MAY 2010

Grid Upgrade Plan 2009 Instalment 4

Part VII: Upper North Island Dynamic Reactive Support Investment Proposal

Keeping the energy flowing




TRANSPOWER

Transpower New Zealand Limited The National Grid

Document Revision Control

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This investment proposal seeks Electricity Commission approval for a bundle of separate projects.

Costing information for some of these projects is confidential at this time because, if approved, we will be tendering for services and equipment associated with those projects. For that reason, only the gross cost for the bundle of projects is included in this document.

A separate document describing the cost assumptions in detail (Attachment B) is provided as a supplement to this investment proposal and is confidential to the Electricity Commission.

Executive Summary

The purpose of this Upper North Island Dynamic Reactive Support Investment Proposal is to obtain Electricity Commission approval to recover the full costs (up to $110.2 million) associated with providing dynamic reactive support for the upper North Island.

Proposal at a Glance	
What:	A package that provides the most economic solution for providing dynamic reactive support in the upper North Island until 2015 while informing the optimal investment path beyond 2015: • Install and commission two reactive support devices – one in Auckland in 2013 and the other in Northland in 2014 • Install and commission a Reactive Power Controller for the upper North Island region in 2013 • Implement demand-side initiatives in the upper North Island region from 2011 • Install system monitoring equipment in the upper North Island in 2011 • Enhance the System Operator's dynamic stability analysis software in 2011 and 2012
When:	Work will commence immediately on these initiatives.
How much:	Transpower is seeking approval for up to $110.2 million

The Proposal

Transpower is seeking approval from the Electricity Commission to recover the costs of this investment proposal (the Proposal) under rule 13.4 as a reliability investment because:

- our investment will reduce expected unserved energy on the grid following a single credible contingent event on the core grid
- our analysis shows the existing grid configuration does not meet the Grid Reliability Standards.

The Proposal is a package of investments designed to meet the immediate need for additional dynamic reactive capacity until 2015 and enhance the operational management of the power system in the upper North Island.

Specifically, the Proposal includes:

- two STATCOMs to meet the ongoing need for dynamic reactive support
- a Reactive Power Controller and enhanced System Operator software to ensure the power system is operable in real-time
- system monitoring equipment to improve our understanding of the upper North Island power system and so help inform the need for future investment beyond this Proposal
- demand-side initiatives to allow more flexible management of the grid in the region during major project commissioning and provide an important contingency measure against uncertainties both in the growth and nature of regional demand and the requirement for reactive support.

The Proposal represents a balanced and appropriate approach to meeting the need for dynamic reactive support and prudently managing the upper North Island power system until 2015.

The need for dynamic reactive support

Under all credible future market development scenarios, demand in the upper North Island (wider Auckland region) will grow at a faster rate than local generation will be built – most economic generation options are located south of the upper North Island.

The North Island Grid Upgrade Project (NIGUP) addresses the thermal capacity requirements for generation import into the upper North Island from the south for many years into the future. However there is also a need for voltage support within the upper North Island. This is linked to the difficulties of importing reactive power over long distances from the south. This need increases over time – how fast depends on the extent to which local generation is built in the upper North Island.

Capacitor banks are the least expensive form of voltage support. They provide steady state or “static” reactive support. However, they can not, on their own, provide a rapid response (i.e. dynamic support) to maintain voltage quality and avoid the risk of cascade failure during power system faults. Generators, synchronous condensers, Static Var Compensators (SVCs) and Static Synchronous Compensators (STATCOMs) all react rapidly to power system faults and provide dynamic reactive support. These are the options that we have considered to meet the need.

The studies for NIGUP, the new 400 kV capable transmission line from Whakamaru (WKM) to Brown Hill (BHL), identified the requirement for ongoing investment in dynamic reactive support in the upper North Island. This need is also identified in our Annual Planning Report (see section 6.4.1 in the 2010 Annual Planning Report).

Our demand projections tell us that each year upper North Island demand for electricity increases by 40 to 60 MW. If this increase is not met by local generation, it creates a need for reactive power equivalent to a new 40 Mvar STATCOM every second year.

Proposed development

Voltage support is currently provided in the upper North Island using capacitor banks (static support), an SVC at Albany, synchronous condensers at Otahuhu A[1] and a generating unit at Southdown (all capable of providing dynamic support).

We used development plans over 20 years to compare seven short-listed options for meeting the dynamic support need. The Reference Case (DP1) is to build STATCOMs as soon as we can – the first in Auckland by 2013 and the second in Northland by 2014 – and a further 8 STATCOMs to 2029. The next most economic option is an initial five year contract for dynamic support from Otahuhu A to 2015 (DP4) – this defers the timing of the first STATCOM in Northland beyond 2014, but still requires a STATCOM in Auckland by 2014 and a further 9 STATCOMs to 2029.

The Reference Case – install STATCOMs now – provides a more certain and reliable choice, and the investment required to 2015 is the basis of the Proposal.

Enabling optimal investment into the future

In our economic comparison of the options for dynamic reactive support, we assume no new generation over the 20 year assessment period – this reflects the lack of any committed new generation in the region, although clearly some local generation will be built in future. Additional local generation will potentially defer the timing of future

[1] The old OTA generating units operated now as synchronous condensers

investment in dynamic support, but as new generation is unlikely before 2015 it will not defer the need for the investment included in this Grid Upgrade Plan.

In our studies we also identified the potential reactive support benefits of bringing forward series compensation on the NIGUP line to 2015, the earliest possible commissioning date. Series compensation was originally intended to occur around 2025. Therefore, given the possibility of generation being committed and the need to explore other options more fully, we are only seeking approval for the investment required to 2015 – two STATCOMs and a wider package of prudent investment initiatives.

The Proposal satisfies the default minimum N-1 grid reliability criteria for the core grid. A full economic reliability analysis may justify a higher standard (i.e.: N-G-1 as for NIGUP) and additional investment. However, the actual requirement for reactive support is dependent on the evolving nature of the load in the upper North Island with the increasing proportion of motor loads and heat pumps influencing how the power system actually responds to major faults. We need further information to understand this uncertainty before determining whether investment (to N-G-1) is justified. To do this, we have included improved power system fault monitoring systems in the upper North Island to provide the necessary information.

In summary, our immediate investment proposal is based on the N-1 minimum for the core grid until we better understand the performance of the regional power system and can accurately determine the quantum of long term investment required.

Covering uncertainties

It is critical that demand-side initiatives are available as contingency measures as soon as practicable - given that:

- the current grid does not meet the Grid Reliability Standards requirements
- we are commissioning two major projects in the upper North Island within the next four years
- there are uncertainties on the extent of future dynamic support needed.

In addition, contingency measures are required to cover the risk that either this or the other upgrades are delayed. A range of demand-side initiatives will help better coordinate load management when the system is near its limit and help secure the necessary outages to assist with the timely delivery of projects. Demand-side initiatives also offer the potential to defer future investment. Our demand-side initiative is targeted to defer a year’s peak load growth.

With this initiative, we will foster the deployment of new demand-side technologies to address a need that is driven by summer afternoon conditions when the traditional ripple controlled water heating option is of limited use. It is likely to include a regional “load controller” for coordinating lines company controllable loads as used in the upper South Island.

Delivering a power system that can be managed and operated

System operation becomes more challenging with a greater dependence on reactive support and the requirement to coordinate a large number of reactive support devices (static and dynamic) over a wide area together with generation. We will address this by installing an area wide Reactive Power Controller to allow for the optimal dispatch of reactive devices with minimal operator manual intervention. We will also enhance the real-time tools used in system operation to ensure operators are “situationally aware” – have visibility of the decisions made by the Reactive Power Controller, are aware of system limits and potential emergency conditions and be able to utilise the full capability of the devices. Without these two initiatives, the full value of the investment in reactive support would not be realised.

Why the Proposal should be approved

The Proposal balances the need for investment now, with preserving options for the future. It ensures a manageable and operable power system. Importantly it provides for contingency measures through the demand-side initiatives to manage uncertainties as well as providing the opportunity to use new technologies to develop a wider range of demand-side options. We believe the Proposal should be approved by the Electricity Commission.

Our economic analysis

The short list

Table 0-1 below shows the short list options to which the Grid Investment Test (GIT) has been applied and the 20 year present value cost. The Reference Case is development plan 1 (DP1), which is to install STATCOMs as required through the 20 year analysis period considered.

Table 0-1: Short-list of options

Option	Description of investment to 2029	PV ($m)
DP1 Reference Case	Ten STATCOMS are built at upper North Island Grid Exit Points	210
DP2	The Penrose 33 kV bus is split and additional and/or replacement 220/33 kV transformers are installed at Penrose. Ten STATCOMS are built at upper North Island Grid Exit Points	220
DP4	The Otahuhu A condensers are contracted until the end of 2012, on a four out of five basis to provide reliability. From the start of 2013 to the end of 2015 the remaining Otahuhu A condensers are contracted on a two out of three basis to provide reliability. Ten STATCOMS are built at upper North Island Grid Exit Points	216
DP5b	The Marsden condenser is contracted for 5 years with a new exciter installed. Ten STATCOMS are built at upper North Island Grid Exit Points as needed	218
DP6d	The Marsden condenser is contracted for 5years with a new exciter installed. . The Otahuhu A condensers are contracted until the end of 2015, on a four out of five basis to provide reliability. Ten STATCOMS are built at upper North Island Grid Exit Points	234
DP7	Six SVCs and four STATCOMS are built at upper North Island Grid Exit Points as needed	227
DP10	Five small STATCOMs are distributed around Auckland Grid Exit Points in 2014. Nine larger STATCOMs (as in other DPs) are built at upper North Island Grid Exit Points.	219

Plans DP2, 4, 5b, 6d and 10 make extensive use of STATCOMs. The difference between these plans and the Reference Case is the timing of STATCOMs is deferred with contracts for synchronous condensers (DP4, 5b, 6d), new transformers (DP2), or smaller distributed STATCOMs (DP10). All plans have series compensation of the NIGUP line in 2025.

We also assume no new generation in the 20 year investment window and have included installation of the Reactive Power Controller in 2012 and implementation of the demand-side initiatives, power system fault monitoring and system operator software in 2011/12.

The present value result from the Grid Investment Test assessment shows that the preferred option from an economic perspective is DP1 – installing ten STATCOMs over 20 years with the first as soon as possible. This option minimises the expected net market cost. Two other options, DP4 and DP5b, have a present value which is marginally higher than DP1. This is understandable given the all plans are very similar with extensive STATCOM build over the 20 year period, the only differences being the investments made in the first few years.

The approach does not account for the higher reliability of the STATCOM and STATCOM/SVC options and therefore underestimates their value.

As the cost difference is small, we have considered a number of other non-quantified criteria to assist decision-making. A comparison of the short list options using these criteria is given in Table 0-2 below. The criteria were as for other Grid Upgrade Plans.

Table 0-2: Qualitative assessment of non-quantified benefits and overall preferred option

Option	Expected Net Market Cost	Option benefits	Consumer benefits	Wider economic benefits	Minimises disruption	Diversity benefits	Operational benefits	Overall ranking
DP1	$210	✓✓	✓✓	✓✓✓	✓✓	✓✓✓	✓✓✓	1
DP2	$220	✓✓	✓✓	✓✓✓	✓	✓	✓✓	
DP4	$216	✓✓	✓✓	✓✓✓	✓✓	✓✓	✓✓	
DP5b	$218	✓✓	✓✓	✓✓✓	✓✓	✓✓	✓✓	
DP6d	$234	✓	✓✓	✓✓✓	✓✓	✓✓	✓✓	
DP7	$227	✓	✓✓	✓✓✓	✓✓	✓✓✓	✓✓✓	
DP10	$219	✓✓	✓✓	✓✓✓	✓	✓✓✓	✓✓	

The main points of difference between the development options relate to:

- option benefits, where investment plans include optionality which allows investment to be deferred or cancelled should the future not turn out as expected e.g. new generation emerges
- disruption benefits, where some options utilise the capacity of the existing network without increasing the footprint of the National Grid and where some options could be commissioned without significant disruption to security of supply
- diversity benefits where not having all of our dynamic reactive support in one geographical location is an advantage
- operational benefits, where investment plans add resilience to the network, particularly in relation to high impact low probability (HILP) events.

Although there is subjectivity involved in ranking the options, the Reference Case ranks highly in terms of non-quantified benefits and higher than all other alternatives which were close economically. This supports the outcome of the GIT analysis and the choice of DP1 as the Proposal.

Accordingly, based on an overall assessment of the GIT analysis, the non-quantified benefits and a comparison of the STATCOM versus synchronous condenser advantages as described below, the Reference Case of installing STATCOMs as required is favoured and is confirmed as the basis for the Proposal with investment in the two STATCOMs required to 2015.

The choice of the STATCOM investment option is only one part of our overall proposal with far wider benefits. The Proposal also:

- enables more optimal investment from a better understanding of the evolving nature of the load mix
- ensures a manageable power system in real time
- delivers a range of demand-side initiatives to manage uncertainties and contingencies.

Use of STATCOMs

Installing STATCOMs allows us to make timely and incremental investments with minimal risk of over investing. If an asset becomes stranded (for example by new generation being built) this will only be temporary, as load growth will catch up. Further, the technology is modular, so the STATCOMs can be relocated if required.

The use of distributed devices – STATCOMs - with an envisaged greater reliability and lower energy consumption than other options allows:

- dynamic reactive support to be located where it can be most effective, for instance in Northland and at Auckland
- a smaller requirement for space in substations and lower voltage connection than the equivalent SVC
- reduced harmonics and filtering requirements that an equivalent SVC requires.

Our solution with STATCOMs fits within the requirements of our Transmission Code which is drawn from international practice and therefore reflects our view of Good Electricity Industry Practice.

Conclusion

There is an ongoing need for dynamic reactive support in the upper North Island. The Proposal adopts the least cost solution to meet the immediate need for dynamic support allowing the Grid Reliability Standards to be met. The use of STATCOMs provides a modular solution with a short investment lead time. It allows us to keep our options open as to how the ongoing need for dynamic reactive support is addressed from 2015 from our improved understanding of the evolving nature of the load in the UNI with the additional load monitoring.

The Proposal is more than just the above investment in dynamic support. It also provides a package to ensure the power system in the upper North Island – a third of New Zealand's total peak demand – can be operated in a prudent and manageable way over a period when two major transmission upgrades in the region are being commissioned.

The Reactive Power Controller and upgrades to System Operator software will significantly improve our ability to effectively manage the power system in the region, ensuring our operators are situationally aware of the status of the UNI power system. These two initiatives allow us to realise the full value of the investment in reactive support..

The demand-side initiatives will provide essential contingency options:

a) for the uncertainties in the need for dynamic support; and

b) to manage outages of the grid for commissioning, and the regional coordination of load when the power system is at its limit thus minimising the enforced shedding of load. The demand-side initiatives create the opportunity to use new technologies to enable new demand-side response options at times when existing sources are not effective. It also has the potential to reduce the need for future investment

In conclusion we have balanced the need for investment now with preserving options for the future. We are ensuring we have a manageable and operable upper North Island power system at a critical time. We are providing for contingency measures through the demand-side initiatives to manage uncertainties as well as providing the opportunity to use new technologies to develop a wider range of demand-side options.

