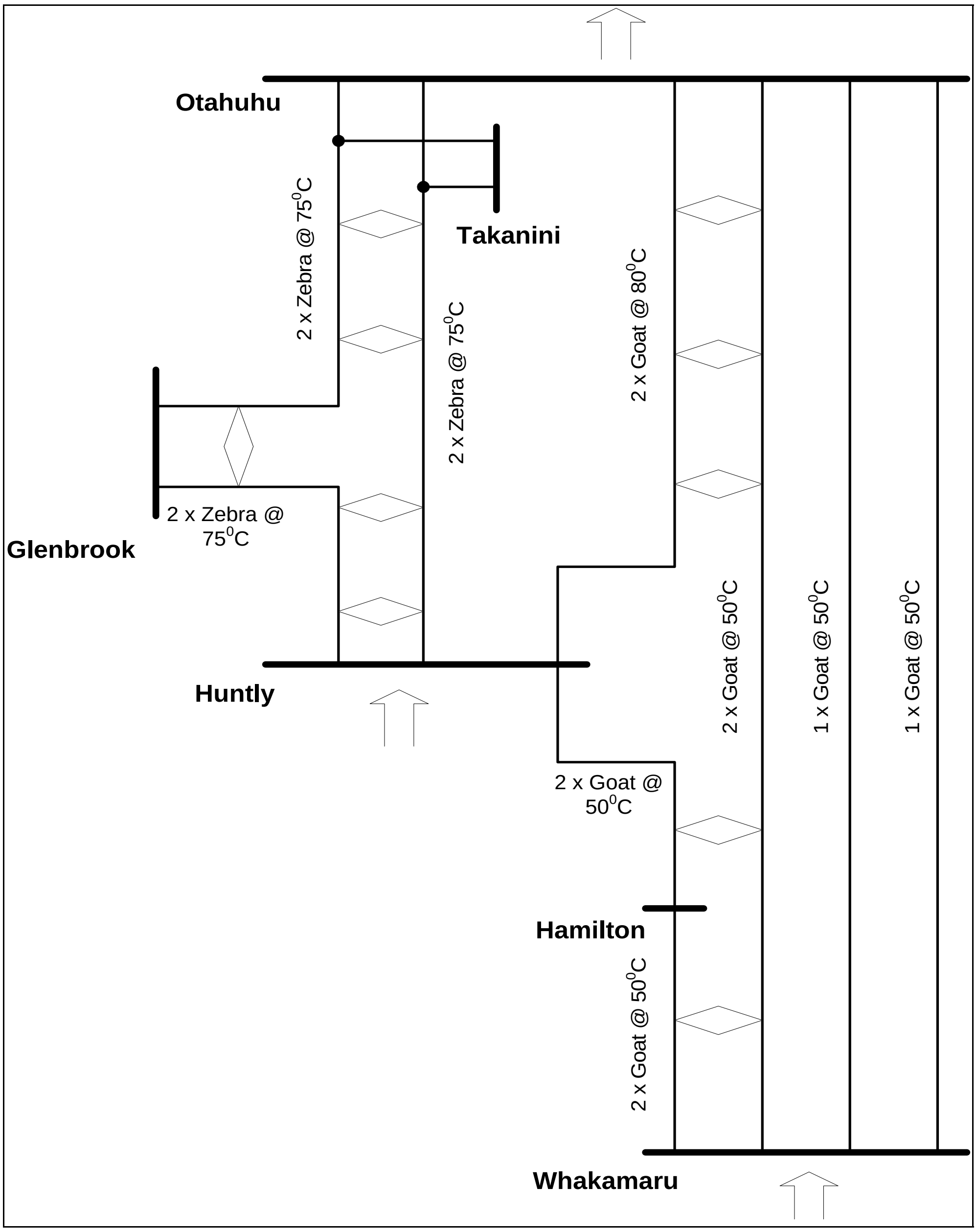

Figure 4-1: Simplified Diagram of Whakamaru to Otahuhu Transmission Network

Auckland is primarily supplied from the south through western and central paths. The western path consists of three 220 kV circuits from Huntly to Otahuhu. The central path consists of three 220 kV circuits from Whakamaru to Otahuhu.

Auckland is also supplied by two 110 kV circuits from Bombay and a 110 kV circuit from Arapuni. However, their contribution is minor compared to the 220 kV circuits.

The existing ratings of the 220 kV circuits supplying Auckland from the south are as follows:

Circuit	Summer rating	Winter rating
Huntly-Takanini-Otahuhu 2	694 MVA (HLY to OTA)	762 MVA (HLY to OTA)
Huntly-Glenbrook 1 and Glenbrook-Otahuhu 1	694 MVA (HLY to OTA)	762 MVA (HLY to OTA)
Huntly-Otahuhu 1	615 MVA (HLY to OTA)	670 MVA (HLY to OTA)
Otahuhu – Whakamaru 1	201 MVA	246 MVA
Otahuhu – Whakamaru 2	201 MVA	246 MVA
Otahuhu – Whakamaru 3	403 MVA	457 MVA

Table 4-2: Circuit Ratings for Circuits Supplying Auckland from the South

4.3 Need Analysis

The following contingencies and generation dispatch patterns govern the loading of the 220 kV circuits supplying Auckland from the south:

- during high load periods, an outage or loss of the 220 kV Huntly-Otahuhu 2 or Huntly-Glenbrook 1 circuits will cause the 220 kV Huntly-Otahuhu 1 circuit to overload with high Huntly generation.
- during high load periods, an outage or loss of the 220 kV Otahuhu-Whakamaru 3 circuit will cause the 220 kV Otahuhu-Whakamaru 1 and 2 circuits to overload with high generation south of Whakamaru and high HVDC transfer north.

With the predicted load increase for Auckland, more power will have to be injected into Auckland through the Huntly 220 kV circuits to ensure that the Otahuhu-Whakamaru 220 kV circuits are not overloaded. However, increasing generation from Huntly will increase the loading on the Huntly to Otahuhu 220 kV circuits which then increase their exposure to overloading during a contingency. In some situations, the overloads can not be relieved by generation re-dispatch and load curtailment will be necessary.

The constraints generally occur during summer months, because of the lower thermal ratings and possible operational restrictions imposed on generation at Huntly[10]. When Otahuhu is not generating Huntly generation needs to be increased to make up for the deficiency in generation in the Auckland region.

Based on the predicted load growth in Auckland, the 220 kV Otahuhu-Whakamaru 1 and 2 circuits will have reached their thermal capacity by 2008. System studies indicate that by then, if Otahuhu is not generating, Huntly would be required to generate a minimum of 1275 MW in summer and 1340 MW in winter to ensure that the 220 kV Otahuhu-Whakamaru 1 and 2 circuits do not overload under contingencies. Any reduction in Huntly generation will result in the 220 kV

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[10] In recent years Huntly generation has been limited in some summer periods due to overheating of the Waikato river.

Otahuhu-Whakamaru 1 and 2 circuits overloading, if the deficiency in generation is to be supplied from the south. The issue is further compounded by the fact that, although generation may be available from Huntly, it may need constraining due to the thermal limitation of the 220 kV Huntly to Otahuhu circuits.

The 110 kV Arapuni-Pakuranga transmission line is also scheduled to be taken out of service in 2007 as part of the 400 kV transmission line proposal. This will accentuate the problem further as generation at Huntly would need to increase by about 75 MW to compensate for the loss of that line. In effect, decommissioning the 110 kV Arapuni-Pakuranga transmission line will advance the requirement for grid reinforcement on the 220 kV circuits into Auckland from the south by a year.

Guaranteed availability for dispatch of all the installed generation in the region including the existing generation at Otahuhu (360 MW) will delay the requirement for grid reinforcement on the 220 kV circuits into Auckland from the south by approximately five years. However, experience has shown that generators have a lower level of reliability compared to transmission lines.

In summary, the requirement for grid reinforcement on the 220 kV circuits into Auckland from the south under the different scenarios is as follows:

Scenario		220 kV circuit reinforcement required by:
All generation available	Arapuni-Pakuranga line in service	2013
	Arapuni-Pakuranga line decommissioned	2012
Major generation unit out of service for a long period	Arapuni-Pakuranga line in service	2008
	Arapuni-Pakuranga line decommissioned	2007

Table 4-3: Timing of Grid Reinforcement for Different Scenarios

Previous operational experience has demonstrated that the availability of a large generating unit (e.g. Otahuhu CCGT) to relieve the loading on the 220 kV circuits into Auckland can not be relied upon. To maintain n-1 security into Auckland, grid reinforcement on the 220 kV circuits into Auckland from the south will be required by 2008.

This upgrade is also critical for managing the supply security to the region, in the event that the completion of the 400 kV transmission line to Auckland is delayed beyond 2010.

4.4 Investment Proposal

4.4.1 Otahuhu to Whakamaru Lines

The existing conductors on the Otahuhu-Whakamaru 1 and 2 circuits are of single Goat construction operating at 50^0C. It is proposed to increase the capacity of these circuits to 293/323 MVA by re-tensioning their conductors for 75^0C operation. This grid enhancement will provide sufficient capacity to maintain n-1 security on these circuits till the year 2010. It is anticipated that the proposed new 400 kV transmission line into Auckland will then resolve any further potential circuit overloading issues on the Otahuhu-Whakamaru 220 kV circuits from 2010 onwards.

An illustration of the proposed investment is shown in red (solid) in Figure 4-2.

4.5 Future Context

There are three 220 kV circuits between the Huntly and Otahuhu 220 kV busses. They are Huntly-Takanini-Otahuhu, Huntly-Takanini-Glenbrook-Otahuhu, and Huntly-Otahuhu circuits. Studies have shown that Huntly-Otahuhu 220 kV circuit could overload for an outage of the Huntly-Takanini-Otahuhu 220 kV circuit. Two possible transmission solutions could alleviate this problem.

4.5.1 Construction of a 220 kV bus near Glenbrook Deviation

One of the two 220 kV circuits between Huntly and Otahuhu deviates into Glenbrook, resulting in unequal sharing of power flow between the two circuits, which can lead to overloading of other circuits. It is proposed to relieve the circuit overloading issues on the 220 kV Huntly to Otahuhu circuits by constructing a bus near Drury on the Glenbrook deviation of the 220 kV Huntly-Glenbrook-Otahuhu transmission line. With the proposed bus, the two 220 kV circuits on the line between Huntly and Otahuhu, would be of the same approximate length, resulting in better load sharing between the circuits.

The potential investment is shown in red (dotted) in Figure 4-2.

4.5.2 Construction of a 220 kV bus near Huntly Deviation

One of the circuits of the 220 kV Whakamaru-Otahuhu C line deviates and connects to the Huntly 220 kV bus. Construction of a 220 kV bus near the Huntly deviation and connecting the other circuit of the 220 kV Whakamaru-Otahuhu C line onto the same bus would increase the transfer capacity between Huntly and Otahuhu.

With the proposed bus, as the transmission capacity between the Huntly and Otahuhu 220 kV transmission system is increased, overloading of the 220 kV transmission circuits between these two buses following an outage of a Huntly-Otahuhu 220 kV circuit is avoided.

The potential investment is shown in red (dotted) in Figure 4-2.

Presently the above proposals are being investigated in detail and do not form a part of this transmission investment proposal. It is expected that a proposal will be made in the near future once the preferred solution is identified.

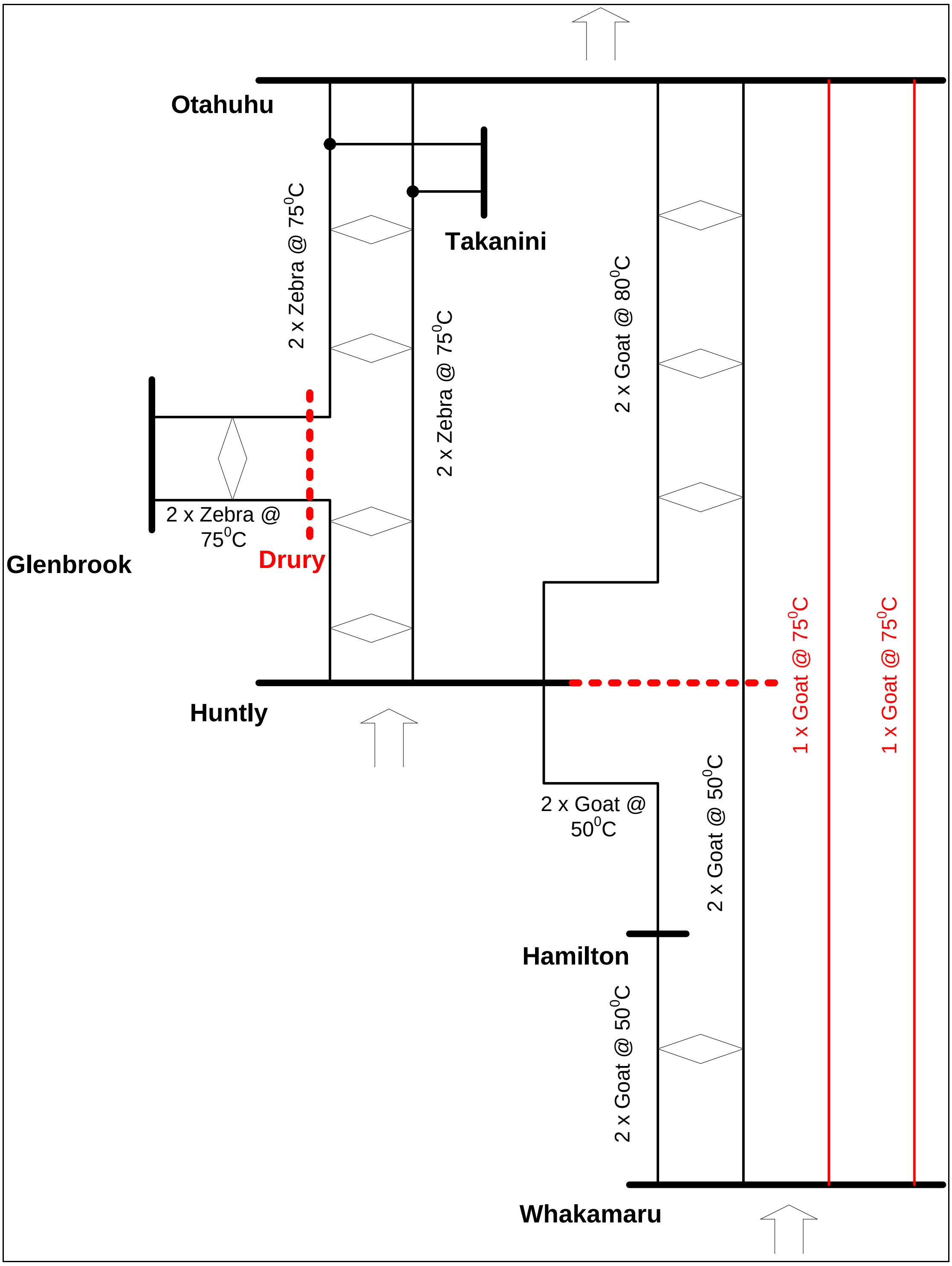

Figure 4-2 Simplified diagram of Whakamaru to Otahuhu transmission system after investment including possible future investments (dotted)

4.6 Property Requirements

It should be noted that the property cost estimates are preliminary estimates only.

Additional detailed engineering design information is required to accurately assess if the works will cause an “injurious affect’ to the land. Additional analysis is required as the valuation methodology applied to these works needs, to be considered on a site by site basis once final design work is available.

The valuation methodology that Transpower currently adopts is the “easement fee approach’ and this is site specific and takes into account factors such as the area of land affected by the easement and towers, proximity of buildings to the works, visual affect through “corridors of affect”, the injurious affect to the balance of the land, permanent disturbance etc.

As final design information becomes available the analysis of the works and whether or not they fall outside of the provisions of the Electricity Act can then be better assessed and the estimate of costs can then be reassessed to a more accurate level.

4.7 Environmental Impact

The environmental impact is dependent on the modifications to the power capacity as well as physical changes to the towers and ground levels. A full environmental risk assessment has not yet been prepared for this project but will be carried out once the engineering investigation is complete. In determining the costs for the environmental component of the work it has been assumed that four resource consents will be required and five certificates of compliance will be obtained. The cost assumes no appeals to the Courts.

4.8 Estimated Cost

Costs estimates have been prepared using the approach described in Appendix: A.

Table 4-4 below summarises the cost estimates for the major components of the project.

Category	Cost Estimated $m (2005)[1]
Line capital costs	6.8
Substation capital costs	0.2
Property	1.5
Dismantling Costs	0.0
Project Management costs	0.8
Approval Costs	0.4
Investigations	0.4
Total	10.0

Notes:
1. Mid-range estimated cost, $m (2005), includes allowance for project contingencies but excludes allowance for financial (eg inflation) contingencies or Interest During Construction

Table 4-4: Estimated Capital Expenditure for OTA-WKM A & B Thermal Upgrades

The timing of capital expenditures is shown in Figure 4-3. Approximately 76% of the expenditure occurs in the final year of the project.

