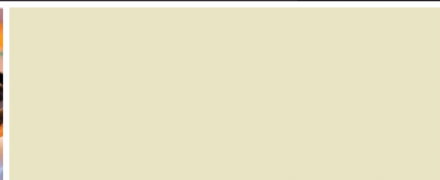
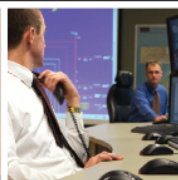
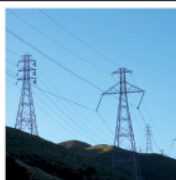
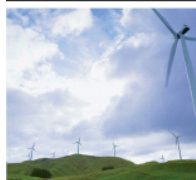


Grid Upgrade Plan 2007

Instalment 3

Part V: HVDC Grid Upgrade
Investment Proposal (Vol. 1)

TRANSPower





T R A N S P O W E R

HVDC GRID UPGRADE PROJECT

PROPOSAL

APPLICATION FOR APPROVAL

MAY 2008

Executive Overview

Transpower's HVDC Grid Upgrade Proposal

The purpose of this high voltage direct current (HVDC) inter-island Grid Upgrade Proposal is to obtain Electricity Commission approval to recover the full costs (up to \$728 million) associated with procuring, constructing and commissioning a new thyristor-based 700 MW pole and associated equipment (including converters, condensers, new control systems, transformers) at Haywards and Benmore by 2012. This pole will replace the existing Pole 1 of the HVDC inter-island link, and together with Pole 2 will provide a 1000 MW link capacity from 2012.¹

Proposal at a Glance

What:	New 700 MW Pole and associated equipment and control systems at both Haywards (North Island) and Benmore (South Island) to replace existing Pole 1.
When:	Commissioning in two stages in 2012 and 2014
How much:	Transpower is seeking approval for up to \$728 million
Total link capacity	1000 MW in 2012 (Stage 1), 1200 MW in 2014 (Stage 2).

The proposal does not include replacement of the existing lines and cables of the HVDC link comprising 571 km of bipolar transmission line and 40 km of submarine cables.

HVDC Inter-Island Link

The HVDC inter-island link connects the North and South Islands of New Zealand.

The link is made up of two "poles", one of which was commissioned in 1965 utilising mercury arc valve technology (known as Pole 1), and the other commissioned in 1991 using newer thyristor technology (known as Pole 2).

Pole 1 is now over 42 years old, utilising equipment and technology that are no longer supported by manufacturers. Transpower has decommissioned half of the existing Pole 1 and is making the remainder available for limited operation during peak demand periods for 2008, with use of pole 1 for subsequent years to be determined on an annual basis. Without Pole 1, the capacity of the link with Pole 2 operating is presently 700 MW.

Process to Date

Transpower has been considering the future of Pole 1 of the HVDC inter-island link for some time - initially as part of its system vision planning work in 2003. Subsequent to this initial work, Transpower submitted a Grid Upgrade Plan to the Electricity Commission to replace Pole 1 in 2005.

Consideration of this proposal was suspended in June 2006 pending clarification of how the proposal should be assessed under the Grid Investment Test (the regulatory test that Transpower's major investments must meet).²

During late 2006 and early 2007, Transpower and the Electricity Commission held discussions to clarify those uncertainties. In March 2007, Transpower began an open and transparent process to consider whether it would be economic to replace Pole 1 pursuant to the requirements of the Electricity Governance Rules (Rules). This process included

¹ The investment is staged so that capacity can be released incrementally. Stage 2 of this proposal (scheduled for 2014) will increase the link capacity to 1200 MW. A further stage (Stage 3), has not been included as part of this proposal as it falls beyond 2017. However, if Stage 3 were undertaken the overall capacity of the link would increase to 1400 MW.