Timing

The technical analysis has demonstrated that the existing grid configuration does not meet the Grid Reliability Standards now, so it is proposed to:

- install the two STATCOMs as soon as possible (by 2012 and 2013)
- install the Reactive Power Controller, before 2013
- undertake the proposed load monitoring in 2011
- enhance the dynamic stability analysis software in 2011 and 2012
- undertake the demand-side initiatives from 2011.

Maximum Approval Costs

This application seeks Commission approval to recover the lesser of actual costs or the estimated Maximum Approved Cost (MAC) of the Proposal. The Expected End Cost of the Proposal is estimated to be $103.4 million and the MAC of the Proposal is estimated to be $110.2 million.

Table 0-3: Maximum Approval Cost

$NZ million	Estimated Cost	Expected Cost	Price contingency	Exchange rate variability	Exchange rate hedge	Inflation	IDC	TOTAL
Expected Cost	82.1	90.1						90.1
Expected End Cost	82.1	90.1		3.0	0.6	4.7	5.1	103.4
Maximum Approved Cost	82.1	90.1	3.1	5.8	0.6	5.3	5.3	110.2

Document structure

The remainder of this document is our formal submission to the Electricity Commission for approval of the costs of the Proposal. It is split into two parts:

- Part A sets out the Proposal for which approval of cost recovery up to $110.2 million is sought
- Part B, together with the attachments, sets out the technical and economic analysis of the investment proposal, and justifies the Proposal against the requirements of the Rules.

Contents

Attachment	Title
A	Technical needs analysis
B	Costing report – confidential to Electricity Commission

Part A – Proposal

This part describes our Upper North Island Dynamic Reactive Support Investment Proposal (the Proposal).

Components of the Proposal

- Install load monitoring equipment in the upper North Island region
- Install software enhancements to improve dynamic stability calculations
- Undertake a range of demand-side initiatives in the upper North Island region
- Install and commission a Reactive Power Controller for the upper North Island region
- Install and commission a reactive support device in Auckland
- Install and commission a reactive support device in Northland
- Procure, construct and commission substation facilities to facilitate the above connections and equipment
- Obtain property rights and environmental approvals required for these works
- Carry out any additional minor works and activities required to facilitate the above.

Timing

We will commission the components of the Proposal between 2011 and 2015.

Costs

We are seeking Commission approval to recover the full costs associated with the Proposal upon commissioning up to a total amount of $110.2 million. This amount is the estimated Maximum Approval Cost (MAC) to implement the Proposal, expressed in New Zealand dollars exclusive of GST. Appendix C sets out how we have calculated the MAC.

Part B – Justification

1 Introduction

This section outlines the purpose and structure of Part B

1.1 Purpose

This document is our request for Commission approval to recover the costs of the Proposal.

The purpose of Part B of this document is to provide information for the Commission to assess compliance of the Proposal with the Rules.

In the course of assessing the options presented in this document, we have sought feedback from interested parties so as to be able to incorporate their views into the decision-making.

1.2 Document structure

The document consists of this paper and attachments as follows:

UPPER NORTH ISLAND DYNAMIC REACTIVE INVESTMENT PROPOSAL
GRID UPGRADE PLAN

* Describes proposal
* Summarises need and application of the GIT

ATTACHMENT A
TECHNICAL ANALYSIS

* Describes the technical needs analysis

ATTACHMENT B
COSTING REPORT

* Describes the costs used in applying the GIT and developing the MAC

The attachments provide detail of the analyses presented in this document.

1.3 The Proposal as part of the 2009 Grid Upgrade Plan

This document forms Part VII of the 2009 Grid Upgrade Plan (GUP).

We have already submitted the following parts of the 2009 GUP to the Commission:

- Part I: Comprehensive Plan for Asset Management and Operation of the Grid; and
- Part II: Investment Contracts
- Part III: Wanganui-Stratford Transmission Investment Proposal
- Part IV: Bay of Plenty Interconnection Capacity Upgrade Investment Proposal

- Part V: Lower South Island Renewables Investment Proposal
- Part VI: Auto Synchronisation Points Investment Proposal

1.4 Type of investment

The majority of grid exit points in the upper North Island are a part of the core grid and our studies have focussed on voltage stability at those grid exit points.

The Proposal is a “reliability investment”, in that:

- the Proposal is an investment by Transpower in the grid;
- the primary effect of the Proposal is to reduce expected unserved energy on the grid following a single credible contingent event; and
- the expected unserved energy will result from likely planned or unplanned outages of primary transmission equipment.

1.5 Glossary/terminology

A glossary of terms and acronyms used in this document is included in Appendix A.

All references to Rules in this document refer to those in section III of Part F of the Electricity Governance Rules 2003 unless otherwise specified.

2 Needs Assessment and Type of Investment

This section provides background on the Upper North Island Dynamic Reactive Support Project

2.1 Description of assets comprising the upper North Island region

The upper North Island region covers the geographical area north of Bombay including Glenbrook, Takanini, Auckland, the North Isthmus and Northland.

A geographical map of the 220 kV and 110 kV Auckland and Northland network is shown in Figure 2-1. Network schematics are included in Attachment A.

Figure 2-1: Upper North Island 220 kV and 110 kV network

The upper North Island does not have enough local generation to meet local demand and the shortfall is met from distant generation. This situation will continue: our long term projections show that, under all Electricity Commission development scenarios, greater Auckland area electricity demand increases more quickly than local generation, and the resulting growing shortfall is met by generation to the south (in the middle and lower North Island, and in the South Island).

To maintain voltage stability within acceptable tolerances in regions relying on distant generation, voltage support (also known as reactive support) is necessary.

Capacitor banks are the least expensive form of voltage support but provide only static voltage support. Capacitors cannot provide the dynamic response required for sudden power system events when a rapid response (milliseconds) is required to maintain voltage quality. For these events, devices which respond dynamically are required. Generators, synchronous condensers, static var compensators (SVCs) and static synchronous compensators (STATCOMs) are all examples of such devices.

Static and dynamic reactive support is currently provided in the upper North Island by a combination of capacitor banks, synchronous condensers[2] and the new Albany SVC. As load continues to grow in the region, the need for additional dynamic reactive support also grows. Planned changes to the upper North Island grid configuration include the NIGUP and NAaN - these provide more transfer capacity into the region but will only reduce the increasing need for dynamic reactive support to a limited extent.

Our technical analysis to assess the dynamic reactive support requirement, considered voltage stability in the upper North Island region, which is influenced by:

- generation in the upper North Island region itself plus Huntly
- the transmission network supplying the upper North Island area, including the transmission network south of Auckland
- the composition of the area's load (and in particular the quantity of motor load connected and its response during power system events).

The upper North Island contains a significant proportion of motor load. The behaviour of this load during and following faults influences regional transmission voltage as during a severe fault motors can stall. Stalled motors draw reaccelerating currents which delays the recovery of the post fault voltage. Severe delays in post fault voltage recovery could result in cascade failure.

Following the results of a motor load survey, we have identified that the period where voltage recovery is most at risk is the late summer period between mid-January and mid-March. In this period it is believed that the greatest amount of motor load is connected. For that reason the studies have been undertaken considering summer conditions and using summer load growth.

As most of the transmission links comprising the upper North Island form part of the core grid as defined under Schedule F3A of the Rules, the technical analysis has been undertaken against a single credible contingent event – in this case a 120 ms three phase 220 kV fault at Otahuhu.

2.2 Process to date

The requirement for ongoing investment in reactive devices was identified in our original studies for the NIGUP, which used a range of scenarios of future generation build and demand growth in the upper North Island. NIGUP includes the installation of 200 Mvar of capacitors in Stage 1, which addressed the immediate need for static reactive support. The need for dynamic reactive support was also identified as the next stage in our 2006 NIGUP and has also been identified in our Annual Planning Reports (APR).

With no prospect of new local generation being committed in the short term (i.e. prior to 2015), further investment in reactive support devices was identified as an urgent need and this investigation project was started.

During June 2009, we consulted with, and sought feedback from, interested parties on the various assumptions, methodologies and the long list of options for what was called the Upper North Island Reactive Support Investigation.

[2] Old generating units at Otahuhu A and a generating unit at Southdown procured on a short term basis by the System Operator.

More information on that consultation can be found on the Grid New Zealand website[3].

As a part of that consultation a public forum was held for interested parties on 30 June 2009. The purpose of the forum was to cover the contents of the consultation document, provide a forum for further questions and invite submissions.

Written submissions were received from five parties. The submissions all supported the need for investment. Many points were raised in the submissions – some of the more significant points were as follows:

- Contact was concerned that the analysis was sensitive to the assumptions on motor load composition and requested that these assumptions be reviewed carefully for the study
- Vector was concerned about increasing levels of static and dynamic reactive support on network harmonic performance
- Vector also noted that summer peaks appeared to be growing quicker than winter peaks and this should be accounted for
- Meridian raised the possibility of investing in a wind farm at Poutu and advised that generation units could be installed which were capable of providing dynamic reactive support even when the wind was not blowing. They suggested this should be accounted for to ensure assets are not built which may become redundant if Poutu is built
- Genesis suggested that an option where Huntly is constrained on during summer should be evaluated. They also suggested an option using fast acting circuit breakers should be considered
- Northpower noted that the nature of the motor loads is likely to change over time and requested that sensitivity studies should be undertaken to consider differing large motor load percentages.

The consultation document also served as a Request for Information (RFI) with respect to transmission alternatives. One expression of interest was received in response to the RFI.

Following receipt of feedback from both the forum and written submissions, we:

- considered and incorporated the feedback received into the ongoing investigation
- further developed the options (as presented in this paper)
- published a Request for Proposals (RFP) with respect to possible transmission alternatives.

The Request for Proposals was issued in September 2009. Four responses were received and a formal tender type process was followed to evaluate the proposals. We then:

- finalised the economic approach to be used for the Grid Investment Test (GIT) analysis
- applied the GIT and analysed the results
- identified the Proposal that is the subject of this GUP.

[3] http://www.gridnewzealand.co.nz/n2500.html

Whilst preparing the GUP, we identified a number of supporting initiatives which are required, both to assist with the immediate identified need and to ensure we can evaluate future dynamic reactive support requirements appropriately. This GUP requests funding for those supporting initiatives, which are described in more detail in section 5.2 below.

This GUP is a bundle of separate initiatives in a single package to address the upper North Island reactive support needs until 2015. These investments will ensure sufficient dynamic reactive support is provided through until 2015 and will allow the optimisation of these investments, both prior to and post 2015 in the absence of any committed new generation from 2015. As a result of the inclusion of the package of supporting initiatives this investment proposal is larger than that signalled in the APR ($50-100 million).

3 Identification and Consideration of Options

This section outlines how we have identified alternative projects to be considered in applying the Grid Investment Test

3.1 Requirements under the Rules

The application of the GIT requires an analysis and comparison of the market benefits and costs of a proposed investment and those of a number of alternative projects[4]. Therefore, we must first identify those options that fall within the definition of "alternative projects" under the Rules.

3.2 Option identification

3.2.1 Long list of options

The long list aimed to canvas a broad range of viable investment options and a consultation process was used to ensure the list was comprehensive.

The long list of options developed, reflecting feedback received during the consultation, was:

a) Install STATCOM devices as required

b) Install SVCs or SVCs and STATCOMs as required

c) Install fast acting circuit breakers as required

d) Replace high impedance transformers with low impedance transformers

e) Contract the use of existing synchronous condensers

f) Advance the conversion of the Whakamaru to Brownhill (WKM-BHL) line to 400 kV

g) Advance installation of the series capacitors on the WKM-BHL line

h) Demand-side options to reduce peak demand

i) Building new lines into the upper North Island

j) Appropriate combinations of the above.

3.2.2 Short-listing approach

The purpose of the short-listing analysis was to reduce the long list of options to a more manageable short list and for the short list to only include practical options which could meet the identified need. The short listed options are carried forward for further development and analysis using the Grid Investment Test (GIT).

Our short-listing approach was to screen its long list to formulate a short list, based on the following criteria:

i. fitness for purpose

[4] Schedule F4, clause 4 of the Rules.

ii. technical feasibility

iii. practicality of implementation

iv. Good Electricity Industry Practice (GEIP)

v. system security

vi. whether an option will clearly be more expensive than another option with similar or greater benefits

vii. feedback from consultation.

Long list option a) meets criteria i) to iv) and based on information from STATCOM suppliers did not appear to be clearly more expensive than other options, so was carried forward to the short list.

Long list option b) meets criteria i) to iv) and based on information from SVC and STATCOM suppliers did not appear to be clearly more expensive than other options, so was carried forward to the short list.

Long list option c) does not meet criteria i) to iv). Our prudent planning criterion is to design assuming circuit breaker opening time of 120 msec. In many cases the circuit breaker will open faster than this, therefore in this sense we already have fast circuit breakers. If a large amount of motor loads disconnect during a fault then there is a risk of overvoltage. Faster circuit breakers in and of themselves don’t address this scenario because they can’t prevent motors disconnecting and they don’t mitigate any resultant overvoltage. Moreover, at a major station such as Otahuhu there are a multitude of circuit breakers in both air insulated substation (AIS) and gas insulated substation (GIS) parts of the 220 kV station. A fault at Otahuhu 220 kV bus reduces the voltage across the entire upper North Island region and therefore many circuit breakers may need to be replaced. Replacing a large portion of them doesn’t appear practical in the time frame required. Therefore option c) was not carried forward to the short list.

Long list option d) meets criteria i) to iv) and based on information from transformer suppliers did not appear to be clearly more expensive than other options, so was carried forward to the short list.

Long list option e) meets criteria i) to iv) and, based on feedback from consultation, there was interest from owners of synchronous condensers in the upper North Island in providing a service to Transpower, so this option was carried forward to the short list.

Long list option f) meets criteria i) to iv), but based on a high level cost estimate and high level technical analysis, this option would clearly be more expensive than other options, so was not carried forward to the short list.

Long list option g) meets criteria i), ii) and iv), but arguably not criteria iii), given the preliminary nature of investigations into this option to date. However, based on a high level cost estimate and high level technical analysis, this option did not appear to be clearly more expensive than other options, so was carried forward to the short list.

Long list option h) partially meets criteria i) to iv). Smaller amounts of demand-side participation could be used to defer the need for investment in assets, but large amounts would be required to substitute for investment in assets. There was no interest in providing demand-side solutions indicated in the Request for Information which accompanied the consultation document, so this option did not meet the criteria to be carried forward to the short list. Given the lack of opportunities for demand-side participants to be involved at present, this lack of response may not be surprising. However, given the potential benefits of active demand-side participation, we will not simply leave it at that. As discussed in section 5.2.4, we are including an application to fund a series of demand-side initiatives with this investment proposal, with a view to leveraging new technologies to deliver demand side response to manage hot summer afternoons (which does not match the capabilities of traditional controllable loads such as water heating) and cold winter evenings. This will raise awareness amongst consumers and industry participants, increase the potential size of demand-side alternatives in the upper North Island and establish products which can be used as contingency options in the short term and for investment deferral in the future.

Long list option i) meets criteria i), ii) and iv), but arguably not criteria iii), given the long lead time that would be involved in building another new line (other than NIGUP) into Auckland. Also, based on a high level cost estimate and high level technical analysis, this option would clearly be more expensive than other options, so was not carried forward to the short list.