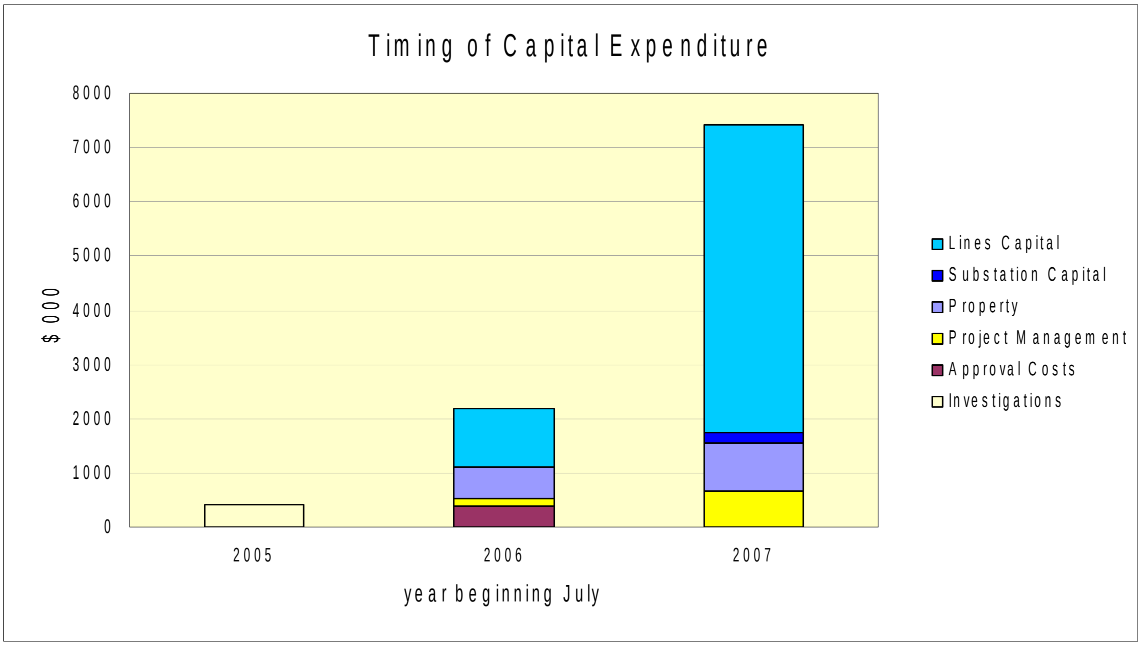

Figure 4-3: Anticipated Incidence of Expenditure on the Proposed OTA-WKM A&B Thermal Upgrade

4.8.1 Contingent Amounts

Table 4-5 provides a summary of the various contingent amounts that have been discussed in this section.

Cost Category	Estimated Cost $k (2005)[1]	Inflation $k	Exchange Rate $k	IDC $k	Expected Cost $k[2]	Cost Contingency $k	Approval Requested from EC $k[3]
Lines	6757	378	0	473	7608	2107	9715
Substations	198	12	0	12	222	0	222
Property	1485	72	0	141	1698	0	1698
Dismantling	0	0	0	0	0	0	0
Project Management	772	43	0	54	869	0	869
Approvals	400	12	0	64	476	0	476
Investigations	402	0	0	109	511	0	511
Total	10014	518	0	852	11384	2107	13491

Notes:

1. Mid-range estimated cost, $m (2005), includes allowance for project contingencies but excludes allowance for financial (eg inflation) contingencies or Interest During Construction
2. Mid-range estimated cost in nominal $ including allowances for financial (eg inflation) contingencies and Interest During Construction
3. Upper-range estimated cost in nominal $ including allowances for financial (eg inflation) contingencies and Interest During Construction

Table 4-5: Relationship between Project Costs in Real and Nominal Terms.

The difference between estimated capital costs and nominal costs including contingencies is approximately $3.5 million. Interest during construction and inflation (which do not affect the economic merits of the project) represent $1.4 million of this difference. Cost contingencies are 21% of real capital costs.

Transpower wishes to recover the actual costs of the proposed investment. The nominal cost estimate including contingencies represents a good faith estimate of what those actual costs might be.

4.9 Transmission Alternatives

The only viable transmission alternative is to enhance the transmission capacity between Otahuhu, Huntly and Whakamaru by building a new transmission circuit, such as that described in the North Island 400 kV transmission upgrade proposal (Volume 2 of the 2005 GUP). However, it is unlikely that any new transmission lines or major upgrade of transmission between Otahuhu and Whakamaru could be implemented within the required short time period. Past and present experience has shown that building new transmission circuits is extremely difficult and significant obstacles are envisaged in obtaining the necessary property easements and environmental consents.

4.10 Non-transmission Alternatives

Non-transmission alternatives available are:

(a). Installation of new generation locally

At present there are no firm proposals for installing new generation in the region in the near future.

(b). Demand management initiatives

As pointed out in the previous sections, the load growth in the Auckland region is higher than the national average and it is unlikely a viable scheme could be implemented within the required time frame. Demand management in the form of controlled load such as water heating is already used extensively and not likely to offer sufficient additional benefits.

Transpower is not aware of any committed demand management project that has the potential to obviate the need for the proposed transmission project.

4.11 Project Timeline

A project of the proposed investment's magnitude would normally be expected to take between two and two and a half years from approval to proceed to final commissioning.

Transpower has identified that the earliest date the proposed investment can be in place is mid 2008, provided investigation and planning commences now.

A tentative timeline for the project is shown below:

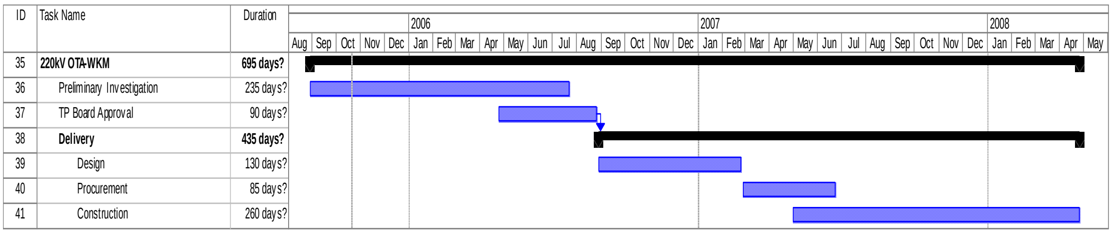

Figure 4-4: Indicative Project Timeline

Any delay in project commencement will result in delay through the project and consequently, prolonging the period of reduced security of supply to Auckland and the North Isthmus regions.

5 Enhancement of the transmission network in the Bay of Plenty

Proposal Summary

To ensure existing transmission capacity into Mt Mauganui and Tauranga can continue to meet winter peak loads until 2009, Transpower proposes to:

- Construct a new 110 kV switching station at Hairini.
- Install a 25 Mvar capacitor bank at Tauranga
- Reconductor the Hairini -Tauranga 110 kV transmission line

These grid developments will effectively increase the transmission capacity into Mt Maunganui and Tauranga. Beyond 2009 a further upgrade of transmission capacity in the area will be required.

This is the least cost transmission investment required for ensuring reliable supply to the region as per Transpower's current grid reliability standards.

The table below provides an estimated cost for the project:

Category	**Cost Estimated $m (2005)**[1]
Line capital costs	2.0
Substation capital costs	10.9
Property	0.1
Dismantling Costs	0.0
Project Management costs	0.5
Approval Costs	0.0
Total	13.5

Notes:

1. Mid-range estimated cost, $m (2005), includes allowance for project contingencies but excludes allowance for financial (eg inflation) contingencies or Interest During Construction

5.1 Planning Assumptions

5.1.1 Existing Generation

In determining the level of supply security to the regional load, only existing or committed generation has been assumed, There is no new generation assumed to emerge in any of Transpower's market development scenarios in the region prior to 2007[11].

The Kaimai hydro power scheme is embedded in the local distribution network and directly impacts on the transmission constraint in this part of the network. There are three power stations making up the Kaimai scheme; these are mainly 'run of river' stations with limited storage. Historically, this chain of stations has been able to provide a minimum of 14 MW of generation at any time of the year. The maximum output of the scheme is 38 MW.

The impact of the Kaimai generation has been incorporated into the transmission planning studies for the area.

5.1.2 Load Forecasts

The power system studies were based on the winter peak load conditions and the 40 year load forecast developed by Transpower in 2005. Transpower utilised the Electricity Commission's 2005 national electricity consumption 40 year forecast as the basis for creating the necessary demand forecasts for the power system analysis[12].

The area supplied by the Tauranga and Mt Maunganui substations has experienced amongst the highest load growth in New Zealand in recent times (about two and a half times the national average). This trend is forecast to continue in the medium term as Table 5-1 demonstrates:

GXP	2005	2010	2015
Mt Maunganui 11kV	17.9	21.8	25.6
Mt Maunganui 33kV	34.3	41.7	49.0
Tauranga 11kV	24.2	29.4	34.6
Tauranga 33kV	54.3	72.4	90.3
Total	**117**	**147**	**199.5**

Table 5-1 –Medium Load Growth Forecasts (MW)

Note that the load forecast shown in Table 5-1 takes into account the natural diversity of the peak loads at the individual grid exit points (GXPs) not occurring simultaneously.

5.1.3 Planning Criteria

The transmission system has been planned in accordance with Transpower's current Grid Reliability Standards[13].

The proposal deals with the adequacy of the capacity of the transmission network supplying Tauranga or Mt Maunganui. The transmission network is considered to provide adequate capacity and reliability if the entire connected load can be supplied

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[11] For further details please refer to North Island 400 kV Project, Planning Assumptions – Demand and Generation Forecasting

[12] For further information, please refer to the Grid Upgrade Plan 2005, Vol 2, Part II.

[13] Transpower Main Transmission Planning Criteria, Grid Upgrade Plan 2005, Vol 2, Supporting Document No. 6

during and following any single credible contingency event occurring in the transmission network.

5.2 Description of the Transmission Asset and the Present Capacity

The configuration of the existing network in the Tauranga and Mt Maunganui area is illustrated in the diagram below:

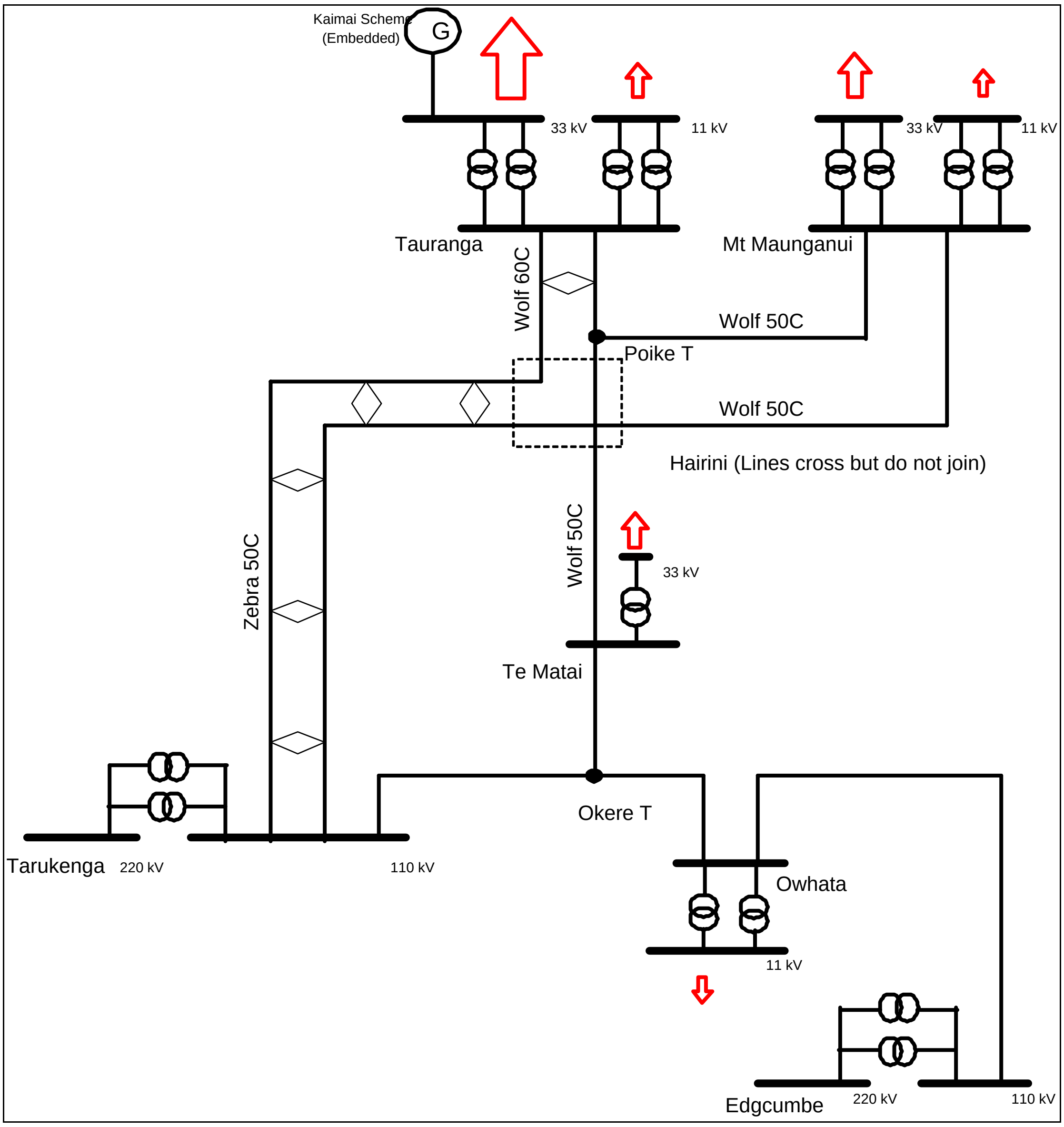

Figure 5-1 – Existing Network

5.3 *Need Analysis*

Mt Maunganui and Tauranga are supplied by the following 110 kV circuits:

Circuit	Summer rating	Winter rating
Tauranga-Tarukenga 1	76 MVA	88 MVA
Mt Maunganui-Tarukenga 1	63 MVA	77 MVA
Okere- Te Matai-Poike-Tauranga 1	63 MVA	77 MVA
Pioke-Mt Maunganui-1	63 MVA	77 MVA

Table 5-2: Summer and winter ratings of the transmission circuits supplying Mt Maunganui and Tauranga

The load growth in the area is such that the peak load at Tauranga will exceed the capacity of the individual circuits supplying the substation from 2005.

During high load periods, an outage of one of these 110 kV circuits will cause the remaining 110 kV circuit to overload and cause low voltage problems at Mt Maunganui and Tauranga. This situation will deteriorate even further if there is little or no generation from the local embedded generation at Kaimai.

The two worst circuit contingencies are the 110 kV Tarukenga-Tauranga and Tarukenga–Mount Maunganui circuit outages. An outage of either circuit transfers approximately two thirds of the load to the other circuit. About one third of the load is transferred through the Tarukenga–Okere 110 kV circuit, because of its impedance.

System studies predict that by 2007, the following post contingency voltage / overload issues may occur, assuming the worst case scenario of no generation from Kaimai:

Contingency event	Bus Voltages			Circuit overloads
	Mt Maunganui 110 kV	Tauranga 110 kV	Te Matai 110 kV	
110 kV Tarukenga – Mt Maunganui	0.94 pu	OK	OK	110 kV Tarukenga – Tauranga
110 kV Tarukenga – Tauranga	0.94 pu	0.93 pu	0.94 pu	110 kV Tarukenga – Mt Maunganui
Notes: The minimum voltage threshold is 0.95 pu				

Table 5-3 – Post contingency voltages 2007: no additional capacitors at Tauranga

From 2005, it will be necessary to constrain-on at least 14 MW of generation from the Kaimai hydro power stations during peak winter load periods in order to provide n-1 security to Tauranga (the normally available minimum generation from the Kaimai scheme is approximately 14 MW). This constraint will apply for approximately 1% of the time in 2005 (about 87 hours). By 2009, even constraining-on full generation of 38 MW will not be sufficient to provide n-1 security to the area during peak load periods.

5.4 Investment Proposal

It is proposed to relieve the immediate circuit overloading and low voltage issues by:

- constructing a new switching station at Hairini
- providing reactive support at Tauranga (installation of 25 Mvar capacitor bank at Tauranga 110 kV bus)
- reconductoring the Hairini-Tauranga line section

Several 110 kV circuits supplying the region pass through Hairini. A 110 kV switching station at Hairini will improve the loading of the circuits post contingency and slightly improve the voltage. It will effectively increase the number of supply routes into Tauranga and Mt Maunganui. As shown in Figure 5-2, this arrangement will create a shared 110 kV circuit (i.e. the Hairini – Poike – Tauranga – Mt Maunganui circuit)

The Hairini – Tauranga line must also be reconductored to increase its rating to ensure security of supply to Tauranga beyond 2005. With this arrangement, the circuits to Mt Maunganui, which cannot be uprated, will no longer overload following a contingency.