3.2.3 Request for Proposals

In order to evaluate the short-listed options, it was necessary to seek actual proposals for transmission alternatives such as those described in long list option d).

As described above in section 2.2, a Request for Proposals (RFP) document was published, requesting firm proposals for the provision of dynamic reactive support. The RFP document did not preclude any particular proposals, but as with the RFI, no demand-side responses were received for evaluation.

Four proposals were received:

a) Contact Energy offered the use of synchronous condensers at their Otahuhu site. The condensers offered were those currently contracted to the System Operator for the provision of voltage support in Zone 1. They were offered to Transpower from the time the System Operator contract expires in December 2010. They offered two alternatives, with differing levels of Mvar support and differing levels of reliability. Contact's proposals were carried forward to the short list for evaluation.

b) Mighty River Power (MRP) offered the use of synchronous condensers at both their Marsden Point site and their Southdown site.

   The Marsden Point offer involved refurbishing an existing synchronous condenser. They offered both a 5 year and 15 year term. MRP's Marsden Point proposals were carried forward to the short list for evaluation.

   The Southdown offer was for existing generation, on the basis that when it was not being dispatched it could be used to provide reactive support. This was rejected as MRP would have an ability to choose whether to generate energy or provide reactive support depending on which is most profitable at the time. Although this sounds sensible for MRP, it is not clear whether such an arrangement would be beneficial to New Zealand overall and/or whether it would distort the energy market. As a result we currently do not entertain such opportunities for funding as transmission alternatives.

c) Power Consultants Limited offered to install several "Dvar" devices, similar to small STATCOMs, distributed at both Transpower and distribution company sub-stations. The Power Consultant proposal was carried forward to the short list for evaluation. A second option consolidating these smaller devices at one location was also considered.

d) Arthur D Riley offered a fast switched capacitor bank that could boost its Mvar output by bypassing some of its capacitor cans with a circuit breaker. Their proposal did not conform to the requirements outlined in the RFP and their proposal was not carried forward to the short list.

3.2.4 Long short list of options

The short listing process described above and the RFP process resulted in the following list, described as a long short list. The list is too long to be considered a feasible short list, so a further review is undertaken to consider whether it can be shortened:

Table 3-1: Long short list of options

Long short list options	
Option	**Description**
DP1 **Reference Case**	STATCOMs are built at upper North Island Grid Exit Points as needed
DP2	The Penrose 33 kV bus is split and additional and/or replacement 220/33 kV transformers are installed at Penrose. STATCOMs are built at upper North Island Grid Exit Points as needed.
DP3	The OTA condensers are contracted until the end of 2015, on a four out of five basis to provide reliability. STATCOMs are built at upper North Island Grid Exit Points as needed
DP4	The OTA condensers are contracted until the end of 2012, on a four out of five basis to provide reliability. From the start of 2013 to the end of 2015 the remaining OTA condensers are contracted on a two out of three basis to provide reliability. STATCOMs are built at upper North Island Grid Exit Points as needed
DP5	The MDN condenser is contracted for 15 years. STATCOMs are built at upper North Island Grid Exit Points as needed
DP5a	The MDN condenser is contracted for 5 years. STATCOMs are built at upper North Island Grid Exit Points as needed
DP5b	The MDN condenser is contracted for 5 years and a new exciter is installed. STATCOMs are built at upper North Island Grid Exit Points as needed
DP6	The MDN condenser is contracted on a 15 year grid support contract. The OTA condensers are contracted until the end of 2015, on a four out of five basis to provide reliability. STATCOMs are built at upper North Island Grid Exit Points as needed
DP6c	The MDN condenser is contracted on a 5 year grid support contract without a new exciter installed. The OTA condensers are contracted until the end of 2015, on a four out of five basis to provide reliability. STATCOMs are built at upper North Island Grid Exit Points as needed
DP6d	The MDN condenser is contracted on a 5 year grid support contract with a new exciter installed. The OTA condensers are contracted until the end of 2015, on a four out of five basis to provide reliability. STATCOMs are built at upper North Island Grid Exit Points as needed
DP7	SVCs and STATCOMs are built at upper North Island Grid Exit Points as needed
DP10	Distributed STATCOMs are built in the upper North Island, and STATCOMs are built at upper North Island Grid Exit Points as needed.
DP12	Series capacitors are installed on the WKM-BHL line as early as possible (2015). STATCOMs are built at upper North Island Grid Exit Points as needed
DP14	The OTA condensers are contracted until the end of 2012, on a four out of five basis to provide reliability. From the start of 2013 to the end of 2015 the remaining OTA condensers are contracted on a two out of three basis to provide reliability. Series capacitors are installed on the WKM-BHL line as early as possible (2015). STATCOMs are built at upper North Island Grid Exit Points as needed

The Option reference is indicated by DP followed by a number. DP stands for development plan. DP1 is the Reference Case. The rationale for the choice of reference case is explained in section 3.3.3 below.

A summary of the development plans themselves is given in Appendix B.

3.2.5 Reducing the long short list to a short list

The long short list is too long for GIT evaluation, so a further consideration of the options is used to shorten it.

DP3 and DP4 are two options offered by Contact for the use of the Otahuhu synchronous condensers. Due to the nature of the two offers, the present value of DP4s costs is always less than DP3. Therefore, only DP4 will be carried forward to the short list. Should DP4 turn out to be the preferred option, a further comparison with DP3 will be made as a check.

Similarly, DP5, 5a and 5b are all variations offered by Mighty River Power for the use of the synchronous condenser at Marsden Point. The present value of DP5bs costs are always less than DP5 and DP5a. Therefore, only DP5b will be carried forward to the short list. Should DP5b turn out to be the preferred option, a further comparison with DP5 and DP5a will be made as a check.

Similarly also, DP6, 6c and 6d are all variations of the Contact and Mighty River Power proposals for the use of the synchronous condensers at Otahuhu and Marsden Point. The present value of DP6ds costs are always less than DP6 and DP6c. Therefore, only DP6d will be carried forward to the short list. Should DP6d turn out to be the preferred option, a further comparison with DP6 and DP6c will be made as a check.

DP12 and DP14 are variations on installing series capacitors on the new WKM-BHL line, as early as possible. We have determined that the earliest the series capacitors could be installed is 2015 and possibly later. Arguably, this option does not meet the criteria for inclusion on the short list, given the preliminary nature of investigations into this option to date. Also, in both of these development plans investment will be required through to 2015 in any case. For those reasons, these options are not taken forward to the short list, but will be reported on for further information (see section 3.2.6).

These considerations have eliminated seven options and reduced the long short list to a manageable short list of seven options:

Table 3-2: Short list of options

Short list of options	
Option	**Description**
DP1 **Reference Case**	STATCOMs are built at upper North Island Grid Exit Points as needed
DP2	The Penrose 33 kV bus is split and additional and/or replacement 220/33 kV transformers are installed at Penrose. STATCOMs are built at upper North Island Grid Exit Points as needed.
DP4	The OTA condensers are contracted until the end of 2012, on a four out of five basis to provide reliability. From the start of 2013 to the end of 2015 the remaining OTA condensers are contracted on a two out of three basis to provide reliability. STATCOMs are built at upper North Island Grid Exit Points as needed
DP5b	The MDN condenser is contracted for 5 years and a new exciter is installed. STATCOMs are built at upper North Island Grid Exit Points as needed
DP6d	The MDN condenser is contracted on a 5 year grid support contract with a new exciter installed. The OTA condensers are contracted until the end of 2015, on a four out of five basis to provide reliability. STATCOMs are built at upper North Island Grid Exit Points as needed
DP7	SVCs and STATCOMs are built at upper North Island Grid Exit Points as needed
DP10	Distributed STATCOMs are built in the upper North Island, and STATCOMs are built at upper North Island Grid Exit Points as needed.

3.2.6 Further options considered for information

We have also considered a range of other options, to provide further information. These options consider the effect of using an N-G-1 reliability criteria, rather than N-1, the effect of new generation emerging and the potential impact of building series capacitors on the new WKM-BHL line in 2015. These options are described below:

Table 3-3: Further options considered for reference

Short List options	
Option	**Description**
DP8	Northland wind farm is built (stage 1 in 2015 and stage 2 in 2021), and STATCOMs are built at upper North Island Grid Exit Points as needed
DP9	Rodney generation is built in 2017, and STATCOMs are built at upper North Island Grid Exit Points as needed
DP11	N-G-1 and STATCOMs are built at upper North Island Grid Exit Points as needed
DP12	Series capacitors advanced to 2015 and STATCOMs are built at upper North Island Grid Exit Points as needed
DP14	The OTA condensers are contracted until the end of 2012, on a four out of five basis to provide reliability. From the start of 2013 to the end of 2015 the remaining OTA condensers are contracted on a two out of three basis to provide reliability. Series capacitors advanced to 2015 and STATCOMs are built at upper North Island Grid Exit Points as needed
DP15	Rodney generation is built in 2017. The OTA condensers are contracted until the end of 2012, on a four out of five basis to provide reliability. From the start of 2013 to the end of 2015 the remaining OTA condensers are contracted on a two out of three basis to provide reliability. Series capacitors advanced to 2015 and STATCOMs are built at upper North Island Grid Exit Points as needed
DP16	New Otahuhu generation is built in 2015. The OTA condensers are contracted until the end of 2012, on a four out of five basis to provide reliability. From the start of 2013 to the end of 2015 the remaining OTA condensers are contracted on a two out of three basis to provide reliability. Series capacitors advanced to 2015 and STATCOMs are built at upper North Island Grid Exit Points as needed
DP17	New Otahuhu generation is built in 2015 and STATCOMs are built at upper North Island Grid Exit Points as needed

DP8, DP9, DP15, DP16 and DP17 show the effect on the need for investment in dynamic reactive support should new generation emerge.

DP11 shows the effect of using an N-G-1 criterion instead of N-1. In the NIGUP it was established that investment to meet an N-G-1 reliability criteria for thermal capacity was economically justified. As discussed in section 5.1.1, we would prefer to gather more information for our technical modelling before evaluating whether the N-G-1 reliability criteria for voltage stability is economic.

DP12 and DP14 are development plans which were recently added for evaluation. The NIGUP development plan includes installing series capacitors on the new NIGUP line in 2021, to even up the flow between all of the transmission lines into Auckland (this timing changes to 2025 with the demand assumptions used in this analysis). The effect of the series capacitors is to lower the impedance of the new NIGUP line, which, as well freeing up thermal capacity, has the effect of lowering the need for dynamic reactive support. These two development plans explore the possibility of advancing the installation of the series capacitors. At the moment, these plans are only preliminary and cannot be considered feasible or practicable yet. We have not yet installed series compensation on the New Zealand grid to date and there are many unknowns. Investigations are underway to explore their feasibility, but we expect 2015 to be the earliest commissioning date achievable.

3.3 Reflecting Good Electricity Industry Practice in meeting the Grid Reliability Standards

Rule 13.4.1.1 permits the Commission to approve a reliability investment where the proposed investment reflects GEIP in meeting the Grid Reliability Standards.

3.3.1 The short list options reflect GEIP

The Rules define GEIP in relation to transmission as:

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

Accordingly, comparable international practice should be considered in assessing what is GEIP in terms of grid investment planning. As a prudent planner, owner and operator of a transmission network, we can reasonably be expected to adopt solutions consistent with good international practice.

We consider that all the short-list options reflect GEIP. Specifically, the approach undertaken for the Proposal is consistent with international practice and our Transmission Code as being prudent investments given the size, nature and importance of the load and generation in the upper North Island.

3.3.2 The short list options meet the Grid Reliability Standards

The Grid Reliability Standards are contained in Schedule F3 of the Rules. These provide that the grid satisfies the grid reliability standards if:

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

As the majority of the upper North Island load does form part of the core grid, the analysis has been undertaken to ensure the power system would remain in a satisfactory state following a credible contingent event. In this case the contingent event is a 120 ms three phase 220 kV fault at Otahuhu which is cleared with the loss of Contact's Otahuhu B combined cycle gas turbine (OTB-CCGT). The loss of OTB-CCGT is the most onerous N-1 fault. Its loss not only reduces the amount of real power produced in the Auckland region, it also reduces the amount of dynamic Mvars available for regulating voltage.

3.3.3 Base case

For the purposes of the GIT, the Rules also require that the Proposal and the alternative projects be assessed against a base case, which is defined[5] as follows:

[5] Clause 20 of Part F Section III Schedule F4

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

As noted by both the Commission and ourselves in analysis of the NIGUP, it is difficult to identify a suitable base case for the analysis when an investment proposal is required to meet the Grid Reliability Standards, and more particularly rule 4.2 of the Grid Reliability Standards because the base case must meet the Grid Reliability Standards, but not be an alternative project.

The Commission has previously resolved this issue by using one of the “alternative projects” as a reference case. We have adopted this approach.

We consider that a reasonable reference case for this investigation is the installation of STATCOMs as required to provide sufficient dynamic reactive support through the analysis period.

4 GIT Methodology and assumptions

This section sets out our approach to applying the Grid Investment Test

The Grid Investment Test (GIT) requires that we determine the market benefits and costs of the base case and each of the short-list options for each of a number of market development scenarios for the future.[6]

The GIT analysis requires certain methodology, input assumptions and parameters to be determined and applied and then results tested against various sensitivities.

4.1 GIT modelling approach and market development scenarios

4.1.1 Demand Forecast

The analysis was based on the 2009 APR peak demand forecasts. Two forecasts were used, reflecting both a winter and summer diversity.

The 2009 APR demand forecast was based on the demand forecasts provided by the Electricity Commission (the Commission) as part of its August 2008 Statement of Opportunities. The peak demand forecast represents a prudent forecast that equates to a probability of exceedance (POE) of 10%. These forecasts were then modified as more specific and relevant information is provided by customers.

Winter peaks are higher than summer peaks, but motor loads are highest during mid January and mid March. Late summer period is when the worst voltage performance is predicted to occur and these demands were used in the technical analysis. Checks were undertaken using winter peaks and winter motor load forecasts to ensure these conditions were not worse. Table 4-1 below lists the yearly demand forecast for the winter and summer diversities used in the analysis.

[6] Clause 5 of Schedule F4, Part F of the Rules.

Table 4-1: Peak demand forecast for the upper North Island (MW)

Year	Winter	Summer
2009	2340	1845
2010	2438	1920
2011	2520	1985
2012	2601	2048
2013	2660	2097
2014	2730	2152
2015	2809	2215
2016	2881	2272
2017	2955	2332
2018	3030	2391
2019	3106	2453
2020	3183	2514
2021	3251	2568
2022	3320	2623
2023	3389	2678
2024	3458	2733
2025	3528	2789
2026	3595	2842
2027	3662	2895
2028	3729	2949
2029	3796	3002

4.1.2 Existing generation

The analysis assumed installed generation in the region as shown in Table 4-2 below.

Table 4-2: Installed generation

upper North Island Generation	Capacity
Otahuhu B	370 MW
Southdown	179 MW
Glenbrook	75 MW (including embedded machines)
Ngawha	22 MW
Total	646 MW

All existing generation was assumed to be in operation until the end of the analysis period, 2030.

4.1.3 New generation

The GIT requires us to develop market development scenarios and analyse the base case and each short-list option against each scenario.[7] The market development scenarios (MDS) include a demand forecast and forecast new generation.

The scenarios use a set of generation drivers as inputs, including details of generation cost, timing, location, carbon charges, demand etc. The Commission establishes the new generation forecast by using these drivers in its generation expansion model (GEM).

[7] Refer to definition of “market development scenarios” at clause 28 of Schedule F4, Part F of the Rules.

In the 2008 SoO, there are five scenarios. We have used these five scenarios as a starting point for the analysis, but as amended for the Lower South Island Renewables Investment Proposal (Instalment 3, Part V of the 2009 Grid Upgrade Plan). The Commission was satisfied that the changes made to the market development scenarios in that proposal were an appropriate update, as they incorporated more current information than used to compile the SoO.

In terms of generation development in the upper North Island, the scenarios forecast new generation as shown in Figure 4-1, Figure 4-2 and Figure 4-3 below:

Figure 4-1: upper North Island baseload generation per the 2008 SoO

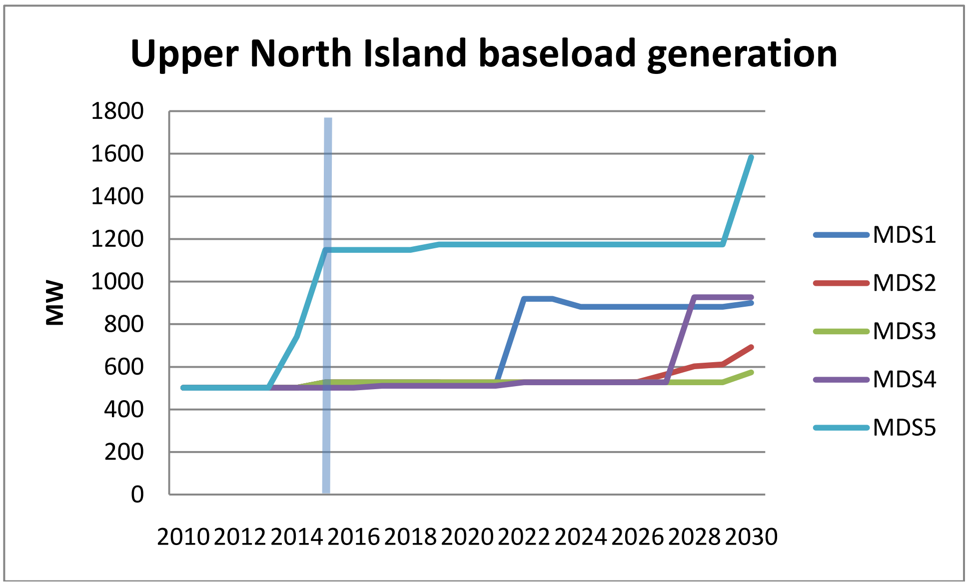


Figure 4-2: upper North Island wind generation per the 2008 SoO

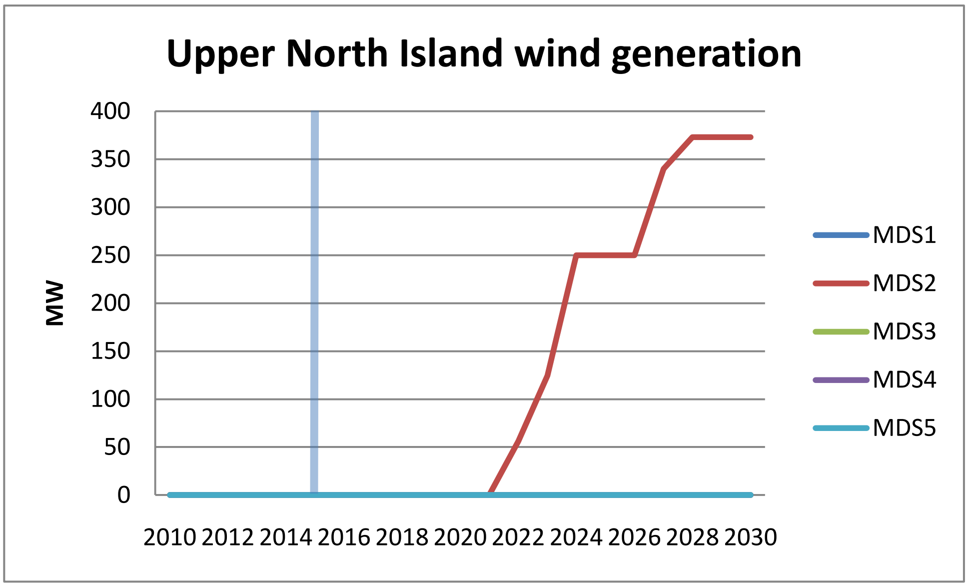
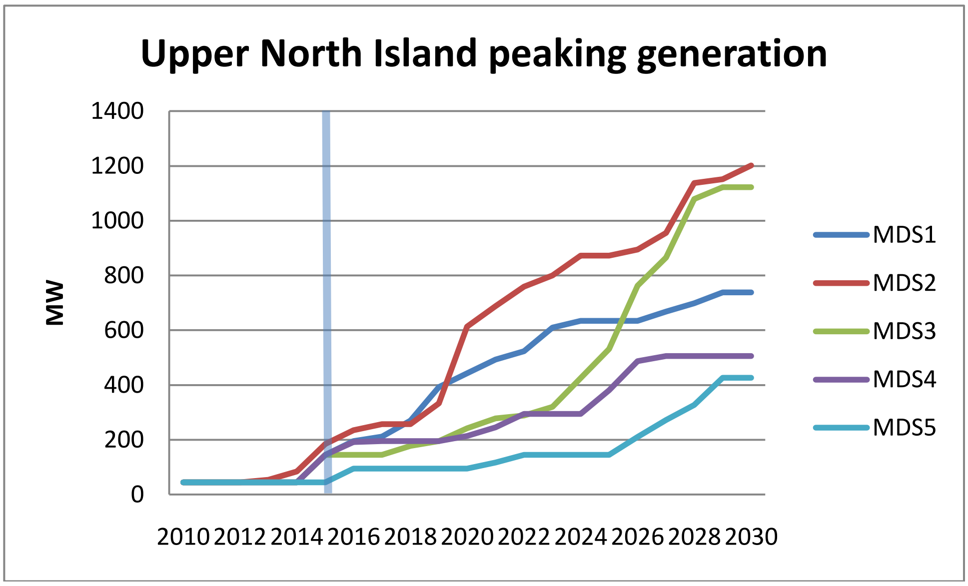


Figure 4-3: upper North Island peaking generation per the 2008 SoO



Although a 20 year analysis period was considered, as required by the GIT, the most important period was the short term up to 2015. Investment in dynamic reactive support is required immediately, but the amount depends upon the emergence of new generation. Given the lead time for planning new grid investment, we have focussed on the period until 2015.

The consultation undertaken revealed no new committed generation in the upper North Island region. The only new generation raised as a possibility was Meridian's Poutu wind farm, but as yet, this is still only a possibility at some time in the future and Meridian have not committed to building this plant.

The generation scenarios show the following new generation appearing prior to 2015:

Table 4-3: Upper North Island new generation up until 2015 per the 2008 SoO

MW		MDS1	MDS2	MDS3	MDS4	MDS5
to 2015	Base load	25	25	25	0	647
	Wind	0	0	0	0	0
	Peaking	100	140	100	100	0

However because no new generation was confirmed or even reasonably firm as a result of feedback during consultation, we have prudently assumed no new generation will appear in the upper North Island prior to 2015.

It was also recognised that the effect of new generation emerging after 2015 was simply to defer the need for further investment in dynamic reactive support. Ultimately, new generation could emerge in the upper North Island and defer the need for investment beyond 2015, but this would be common across all development plans. The technical analysis involved in this project is lengthy, time-consuming and therefore expensive. It was decided there was no added value to be had from developing a full set of development plans for each generation scenario, so we have made the simplifying assumption that no new generation will emerge at all in the upper North Island, in any scenario, during the analysis period. Although this may seem an extreme modification of the generation scenarios, it simplifies the analysis a great deal and does not affect the GIT results.

The development plans are therefore the same for each scenario and weighting each scenario equally is the same as reporting just the GIT result.

For information however, we have included development plans to show the effect on the expenditure required over 20 years if a large (400 MW) thermal plant emerged at either Otahuhu or Rodney, or a large wind farm emerged (2 x 250 MW staged build – nominally called Poutu). These results are reported in section 5.1.1.

We have also included a sensitivity, for DP1 and DP4 (the two most economic options) to show the effect of new generation emerging at Otahuhu in 2015, or Rodney in 2017, which are probably the earliest practicable commissioning dates for each location. This is reported in section 5.1.2.

4.1.4 Changes to demand forecasts and market development scenarios

The demand forecast is consistent with the forecast used in the Lower South Island Renewables project and the 2009 APR.

The changes made to the generation scenarios are relatively extreme i.e. that no new generation will emerge. We consider that the updated generation scenarios are more appropriate than the possible future scenarios outlined in the SoO prior to 2015 and the simplification that no new generation will emerge post 2015 does not affect the GIT result and is reasonable considering the amount of analysis saved.

For the purposes of clause 6.1 of the GIT, we are seeking a determination by the Commission that these market development scenarios are (for this analysis) more appropriate than the possible future scenarios outlined in the SoO.

4.1.5 Summary of the approach to the GIT and assumptions

The following is a summary of the high level approach taken to the GIT analysis along with a summary of the assumptions utilised in the analysis.

Table 4-4: Summary of the GIT approach

Approach	Value
Market development scenarios (MDS)	5 Scenarios based on 2008 SoO
Scenario weightings	Equally weighted
Demand Forecast	2009 APR
Analysis period	20 years
Net present value or real options analysis	PV with scenarios
Discount rate	7%
Analysis in current or future dollars	2010 dollars

4.2 Calculating the expected market benefits

Market benefits under the Rules cover benefits to those persons who produce, distribute, retail and consume electricity in New Zealand[8]. For this analysis, for the options on the short list, it has been assumed there are no significant benefit differences between the options.

There are two areas where benefits may differ:

a) Reliability benefits. The options include the use of equipment such as STATCOMs, SVCs and synchronous condensers. The reliability of devices such

[8] Clause 27 of the GIT.

as STATCOMs and SVCs is higher than synchronous condensers. The reliability benefit derives from:

- the non-mechanical nature of STATCOMs and SVCs versus the condensers which are mechanical.
- the age of some of the condensers considered – they are former generating units from the 60's and 70's.

The approach taken in this analysis is to be conservative and not consider the reliability costs of synchronous condensers. Given the reference case is to install STATCOMs as required, this is consistent with the Electricity Commission's preferred approach in ensuring that such simplifications do not favour the Reference Case or the Proposal.

b) DP12 and DP14 both reflect advancing the installation of series capacitors on the new WKM-BHL line. For these options there may be transmission loss differences, which will be assessed and reported during analysis of those options. As discussed earlier though, these development plans are preliminary and until further work is undertaken, they do not meet the criteria for practicality of implementation. More discussion on this option is included in section 5.4.

The following is a summary of the approach to estimating benefits:

Table 4-5: Summary of market benefits

Market benefit	Approach
Capital benefits – capital cost of generation	Not included
Fuel costs and transmission losses	Not included[9]
Greenhouse gas emission, spill and load shedding	Not included
Reliability benefits	Not included[10]
Operational benefits	Not included[9]
Market services (ancillary services and reserves)	Not included[9]
Competition benefits	Not included[9]
Consumer benefits	Not included[9]
Future options	Not included[9]
Terminal benefits	Not included

4.3 Market costs

For the purposes of applying the GIT, we have estimated costs for the short-listed options to a level of accuracy that will determine the difference between the options and between the costs and benefits such that a sufficiently robust decision can be made on the most economic option.

Our approach to estimating the costs of each short-list option is set out in detail in Attachment B. Attachment B is confidential to the Electricity Commission as it

[9] Except as discussed above, for DP12 and DP14

[10] Clause 9 of the GIT provides that where a material benefit cannot be quantified, the direction and likely magnitude of the benefit must be identified. Transpower did not consider estimating the "likely magnitude" to be possible or commensurate with the project spend. However, such benefits are important and have been accounted for as discussed in section 6.1.3.

includes the details of our assumed STATCOM and SVC costs plus the proposed contracting costs for the transmission alternatives offered as a result of the RFP process.

The following is a summary of the approach to estimating costs.

Table 4-6: Summary of market costs

Market Cost		Approach
Transmission costs	Capital equipment costs	Included
	Line and Substation capital costs	Included
	Installation costs	Included
	Property costs	Included
	Project management	Included
	Consenting costs	Included
	Community fund costs	Included
	Operating and maintenance costs	Included
	Investigation costs	Included
Transmission alternative contracting costs		Included

4.4 GIT Sensitivities

The sensitivities analysed in applying the GIT to the short list of options are shown in the table below:

Table 4-7: Summary of Sensitivities

Sensitivity	Value
Forecast demand	Not included – all investments would be accelerated at the same rate and the GIT result would not be affected
Variations in the size, timing, location, and O&M costs	O&M costs included
Capital cost	Relative capital costs included
Timing of decommissioned assets	Not included
Value of expected unserved energy	Not included
Discount rate	4% and 10%
Variation in hydrological inflow sequences	Not included
Generator and demand-side bidding strategies	Not included
Competition benefits	Not included
Carbon charges	Not included
Property Costs	Not included
Operating and Maintenance costs	Included
Market development scenarios	Partially included
Energy costs (for operation of capital equipment)	Included
Transmission alternative costs	Included

We consider this level of sensitivity analysis is sufficient to ensure the rigour and comprehensiveness of the analysis is commensurate with the estimated capital expenditure required for the Proposal.

5 Application of the Grid Investment Test

This section sets out our application of the Grid Investment Test

5.1 Compliance with the Grid Investment Test

The investment proposal under consideration contemplates an investment in the upper North Island region which is part of the core grid. As such, the Proposal will satisfy the GIT under clause 4.2 of Schedule F4 if the Proposal:

- maximises expected net market benefit or minimises expected net market cost compared with a number of alternatives; and
- the GIT results are robust with respect to any sensitivity analysis.

5.1.1 GIT results

The GIT results are presented as a comparison of the expected net market cost of the short-listed options in Table 5-1 and Table 5-2 and the sensitivity of the expected net market cost to various parameters in section 5.1.2.

Table 5-1: Overall results of application of the Grid Investment Test (I)

Option	Description	Present Value Cost $ million
DP1 Reference Case	STATCOMs	$210
DP2	Replace PEN Transformers	$220
DP4	OTA 5 year contract	$216
DP5b	MDN 5 year contract (new exciter)	$218
DP6d	OTA 5 year + MDN 5 year contracts	$234
DP7	SVCs and STATCOMs	$227
DP10	Distributed STATCOMs	$219

These results show that the Reference Case, DP1, building STATCOMs as required, has the lowest expected net market cost of the short list options. However, the cost of DP1 is close to several other options and thus it is necessary to consider the sensitivity analysis before deciding if it passes the requirements of the GIT. Subject to the sensitivity analysis though, DP1 satisfies the requirements of clauses 4.2.1 and 4.2.2 of the GIT.