A 25 Mvar capacitor bank is also required at Tauranga to relieve the existing low voltage issues at Tauranga and Mt Maunganui following a circuit outage.

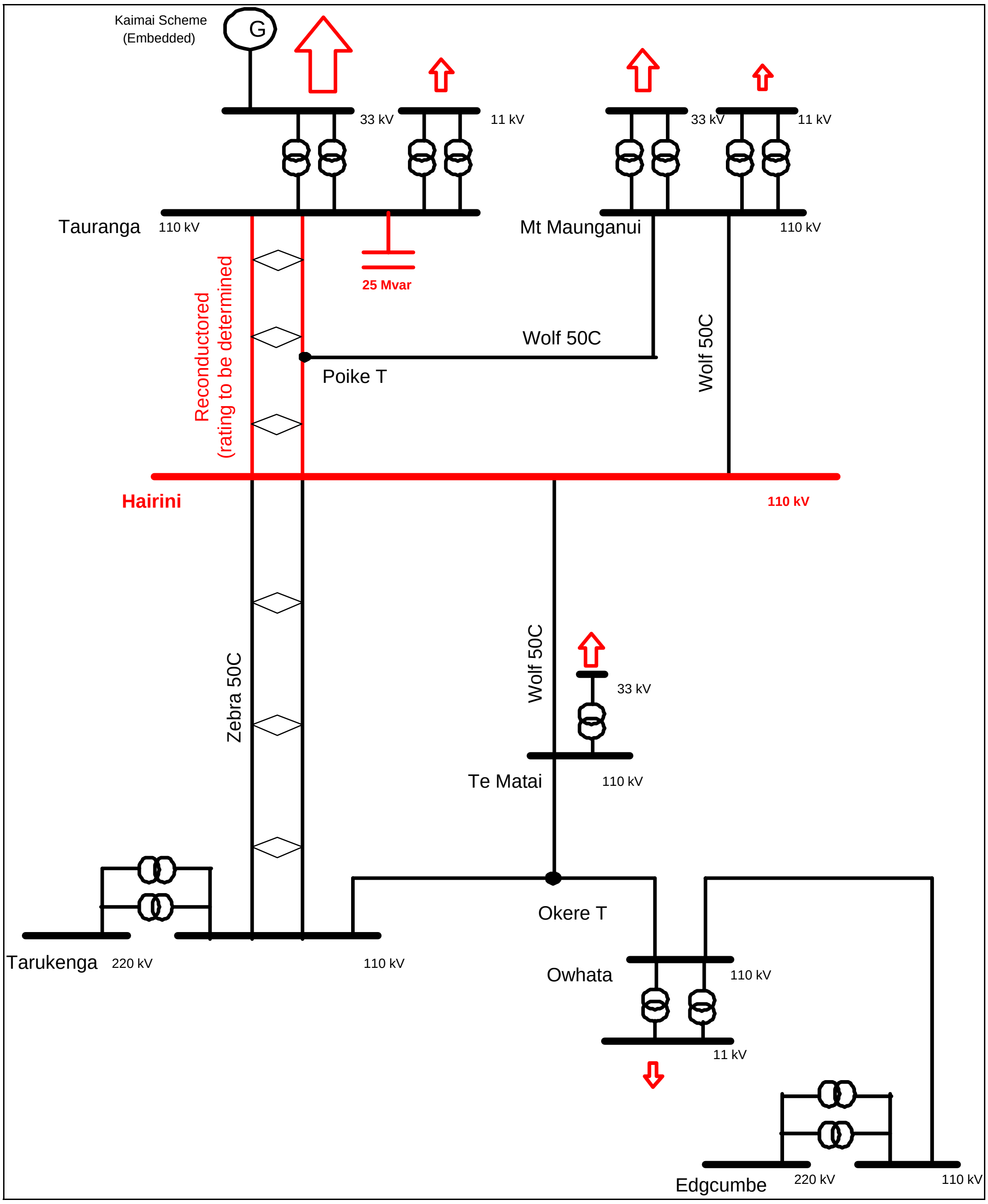

Figure 5-2 - Proposed transmission network upgrades for the Bay of Plenty

With the new Hairini switching station and additional 25 Mvar of voltage support at Tauranga, n-1 security will be achieved until 2009 without the need to constrain any generation into Tauranga above a minimum generation of 14 MW at Kaimai.

By 2009, an outage of a Tarukenga – Hairini circuit will overload the Tarukenga – Okere circuit. This overload can be relieved by automatically splitting the system between Hairini and Te Matai, but this will overload the remaining Tarukenga – Hairini circuit. Technically, the Tarukenga – Hairini line can be upgraded, although detailed investigation is still required.

5.5 Property Requirements

Transpower owns the land at Hairini for the switching station.

It is considered possible to reconductor the Hairini -Tauranga line without requiring easements over the line route. However, it should be noted that the property cost estimates are preliminary estimates only.

Additional detailed engineering design information is required to accurately assess if the works will cause an “injurious affect’ to the land. Additional analysis is required as the valuation methodology applied to these works needs, to be considered on a site by site basis once final design work is available.

The valuation methodology that Transpower currently adopts is the “easement fee approach’ and this is site specific and takes into account factors such as the area of land affected by the easement and towers, proximity of buildings to the works, visual affect through “corridors of affect”, the injurious affect to the balance of the land, permanent disturbance etc.

As final design information becomes available the analysis of the works and whether or not they fall outside of the provisions of the Electricity Act can then be better assessed and the estimate of costs can then be reassessed to a more accurate level.

5.6 Environmental Impact

Hairini is designated for a substation, but the designation expires in 2008 unless the substation is built or substantially built. However, substantial screen planting will be required.

For the capacitor at Tauranga substation, project noise levels will need to be assessed as part of the investigation and noise mitigation may be required.

Transpower believes the Hairini - Tauranga A line can be reconductored without resource consents being required under the present District Plan but some constrains may be imposed on the method of construction to be employed (e.g. use of helicopters).

5.7 Estimated Cost

Cost estimates have been prepared using the approach described in Appendix: A.

Table 5-4 below summarises the cost estimates for the major components of the project.

Category	Cost Estimated $m (2005)[1]
Line capital costs	2.0
Substation capital costs	10.9
Property	0.1
Dismantling Costs	0.0
Project Management costs	0.5
Approval Costs	0.0
Total	13.5

Notes:
1. Mid-range estimated cost, $m (2005), includes allowance for project contingencies but excludes allowance for financial (eg inflation) contingencies or Interest During Construction

Table 5-4: Estimated Capital Expenditure for Hairini/Tauranga Grid Development

The timing of capital expenditures is shown in Figure 5-3. Expenditure in the final year of the project amounts to 92% of total project costs.

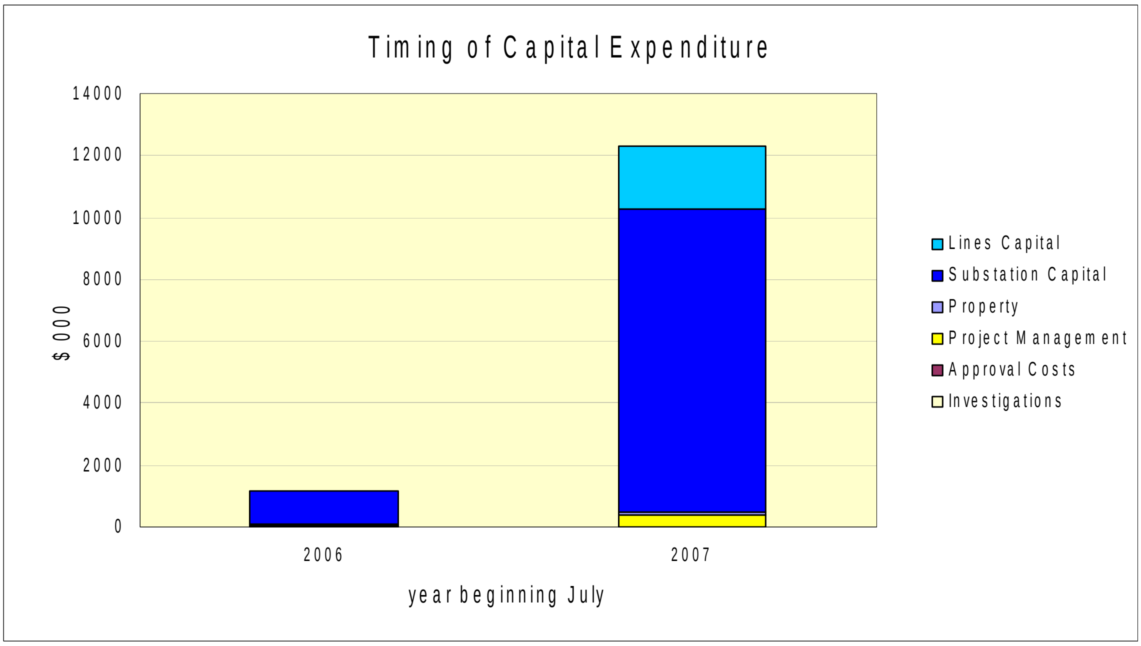

Figure 5-3: Anticipated Incidence of Expenditure on the Proposed Hairini/Tauranga Development project

5.7.1 Contingent Amounts

Table 5-5 provides a summary of the various contingent amounts that have been discussed in this section.

Cost Category	Estimated Cost $k (2005)[1]	Inflation $k	Exchange Rate $k	IDC $k	Expected Cost $k[2]	Cost Contingency $k	Approval Requested from EC $k[3]
Lines	2000	60	0	103	2163	187	2350
Substations	10881	294	0	642	11817	1021	12839
Property	100	3	0	5	108	0	108
Dismantling	0	0	0	0	0	0	0
Project Management	440	12	0	27	479	0	479
Approval	30	0	0	5	35	0	35
Investigation	0	0	0	0	0	0	0
Total	13451	369	0	782	14602	1209	15811

Notes:

1. Mid-range estimated cost, $m (2005), includes allowance for project contingencies but excludes allowance for financial (eg inflation) contingencies or Interest During Construction
2. Mid-range estimated cost in nominal $ including allowances for financial (eg inflation) contingencies and Interest During Construction
3. Upper-range estimated cost in nominal $ including allowances for financial (eg inflation) contingencies and Interest During Construction

Table 5-5: Relationship between Project Costs in Real and Nominal Terms.

The difference between estimated capital costs and nominal costs including contingencies is approximately $2.4 million. However, interest during construction and inflation (which do not affect the economic merits of the project) represent $1.2 million of this difference. Cost contingencies are 9% of real capital costs, but it should be noted that these cover only a limited number of potential variations in project costs.

Transpower wishes to recover the actual costs of the proposed investment. The nominal cost estimate including contingencies represents a good faith estimate of what those actual costs might be.

5.8 Transmission Alternatives

5.8.1 Install an additional 110 kV Tarukenga –Tauranga circuit

A third 110 kV transmission circuit between Tarukenga –Tauranga would provide transmission security to the region, and would be an alternative to the proposed development. However, past experience has shown that building new transmission circuits is extremely difficult and significant obstacles are envisaged in obtaining the necessary property easements and environmental consents.[14] In particular, the highly urbanised nature of the land between Hairini and Tauranga substation would make construction difficult. Underground cables would likely be the only feasible alternative for a new circuit, should one be required.

While this option is technically sound, it is unable to be implemented within the required short time period and so is not considered to be a viable option.

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[14] In the mid 1990's, Transpower attempted to install a new 110 kV circuit between Mt Maunganui and Härini. Issues with local land owners meant that this was not possible, and instead of running to Hairini, the new line was 'Teed' into the Te Matai – Tauranga line at Poike.

5.8.2 *Upgrading the 110 kV circuits to Mt Maunganui and Tauranga*

Re-conductoring or thermally upgrading these circuits is not feasible without replacing the structures, as both the existing 110 kV lines into Mt Maunganui are both optimised for their present conductors. It is likely that any replacement structures would require Transpower to obtain environmental consents and property easements. Such activity is unlikely to be able to be completed within the short time period required.

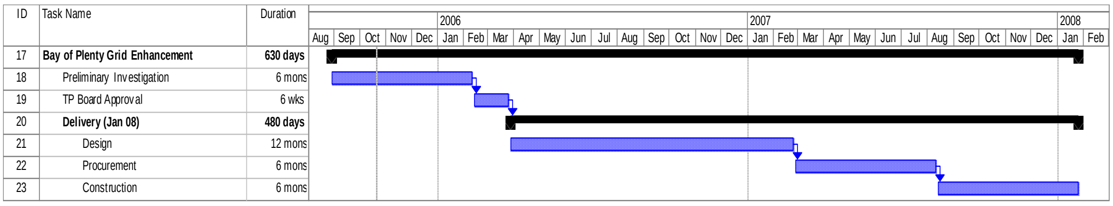
However, with the Hairini switching station in place, and with the upgrading of the capacity in the Hairini – Tarukenga 110 kV circuits, and some further reactive support in the area, it may be possible to meet supply security beyond 2015. A proposal for this further work will be submitted in a future Grid Upgrade Plan.

5.9 *Project Timeline*

A project of this magnitude would normally be expected to take a period of approximately two and a half years from approval to proceed to final commissioning

Transpower has identified that the earliest date the proposed investment can be in place is early 2008, provided investigation and planning commences now.

A tentative timeline for the project is shown below:



ID	Task Name	Duration
17	**Bay of Plenty Grid Enhancement**	**630 days**
18	Preliminary Investigation	6 mons
19	TP Board Approval	6 wks
20	**Delivery (Jan 08)**	**480 days**
21	Design	12 mons
22	Procurement	6 mons
23	Construction	6 mons

Figure 5-4: Indicative Project Timeline

Any delay in project commencement will result in delay through the project and consequently prolonging the period of reduced security of supply to Tauranga and Mt Maunganui.

6 Replacement of the 220/110 kV Interconnecting Transformer at Kikiwa

Proposal Summary

To meet load growth in the upper South Island and West Coast regions in 2007 with all equipment in service, and to prevent overloading of the grid assets following circuit contingencies, Transpower proposes to replace the existing 220/110 kV transformer at Kikiwa with a higher rated unit.

This grid development will increase the transmission capacity into the 110 kV and 66 kV systems in Nelson, Marlborough, Buller and the West Coast.

This is the least cost transmission investment required for ensuring the supply reliability to the region as per Transpower's current grid reliability standards.

The table below provides the estimated costs for the Kikiwa and Stoke interconnector replacement projects:

Category	**Cost Estimated $m (2005)**[1]
Line capital costs	0.0
Substation capital costs	7.3
Property costs	0.0
Dismantling costs	0.0
Project Management costs	0.2
Approval and Investigations costs	0.0
Total	7.5

Notes:

1. Mid-range estimated cost, $m (2005), includes allowance for project contingencies but excludes allowance for financial (eg inflation) contingencies or Interest During Construction

6.1 Planning Assumptions

6.1.1 Generation Scenarios

In determining the level of supply security to the regional load, only existing or committed generation has been assumed.

The local hydro power stations in the region, that have been incorporated in the transmission planning studies are:

- Kumara (10 MW),
- Branch River (11 MW) and
- Cobb (32 MW).

There are also several low capacity generators embedded within the West Coast distribution network which are not separately modelled in the studies. Instead, these generators appear as a net reduction in load off-take in the load forecast.

6.1.2 Load Forecasts

The power system studies were based on the winter peak load conditions and the 40 year load forecast developed by Transpower in 2005. Transpower utilised the Electricity Commission's 2005 national electricity consumption 40 year forecast as the basis for creating the necessary demand forecasts for the power system analysis[15].

Table 6-1 below summarises the expected load growth from the substations supplied directly or indirectly from the Kikiwa interconnecting transformer. The table includes committed and expected block load increases totalling 28.7 MW, which are not otherwise included in the forecast.

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[15] For further information, please refer to the Grid Upgrade Plan 2005, Vol 2, Part II.

GXP	Diversity	2005	2010	2015
Hokitika (2005 forecast)	84.78%	12.4	14.5	16.1
Hokitika (block increase 2004)	100.00%	0.7	0.7	0.7
Hokitika (block increase 2005)	100.00%	2.5	2.5	2.5
Hokitika (block increase 2006)	100.00%	2.5	2.5	2.5
Hokitika (total)		18.1	20.2	21.8
Greymouth (2005 forecast)	85.74%	11.5	12.6	13.5
Dobson (2005 forecast)	86.43%	12.2	14.5	16.1
Dobson (block increase May 2004)	100.00%	2.0	2.0	2.0
Dobson (block increase Sept 2004)	100.00%	1.0	1.0	1.0
Dobson (total)		15.2	17.5	19.1
Reefton (block increase May 2006)	100.00%	7.0	7.0	7.0
Reefton (block increase Dec 2006)	100.00%	13.0	13.0	13.0
Reefton (total)		20.0	20.0	20.0
Orowaiti (aka Robertson St)	94.23%	7.4	8.0	8.4
Westport	81.93%	9.2	10.0	10.6
Murchinson	78.46%	2.4	2.9	3.3
Kikiwa	73.75%	2.8	3.3	3.8
Blenheim	98.27%	57.5	68.6	78.3
Motueka	97.14%	17.9	21.1	24.0
Motupipi	59.57%	7.3	8.6	9.8
TOTAL (coincident peaks)		169.3	192.8	212.6
TOTAL (ADMD)		**156.3**	**177.8**	**195.9**

Table 6-1: Load Forecasts (MW)

6.1.3 Planning Criteria

The transmission system has been planned in accordance with Transpower's current Grid Reliability Standards[16].