The GIT results, or expected net market cost, for the other development plans considered are reported in Table 5-2 below:

Table 5-2: Overall results of application of the Grid Investment Test (II)

Option	Description	Present Value Cost $ million
DP11	N-G-1	$299
DP12	Series caps in 2015	$212
DP14	OTA 5 year contract, series caps as required	$217
DP8	Wind farm (stage 1 in 2015, stage 2 in 2021)	$158
DP9	Rodney generation in 2017	$142
DP15	OTA 5 year contract, Rodney generation in 2017	$148
DP16	OTA 5 year contract, Otahuhu generation in 2015	$158
DP17	STATCOMs, Otahuhu generation in 2015	$152

The costs of development plans DP12 and DP14 are close to DP1 and this is without including any loss saving benefit they may have. Lowering the effective impedance of the NIGUP line will result in more energy flowing through these (lightly loaded) lines compared to the other 220 kV lines between Otahuhu and Whakamaru (more heavily loaded) lines. There are likely to be overall loss savings as a result.

The potential cost savings if new generation is built in the upper North Island are obvious when we look at the costs of DP8, DP9, DP15, DP16 and DP17. Thus an option that includes some optionality to avoid investment in dynamic reactive support, should new generation appear, may have higher value than an option which does not include such optionality.

DP11 shows the extra cost involved if an N-G-1 planning standard is used instead of the N-1 standard. As mentioned earlier, although the NIGUP showed that N-G-1 was economically justified in the upper North Island region, we will gather more information and reassess the value of building to an N-G-1 standard before proposing the extra investment required.

5.1.2 Sensitivity analysis

We have considered the sensitivity of the GIT results to changes in key variables and parameters to assess the robustness of this result (in accordance with clause 4.2.3 of the GIT). Table 5-3 to Table 5-10 show the results of these sensitivities.

Table 5-3: Sensitivity of short-list options to choice of discount rate

Option	Present Value cost, $million		
	Discount rate		
	4%	7%	10%
DP1	$262	$210	$171
DP2	$277	$220	$178
DP4	$267	$216	$175
DP5b	$278	$218	$177
DP6d	$297	$234	$190
DP7	$287	$227	$183
DP10	$278	$219	$175

This analysis shows that DP1 is preferred at all discount rates and therefore that the GIT result is robust to discount rate.

Table 5-4: Sensitivity of short-list options to STATCOM cost

Option	Present Value cost, $million			
	STATCOM installed cost			
	-10%	Base	+10%	+20%
DP1	$200	$210	$220	$229
DP2	$211	$220	$229	$238
DP4	$207	$216	$226	$235
DP5b	$209	$218	$228	$237
DP6d	$225	$234	$243	$252
DP7	$223	$227	$231	$234
DP10	$210	$219	$227	$235

The analysis shows that over the sensitised range of STATCOM capital cost variation, DP1 is preferred. We conclude that the GIT result is robust to STATCOM cost.

Table 5-5: Sensitivity of short-list options to SVC cost

Option	Present Value cost, $million		
	SVC installed cost		
	-10%	Base	+10%
DP1	$210	$210	$210
DP2	$220	$220	$220
DP4	$216	$216	$216
DP5b	$218	$218	$218
DP6d	$234	$234	$234
DP7	$218	$227	$236
DP10	$219	$219	$219

The analysis shows that over the sensitised range of SVC capital cost variation, DP1 is preferred. We conclude that the GIT result is robust to SVC cost.

Table 5-6: Sensitivity of short-list options to transformer cost

Option	Present Value cost, $million		
	Transformer installed cost		
	-20%	Base	+20%
DP1	$210	$210	$210
DP2	$216	$220	$224
DP4	$216	$216	$216
DP5b	$218	$218	$218
DP6d	$234	$234	$234
DP7	$227	$227	$227
DP10	$219	$219	$219

The analysis shows that over the sensitised range of transformer capital cost variation, DP1 is preferred. We conclude that the GIT result is robust to transformer cost.

Table 5-7: Sensitivity of short-list options to MRP annual contract cost

Option	Present Value cost, $million		
	MRP contract annual cost, $m		
	-20%	Base	+20%
DP1	$210	$210	$210
DP2	$220	$220	$220
DP4	$216	$216	$216
DP5b	$216	$218	$221
DP6d	$231	$234	$237
DP7	$227	$227	$227
DP10	$219	$219	$219

The analysis shows that over the sensitised range of MRP annual contract cost variation, DP1 is preferred. We conclude that the GIT result is robust to the likely cost of a contract with MRP.

Table 5-8: Sensitivity of short-list options to annual Contact contract cost

Option	Present Value cost, $million			
	Contract annual cost, $m			
	-20%	-10%	Base	+10%
DP1	$207	$209	$210	$211
DP2	$217	$219	$220	$222
DP4	$211	$214	$216	$219
DP5b	$215	$217	$218	$220
DP6d	$228	$231	$234	$237
DP7	$224	$226	$227	$228
DP10	$216	$217	$219	$220

The analysis shows that over the sensitised range of Contact annual contract cost variation, DP1 is preferred. We conclude that the GIT result is robust to the likely cost of a contract with Contact.

Table 5-9: Sensitivity of short-list options to annual O & M costs

Option	Present Value cost, $million		
	Annual O&M costs STATCOMs, $m		
	0.00	0.05	0.20
DP1	$208	$210	$217
DP2	$218	$220	$226
DP4	$214	$216	$223
DP5b	$216	$218	$225
DP6d	$232	$234	$240
DP7	$225	$227	$233
DP10	$217	$219	$224

The analysis shows that over the sensitised range of O&M cost variation, DP1 is preferred. We conclude that the GIT result is robust to O&M costs.

Table 5-10: Sensitivity of short-list options to energy consumption

Option	Present Value cost, $million		
	Energy consumption, kW		
	0	200	500
DP1	$204	$210	$220
DP2	$215	$220	$229
DP4	$210	$216	$226
DP5b	$212	$218	$227
DP6d	$228	$24	$243
DP7	$221	$227	$236
DP10	$213	$219	$227

The analysis shows that over the sensitised range of assumed energy consumption for STATCOMs, DP1 is preferred. We conclude that the GIT result is robust to energy consumption assumptions.

To consider the effect of our assumption that new generation emerging post 2015 will not affect the preferred option, we have undertaken a sensitivity looking at new generation emerging in 2015 and 2017.We compared the development plan costs for DP1 and DP4, modified to reflect significant new generation being built. We have considered a new plant at Otahuhu in 2015 and a new plant at Rodney in 2017 – which are probably the earliest practicable commissioning dates for each location. These development plan costs are reported in Table 5-12.

Table 5-11: GIT results for DP1 and DP4 with new generation in 2015 and 2017

Option	Description	Present Value cost $ million
No new generation appears		
DP1 Reference Case	STATCOMs	$210
DP4	OTA 5 year contract and STATCOMs	$216
400 MW generation commissioned at Rodney in 2017		
DP9	STATCOMs	$142
DP15	OTA 5 year contract and STATCOMs	$149
400 MW generation commissioned at Otahuhu in 2015		
DP17	STATCOMs	$152
DP16	OTA 5 year contract and STATCOMs	$158

Although the development plan costs are significantly lower in both cases, DP1 is still marginally cheaper than DP4. This confirms our assumption that new generation emerging post 2015 will not affect the GIT result, is robust.

In conclusion, the GIT indicates that the Reference Case (DP1) of installing STATCOMs as required, is the preferred option over all sensitivities considered. The sensitivity analysis was undertaken for several important variables, within their credible ranges.

In our view DP1 therefore meets the requirements to pass the GIT.

Importantly while DP1's economic (cost) advantage is only slightly greater than DPs 4 and 5b we have not explicitly accounted for the anticipated greater reliability and availability of the STATCOMs proposed in DP1 compared to the synchronous condensers in those development plans. In particular, the Otahuhu A synchronous condensers are former generating units from the 60's and 70's with decreasing reliability. Although well managed, there is a risk that if contracted, the full reactive support commitment for the required five years to 2015 would not be met with these units. From 2013 to 2015, where 2 of 3 machines are offered for a period of 3 years, a major machine failure is unlikely to be economic to repair. The grid would have less reactive support to call on until we could build (or contract) new assets. During this interim period the grid would be less secure and this makes this option materially less attractive.

However, to further assist in decision-making, we have also undertaken an assessment of the options using non-quantified criteria and this is reported in section 5.1.3.

5.1.3 Other non-quantified differences

Given that there are several short-listed options which are close economically, we have also considered other non-quantified differences, as a means of helping to differentiate between the options.

The standard list we consider is as follows:

Option benefits – does the option include flexibility to be amended in the future if there are significant changes? Options which can be amended include an inherent value, because demand growth could be higher or lower than forecast, new generation may appear, a new Grid Exit Point may be required or technology changes may mean a different solution is preferable, etc.

Although not relevant to this GUP, the dismantling of lines resulting in a loss of statutory rights on that line would be one example. As a result of losing statutory rights, we would need to acquire property rights along the line route if it needed to re-establish the line in the future. At a minimum this would be extremely expensive and would inevitably be fraught with prospective difficulties in securing easements on what would, in future, be a “greenfield” site. In dismantling the line, we effectively close off future upgrade options along the existing route which may be required to connect future generation in the region.

Consumer benefits through enhanced competition – to what extent will the option enhance competition in the New Zealand electricity market? The more competitive a market is, the more efficient it will be at delivering the advantages that markets can provide to consumers. Transmission investment may enable a more competitive generation investment market through lower nodal prices for consumers and can increase market liquidity (which should result in increased availability of electricity price risk management products).

Transmission investment such as “transmission to enable renewables” is an example of investment which enhances competition.

Wider economic benefits – to what extent will the option deliver wider economic benefits? The GIT assesses the benefits of transmission investment in terms of lower electricity costs and avoided unserved energy for only consumers of electricity. There is no consideration of the wider benefit to New Zealand that electricity provides. For example, a low cost and secure supply of electricity will encourage foreign investment in New Zealand, compared to a higher cost, less reliable supply. Also, a more secure supply of electricity may encourage more tourists to visit New Zealand. This factor differentiates between options on the basis of their potential to provide wider economic benefits for all New Zealanders. Options which provide certainty to investors in new generation and/or confidence to investors in the New Zealand economy and/or more tourism, for instance, are preferred.

Minimises disruption – to what extent will the local community be disrupted by the implementation of an alternative? Whilst staged options can provide economic benefit by deferring capital expenditure and providing flexibility to deal with future changes, they may also be more disruptive to the community and in particular landowners. Staged options could mean, for instance, that we would be revisiting the same landowners every few years to incrementally increase transmission line capacity. This factor considers the extent to which an option would disrupt the community over the analysis period.

Diversity benefits – to what extent will the option provide diversity of supply? GIT analysis typically quantifies reliability benefits for each option, where the differences are considered significant and can be readily quantified. However, some differences are important but too difficult to quantify. For example, providing electricity supply to an area through two separate transmission lines, rather than one, provides protection against losing a portion of a line. The statistics of this and other such low probability events are not available and so rather than guesstimate them, we consider it is more appropriate to rank the options in terms of their ability to provide resilience against such events. Another diversity benefit transmission can provide is access to a more diverse electricity supply. In some circumstances new transmission will mean consumers in an area have access to more fuel sources than previously available.

Operational benefits – to what extent does the option provide operational benefits not reflected in the economic analysis? Some options will provide operational benefits by making outage planning easier, for example. Other options may provide more flexibility to deal with the modified grid configurations required in dry hydrological years. Such benefits are not always reflected in GIT analysis. Some options may result in a more resilient grid, particularly to High Impact Low Probability (HILP) events. Such a benefit is particularly valuable, but notoriously difficult to quantify.

Alignment with long term grid development – to what extent is the option consistent with our longer term vision for the Grid. Ours longer term vision for how the Grid should develop considers a longer time period than considered in the GIT. This factor considers whether an option is consistent with the long term vision, or whether considering a shorter term analysis period may have led to a different decision.

Aligns NZ govt environmental goals – to what extent does an option conform to governmental environmental goals, not specifically reflected in the GIT e.g. moving toward a high proportion of renewable energy?

For this particular investment, there is little or no difference between the options in terms of the last two qualitative benefits so they have been omitted from the analysis.

For the others though, a qualitative assessment of these benefits against each of the options is given in Table 5-12 below. The benefit for each option has been qualitatively ranked between ✓ (least benefit) and ✓✓✓ (most benefit).

The table also includes the GIT result and our conclusion for the overall preferred option.

Table 5-12: Qualitative assessment of non-quantified benefits and overall preferred option

Option	Expected Net Market Cost	Option benefits	Consumer benefits	Wider economic benefits	Minimises disruption	Diversity benefits	Operational benefits	Overall ranking
DP1	$210	✓✓	✓✓	✓✓✓	✓✓	✓✓✓	✓✓✓	1
DP2	$220	✓✓	✓✓	✓✓✓	✓	✓	✓✓	
DP4	$216	✓✓	✓✓	✓✓✓	✓✓	✓✓	✓✓	
DP5b	$218	✓✓	✓✓	✓✓✓	✓✓	✓✓	✓✓	
DP6d	$234	✓	✓✓	✓✓✓	✓✓	✓✓	✓✓	
DP7	$227	✓	✓✓	✓✓✓	✓✓	✓✓✓	✓✓✓	
DP10	$219	✓✓	✓✓	✓✓✓	✓	✓✓✓	✓✓	

Although there is subjectivity involved in ranking the options, the Reference Case has the most benefit in enough criteria for it to be the preferred option in terms of non-quantified benefits.

In short, the new STATCOM and/or SVC technology is cheap, reliable and flexible compared to the older synchronous condenser technology.

Our DP1 includes the installation of two STATCOMs.

Hence, based on an overall assessment of the GIT analysis, the non-quantified benefits and a comparison of the STATCOM versus synchronous condenser advantages, the Reference Case of installing STATCOMs as required is favoured and forms the basis for the Proposal.

5.1.4 Accuracy of GIT

There is a level of uncertainty inherent in the input assumptions and the formulation of the GIT analysis.

Taking this uncertainty into account, readers should be careful not to infer a level of precision that does not exist.

However, within the context of the rules, we consider that the rigour and comprehensiveness of the analysis undertaken is commensurate with the estimated capital expenditure required for the investment proposal. Based on the overall assessment of quantified and unquantified benefits, we consider the option selected by applying the GIT (the Reference Case) is the best option and satisfies the requirements for approval under the Rules.

5.1.5 GIT Analysis Conclusion

We consider that the Reference Case satisfies the GIT because:

- it minimises the expected net market cost (including accounting for the impact of non-quantified market benefits) when compared with the alternative projects; and
- the conclusions are robust having regard to the results of sensitivity analysis
- this conclusion is supported by our analysis of non-quantified benefits.

5.2 The Proposal

The economic analysis included a number of items common to all options and with the same timing. These are all included in the Proposal and are described below:

5.2.1 New Reactive Support Devices

Two 40 Mvar STATCOMs are proposed, one each to be commissioned in 2013 and 2014.

This solution will provide sufficient dynamic reactive support in the upper North Island through until 2015. This improves the quality of electricity supply to electricity users, which is particularly important for large industrial processes, such as oil refining and steel making. Installing STATCOMs is a high-reliability low-footprint solution which will improve the overall resilience of the grid in the upper North Island and which has the lowest long term energy consumption.