The proposal deals with the adequacy of the capacity provided by the transmission network supplying the upper South Island. The transmission network is considered to provide adequate capacity and reliability if the entire connected load can be supplied during and following any single credible contingency event occurring in the transmission network.

6.2 Description of the Transmission Asset and the Present Capacity

The configuration of the existing network is illustrated in Figure 6-1 below:

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[16] Transpower Main Transmission Planning Criteria, Grid Upgrade Plan 2005, Vol 2, Supporting Document No. 6

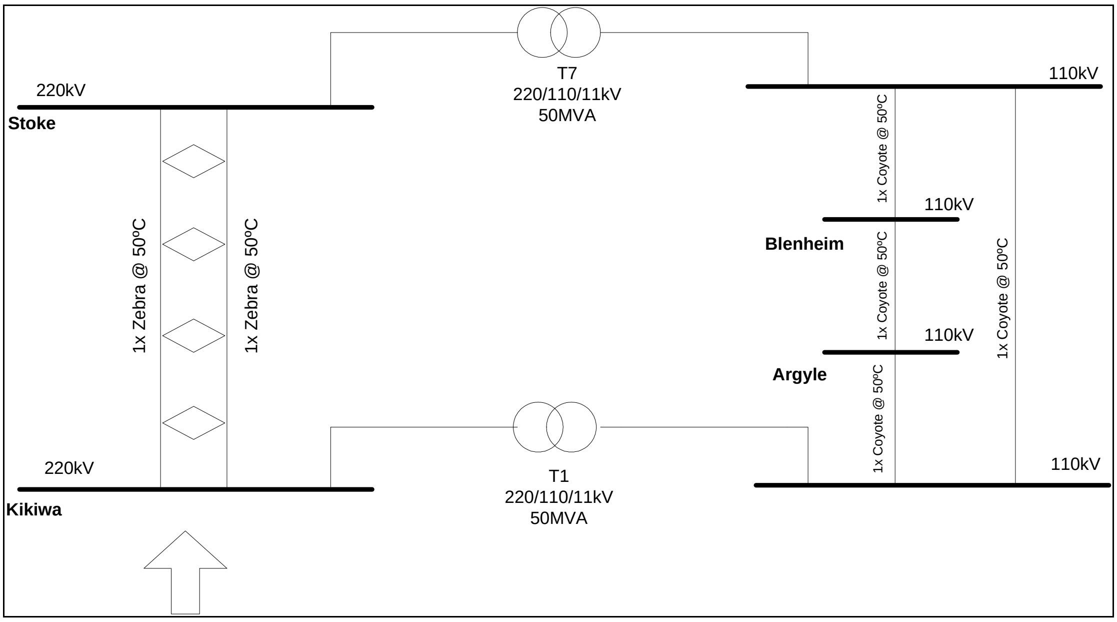


Figure 6-1 – Existing Network

6.3 *Need Analysis*

For the normal system configuration, the existing Kikiwa transformer supplies some of the Blenheim load, plus the loads in Buller and part of the West Coast. Power tends to flow from Kikiwa to Stoke on the 110 kV system, as it is in parallel with the 220 kV Kikiwa to Stoke circuits and the Kikiwa transformer has low impedance.

With all equipment in service and maximum local generation, the Kikiwa transformer will be at full capacity for the 2007 peak load. This occurs with full local generation, which is an optimistic assumption given that some of the hydro generators have limited storage and that the block load is base load. The outage of a 220 kV Kikiwa-Stoke circuit overloads the Kikiwa transformer, even at less than peak load, depending on the amount of local hydro generation.

The Kikiwa transformer is effectively in parallel with the Stoke 220/110 kV transformer, although in normal service the Stoke transformer is slightly less highly loaded. An outage of the Kikiwa transformer means that its load is transferred to the Stoke transformer and vice versa. The replacement of the Stoke transformer is covered in section 8.

6.4 *Investment Proposal*

Replacing the existing Kikiwa transformer will address the above issues. The replacement transformer will also allow for outages of the Stoke 220/110 kV transformer. The replacement transformer will have an approximate capacity of 150 MVA, which is adequate for about 20 years of load growth (provided that 110 kV voltage issues due to load growth and the Stoke 220/110 kV transformer replacement are also addressed).

There is also an additional benefit of the replacement transformers, over and above the coverage of a circuit contingency. The replacement transformer will have an on-load tap changer (the existing transformer has an off-load tap changer). The on-load tap changer will assist in addressing voltage and stability issues associated with supplying the West Coast and top of the South Island over the long transmission route from the Waitaki Valley to Christchurch and onto Kikiwa, by allowing some decoupling between the 220 kV and 110 kV voltages for variations in load and generation scenarios due to daily, seasonal and multi-year load changes. However, as the Stoke 220/110 kV transformer has an off-load tap changer and is effectively in parallel with the Kikiwa transformer, the full benefit of the on-load tap changer will not be obtained until the Stoke transformer is also replaced.

Functionally, the new Kikiwa 220/110 kV transformer will replace the existing transformer. However, it is expected that it will not be possible to reuse the infrastructure of the existing transformer (220 kV and 110 kV bays, and protection). This is because it is not possible to have an extended outage of the existing transformer for replacement (even with the existing loads, prior to the block load increases), and maintain the Kikiwa GXP which is supplied from the transformer tertiary winding. Instead, the existing transformer will be retained, but optimised down to a supply transformer.

The configuration of the proposed grid investment is illustrated in the diagram below:

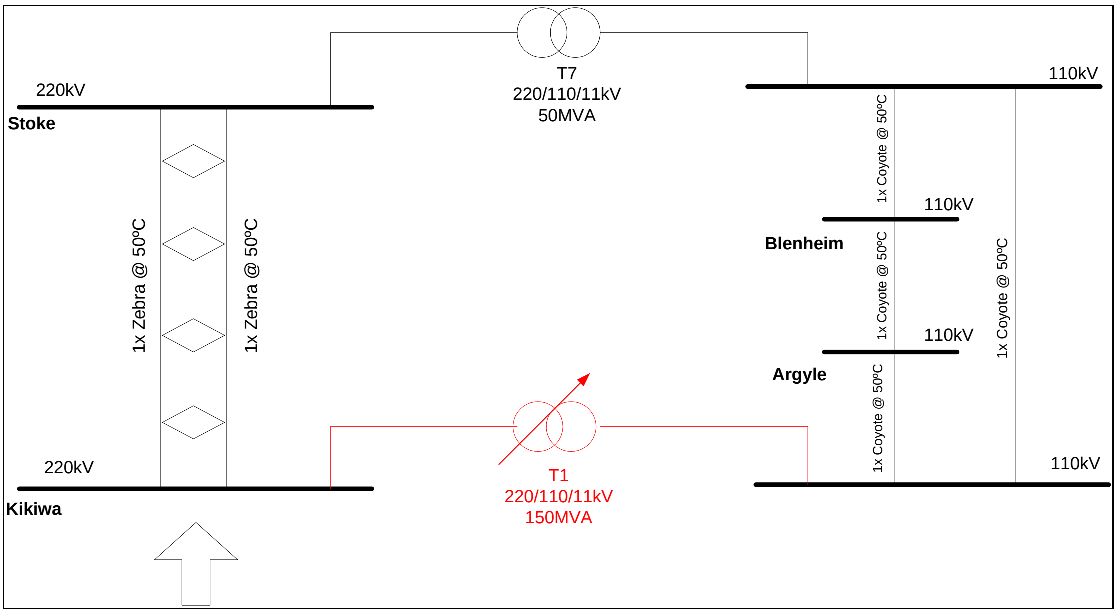


Figure 6-2– Proposed Network Post Investment

6.5 *Property Requirements*

Transpower owns the land at Kikiwa substation. The switchyard should not require expansion to install the replacement transformer. However, it is expected that the Kikiwa transformer will need installing in a new bay as it is not possible to have an outage of the existing transformer for the extended period required for a simple replacement, and/or due to site access restrictions.

6.6 Environmental Impact

The audible noise at Kikiwa may marginally increase if the existing transformer is retained to supply the existing Kikiwa load, and this may require some additional noise mitigation measures.

Provision will need to be made for the increased oil volume of the new transformers, compared with the existing transformers. These changes may require new discharge consents to be obtained.

6.7 Estimated Cost

This summary presents analysis of costs for the replacement of the Kikiwa interconnecting bank and replacement of the Stoke interconnecting bank. For clarity it does not include costs for the 220 kV bus security upgrade at Kikiwa

Cost estimates have been prepared using the approach described in Appendix: A.

Table 6-2 below summarises the cost estimates for the major components of the project.

Category	**Cost Estimated $m (2005)[1]**
Line capital costs	0.0
Substation capital costs	7.3
Property costs	0.0
Dismantling costs	0.0
Project Management costs	0.2
Approval and Investigations costs	0.0
Total	7.5

Notes:

1. Mid-range estimated cost, $m (2005), includes allowance for project contingencies but excludes allowance for financial (eg inflation) contingencies or Interest During Construction

Table 6-2: Estimated Capital Expenditure for the Upper South Island Grid Development Projects

The timing of capital expenditures is shown in Figure 6-3. Expenditure in the final year of the project amounts to 85% of total project costs.

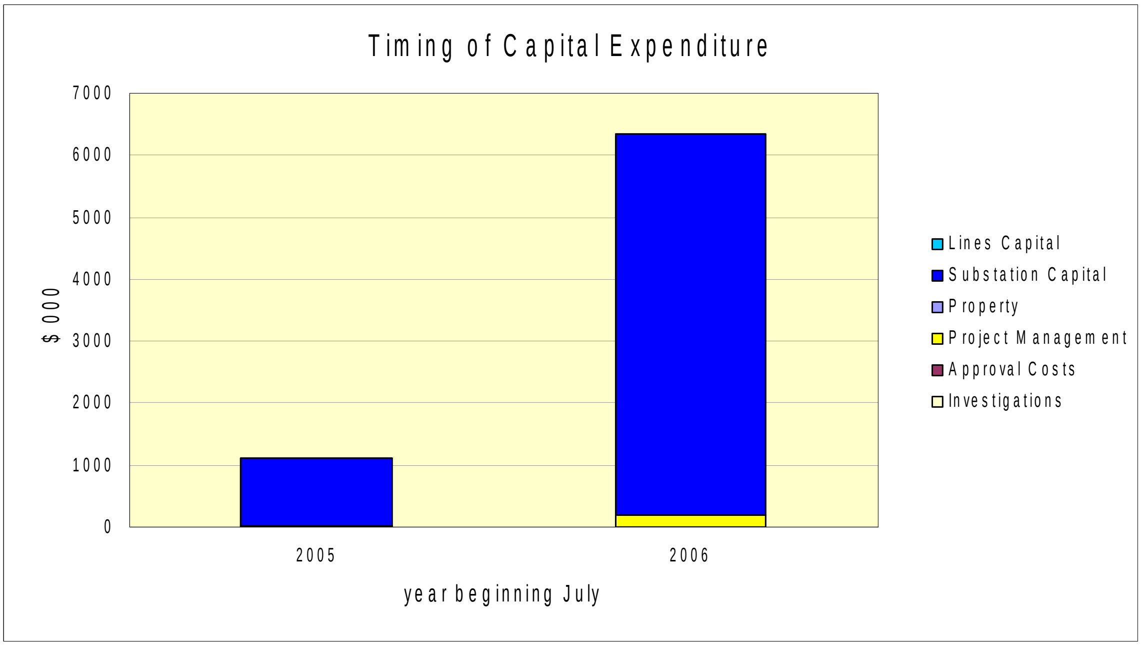


Figure 6-3: Anticipated Incidence of Expenditure on the proposed Upper South Island Grid Development Project

6.7.1 Contingent Amounts

Table 6-3 provides a summary of the various contingent amounts that have been included in the nominal cost estimate for the project.

Cost Category	Estimated Cost $k (2005)[1]	Inflation $k	Exchange Rate $k	IDC $k	Expected Cost $k[2]	Cost Contingency $k	Approval Requested from EC $k[3]
Lines	0	0	0	0	0	0	0
Substations	7241	185	0	485	7911	1003	8914
Property	0	0	0	0	0	0	0
Dismantling	0	0	0	0	0	0	0
Project Management	233	6	0	16	255	0	255
Consenting	0	0	0	0	0	0	0
Investigation	0	0	0	0	0	0	0
Total	7474	191	0	501	8166	1003	9169

Notes:

1. Mid-range estimated cost, $m (2005), includes allowance for project contingencies but excludes allowance for financial (eg inflation) contingencies or Interest During Construction
2. Mid-range estimated cost in nominal $ including allowances for financial (eg inflation) contingencies and Interest During Construction
3. Upper-range estimated cost in nominal $ including allowances for financial (eg inflation) contingencies and Interest During Construction

Table 6-3: Relationship between Project Costs in Real and Nominal Terms.

The difference between estimated capital costs and nominal costs including contingencies is approximately $1.7 million. However interest during construction and inflation (which do not affect the economic merits of the project) represent $0.7 million of this difference. Cost contingencies are 13.4% of real capital costs, but it should be noted that these cover only a limited number of potential variations in project costs.

Transpower wishes to recover the actual costs of the proposed investment. The nominal cost estimate including contingencies represents a good faith estimate of what those actual costs might be.

6.8 Transmission Alternatives

Installing a second, lower rated, transformer in parallel with the existing transformer (rather than simply replacing the transformer) results in poor load sharing, principally because of the low impedance of the existing transformer.

The existing transformer has no on-load tap changer so a parallel transformer will not be able to have an on-load tap changer either. This is a significant disadvantage as an on-load tap changer will provide voltage control benefits.

6.9 Non Transmission Alternatives

There is limited opportunity for non transmission alternatives, because the Kikiwa transformer is fully loaded with all circuits in service and full local hydro generation. Assuming full local hydro generation is an onerous assumption, as some of the generation is run of the river with limited head ponds, so generation availability cannot be assured for extended periods.

(a) Installation of new local generation

At present there are no firm proposals for installing new generation in the region in the near future. Generation proposals which are known to be under investigation include wind, hydro and coal but are unlikely to be implemented in time. While peaking generation units would be an alternative, a significant amount of generation needs to be installed to provide a level of security similar to the proposed grid upgrade.

(b) Demand management initiatives

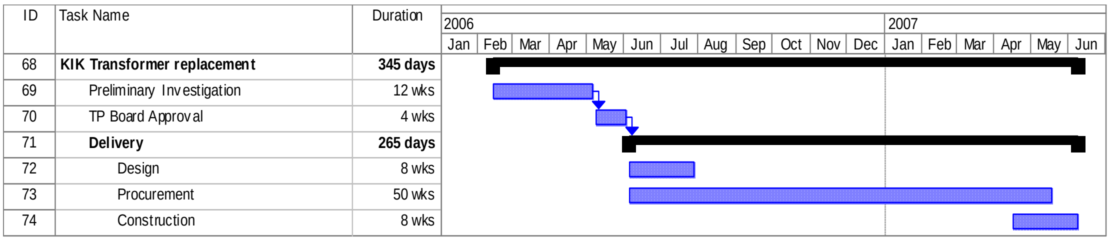
Demand management in the form of controlled load such as water heating is already used extensively. Additional demand management initiatives would need to be extensive as the Kikiwa transformer will be at full capacity with all circuits in service, and it is assumed that all local generation is fully committed (probably an unrealistically optimistic assumption).

Transpower is not aware of any committed demand management project that has the potential to obviate the need for the proposed transmission project.

6.10 Project Timeline

A project of this magnitude is expected to take a period of approximately one and a half years from approval to final commissioning.

A tentative timeline for the project is shown below:



ID	Task Name	Duration
68	**KIK Transformer replacement**	**345 days**
69	Preliminary Investigation	12 wks
70	TP Board Approval	4 wks
71	**Delivery**	**265 days**
72	Design	8 wks
73	Procurement	50 wks
74	Construction	8 wks

Figure 6-4: Indicative Project Timeline

7 Grid Developments: Kikiwa 220 kV Bus Security Upgrade

Proposal Summary

The Kikiwa bus is a critical part of the 220 kV transmission grid, and supplies the Nelson, Marlborough, Buller and part of the West Coast areas. It is proposed to increase the Kikiwa 220 kV bus security to reduce the number of circuits and transformers disconnected during a tripping of a bus section. This increases the maximum load that can be supplied without causing a voltage collapse.

This is the least cost transmission investment required for ensuring reliable supply to the region as per Transpower's current grid reliability standards.

The table below provides the estimated costs for the project:

Category	**Cost Estimated $m (2005)**[1]
Line capital costs	0.0
Substation capital costs	3.5
Property costs	0.0
Dismantling costs	0.0
Project Management costs	0.04
Approval and Investigations costs	0.0
Total	3.6

Notes:

1. Mid-range estimated cost, $m (2005), includes allowance for project contingencies but excludes allowance for financial (eg inflation) contingencies or Interest During Construction

7.1 Planning Assumptions

7.1.1 Generation Scenarios

In determining the level of supply security to the regional loads, only existing or committed generation has been assumed.

There are hydro power stations in the regions that have been incorporated in the transmission planning studies are:

- Kumara (10 MW),
- Branch River (11 MW) and

- Cobb (32 MW).

There are also several low capacity generators embedded within the West Coast distribution network which are not separately modelled in the studies. Instead, these generators appear as a net reduction in load off-take in the load forecast.

7.1.2 Load Forecasts

The power system studies were based on the winter peak load conditions and the 40 year load forecast developed by Transpower in 2005. Transpower utilised the Electricity Commission's 2005 national electricity consumption 40 year forecast as the basis for creating the necessary demand forecasts for the power system analysis[17].

Table 7-1 below summarises the expected load growth from the substations supplied directly or indirectly from the Kikiwa 220 kV bus. The table includes committed and expected block load increases totalling 28.7 MW, which are not otherwise included in the forecast.

GXP	Diversity	2005	2010	2015
Hokitika (2005 forecast)	84.78%	12.4	14.5	16.1
Hokitika (block increase 2004)	100.00%	0.7	0.7	0.7
Hokitika (block increase 2005)	100.00%	2.5	2.5	2.5
Hokitika (block increase 2006)	100.00%	2.5	2.5	2.5
Hokitika (total)		*18.1*	*20.2*	*21.8*
Greymouth (2005 forecast)	85.74%	11.5	12.6	13.5
Dobson (2005 forecast)	86.43%	12.2	14.5	16.1
Dobson (block increase May 2004)	100.00%	2.0	2.0	2.0
Dobson (block increase Sept 2004)	100.00%	1.0	1.0	1.0
Dobson (total)		*15.2*	*17.5*	*19.1*
Reefton (block increase May 2006)	100.00%	7.0	7.0	7.0
Reefton (block increase Dec 2006)	100.00%	13.0	13.0	13.0
Reefton (total)		*20.0*	*20.0*	*20.0*
Orowaiti (aka Robertson St)	94.23%	7.4	8.0	8.4
Westport	81.93%	9.2	10.0	10.6
Murchinson	78.46%	2.4	2.9	3.3
Kikiwa	73.75%	2.8	3.3	3.8
Blenheim	98.27%	57.5	68.6	78.3
Motueka	97.14%	17.9	21.1	24.0
Motupipi	59.57%	7.3	8.6	9.8
TOTAL (coincident peaks)		169.3	192.8	212.6
TOTAL (ADMD)		**156.3**	**177.8**	**195.9**

Table 7-1 – Load Forecasts (MW)

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[17] For further information, please refer to the Grid Upgrade Plan 2005, Vol 2, Part II.

7.1.3 Planning Criteria

The transmission system has been planned in accordance with the Transpower's current Grid Reliability Standards[18].

The proposal deals with the adequacy of the capacity provided by the transmission network supplying the upper South Island. The transmission network is considered to provide adequate capacity and reliability if all the connected load can be supplied during and following any single credible contingency event occurring in the transmission network.

7.2 Description of the Transmission Asset and the Present Capacity

In determining the level of supply security to the regional loads, only the existing grid or committed upgrades have been assumed. The only committed upgrade assumed is the commissioning of the third 220 kV Islington-Kikiwa circuit. The configuration of the existing and committed network is illustrated in the diagram below:

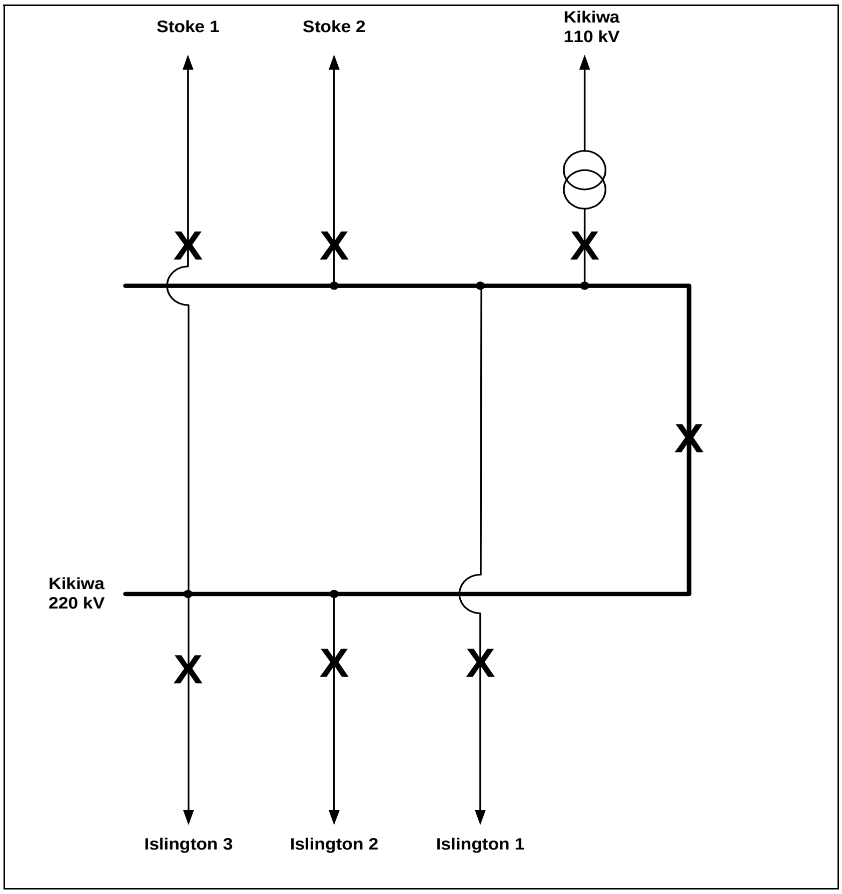

Figure 7-1- Existing and Assumed Committed Network

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[18] Transpower Main Transmission Planning Criteria, Grid Upgrade Plan 2005, Vol 2, Supporting Document No. 6

7.3 Need Analysis

The Kikiwa 220 kV bus transformer supplies power to the Nelson, Marlborough, Buller and part of the West Coast areas. The Kikiwa 220 kV bus presently has two bus zones, configured as a double selectable bus with a single bus coupler.

The above bus configuration means that two of the three 220 kV Islington - Kikiwa circuits must be selected to the same bus section. Should this bus section trip, then two of the three Islington - Kikiwa circuits will trip. Supplying all the load on the remaining single Islington - Kikiwa circuit will lead to a voltage collapse at high loads.

There are also three transmission "circuits" from Kikiwa north towards Stoke: the two 220 kV Kikiwa - Stoke circuits and the Kikiwa 220/110 kV transformer. The above bus configuration also means that two of these three "circuits" must be selected to the same bus section. Should this bus section trip, the loss of two of the three Kikiwa "circuits" will exacerbate voltage and reactive power issues.

7.4 Investment Proposal

An initial investigation identified that the least cost option which met the security requirements was to convert the Kikiwa 220 kV to a breaker and a half configuration. A bus tripping, due to either a bus fault or a circuit breaker failure, will result in the outage of just one circuit or transformer. A failure of a half breaker will result in the tripping of one "south" circuit to Islington and one "north circuit" to Kikiwa.

While not a design driver, the conversion of Kikiwa to breaker and a half will allow for the straight forward connection of other 220 kV equipment. For example, this could be operating the Inangahua - Kikiwa B line at 220 kV if there is sizeable new generation in the Buller area.

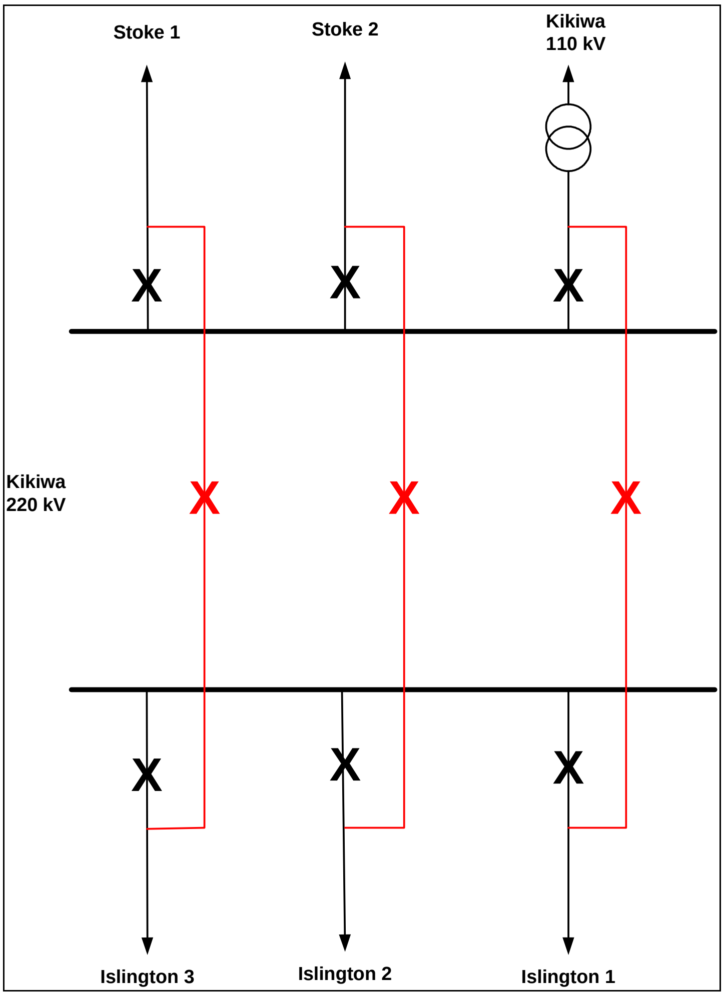


Figure 7-2– Proposed Investment

7.5 *Property Requirements*

Transpower owns the land at Kikiwa substation. The switchyard should not require expansion for the bus security upgrade.

7.6 *Environmental*

The environmental impact is expected to be minimal. The switchyard should not require expansion for the bus security upgrade.

7.7 *Estimated Cost*

Costs estimates have been prepared using the approach described in Appendix: A.

Table 7-2 below summarises the cost estimates for the major components of the project.

Category	**Cost Estimated $m (2005)**
Line capital costs	0.0
Substation capital costs	3.5
Property costs	0.0
Dismantling costs	0.0
Project Management costs	0.04
Approval and Investigations costs	0.0
Total	3.6
Notes: 1. Mid-range estimated cost, $m (2005), includes allowance for project contingencies but excludes allowance for financial (eg inflation) contingencies or Interest During Construction	

Table 7-2: Estimated Capital Expenditure for the Kikiwa Bus Security Project

The timing of capital expenditures is shown in Figure 7-3.

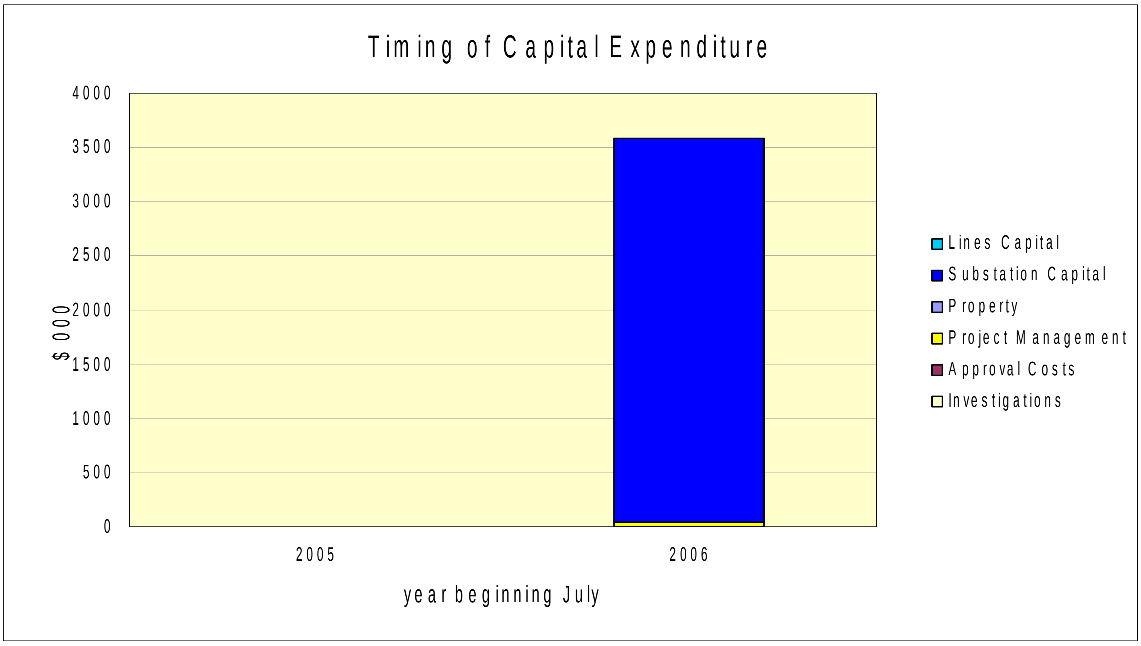


Figure 7-3: Anticipated Incidence of Expenditure on the proposed Kikiwa Bus Security Upgrade

7.7.1 Contingent Amounts

Table 7-3 provides a summary of the various contingent amounts that have been included in the nominal cost estimate for the project.

Cost Category	Estimated Cost $k (2005)[1]	Inflation $k	Exchange Rate $k	IDC $k	Expected Cost $k[2]	Cost Contingency $k	Approval Requested from EC $k[3]
Lines	0	0	0	0	0	0	0
Substations	3544	106	0	183	3833	342	4174
Property	0	0	0	0	0	0	0
Dismantling	0	0	0	0	0	0	0
Project Management	40	1	0	2	43	0	43
Consenting	0	0	0	0	0	0	0
Investigation	0	0	0	0	0	0	0
Total	3584	108	0	185	3876	342	4218

Notes:

1. Mid-range estimated cost, $m (2005), includes allowance for project contingencies but excludes allowance for financial (eg inflation) contingencies or Interest During Construction
2. Mid-range estimated cost in nominal $ including allowances for financial (eg inflation) contingencies and Interest During Construction
3. Upper-range estimated cost in nominal $ including allowances for financial (eg inflation) contingencies and Interest During Construction

Table 7-3: Relationship between Project Costs in Real and Nominal Terms.

The difference between estimated capital costs and nominal costs including contingencies is approximately $0.6 million. However interest during construction and inflation (which do not affect the economic merits of the project) represent $0.3 million of this difference. Cost contingencies are 9.5% of real capital costs, but it should be noted that these cover only a limited number of potential variations in project costs.

Transpower wishes to recover the actual costs of the proposed investment. The nominal cost estimate including contingencies represents a good faith estimate of what those actual costs might be.

7.8 Transmission Alternatives

There are no credible transmission alternatives to avoid a loss of supply for a Kikiwa 220 kV bus tripping.

In principle, bus security could be maintained by installing sufficient static and dynamic reactive support to maintain supply following a Kikiwa 220 kV bus tripping, which results in only one Islington - Kikiwa circuit in service. The circuit would also need to be thermally upgraded. The reactive power compensation required would be excessive as a bus tripping would result in the loss of a “south” circuit to Islington and up to two of the three “north” circuits to Kikiwa.

Another transmission alternative is to install a fourth 220 kV Islington - Kikiwa circuit, which would allow two circuits to be connected to each of the two existing Kikiwa bus zones. A Kikiwa 220 kV bus tripping would then keep two of the circuits in service, which provides the required bus security. However, Transpower considers a fourth circuit for the sole purpose of providing bus security excessive.

7.9 Non Transmission Alternatives

(a) Installation of new local generation

At present, there are no firm proposals for installing new generation in the region in the near future. Generation proposals which are known to be under investigation include wind, hydro and coal, but these are unlikely to be implemented in time. While peaking generation units would be an alternative, a significant amount of generation needs to be installed to provide a level of security similar to the proposed grid upgrade.