We have not considered seeking approval for investment beyond 2015 as new generation in the region would have a significant impact on the requirement and it is prudent to keep our options open at this stage.

The other projects included in this Proposal are described below and were common to all options considered.

5.2.2 Reactive Power Controller (RPC)

Coordinating the reactive devices across the upper North Island region is a significant operational challenge. As more reactive support – both static and dynamic - is added, a control system to manage reactive devices, a Reactive Power Controller (RPC), is required. An RPC allow the devices to act in a coordinated manner, without manual switching by power system operators allowing optimal dispatch of the power system. In the upper North Island the reactive devices are spread over a large number of substations and along with generation in the region, makes the existing manual coordination of reactive power management an extensive operational challenge for the System Operator.

The upper North Island region RPC will be developed based on our experience gained in developing and implementing an area RPC for Christchurch. The Christchurch RPC has a modular design and is intended to be operable over multiple sites and control both grid reactive devices as well as generating units in future. The Auckland RPC would initially coordinate devices at the key Auckland substations with scope for extension to all reactive devices in the region and including generators.

5.2.3 Enhancement to System Operator software

The upper South Island reactive support implementation has identified that the dispatch of dynamic reactive support devices will require improved and enhanced tools for the System Operator to manage and calculate dynamic reactive support requirements in real time. The same need applies to the upper North Island. Therefore the Proposal includes the necessary funds to enhance the dynamic stability assessment software used by our system co-ordinators, so that the reactive devices can be fully utilised. The software enhancements will create a real time instance of a dynamic voltage transient (e.g. Powertech's TSAT, DigSilent) that can identify the reactive power reserve required in system operation. It will also provide situational awareness giving power system operators a validation of the correct working of the RPC and prior warning of emergency conditions.

The enhanced software will be used by operators and along with the RPC are together are essential for day-to-day operation and efficient management of upper North Island voltage stability.

Installation and commissioning of the software tools will be targeted to coincide with the RPC.

5.2.4 Load Monitoring equipment

To improve our analysis on the future need for dynamic reactive support we have included funding for additional instrumentation to better understand how the regional power system responds dynamically to severe power system faults. This is essential as the nature of the load mix in the upper North Island is changing as the installation of heat pumps and motors continues, impacting on the need for further dynamic reactive support.

The Proposal includes the roll out of 15 power quality meters at Grid Exit Points in time for summer 2010/11. The meters collect data on how the load responds transiently to system events. This data will be downloaded from the substations and analysed to improve our load models which allows us to more accurately understand the need for dynamic reactive support. The load monitoring equipment is portable and can therefore be readily moved around to gather data from different sites thereby building a comprehensive picture of load dynamics over time.

Installation and commissioning will be targeted for 2011.

5.2.5 Demand-side Initiatives

No demand-side options were offered as alternatives in the RFP process. The ability to call on demand-side response to reduce demand at peak times or during outages is an effective alternative to additional dynamic reactive support devices and can provide significant value. Demand-side options would also help manage any delay in the delivery of this project or other key upgrade projects such as the new NIGUP line and may create options for avoiding unnecessary investment in the face of uncertainty such as the commitment of new generation.

To ensure demand-side solutions are enabled, the Proposal includes funding for demand-side initiatives – including initiatives similar to those undertaken in the upper South Island in 2007 – 2009 (demand-side response trials in 2007 and 2008 and implementation of a load controller in 2009). This initiative will seek demand-side participation equivalent to one year's load growth in the region (60 MW). It will provide funding for the equipment necessary for one entity (such as a major line company) to coordinate ripple control in the region, in a manner similar to the service provided by Orion in the upper South Island. Importantly, it will also foster the use of new technologies to develop demand-side options to meet the need for reactive support which is driven more by summer afternoon conditions than the traditional winter peaks. These initiatives are expected to be commenced in 2011, with the aim of having a demand-side product available for contingent use by 2012.

The range of initiatives therefore includes:

- A load controller similar to that used in the upper South Island, allowing distributors to better co-ordinate distributor ripple control loads at times of system stress or planned outages
- An initiative to use new approaches and technologies to reduce:
  - Winter day time peaks, as a contingency measure in the event that major projects are not commissioned on time; and
  - Summer afternoon peaks, as a contingency measure in the event that STATCOMs cannot be commissioned in time and as a potential means of deferring future investment in dynamic reactive support. This will include means to control e.g. chillers, air-conditioning, etc as well as run standby generation; and
  - reactive as well as active power demand.
- The development of supporting systems to “call” and manage demand side call.

5.3 Proposal Approval

Transpower is seeking approval from the Electricity Commission for the Proposal under rule 13.4 as a reliability investment, on the basis that the investments will be to reduce expected unserved energy on the grid following a single credible contingent event on the core grid. Investment is required now to ensure system security as our analysis has determined the existing grid configuration does not meet the Grid Reliability Standards.

Our approach recognises:

- the immediate need, by providing a solution with the minimum expected net market cost, derived from a short list of options which included transmission alternatives from a RFP process
- the nature of the load mix in the upper North Island is changing (as the installation of heat pumps and motors continues), which will result in a changing need for further dynamic reactive support. We are committed to install load monitoring equipment to build our understanding of the changing demands on the system. This is essential to ensure optimal investment in the future
- new generation in the region would have a significant impact on the requirement for dynamic reactive support. As there appears little prospect of any emerging in the medium term, we have covered the possibility of no new generation by planning to install two STATCOMs by 2014.
- although no demand-side options were offered as alternatives in our RFP process, demand-side options have significant value:
  - If successfully developed they can be used to defer significant capital investment
  - Where uncertainty exists (around the emergence of new generation, for instance) they have significant option value and may enable unnecessary investment to be avoided
  - They an important contingency measures for managing the maintenance of existing transmission equipment and the possibility of delays in commissioning new transmission

  Demand-side options take advantage of “low value” load allowing supply to be curtailed for where the compensation offered results in this being economically preferred by consumers. We will take some initiatives forward which will ensure demand-side solutions are practicable considerations in the future in Auckland that help defer the need for dynamic support.

- our intent to investigate transmission solutions that are not current practice in New Zealand, through further studies into advancing series compensation of the NIGUP line, which may be an economic alternative to investment in further dynamic reactive support
- system operation becomes more challenging with a greater dependence on reactive support and a mixture of devices spread over a wide area. This is addressed by two initiatives essential for the day to day management and optimal operation with:
    - a RPC to permit the optimal dispatch of reactive devices
    - enhancement to the real time tools used in system operation to ensure operators are trained to be more "situationally aware" and can utilise the full capability of the devices.

The Proposal provides a long term solution using devices with potentially greater reliability and reduced energy consumption than other options. The use of STATCOMs as proposed allows:

- dynamic reactive support to be located where it can be most effective, for instance in Northland and Auckland
- a smaller requirement for space in substations and lower voltage connection than the equivalent SVC
- reduced harmonics and need for filtering that an equivalent SVC requires.

It is recognised that grid connected STATCOMs are relatively new. The technology has been widely used to address the transient voltage performance of wind generation but is less commonly used for grid solutions. We are and will continue to monitor the performance of STATCOMs both at Kikiwa and internationally.

Importantly, the Proposal provides the upper North Island with greater resilience to High Impact Low Probability (HILP) events - unforeseen multiple failures of power system equipment - both within and external to the upper North Island. This resilience comes from:

- the distribution of STATCOMs within the region
- the ability of STATCOMs to respond transiently to both over- and under-voltages
- enabling demand-side response to assist with planned outages and system restoration
- improving our understanding of the power system dynamics of the region through load monitoring
- providing the System Operator with tools to enable situational awareness in a region that comprises a third of New Zealand peak demand and is heavily dependant on transmission into the region.

The solution fits within the requirements of our Transmission Code which is drawn from international practice and therefore reflects our view of Good Electricity Industry Practice.

In conclusion, the Proposal balances the need for investment now, while managing future uncertainties appropriately. It also provides flexibility to take advantage of the outcomes of the investigative and demand-side work proposed to determine the need for future investment. The Proposal should be approved by the Electricity Commission.

5.4 DP12 and DP14 – Advancing series capacitors on the new WKM-BHL line

As part of our analysis we also considered advancing the timing of the installation of series capacitors on the new NIGIP line.

The NIGUP included installing series capacitors on the new NIGUP line as a modelled project which, using our updated demand forecast, will occur in 2025. This was necessary to access the high thermal capacity of the new line, by ensuring equal sharing across all lines into Auckland. Series capacitors effectively lower the impedance of the line and, as a result, also reduce the need for dynamic reactive support in Auckland by allowing more reactive power to flow into the region during faults, they may also result in a significant benefit from a reduction in system losses. Although mature worldwide, this is a solution not previously contemplated in New Zealand.

We have begun an investigation into the feasibility of advancing their installation and this may be the next logical development option beyond 2015 once the region specific needs are addressed in Northland and Auckland by the two STATCOMs proposed here.

5.5 Timing of the Proposal

Technical analysis has demonstrated that the existing grid configuration does not meet the Grid Reliability Standards now, so it is proposed to:

- install the first two STATCOMs as soon as possible (by 2012 and 2013)
- install the RPC by 2013
- undertake the proposed load monitoring in 2011
- enhance the dynamic stability analysis software in 2011 and 2012
- undertake the demand-side initiatives from 2011.

5.6 Compliance with the processes set out in the Rules

The Commission may approve a proposed reliability investment where the proposed investment complies with the processes set out in the Rules.

The processes in the Rules require us to:

- submit a grid upgrade plan in accordance with Rule 12.2
- comply with any requests from the Commission prescribed in writing to provide information it considers is reasonably required to enable it and interested persons to evaluate the proposed investment – Rule 12.3.4
- comply with the timetable for consultation and approval of reliability investments proposed in our grid upgrade plan, agreed between us and the Commission, or as stipulated by the Commission, in accordance with Rule 13.2
- respond to any requests for further investigation or further information in accordance with Rule 13.3.3.

5.7 Submission of a Grid Upgrade Plan

Rule 12.2.1 provides that either:

- We must submit a grid upgrade plan to the Commission within 3 months of receiving a written request from the Commission, or such other date as the Commission agrees, or

- We may submit a grid upgrade plan for the Commission's consideration at any other time.

We have not received a written request for submission of a grid upgrade plan. We are submitting this document, as part of its 2009 Grid Upgrade Plan to the Commission.

5.8 Provision of information

Rule 12.3.4 requires a grid upgrade plan to, amongst other things, include:

"such other content as prescribed in writing by the **Board**, to ensure that **grid upgrade plans** includes such information that the **Board** considers is reasonably required to enable the **Board** and interested parties to evaluate **proposed transmission investments**, such as indicative pricing impacts of **investment proposals**."

The Commission has not requested that we provide any additional information under Rule 12.3.4.

Accordingly, we have complied with the requirements of Rule 12.3.4.

5.9 Compliance with the timetable and process

Rule 13.2.1 requires the Commission and Transpower to agree a timetable for consultation and approval of reliability investments. In the absence of agreement, the Commission may stipulate such a timetable.

Additionally, the Commission must consult with Transpower on the process for consultation with persons that the Commission thinks should be consulted with.

We consider that, to date, it has complied with the Grid Planning Process as agreed with the Commission.

5.10 Requests for further investigation and further information

Under rule 13.3.3, the Board may:

- direct Transpower to undertake further investigations into its proposed reliability investment
- ask questions of Transpower or require further information or consultation on part or all of the Proposal
- ask Transpower to evaluate alternative reliability investments
- where Transpower possesses relevant expertise, ask Transpower to evaluate transmission alternatives.

The Commission has not requested any information under rule 13.3.3. We will comply with any requests the Commission may have in accordance with the above requirements.

6 The Proposal meets the Rule requirements

As the Proposal is a "reliability investment", the Commission can approve the Proposal under rule 13.4.1 if the Proposal:

- reflects good electricity industry practice in meeting the Grid Reliability Standards
- complies with the processes set out in the Rules
- meets the requirements of the GIT.

We consider the Commission may approve the Proposal on the grounds that it satisfies the criteria under rule 13.4.1.

7 Approval Amount for the Proposal

7.1 Approval amount sought

This application seeks Commission approval to recover the lesser of actual costs or the estimated Maximum Approved Cost (MAC) of the Proposal. The Expected End Cost of the Proposal is estimated to be $103.4 million and the MAC of the Proposal is estimated to be $110.2 million.

7.2 Approval amount methodology

We propose to use a formulaic Maximum Approval Cost (MAC). The MAC methodology allows for variations in such items as financing costs, exchange rates and commodity prices, costs typically beyond our control. We consider the use of a MAC aids transparency and makes tracking of project costs against the approved amount simple.

An allowance for the cost of foreign exchange hedging is included in the MAC.

The amount for which approval is sought from the Commission is shown below in comparison to the Expected Cost as used in the GIT analysis, and the Expected End Cost, which is the cost we expect the Proposal to cost in commissioning year dollars.

Table 7-1: Maximum Approval Cost

$NZ million	Estimated Cost	Expected Cost	Price contingency	Exchange rate variability	Exchange rate hedge	Inflation	IDC	TOTAL
Expected Cost	82.1	90.1						90.1
Expected End Cost	82.1	90.1		3.0	0.6	4.7	5.1	103.4
Maximum Approved Cost	82.1	90.1	3.1	5.8	0.6	5.3	5.3	110.2

Full details of the MAC methodology can be found in Appendix C.

Appendix A Glossary

Term	Description
Alternative Project	Projects that are reasonable to consider as alternatives to the proposed investment in applying the Grid Investment Test, in accordance with rule 19, Schedule F4, Part F Section III, Electricity Governance Rules.
APR	**A**nnual **P**lanning **R**eport produced by Transpower in March each year.
Base Case	The option against which the other options are compared. Also known as the Reference Case
Commission	The Electricity Commission
Demand-side Participation	Obtaining reductions in demand by participating consumers via pricing incentives. Also known as Demand Response or Demand-side Management.
DP	Development Plan
Dynamic reactive support	Reactive support which is continuously adjustable and automatically responds to system events to support the voltage.
Expected project costs	Expected project costs (or expected costs) represent the estimated (P50) cost plus a contingency for scope accuracy. Scope accuracy allows for unexpected variations in the design scope and a standard allowance, based on experience, for items not considered in the design.
Expected unserved energy	A forecast of the aggregate amount by which the demand for electricity exceeds the supply of electricity at each grid exit point as a result of likely planned or unplanned outages of primary transmission equipment.
GEIP	**G**ood **E**lectricity **I**ndustry **P**ractice.
GEM	**G**eneration **E**xpansion **M**odel, a model for generation expansion modelling developed by the Commission.
GIT	**G**rid **I**nvestment **T**est. A cost-benefit analysis for both reliability and economic investments. The specific rules defining the Grid Investment Test, as developed according to the process in rule 6 of section III, are set out in Schedule F4 of section III of Part F.
GUP	**G**rid **U**pgrade **P**lan. A plan for grid expansions, replacements and upgrades, developed in accordance with rule 12 of section III of part F, Electricity Governance Rules.
GXP	Grid Exit Point
Load controller	System for coordinating the control of network load management in a region encompassing networks operated by several network companies.
MAC	Maximum Approval Cost
Monte Carlo	Monte Carlo simulation is a method for iteratively evaluating a deterministic model using sets of numbers randomly generated within certain ranges as inputs. It creates a distribution of possible outcomes on which descriptive statistics can then be run.
NAaN	North Auckland and Northland Project
NIGUP	North Island Grid Upgrade Project – Whakamaru (WKM) to Brownhill (BHL) transmission line
P90 cost	Estimated 90th percentile of project costs.
Reactive Power Controller	Control system that manages and coordinates reactive devices in one or multiple substations (RPC)
Reactive support	Static and/or dynamic devices providing reactive power to the network. Also known as voltage support
Reference Case	The option against which the other options are compared. See also “Base Case.”
Reliability investment	Investments by Transpower in the grid, or alternative arrangements by Transpower, the primary effect of which is, or would be, to reduce Expected Unserved Energy.
Rules	The Electricity Governance Rules 2003. In the context of this document, it generally refers to Part F Transport, Section III Grid Upgrade and Investments.
SoO	Statement of Opportunities published by the Electricity Commission.
STATCOM	Static Synchronous Compensator
SVC	Static Var Compensator
TF	Transformer

Term	Description
Transmission Code	Transpower’s set of technical planning requirements that Transpower would apply to ensure the transmission grid remains resilient and fit for purpose, and consistent with good industry practice
Transpower	Transpower New Zealand Limited, owner and operator of New Zealand’s high-voltage electricity network (the National Grid).