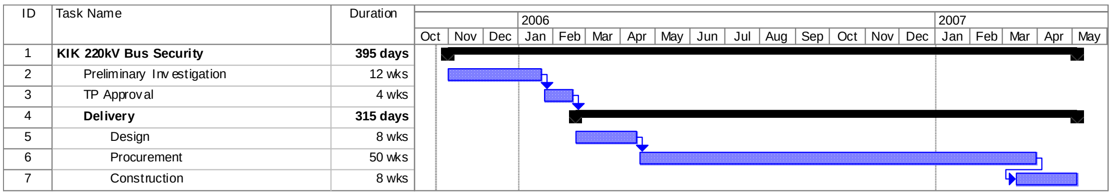
(b) Demand management initiatives

Demand management in the form of controlled load such as water heating is already used extensively. Additional demand management initiatives would need to be extensive as the Kikiwa transformer will be at full capacity with all circuits in service, and it is assumed that all local generation is fully committed (probably an unrealistically optimistic assumption).

Transpower is not aware of any committed demand management project that has the potential to obviate the need for the proposed transmission project.

7.10 Project Timeline

A tentative timeline for the project is shown below. It shows that the proposed investment can be in place by early 2007.



ID	Task Name	Duration
1	**KIK 220kV Bus Security**	**395 days**
2	Preliminary Investigation	12 wks
3	TP Approval	4 wks
4	**Delivery**	**315 days**
5	Design	8 wks
6	Procurement	50 wks
7	Construction	8 wks

Figure 7-4: Estimated Project Timeline Kikiwa Bus Security Upgrade

Any delay in project commencement will prolong the period of reduced security to the Nelson-Marlborough and West Coast regions of the South Island.

8 Replacement of the 220/110 kV Interconnecting Transformer at Stoke

Proposal Summary

To meet load growth in 2007 with all equipment in service and to prevent overloading of the grid assets following circuit contingencies Transpower proposes to replace the existing 220/110 kV transformer at Stoke with a higher rated unit.

This grid development will increase the transmission capacity into the 110 kV and 66 kV systems in Nelson Marlborough Buller and the West Coast.

This is the least cost transmission investment required for ensuring reliable supply to the region as per Transpower's current grid reliability standards.

The estimated costs for this project have been combined with the Kikiwa interconnecting transformer project (see Section 6)

8.1 Planning Assumptions

8.1.1 Generation Scenarios

In determining the level of supply security to the regional load, only existing or committed generation has been assumed.

The local hydro power stations in the region, that have been incorporated in the transmission planning studies are:

- Kumara (10 MW),
- Branch River (11 MW) and
- Cobb (32 MW).

There are also several low capacity generators embedded within the West Coast distribution network which are not separately modelled in the studies. Instead, these generators appear as a net reduction in load off-take in the load forecast.

8.1.2 Load Forecasts

The power system studies were based on the winter peak load conditions and the 40 year load forecast developed by Transpower in 2005. Transpower utilised the Electricity Commission's 2005 national electricity consumption 40 year forecast as the basis for creating the necessary demand forecasts for the power system analysis[19].

Table 8-1 below summarises the expected load growth from the substations supplied directly or indirectly from the Stoke interconnecting transformer. The table includes committed and expected block load increases totalling 28.7 MW, which are not otherwise included in the forecast.

GXP	Diversity	2005	2010	2015
Hokitika (2005 forecast)	84.78%	12.4	14.5	16.1
Hokitika (block increase 2004)	100.00%	0.7	0.7	0.7
Hokitika (block increase 2005)	100.00%	2.5	2.5	2.5
Hokitika (block increase 2006)	100.00%	2.5	2.5	2.5
Hokitika (total)		*18.1*	*20.2*	*21.8*
Greymouth (2005 forecast)	85.74%	11.5	12.6	13.5
Dobson (2005 forecast)	86.43%	12.2	14.5	16.1
Dobson (block increase May 2004)	100.00%	2.0	2.0	2.0
Dobson (block increase Sept 2004)	100.00%	1.0	1.0	1.0
Dobson (total)		*15.2*	*17.5*	*19.1*
Reefton (block increase May 2006)	100.00%	7.0	7.0	7.0
Reefton (block increase Dec 2006)	100.00%	13.0	13.0	13.0
Reefton (total)		*20.0*	*20.0*	*20.0*
Orowaiti (aka Robertson St)	94.23%	7.4	8.0	8.4
Westport	81.93%	9.2	10.0	10.6
Murchinson	78.46%	2.4	2.9	3.3
Kikiwa	73.75%	2.8	3.3	3.8
Blenheim	98.27%	57.5	68.6	78.3
Motueka	97.14%	17.9	21.1	24.0
Motupipi	59.57%	7.3	8.6	9.8
TOTAL (coincident peaks)		169.3	192.8	212.6
TOTAL (ADMD)		**156.3**	**177.8**	**195.9**

Table 8-1: Load Forecasts (MW)

8.1.3 Planning Criteria

The transmission system has been planned in accordance with the Transpower's current Grid Reliability Standards[20].

The proposal deals with the adequacy of the capacity provided by the transmission network supplying the upper South Island. The transmission network is considered to provide adequate capacity and reliability if all the connected load can be supplied

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[19] For further information, please refer to the Grid Upgrade Plan 2005, Vol 2, Part II.

[20] Transpower Main Transmission Planning Criteria, Grid Upgrade Plan 2005, Vol 2, Supporting Document No. 6

during and following any single credible contingency event occurring in the transmission network.

8.2 Description of the Transmission Asset and the Present Capacity

The configuration of the existing network is illustrated in the diagram below:

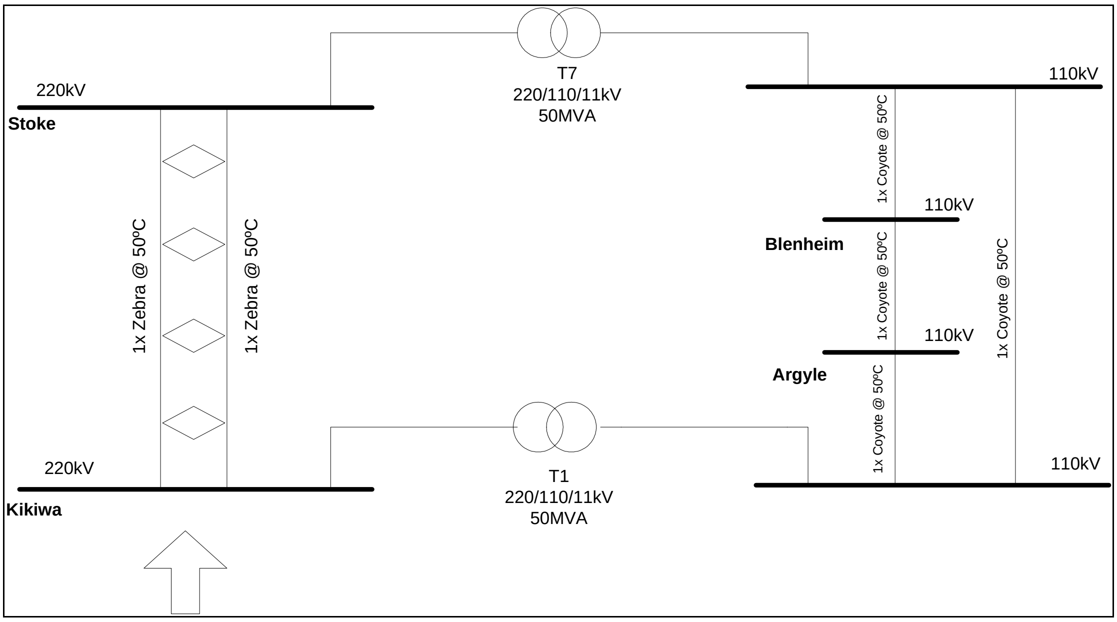


Figure 8-1: Existing Network

8.3 Need Analysis

For the normal system configuration, the Stoke transformer supplies the majority of the Blenheim load, plus the loads of Motueka and Motupipi through the 66 kV network when Cobb generation is low. The Stoke transformer is effectively in parallel with the Kikiwa transformer, which supplies some of the Blenheim load, plus the loads in Buller and part of the West Coast.

The Kikiwa transformer also needs replacement to prevent overloading in the steady state. This is covered in section 6.

The critical contingency, which results in the highest loading of the Stoke 220/110 kV transformer, is the outage of the Kikiwa transformer. The shortfall in capacity in 2007 will be about 25 MW, increasing every year with load growth, assuming full local hydro generation and that the existing 50 MVA Stoke transformer can be loaded to 75 MVA. A fault in the Kikiwa transformer means that it will not be possible to supply all the load. A transformer fault, although a low probability event, could take slightly more than a year to repair or replace.

The assumptions of full local hydro generation and a 75 MVA post contingency rating for the existing Stoke transformer are both very optimistic. Some of the local generation has limited storage, so there is limited ability to store and release water when required for maximum generation. The existing Stoke transformer will also be

53 years old in 2007, and it is unknown if the transformer is capable of sustained operation of 50% above nameplate rating. The transformer would need to be inspected and probably refurbished and, even then, a 75 MVA rating could not be assured.

The failure of the Kikiwa transformer is a low probability but with high consequences, therefore, it is a high risk.

8.4 *Investment Proposal*

Replacing the existing Stoke transformer will address the above issues. The replacement transformer will also allow for outages of the Kikiwa 220/110 kV transformer. The replacement transformer needs to be about 150 MVA, which is adequate for about 20 years of load growth provided that 110 kV voltage issues due to load growth and the Kikiwa 220/110 kV transformer replacement are also addressed.

The replacement transformer will have an on-load tap changer (the existing transformer has an off-load tap changer). The on-load tap changer will assist in addressing voltage and stability issues associated with supplying the top and West Coast of the South Island over the long transmission route from the Waitaki Valley to Christchurch and onto Kikiwa, by allowing the 220 kV and 110 kV voltages to be independently set for the entire range of load and generation scenarios due to daily, seasonal and multi-year load changes.

The new Stoke transformer would replace the existing transformer, and utilise the existing 220 kV and 110 kV circuit breakers. The transformer protection would be replaced. Fire walls will also need to be installed between the new transformer and the two adjacent transformers. A new interconnecting transformer must be installed at Kikiwa prior to replacing the transformer at Stoke, so that there is enough 220/110 kV transformer capacity to allow the Stoke transformer to be taken out of service for replacement.

The configuration of the proposed grid investment is illustrated in Figure 8-2 below:

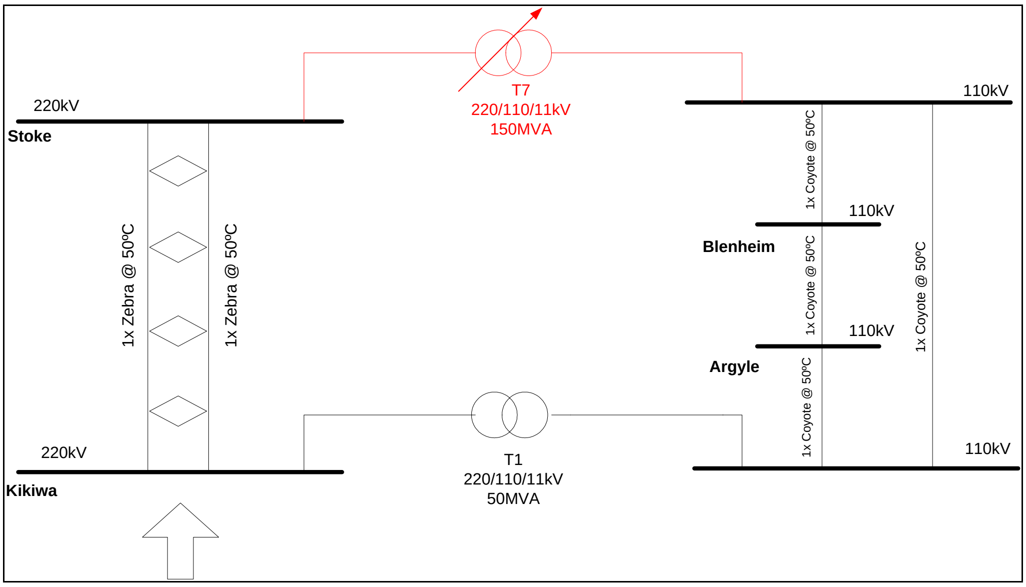


Figure 8-2: Proposed Network

8.5 Property Requirements

Transpower owns the land at Stoke substation. The switchyard should not require expansion to install the replacement transformer.

8.6 Environmental Impact

The environmental impact is expected to be minimal, as the transformers will be located within the existing designated sites owned by Transpower. The environmental impact is expected to be minimal with the replacement of the Stoke 220/110 kV interconnecting transformer, as the noise level is expected to reduce slightly compared to the existing noise levels. Provision will need to be made for the increased oil volume of the new transformers, compared with the existing transformers. These changes may require new discharge consents to be obtained.

8.7 Estimated Cost

Refer to the estimated cost section for the Kikiwa second interconnecting bank (Section 6) for combined cost estimates for both projects.

8.8 Transmission Alternatives

There are no credible transmission alternatives. Installing a new lower rated transformer in parallel with the existing transformer (rather than simply replacing the transformer) results in duplication of infrastructure such as circuit breakers. Also, the load sharing between the transformers is poor, principally because of the low impedance of the existing transformer.

8.9 Non Transmission Alternatives

There is limited opportunity for non transmission alternatives, because the Stoke transformer will exceed its short term rating following the failure of the Kikiwa transformer, even with full local hydro generation. Assuming full local hydro generation is an onerous assumption, as some of the generation is run of the river with limited head ponds, so generation availability cannot be assured for extended periods.

(a) Installation of new local generation

At present, there are no firm proposals for installing new generation in the region in the near future. Generation proposals which are known to be under investigation include wind, hydro and coal but are unlikely to be implemented in time. While peaking generation units would be an alternative, a significant amount of generation needs to be installed to provide a level of security similar to the proposed grid upgrade.

(b) Demand management initiatives

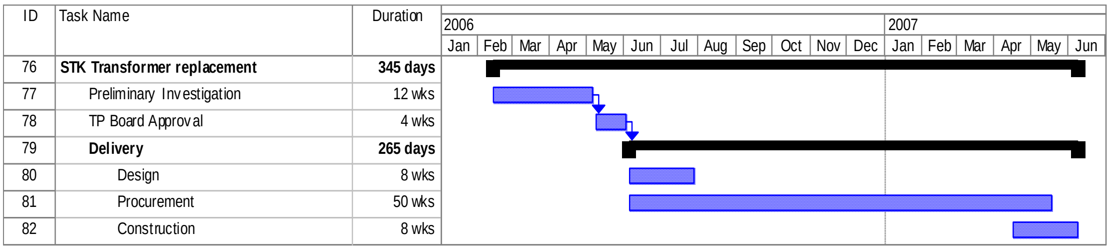
Demand management in the form of controlled load such as water heating is already used extensively. Additional demand management initiatives would need to be extensive as the Stoke transformer will be significantly over its short term rating following a failure of the Kikiwa transformer.

Transpower is not aware of any committed demand management project that has the potential to obviate the need for the proposed transmission project.

8.10 Project Timeline

A project of the proposed investment’s magnitude is expected to take a period of approximately one and a half years from approval to final commissioning.

A tentative timeline for the project is shown below:



ID	Task Name	Duration
76	**STK Transformer replacement**	**345 days**
77	Preliminary Investigation	12 wks
78	TP Board Approval	4 wks
79	**Delivery**	**265 days**
80	Design	8 wks
81	Procurement	50 wks
82	Construction	8 wks

Figure 8-3: Indicative Project Timeline

9 Reconductoring 220 kV Aviemore Waitaki–Livingstone circuits

Proposal Summary

To avoid overloading the 220 kV Aviemore to Livingstone circuits during HVDC south transfer and/or low Otago/Southland generation, Transpower proposes to reconductor the 220 kV Aviemore-Waitaki and Livingstone-Waitaki circuits to twin Goat conductor operating at 75^{0}C. This will increase their rated capacity to 586/646 MVA (summer/winter).

In order to obtain the maximum benefits of this investment, it needs to be completed as soon as practicable.

This is the least cost transmission investment required for ensuring reliable supply to the South Island loads as per Transpower's current grid reliability standards.

The estimated project costs are as per the table below:

Category	**Cost Estimated $m (2005)**[1]
Line capital costs	8.1
Substation capital costs	0.8
Property costs	1.3
Dismantling costs	0.0
Project Management costs	0.3
Approval and Investigations costs	0.2
Total	10.7

Notes:

1. Mid-range estimated cost, $m (2005), includes allowance for project contingencies but excludes allowance for financial (eg inflation) contingencies or Interest During Construction

9.1 Planning Assumptions

9.1.1 Generation Scenarios

Only existing generation and committed new generation is considered in determining the level of supply security to the region.

A range of dispatch schedules with existing generation were considered, reflecting the potential hydrological conditions. The assumed generation dispatch scenarios include high, medium and low generation from South Island hydro catchments, namely Waitaki, Clutha and Manapouri.

In addition, a generation scenario with 1000 MW of new Southland generation injected at Roxburgh, with high Clutha/Southland and high Waitaki, was also considered.

9.1.2 *Load Forecasts*

The power system studies were based on the winter peak load conditions and the 40 year load forecast developed by Transpower's in 2003.

The South Island winter peak ADMD demand forecast is as shown in Table 9-1 below.

	South Island winter peak ADMD demand forecast (MW)						
	2010	**2015**	**2020**	**2025**	**2030**	**2035**	**2040**
North of Waitaki total load	1205	1346	1485	1613	1729	1841	1964
Waitaki total load	63	67	70	72	73	73	73
Clutha & Southland total load	1042	1080	1116	1145	1167	1187	1207
South Island total load	2310	2493	2670	2830	2969	3101	3244

Table 9-1: South Island winter peak ADMD demand forecast

9.1.3 *Planning Criteria*

The transmission system has been planned in accordance with the Transpower's current Grid Reliability Standards[21].

The proposal deals with the adequacy of the capacity provided by the transmission network supplying the South Island load. The transmission network is considered to provide adequate capacity and reliability if all the connected load can be supplied during and following any single credible contingency event occurring in the transmission network.

9.2 *Description of the Transmission Asset and the Present Capacity*

The configuration of the existing transmission network in Waitaki is illustrated in the diagram below:

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[21] Transpower Main Transmission Planning Criteria, Grid Upgrade Plan 2005, Vol 2, Supporting Document No. 6

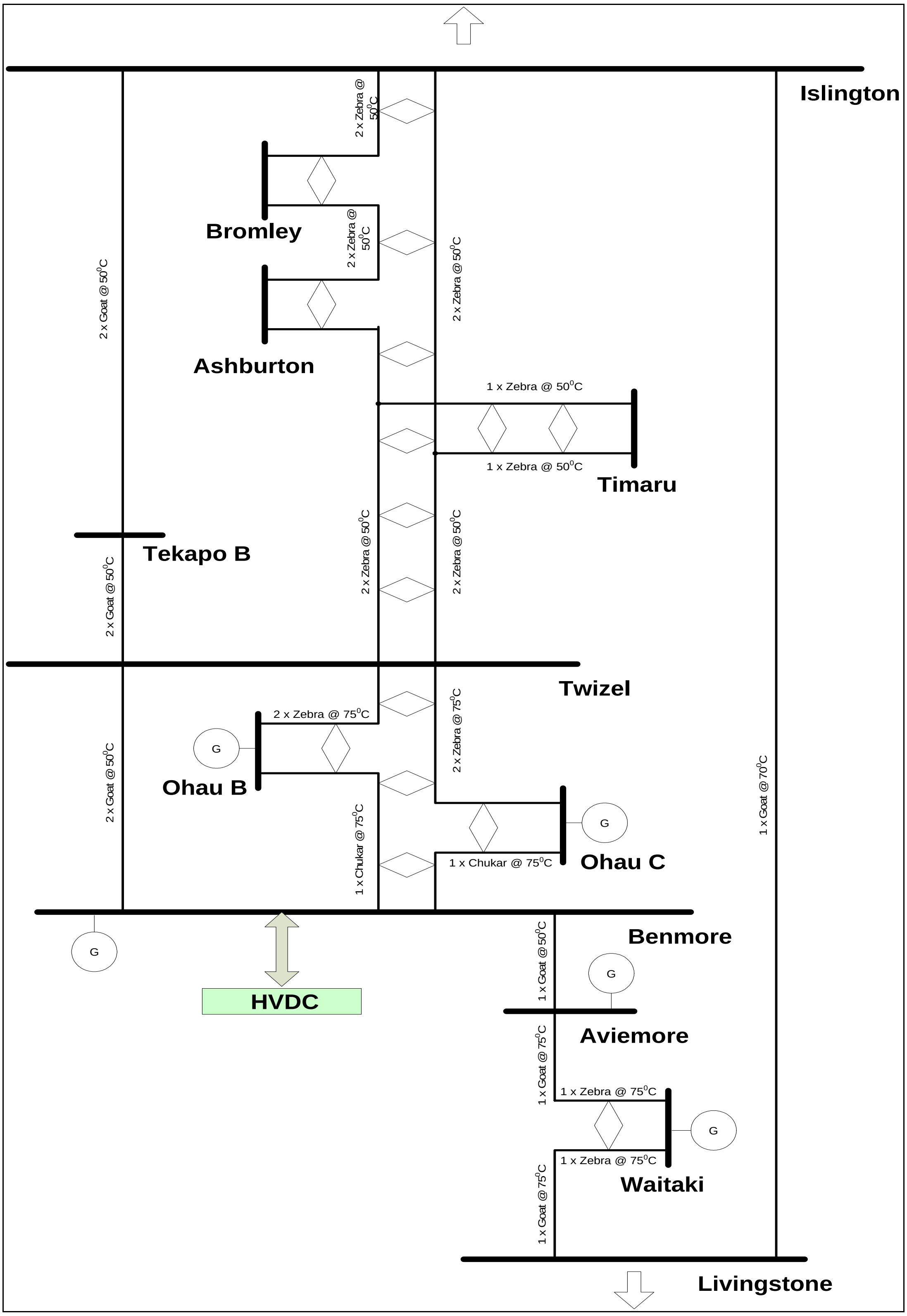

Figure 9-1: Core Waitaki 220 kV Transmission Schematic

The 220 kV Aviemore-Livingstone A transmission line consists of three line sections as per Table 9-2 below:

Section	Construction/Operation
Aviemore-Waitaki Tee section	7.4 km long single circuit simplex line mounted on steel flat top towers (simplex goat at 75°C).
Waitaki Tee - Waitaki section (loop in and out)	1.4 km long double circuit line, on steel double circuit towers (simplex zebra at 75°C).
Waitaki Tee – Livingstone section	31.9 km long and comprises of a single circuit simplex line mounted on steel flat top towers (simplex goat at 75°C).

Table 9-2: Line Sections of the Aviemore-Livingstone A transmission line.

The present rating of each circuit of the line is as follows:

Circuit	Rating (A)	Rating (MVA)
Aviemore – Waitaki 1	292 MVA	322 MVA
Livingstone- Waitaki 1	292 MVA	322 MVA

Table 9-3: Ratings for Aviemore to Livingstone 220 kV Circuits

9.3 Need Analysis

Christchurch and the upper South Island loads are mainly supplied using power from the Waitaki and Clutha river generation schemes. The other major load centre in the South Island - Tiwai aluminium smelter - is mainly supplied using generation from Manapouri. During dry years, South Island hydro generation is supplemented by the generation from the North Island, transferred through the inter-island HVDC link, and injected into the South Island grid via the converter stations at Haywards and Benmore.

The 220 kV Aviemore–Waitaki and Livingstone–Waitaki circuits normally transfer power from the Benmore, Waitaki and Aviemore generating stations to Christchurch through the 220 kV Livingston–Islington circuit. During dry years, HVDC transfer from the North Island via Benmore is used for ensuring energy security to all major load centres (Christchurch as well as Tiwai smelter), thereby supplementing the hydro generation in the South Island. This significantly increases the loading on the Aviemore to Livingstone 220 kV circuits.

The Aviemore to Livingstone 220 kV circuits may already overload during high HVDC transfer southward and/or low generation in the Otago and Southland region.

The following potential transmission upgrades could have an adverse impact on the loading of the Aviemore to Livingstone 220 kV circuits:

- Replacement and capacity upgrade of Pole-1 of the HVDC inter-island transmission link.[22]
- Building of a new AC transmission link from Twizel to Christchurch, in 2012

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[22] It is planned that in 2010, the existing pole-1, mercury arc valve converters will be replaced with modern thyristor valves and the capacity will be upgraded to 1400 MW sent and 1000 MW received at Benmore.

These potential upgrades have been incorporated into the analysis of the need for reconductoring of the 220 kV Aviemore-Waitaki and Livingstone-Waitaki circuits.

Table 9-4 shows the expected loading of the Aviemore to Livingstone 220 kV circuits until 2009, with the existing generation and HVDC link capacity (Note HVDC south transfer capacity is assumed to be 600 MW received at Benmore). As the load in Christchurch and the upper South Island increases, the loading of the circuit will also increase.

		2006	2007	2008	2009
Aviemore-Waitaki	Simplex Goat 75^{o}C (770/848A)	54%(N) 104%(S)	57%(N) 106%(S)	58%(N) 108%(S)	59%(N) 110%(S)
Livingstone-Waitaki	Simplex Goat 75^{o}C (770/848A)	58%(N) 112%(S)	60%(N) 115%(S)	62%(N) 117%(S)	64%(N) 120%(S)

Table 9-4: Summary of system loading (% summer rating for North flow, % winter rating for South flow) with existing generation and the existing HVDC link

With the proposed upgrade of the Pole 1 of the HVDC inter island link in 2010, the capacity of the link is expected to increase to 1000 MW for south transfer, measured at Benmore. This increase in capacity will increase the loading of the Aviemore to Livingstone 220 kV circuits for south transfer.

The following table shows the expected loading of the circuits, with existing generation and upgraded HVDC link capacity.

		2010	2011	2012
Aviemore-Waitaki	Simplex Goat 75^{o}C (770/848A)	82%(N) 124%(S)	83%(N) 126%(S)	83%(N) 128%(S)
Livingstone-Waitaki	Simplex Goat 75^{o}C (770/848A)	58%(N) 125%(S)	59%(N) 128%(S)	59%(N) 131%(S)

Table 9-5: Summary of system loading (% summer rating for North flow, % winter rating for South flow) with the existing generation the upgraded HVDC link

Load flow studies were carried out to determine the core grid system requirements under system normal and n-1 outage conditions with a potential 400 kV double circuit line from Twizel to Christchurch. A summary of maximum circuit loading under n-1 for different dispatch schedules with the existing generation is listed in Table 9-6. The results show that the new transmission development between Twizel and Christchurch will have very little influence on the loadings of the Aviemore to Livingstone circuits for HVDC south transfer, especially during dry years.

		2015	2020	2025	2030	2035	2040
Aviemore - Waitaki	Simplex Goat 75^{o}C (770/848A)	74% (N) 116%(S)	74%(N) 128%(S)	75%(N) 118%(S)	76%(N) 127%(S)	77%(N) 132%(S)	78%(N) 129%(S)
Livingstone - Waitaki	Simplex Goat 75^{o}C (770/848A)	67%(N) 125%(S)	80%(N) 137%(S)	59%(N) 134%(S)	64%(N) 142%(S)	70%(N) 148%(S)	49%(N) 147%(S)

Table 9-6: N-1 Circuit Loading with Existing Generation and Different Dispatch Schedules

While generation south of Roxburgh would reduce the loading of the Aviemore-Livingstone circuits during south transfer, it is likely to increase for HVDC north transfer. Table 9-7 demonstrates the impact of new generation south of Roxburgh on the circuit loading, assuming 1000 MW new generation in Southland. The results show that the existing capacity of the circuits is sufficient for development of new generation plant up to approximately 800 MW of capacity.

		2006	2007	2008	2009	2010	2011	2012
Aviemore - Waitaki	Simplex Goat 75^{o}C (770/848A)	96%	100%	105%	107%	104%	114%	118%
Livingstone – Waitaki	Simplex Goat 75^{o}C (770/848A)	73%	77%	81%	84%	88%	91%	96%

Table 9-7: Summary of system loading (% summer rating) with 1000 MW new generation in Southland

New generation developments in Canterbury, the upper South Island or West Coast regions will likely reduce the southward HVDC transmission and hence reduce the loading of the Aviemore to Livingstone 220 kV circuits.

In summary, the Aviemore to Livingstone 220 kV circuits play a vital role in ensuring supply security to the South Island during dry years. The circuit loadings are expected to increase over the present capacity from 2006 onwards.

9.4 Investment Proposal

A major portion of the 220 kV Aviemore-Waitaki and Livingstone-Waitaki circuits are of single goat strung at 75^{0}C. The only exception is the deviation into Waitaki which is of single Zebra strung at 75^{0}C. This limits the rating on these to 293/322 MVA (summer/winter).

It is proposed to reconductor the single Goat sections of the 220 kV Aviemore-Waitaki and Livingstone-Waitaki circuits to twin Goat at 75^{0}C. This will increase their rated capacity to 586/646 MVA (summer/winter).

This grid enhancement will provide sufficient capacity to avoid overloading the circuits during high HVDC south transfer and or low Otago and Southland generation.

The network configuration with the proposed enhancement is illustrated in Figure 9-2.

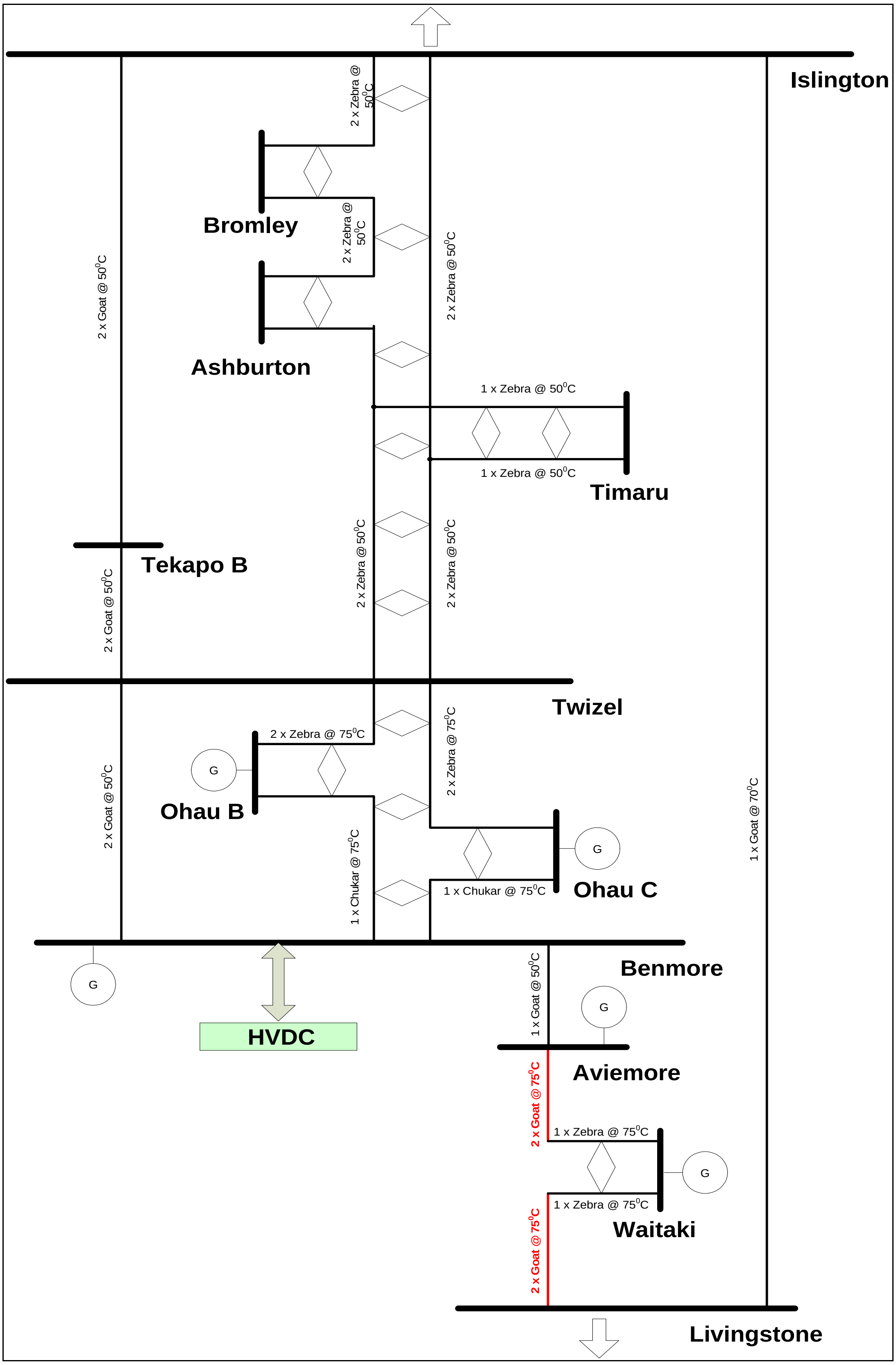


Figure 9-2: Proposed Transmission Configuration Following Investment

9.5 Property Requirements

The proposed development is similar to the reconductoring (duplexing) of the Geraldine – Livingstone section of the Roxburgh- Islington – which is presently underway. For the above reconductoring, only limited easements were found to be necessary. However, it should be noted that the property cost estimates are preliminary estimates only.

Additional detailed engineering design information is required to accurately assess if the works will cause an “injurious affect’ to the land. Additional analysis is required as the valuation methodology applied to these works needs, to be considered on a site by site basis once final design work is available.

The valuation methodology that Transpower currently adopts is the “easement fee approach’ and this is site specific and takes into account factors such as the area of land affected by the easement and towers, proximity of buildings to the works, visual affect through “corridors of affect”, the injurious affect to the balance of the land, permanent disturbance etc.