Appendix B Summary of development plans

Summary of development plans

Table B-1: Development Plan Summary, Plans 1 to 3

		DP1 N-1	DP2 N-1	DP3 N-1
Forecast Year	**Summer Load (MW)**	**STATCOMs**	**Penrose TF**	**5 year OTA Contract**
2010	1920			
2011	1985	2 year, 4 out of 5, OTA contract started	2 year, 4 out of 5, OTA contract begun	5 year, 4 out of 5, OTA contract begun
2012	2048	Last year of 4 out of 5 OTA contract	Last year of 4 out of 5 OTA contract	
2013	2097	PEN33 +/- 40 Mvar	Build new 220/33 TFs at PEN, and split 33kV buses	
2014	2152	MPE33 +/- 40 Mvar	MPE33 +/- 40 Mvar	
2015	2215	PEN33 +/- 40 Mvar	HEP33 +/- 40 Mvar	Last year of 4 out of 5 OTA contract PEN33 +/- 40 Mvar
2016	2272			PEN33 +/- 40 Mvar MPE33 +/- 40 Mvar
2017	2332	HEP33 +/- 40 Mvar	PEN33 +/- 40 Mvar	HEP33 +/- 40 Mvar
2018	2391	MNG33 +/- 40 Mvar	MNG33 +/- 40 Mvar	MNG33 +/- 40 Mvar
2019	2453	GLN33/2 +/- 40 Mvar	GLN33/2 +/- 40 Mvar	GLN33/2 +/- 40 Mvar
2021	2568	PEN33 +/- 40 Mvar	MDN11 +/- 40 Mvar	PEN33 +/- 40 Mvar
2023	2678	MDN11 +/- 40 Mvar	WRU33 +/- 40 Mvar ROS22 +/- 40 Mvar	MDN11 +/- 40 Mvar
2025	2789	Series capacitor on NIGU circuits	Series capacitor on NIGU circuits	Series capacitor on NIGU circuits
2027	2895	MNG33 +/- 40 Mvar 100Mvar Caps at HEN220 50Mvar Caps at MPE110	OTA110 +/- 40 Mvar 100Mvar Caps at HEN220 50Mvar Caps at MPE110	MNG33 +/- 40 Mvar 100Mvar Caps at HEN220 50Mvar Caps at MPE110
2029	3002	OTA110 +/- 40 Mvar 100Mvar Caps at OTA220	PEN33 +/- 40 Mvar 100Mvar Caps at OTA220	OTA110 +/- 40 Mvar 100Mvar Caps at OTA220

Table B-2: Development Plan Summary, Plans 4 to 5a

		DP4 N-1	DP5 N-1	DP5a N-1
Forecast Year	**Summer Load (MW)**	**OTA 5 year contract 4 out of 5 for 2 years, 2 out of 3 for 3 years**	**MDN 15 year contract**	**MDN 5 year contract, existing exciter**
2010	1920			
2011	1985	2 year, 4 out of 5, OTA contract started	2 year, 4 out of 5, OTA contract begun 15 year MDN contract begun	2 year, 4 out of 5, OTA contract begun 5 year MDN contract begun with old exciter
2012	2048	Last year of 4 out of 5 OTA contract	Last year of 4 out of 5 OTA contract	Last year of 4 out of 5 OTA contract
2013	2097	3 year, 2 out of 3, OTA contract started		PEN33 +/- 40 Mvar
2014	2152	PEN33 +/- 40 Mvar	PEN33 +/- 40 Mvar	
2015	2215	Last year, 2 out of 3, OTA contract started		PEN33 +/- 40 Mvar Last year of MDN contract
2016	2272	PEN33 +/- 40 Mvar MPE33 +/- 40 Mvar	PEN33 +/- 40 Mvar	MPE33 +/- 40 Mvar
2017	2332	HEP33 +/- 40 Mvar		HEP33 +/- 40 Mvar
2018	2391	MNG33 +/- 40 Mvar	PEN33 +/- 40 Mvar	MNG33 +/- 40 Mvar
2019	2453	GLN33/2 +/- 40 Mvar	GLN33/2 +/- 40 Mvar	GLN33/2 +/- 40 Mvar
2021	2568	PEN33 +/- 40 Mvar	MPE33 +/- 40 Mvar	PEN33 +/- 40 Mvar
2023	2678	MDN11 +/- 40 Mvar	MNG33 +/- 40 Mvar HEP33 +/- 40 Mvar	MDN11 +/- 40 Mvar
2025	2789	Series capacitor on NIGU circuits	Series capacitor on NIGU circuits MDN33 +/- 40 Mvar	Series capacitor on NIGU circuits
2026			Last year of MDN contract	
2027	2895	MNG33 +/- 40 Mvar 100Mvar Caps at HEN220 50Mvar Caps at MPE110	MNG33 +/- 40 Mvar 100Mvar Caps at HEN220 50Mvar Caps at MPE110	MNG33 +/- 40 Mvar 100Mvar Caps at HEN220 50Mvar Caps at MPE110
2029	3002	OTA110 +/- 40 Mvar 100Mvar Caps at OTA220	OTA110 +/- 40 Mvar 100Mvar Caps at OTA220	OTA110 +/- 40 Mvar 100Mvar Caps at OTA220

Table B-3: Development Plan Summary, Plans 5b to 6c

		DP5b N-1	DP6 N-1	DP6c N-1
Forecast Year	**Summer Load (MW)**	**MDN 5 year contract, enhanced exciter**	**OTA 5 year and MDN 15 year**	**OTA 5 year, MDN 5 year contract, existing exciter**
2010	1920			
2011	1985	2 year, 4 out of 5, OTA contract begun 5 year MDN contract begun with existing exciter	5 year, 4 out of 5, OTA contract begun 15 year MDN contract begun	2 year, 4 out of 5, OTA contract begun 5 year MDN contract begun with existing exciter
2012	2048	Last year of 4 out of 5 OTA contract		Last year of 4 out of 5 OTA contract
2013	2097			2 year, 2 out of 3, OTA contract started
2014	2152	PEN33 +/- 40 Mvar		PEN33 +/- 40 Mvar
2015	2215	Last year of MDN contract	Last year of 4 out of 5 OTA contract	Last year, 2 out of 3, OTA contract started Last year of MDN contract
2016	2272	PEN33 +/- 40 Mvar MPE33 +/- 40 Mvar	2 by PEN33 +/- 40 Mvar	PEN33 +/- 40 Mvar MPE33 +/- 40 Mvar
2017	2332	HEP33 +/- 40 Mvar		HEP33 +/- 40 Mvar
2018	2391	MNG33 +/- 40 Mvar	PEN33 +/- 40 Mvar	MNG33 +/- 40 Mvar
2019	2453	GLN33/2 +/- 40 Mvar	GLN33/2 +/- 40 Mvar	GLN33/2 +/- 40 Mvar
2021	2568	PEN33 +/- 40 Mvar	MPE33 +/- 40 Mvar	PEN33 +/- 40 Mvar
2023	2678	MDN11 +/- 40 Mvar	MNG33 +/- 40 Mvar HEP33 +/- 40 Mvar	MDN11 +/- 40 Mvar
2025	2789	Series capacitor on NIGU circuits	Series capacitor on NIGU circuits MDN11 +/- 40 Mvar STATCOM	Series capacitor on NIGU circuits
2026			Last year of MDN contract	
2027	2895	MNG33 +/- 40 Mvar 100Mvar Caps at HEN220 50Mvar Caps at MPE110	MNG33 +/- 40 Mvar 100Mvar Caps at HEN220 50Mvar Caps at MPE110	MNG33 +/- 40 Mvar 100Mvar Caps at HEN220 50Mvar Caps at MPE110
2029	3002	OTA110 +/- 40 Mvar 100Mvar Caps at OTA220	OTA110 +/- 40 Mvar 100Mvar Caps at OTA220	OTA110 +/- 40 Mvar 100Mvar Caps at OTA220

Table B-4: Development Plan Summary, Plans 6d to 8

Forecast Year	Summer Load (MW)	DP6d N-1	DP7 N-1	DP8 N-1
		OTA 5 year, MDN 5 year contract, enhanced exciter	**SVCs and STATCOMs**	**Pouto wind farm**
2010	1920			
2011	1985	2 year, 4 out of 5, OTA contract begun 5 year MDN contract begun with enhanced exciter	2 year, 4 out of 5, OTA contract begun	2 year, 4 out of 5, OTA contract begun
2012	2048	Last year of 4 out of 5 OTA contract	Last year of 4 out of 5 OTA contract	Last year of 4 out of 5 OTA contract
2013	2097	2 year, 2 out of 3, OTA contract started	PEN33 +/- 40 Mvar	PEN33 +/- 40 Mvar
2014	2152		MPE110 +150/-75 Mvar SVC	MPE33 +/- 40 Mvar
2015	2215	Last year, 2 out of 3, OTA contract started Last year of MDN contract		Pouto wind-farm stage 1, 250 MW.
2016	2272	2 by PEN33 +/- 40 Mvar MPE33 +/- 40 Mvar	PEN33 +/- 40 Mvar	
2017	2332	HEP33 +/- 40 Mvar	OTA220 +150/-75 Mvar SVC	PEN33 +/- 40 Mvar
2018	2391	MNG33 +/- 40 Mvar		
2019	2453	GLN33/2 +/- 40 Mvar	ROS110 +150/-75 Mvar SVC	
2021	2568	PEN33 +/- 40 Mvar	PEN110 +150/-75 Mvar SVC	Pouto wind-farm stage 2, 250 MW.
2023	2678	MDN11 +/- 40 Mvar	HEP110 +150/-75 Mvar SVC OTA110 +150/-75 Mvar SVC	PEN33 +/- 40 Mvar GLN33/2 +/- 40 Mvar
2025	2789	Series capacitor on NIGU circuits	Series capacitor on NIGU circuits	Series capacitor on NIGU circuits
2027	2895	MNG33 +/- 40 Mvar 100Mvar Caps at HEN220 50Mvar Caps at MPE110	PEN33 +/- 40 Mvar 100Mvar Caps at HEN220 50Mvar Caps at MPE110	PEN33 +/- 40 Mvar 100Mvar Caps at HEN220 50Mvar Caps at MPE110
2029	3002	OTA110 +/- 40 Mvar 100Mvar Caps at OTA220	MPE33 +/- 40 Mvar 100Mvar Caps at OTA220	OTA33 +/- 40 Mvar 100Mvar Caps at OTA220

Table B-5: Development Plan Summary, Plans 9a, 10, and 15

		DP9a **N-1**	**DP15** **N-1**	**DP10** **N-1**
Forecast Year	**Summer Load (MW)**	**Rodney generation in 2017 with STATCOMs**	**Rodney generation with OTA condensers**	**Distribution network STATCOMs**
2010	1920			
2011	1985	2 year, 4 out of 5, OTA contract begun	2 year, 4 out of 5, OTA contract begun	2 year, 4 out of 5, OTA contract started
2012	2048	Last year of 4 out of 5 OTA contract	Last year of 4 out of 5 OTA contract	Last year of 4 out of 5 OTA contract
2013	2097	PEN33 +/- 40 Mvar	3 year, 2 out of 3, OTA contract started	PEN33 +/- 40 Mvar
2014	2152	MPE33 +/- 40 Mvar	PEN33 +/- 40 Mvar	ALB 11kV +/-8MVAR STATCOM BRB 33kV 8MVAR OTA_T4 11kV 8MVAR HEN 11kV 8MVAR LST_110/PEN 11kV 8MVAR MPE33kV 8MVAR
2015	2215	PEN33 +/- 40 Mvar	Last year, 2 out of 3, OTA contract	PEN33 +/- 40 Mvar
2016	2272		PEN33 +/- 40 Mvar MPE33 +/- 40 Mvar	
2017	2332	400 MW generator at Rodney	400 MW generator at Rodney	HEP33 +/- 40 Mvar
2018	2391			MNG33 +/- 40 Mvar
2019	2453			GLN33/2 +/- 40 Mvar
2021	2568			PEN33 +/- 40 Mvar
2023	2678	GLN33 +/- 40 Mvar	GLN33 +/- 40 Mvar	MDN11 +/- 40 Mvar
2025	2789	Series capacitor on NIGU circuits	Series capacitor on NIGU circuits	Series capacitor on NIGU circuits
2027	2895	50 Mvar Caps at OTA110	50 Mvar Caps at OTA110	MNG33 +/- 40 Mvar 100Mvar Caps at HEN220 50Mvar Caps at MPE110
2029	3002	HEP33+/- 40 Mvar 50 Mvar caps at HEN110 75 Mvar caps at HEN220	HEP33+/- 40 Mvar 50 Mvar caps at HEN110 75 Mvar caps at HEN220	OTA110 +/- 40 Mvar 100Mvar Caps at OTA220

Table B-6: Development Plan Summary, Plans 11, 12 and 14

		DP11 N-G-1	DP12 N-1	DP14 N-1
Forecast Year	**Summer Load (MW)**	**N-G-1 STATCOMs**	**Series caps in 2015**	**OTA 5 year contract 4 out of 5 for 2 years, 2 out of 3 for 3 years** **Series capacitors in 2016**
2010	1920	PEN33 +/- 40 Mvar		
2011	1985	2 year, 4 out of 5, OTA contract begun PEN33 +/- 40 Mvar OTA110 +/- 40 Mvar MPE33 +/- 40 Mvar	2 year, 4 out of 5, OTA contract started	2 year, 4 out of 5, OTA contract started
2012	2048		Last year of 4 out of 5 OTA contract	Last year of 4 out of 5 OTA contract
2013	2097		PEN33 +/- 40 Mvar	2 year, 2 out of 3, OTA contract started
2014	2152		MPE33 +/- 40 Mvar	PEN33 +/- 40 Mvar
2015	2215	MNG33 +/- 40 Mvar	Series caps on NIGU circuits	Last year, 2 out of 3, OTA contract started
2016	2272	GLN33 +/- 40 Mvar	MPE33 +/- 40 Mvar	Series caps on NIGU circuits MPE33 +/- 40 Mvar
2017	2332	PEN33 +/- 40 Mvar	PEN33 +/- 40 Mvar	PEN33 +/- 40 Mvar
2018	2391			
2019	2453			
2021	2568	MDN11 +/- 40 Mvar TAK33 +/- 40 Mvar	PEN33 +/- 40 Mvar GLN33/2 +/- 40 Mvar	PEN33 +/- 40 Mvar GLN33/2 +/- 40 Mvar
2023	2678	ROS22 +/- 40 Mvar MPE33 +/- 40 Mvar	MNG33 +/- 40 Mvar	MNG33 +/- 40 Mvar
2025	2789	Series caps on NIGU circuits MNG33 +/- 40 Mvar	MDN11 +/- 40 Mvar	MDN11 +/- 40 Mvar
2027	2895	MDN11 +/- 40 Mvar PEN33 +/- 40 Mvar 100Mvar Caps at HEN220 50Mvar Caps at MPE110	HEP33 +/- 40 Mvar MNG33 +/- 40 Mvar 100Mvar Caps at HEN220 50Mvar Caps at MPE110	HEP33 +/- 40 Mvar MNG33 +/- 40 Mvar 100Mvar Caps at HEN220 50Mvar Caps at MPE110
2029	3002	HEP33 +/- 40 Mvar ALB33 +/- 40 Mvar 100Mvar Caps at OTA220	OTA110 +/- 40 Mvar 100Mvar Caps at OTA220	OTA110 +/- 40 Mvar 100Mvar Caps at OTA220

Table B-7: Development Plan Summary, Plans 16, and 17

		DP16 N-1	DP17 N-1
Forecast Year	**Summer Load (MW)**	**Otahuhu generation in 2015 with OTA condensers**	**Otahuhu generation in 2015 with STATCOMs**
2010	1920		
2011	1985	2 year, 4 out of 5, OTA contract begun	2 year, 4 out of 5, OTA contract begun
2012	2048	Last year of 4 out of 5 OTA contract	Last year of 4 out of 5 OTA contract
2013	2097	3 year, 2 out of 3, OTA contract started	PEN33 +/- 40 Mvar
2014	2152	PEN33 +/- 40 Mvar	MPE33 +/- 40 Mvar
2015	2215	Last year, 2 out of 3, OTA contract 400 MW generator at Otahuhu	400 MW generator at Otahuhu
2016	2272		
2017	2332		
2018	2391	MPE33 +/- 40 Mvar	
2019	2453		
2021	2568	PEN33 +/- 40 Mvar	PEN33 +/- 40 Mvar
2023	2678	GLN33 +/- 40 Mvar PEN33 +/- 40 Mvar	GLN33 +/- 40 Mvar PEN33 +/- 40 Mvar
2025	2789	Series capacitor on NIGU circuits	Series capacitor on NIGU circuits
2027	2895	50 Mvar Caps at OTA110	50 Mvar Caps at OTA110
2029	3002	HEP33+/- 40 Mvar MDN11+/- 40 Mvar 50 Mvar caps at HEN110 75 Mvar caps at HEN220	HEP33+/- 40 Mvar MDN11+/- 40 Mvar 50 Mvar caps at HEN110 75 Mvar caps at HEN220

Appendix C Maximum Approval Cost methodology

This application seeks Commission approval to recover the lesser of actual costs or the estimated Maximum Approved Cost (MAC) of the Proposal.

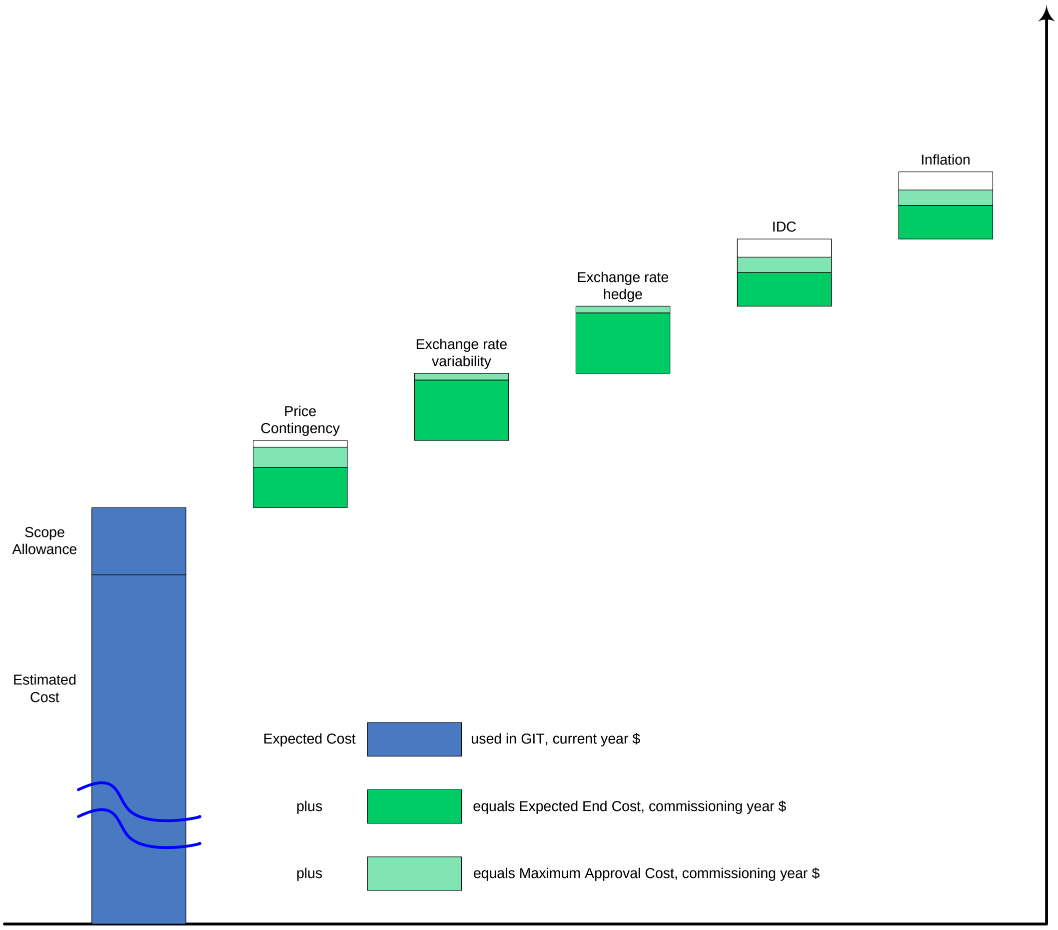
The Expected Cost of the Proposal, as used in the GIT, is estimated to be $103.4 million and the MAC of the Proposal is estimated to be $110.2 million. This section sets out how we have estimated the MAC and describes the difference between the Expected Cost and the MAC.

In previous investment proposals submitted to the Commission, we have sought approval to recover up to a P90 cost. It is expected there is only a 10% probability that the P90 figure would be exceeded once the Proposal was commissioned. The P90 figure was derived from a probabilistic analysis of the expected cost of the Proposal using a Monte Carlo approach.

However, experience has shown that the development of a P90 figure lacks transparency and in particular it is difficult to relate the P90 back to actual, trackable, project specific costs. We have applied a different method for this investment proposal and have determined a MAC. The methodology for determining a MAC is described below.

The relationship between the Expected Cost used in the GIT and the MAC is represented in Appendix C Figure C-1.

Appendix C Figure C-1: Relationship between Expected Cost and MAC



The approval amount is higher than the Expected Cost used in the GIT because:

- The Expected Cost comprises an estimated cost plus an allowance for scope variations. It does not include an allowance for all uncertainties present in a construction project of the type proposed.
- The Expected Cost is in current (today's) dollars, whereas the approval amount is an estimate of the end cost of the project in future (commissioning year) dollars.
- The approval amount is required to cover the full cost of the project including financing costs, price variations on materials, exchange rate variations and foreign exchange hedging, etc.

Importantly at the approval stage the actual costs are known at a high level only as such things as line routes are yet to be determined and there is also a reasonable time gap between approvals and when the majority of actual costs are incurred.

Appendix C Figure C-1 shows that the Expected Cost used in the GIT is the Estimated Cost plus Scope Allowance only, in current dollars.

The Maximum Approved Cost is higher than the Expected Cost because it includes an allowance for price contingencies and all other variables.

Method of calculating Maximum Approval Cost

The following inputs and variables are considered in deriving the Expect Cost and MAC:

- **Estimated Cost.** The Estimated Cost is the estimated cost of designing, procuring, constructing and commissioning the components which make up the Proposal. These costs can include decommissioning costs and the costs of obtaining designations, easements, resource consents and property purchases for these works if applicable. The Estimated Cost does not include contingencies. The Estimated Cost is in current dollars, as calculated on the Reference Date.
- **Reference Date.** We prepared estimated capital costs as at 1 February 2010. A reference date is used to ensure consistency between the estimated capital costs of components within each option considered in the GIT and between options. For calculating costs at commissioning time, we have assumed various commissioning dates between 2011 and 2015. These commissioning dates are assumed to be the dates at which accumulated costs for the project would be included in our regulated asset base and from which costs would start to be recovered through the Transmission Pricing Methodology.
- **Scope allowance.** We also estimates a scope allowance, which is added to the Estimated Cost, to cover two distinct categories of costs: (a) costs for works which are planned, but which have not been included in the estimated capital costs except through this general allowance, and (b) costs for works not anticipated at the time costs were estimated. The Estimated Cost plus Scope Allowance equals the **Expected Cost** of the project or various components of it and this is the cost used in GIT analyses. The Scope Allowance is treated as a fixed percentage of Estimated Costs which are added to the Estimated Cost.
- **Price Contingency.** As regulatory approval occurs prior to the issuing of tenders, there is uncertainty over the price of equipment to be installed. In particular, this includes the risks that:
  - market pressures may affect the cost of capital items, e.g. if worldwide demand for transformers is high at the time we seek tenders, the prices offered may reflect a tighter supply situation and therefore be higher than at other times; and
  - commodity price movements may occur. Tender prices for some capital items include escalators linked to market price variations in significant elements of that item e.g. metals such as steel and copper. As with exchange rate variations, we would not typically consider hedging anticipated commitments until a contract is awarded/signed. This is because of the somewhat speculative nature of entering commodity futures contracts in advance of commitment and the costs involved, which may or may not be required, depending upon the terms of the eventual contract. Hence, we are exposed to commodity price movements up until contracts are signed and so an estimate is made of the potential cost variation this might cause.

Price movements could be downward as well as upward and for this reason the price contingency is estimated as the minimum and maximum variations expected. A price contingency of -10% to +20%, would be typical.

For the purposes of calculating the Expected End Cost, the mean-point of this range is taken, i.e. 3%, for the example above.

For the purposes of calculating the MAC, the 60-70th percentile of this range is taken, i.e. 12%, for the example above.

- **Exchange rate variations.** Our current practice is to enter foreign exchange contracts to hedge foreign exchange movements, once contractual commitments are made. This provides NZ dollar cost certainty from the point that tenders are awarded/contracts signed.

We do not, typically, hedge anticipated commitments. This is because of the somewhat speculative nature of entering foreign exchange contracts in advance of commitment and the added costs of having to pay option premiums for hedging a range of possible currencies and execution dates, most of which would not be exercised. Hence the requirement to estimate the effect on costs of exchange rates moving in the interim period before signing contracts.

The Estimated Costs were based on the exchange rate prevailing on the Reference Date, 1 February 2010.

The exchange rate variations are based on historical volatility and are estimated on either a 50th or 90th percentile likely over the period between the Reference Date and when tenders might be accepted. The methodology used to calculate the 50th and 90th percentile volatility variations is as developed by Bancorp and as used for the HVDC Proposal.

- **Exchange rate hedge.** As mentioned above, our current practice is to enter foreign exchange contracts to hedge foreign exchange movements, once contractual commitments are made. The hedging cost included has been estimated using current forward exchange rate premiums, for the expected period between committing to contracts which include foreign exchange exposure and the expected payment dates under those contracts.
- **Real interest rates**. Real interest rates are used in the calculation of Interest During Construction costs and are assumed to vary between 3.2% and 5.2%, with a mean of 4.2%. The nominal interest rate is the real interest rate plus the inflation rate, equating to a mean nominal interest rate of 7.2% in this instance. This is approximately Transpower's current cost of debt.

For the purposes of calculating the Expected End Cost, the mean of 4.2% is used. This is also used in the MAC.

- **Inflation**. We assume inflation will vary between 2% and 4% per annum, with a mean of 3%.

For the purposes of calculating the Expected End Cost, the mean of 3% per annum is used. This is also used in the MAC.

Results of Expected Cost, Expected End Cost and MAC calculations

The Expected Cost of the Proposal, as estimated in 2010, is $90.1 million.

This cost includes a scope allowance and represents our estimate of the cost of designing, purchasing, constructing and commissioning the Proposal, in current dollars. We will not start recovering the costs of a stage of the Proposal until it is commissioned. The cost we will look to recover at that time is higher, due to financing costs incurred throughout the construction period and inflation.

The MAC for the Proposal is $110.2 million and we are seeking approval to recover the lesser of actual costs or the MAC. Appendix C Table C-1 shows the break down of the MAC.

Appendix C Table C-1: Maximum Approval Cost for the Proposal, $ million

$NZ million	Estimated Cost	Expected Cost	Price contingency	Exchange rate variability	Exchange rate hedge	Inflation	IDC	TOTAL
Expected Cost	82.1	90.1						90.1
Expected End Cost	82.1	90.1		3.0	0.6	4.7	5.1	103.4
Maximum Approved Cost	82.1	90.1	3.1	5.8	0.6	5.3	5.3	110.2

There is a probability of exceeding the MAC. If there are changes which are materially different to those assumptions used in deriving the MAC, then this cost may be exceeded. In such a case, we would apply for approval for the revised costs of the project in accordance with Rule 17.2.

For comparison, we have calculated a P90 figure for the Proposal, but using a different approach to past investment proposals. The installation of load monitoring equipment and installation of the STATCOMs themselves are different projects. They will be run as separate projects within Transpower, with different project managers and each project will have a separate budget. Therefore, we have not derived a single P90 figure for the two projects because they are simply not related. It would not be sensible, or good project management practice to establish a single contingency bucket for the two projects and transfer contingency between them. In order to align our approval amounts with good project management practice, we have therefore calculated separate P90 figures for each project within the bundle included in this GUP. The exception is for installation of the two STATCOMs where we have calculated a single value because it is likely that installation of the two STATCOMs will actually be managed as a single project. The resulting MAC and P90 values are shown in Appendix C Table C-2 below:

Appendix C Table C-2: Maximum Approval and P90 Costs

Maximum Approval Cost	P90
110.2	110.1

Summary of estimated Expected End Cost and Maximum Approval Cost

We estimate the expected end cost, with variations accounted for, to be $103.4 million and the Maximum Approval Cost of the Proposal to be $110.2 million.