As final design information becomes available the analysis of the works and whether or not they fall outside of the provisions of the Electricity Act can then be better assessed and the estimate of costs can then be reassessed to a more accurate level.

9.6 Environmental Impact

The proposed development is similar to the reconductoring (duplexing) of the Geraldine – Livingstone section of the Roxburgh- Islington – A line. For this work, consents have been obtained with no great difficulty and if the scope of work is similar this could be the same for this project.

9.7 Estimated Cost

Costs estimates have been prepared using the approach described in Appendix: A.

Table 9-8 below summarises the cost estimates for the major components of the project.

Category	Cost Estimated $m (2005)[1]
Line capital costs	8.1
Substation capital costs	0.8
Property costs	1.3
Dismantling costs	0.0
Project Management costs	0.3
Approval and Investigations costs	0.2
Total	10.7

Notes:

1. Mid-range estimated cost, $m (2005), includes allowance for project contingencies but excludes allowance for financial (eg inflation) contingencies or Interest During Construction

Table 9-8: Estimated Capital Expenditure for Aviemore-Waitaki-Livingston Re-conductoring

The timing of capital expenditures is shown in Figure 9-3. Expenditure in the final year of the project amounts to 55% of total project costs.

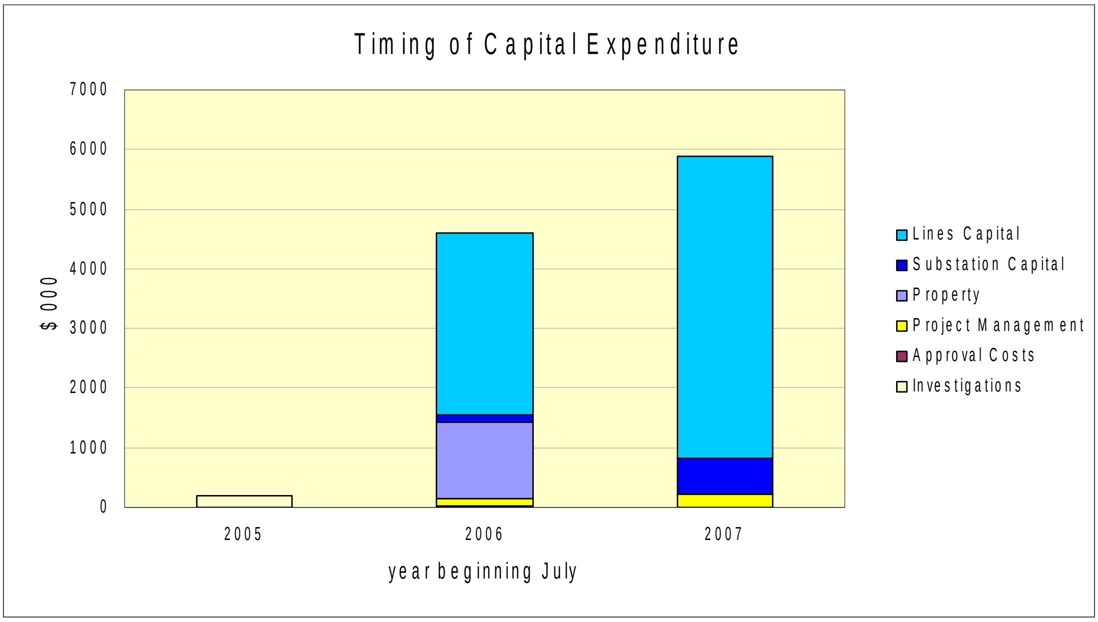


Figure 9-3: Anticipated Incidence of Expenditure on the Proposed Aviemore-Waitaki-Livingston Re-conductoring project

9.7.1 Contingent Amounts

Table 9-9 provides a summary of the various contingent amounts that have been included in the nominal cost estimate for the project.

Cost Category	Estimated Cost $k (2005)[1]	Inflation $k	Exchange Rate $k	IDC $k	Expected Cost $k[2]	Cost Contingency $k	Approval Requested from EC $k[3]
Lines	8096	399	0	754	9249	1704	10953
Substations	759	42	0	54	855	126	981
Property	1287	39	0	206	1531	225	1756
Dismantling	0	0	0	0	0	0	0
Project Management	322	16	0	29	367	0	367
Approval	23	1	0	4	27	4	31
Investigation	190	0	0	51	241	0	241
Total	10677	497	0	1098	12271	2059	14330

Notes:
1. Mid-range estimated cost, $m (2005), includes allowance for project contingencies but excludes allowance for financial (eg inflation) contingencies or Interest During Construction
2. Mid-range estimated cost in nominal $ including allowances for financial (eg inflation) contingencies and Interest During Construction
3. Upper-range estimated cost in nominal $ including allowances for financial (eg inflation) contingencies and Interest During Construction

Table 9-9: Relationship between Project Costs in Real and Nominal Terms.

The difference between estimated capital costs and nominal costs including contingencies is approximately $3.6 million. However interest during construction and inflation (which do not affect the economic merits of the project) represent $1.6 million of this difference. Cost contingencies are 19% of real capital costs, but it should be noted that these cover only a limited number of potential variations in project costs.

Transpower wishes to recover the actual costs of the proposed investment. The nominal cost estimate including contingencies represents a good faith estimate of what those actual costs might be.

9.8 Transmission Alternatives

The only viable transmission alternative is to build a new transmission line between Aviemore and Livingstone. However, it is unlikely that any new transmission lines or major upgrade of transmission between Aviemore and Livingstone could be implemented within the required short time period.

9.9 Non-transmission Alternatives

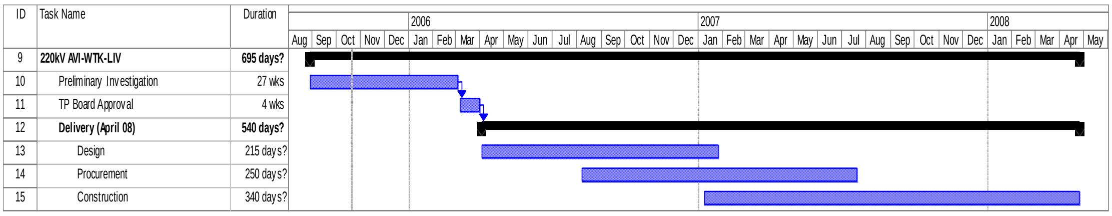
Non-transmission alternatives are limited and constrained by the hydrological inflows expected during dry years. The overloading of the lines during HVDC south flow conditions can be managed by constraining-off the HVDC flow and constraining-on the South Island generation during peak periods. However, the availability of sufficient generation to be constrained-on during the dry year peak load periods will depend considerably on the hydrological conditions. Further, sufficiency of the constrained-on hydro generation for supplying the peak load reduces with the load growth.

9.10 Project Timeline

A project of the proposed investment's magnitude would normally be expected to take approximately two years from approval to proceed to final commissioning

Transpower has identified that the earliest date the proposed investment can be in place is early 2008, provided investigation and planning commences now.

A tentative timeline for the project is shown below:



ID	Task Name	Duration
9	**220kV AVI-WTK-LIV**	**695 days?**
10	Preliminary Investigation	27 wks
11	TP Board Approval	4 wks
12	**Delivery (April 08)**	**540 days?**
13	Design	215 days?
14	Procurement	250 days?
15	Construction	340 days?

Figure 9-4: Indicative Project Timeline

Any delay in project commencement will result in delay through the project and consequently, prolong the period of risk of overloading the 220 kV Aviemore-Waitaki and Livingstone-Waitaki circuits.

Appendix: A Approach to Estimating Costs

A. Approach to Estimating Costs

In estimating project costs, Transpower's focus has been to establish an appropriate conceptual design for the capital equipment, preparing cost estimates and identifying major sources of risk.

For clarity, Transpower expects to be able to recover the costs of risk mitigation in addition to direct project costs.

Operating and maintenance costs have not been included in the capital cost analysis presented in this report.

Assumptions

The following general assumptions have been made in preparing capital cost estimates:

Cost of Plant and Materials

Material prices are based on budgetary prices obtained from manufacturers/suppliers for approximate quantities estimated from preliminary designs. They are exclusive of economies of scale for purchasing.

Cost of Labour

Installation rates are based on average wage rates and productivity levels in New Zealand and Australia on medium to large projects. Skilled Labour market conditions could dramatically change these estimated rates.

Real costs

Capital cost estimates are in 2005 NZ dollars. No allowance has been made for escalation of prices due to inflation or market conditions.

Allowances for detailed engineering and contractor's project management costs have been based on past experience and are subject to contract type and market conditions at the time.

Project Financing Costs (Interest During Construction)

Project financing costs or interest during construction have not been included in the cost estimates. Instead, it has been assumed that these costs can be expensed during project implementation.

Exchange Rates

Project expenditures are denominated in New Zealand dollars. No allowance has been made for variation in exchange rates.

Project Time Frame

Costs have been prepared according to tentative project timelines. Delays in projects are likely to increase time dependent costs (most particularly project management costs) and to increase the risk associated with other cost estimates.

Contingencies

Capital cost estimates provided in this report have been prepared to be consistent with the economic methodology described and applied in the economic analysis. As a consequence the costs differ from those ordinarily presented in business cases (and equally from the type of costs upon which revenue recovery might be based). Furthermore, the costs presented are based on preliminary design work and are estimates only.

The purpose of this section is to provide a bridge between the project capital costs, and those that might ordinarily be presented in a business case.

Price Contingencies

Inflation Adjustment

Capital cost estimates been calculated in real (2005) dollars in order to maintain consistency with the real discount rate used in the calculation of expected net market benefits, to simplify the calculation of market benefits and costs and to provide greater transparency in the comparison of the proposed transmission investments with non-transmission investment options. The use of real or nominal costs should have no impact on the outcome of the economic analysis in expected net market benefit terms provided the treatment of inflation is consistent throughout the analysis.

Transpower wishes to recover the actual (nominal) costs of the proposed investment. Nominal costs have been estimated by applying a 3% inflation rate to the expected expenditure programme.

Interest During Construction

Interest during construction has been omitted from the capital cost estimates used in the economic analysis because it is not consistent with the measurement of national benefit[23].

Transpower wishes to recover the actual costs of proposed investments, including a return on capital invested during the commissioning of projects. Transpower's preference is to recover these costs during implementation of the project. However, whether or not this can be done is in part dependent upon the regulatory asset valuation methodology. Because there is uncertainty over the treatment, an estimate of the scale of nominal interest during construction costs has been prepared, using a 10% pre-tax nominal discount rate[24].

Cost Contingencies

Approach

Costs will become more certain as the project progresses through its various stages, and as risks are mitigated. For this forecast scenario, analysis techniques have been used to quantify expected variations, and establish a risk profile for the costings.

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[23] In a national cost/benefit framework the opportunity cost of an investment to society is represented though the discount rate. Interest during construction represents the opportunity cost of an investment to providers of funds, and is in essence a value transfer paid by beneficiaries to investors to ensure that the investment takes place. As a general principle such value transfers should net out of the economic analysis.

[24] This is consistent with the 7% pre-tax real discount rate applied in the economic test, adjusted for 3% inflation.

High level estimates of cost contingencies have been made for major components of the capital spend using Monte Carlo simulation. Under this approach, estimated costs for major cost components have been generated at random using point estimates of cost used in the proposal, and assumed accuracy bounds. A value for physical contingencies has then been set such that 95% of the randomly generated cases will have lower costs than the point estimate plus physical contingency. The approach is sensitive to assumptions made about the random distribution of costs.

For illustrative purposes, Figure 9-5 shows a probability density function for nominal capital costs generated by simulation. The 95% limit on nominal capital costs is approximately $7 m, while the expected cost is approximately $6.3 m.

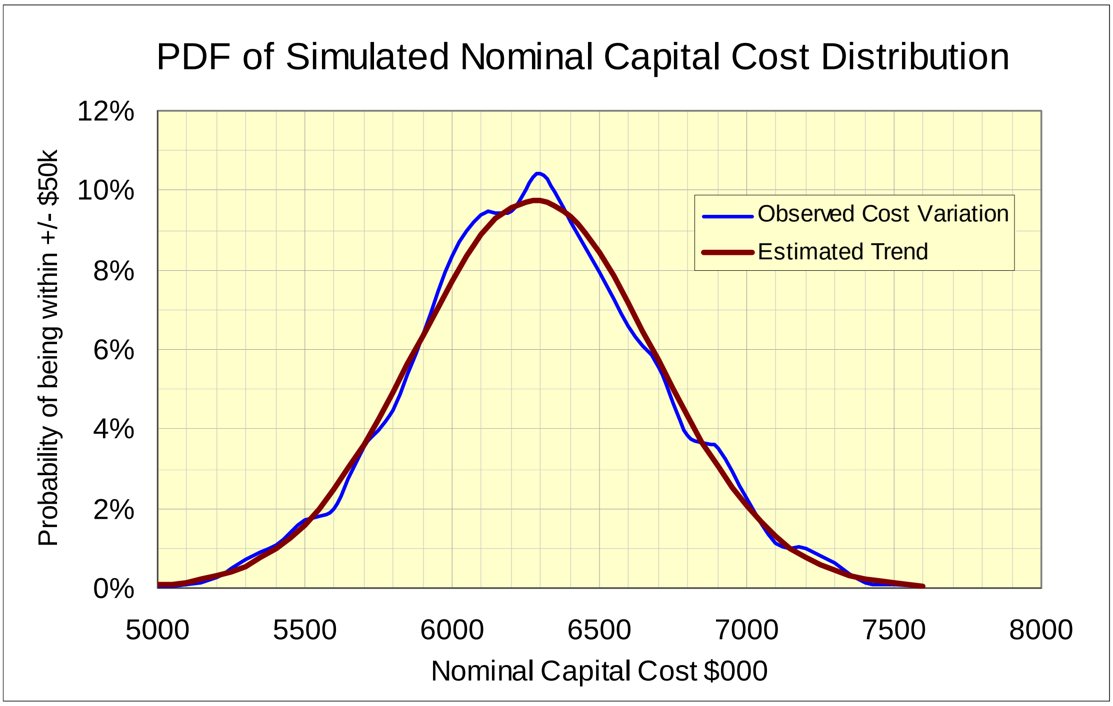

Figure 9-5: Frequency Distribution of Capital Cost Estimates

Figure 9-6 shows the relationship between the various cost estimates used in the preparation of the investment proposal. The estimated trend from Figure 9-5 is superimposed on the chart to illustrate the likelihood of a given level of actual costs occurring.

Real capital cost estimates (separated into Capital Cost and Contingency) are shown on the left. To these are added an adjustment to convert the figures into nominal funds, and an amount for capitalised interest, giving the expected capital cost. This figure is accurate to +/-15%, for which a further adjustment is made to produce a 95% limit (upper range) on the expected capital costs.

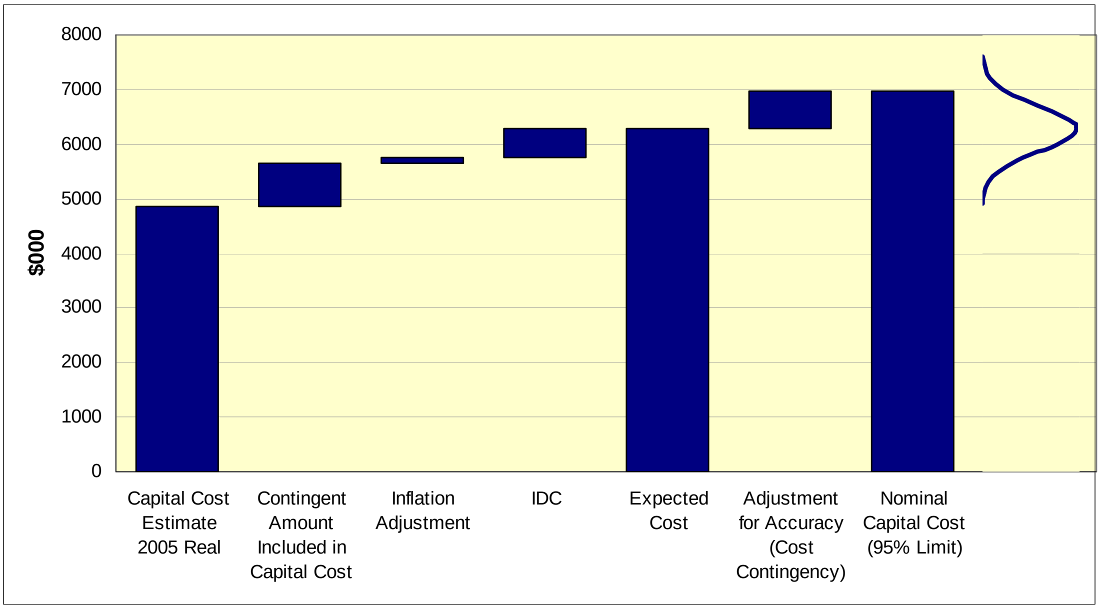

Figure 9-6: Relationship between Cost Estimates