² The 2005 proposal was finally and formally withdrawn on 2 May 2008.

engagement with interested parties to develop a short list of options, and publish key assumptions, methodologies and models to be used in the analysis. From this process four short-listed options were developed:

- Base case option – no Pole 1 replacement;
- Option 1 – 500 MW pole at Benmore and Haywards;
- Option 2 – 700 MW pole at Benmore and Haywards; and
- Option 3 – 1000 MW pole at Benmore and Haywards.

Application of the Grid Investment Test

Once the overall approach to applying the Grid Investment Test had been clarified with the Electricity Commission, Transpower undertook an initial assessment of the four short-listed options. This assessment (taking into account points raised in consultation) showed that the preferred option from an economic perspective was the 700 MW Pole 1 option as it had a higher net market benefit (\$191 million) compared to the next closest option (500 MW pole, \$138 million).

Table 0-1: Grid Investment Test Results

Item	Base Case No Pole 1 replacement	Option 1 500 MW Pole 1	Option 2 700 MW Pole 1	Option 3 1000 MW Pole 1
Present Value 2007\$M				
Generation fixed costs (A)	7,000	6,847	6,769	6,800
Generation variable costs (B)	9,499	9,392	9,356	9,291
HVDC costs (C)	59	325	436	554
AC augmentation costs (D)	45	47	48	49
Terminal benefit (E)	5,858	5,712	5,660	5,661
Total cost (A+B+C+D+E)	22,461	22,323	22,269	22,355
Expected Net Market Benefit	-	138	191	106

Following its initial assessment, Transpower consulted with affected parties under Part F of the Rules between February and April 2008. The purpose of the consultation was to determine whether Transpower had applied the Grid Investment Test reasonably.

Transpower received four submissions to this consultation. In general terms, two submissions considered that the analysis was reasonable, and two raised concerns with some aspects of the analysis. Transpower has considered these submissions fully and without preconceptions in determining the final proposal.

Other benefits of the HVDC pole 1 replacement proposal

The Grid Investment Test assesses the economic merit of a proposal against a specific set of costs and benefits, which mostly assume normal operation of the system. Abnormal and high impact low probability (HILP) events are, in general, not considered.

Transpower considers that this Proposal also provides a number of benefits, not fully reflected in the Grid Investment Test results, including:

- enabling the development of renewable generation in the South Island by ensuring a reliable connection between the South and North Island;

- enabling development of ancillary markets (such as frequency keeping, reserves and balancing markets) to support increased generation from intermittent renewable sources;
- increasing resilience of the National Grid to high impact, low probability events by increasing the flexibility of system operation;
- improving security of supply in dry years, by enabling greater southwards transfer of electricity for North Island generators when there are low inflows into the South Island hydro schemes; and
- mitigating the consequences for security of supply of a Pole 2 failure, noting that the existing Pole 2 is aging and there is an inherent, increasing risk of it failing.

Capital Cost

Replacement of the existing Pole 1 with a new 700 MW thyristor-based pole will be undertaken in two stages, with the capacity of the link increasing to 1000 MW after Stage 1 (in 2012) and 1200 MW after Stage 2 (in 2014). Further work to increase the capacity to a maximum of 1400 MW has been modelled by Transpower, but not included within this investment proposal, as it would not be required until beyond 2017.

For approval purposes, the costs for each stage of investment are calculated for a 90% probability level (in other words, there is a 90% probability of the actual costs falling within the figures quoted). At this level, the capital costs total \$728 million in the expected commissioning years of 2012 and 2014, and this is the amount for which approval is sought from the Electricity Commission.

Category	Estimated P50 cost \$million	Estimated P90 cost \$million
Stage 1	573	676
Stage 2	47	52
Total	620	728

This Document

The remainder of this document is Transpower's formal submission to the Electricity Commission for the purposes of obtaining approval for the funding of the HVDC Grid Upgrade Proposal. It is split into two parts where:

- Part A provides the actual proposal in terms of the activities for which cost recovery up to \$728 million is sought; and
- Part B, together with the attachments, provides justification for the proposal set out in Part A. As well as the technical and economic analysis surrounding the development of the proposal, Part B also justifies the proposal against the requirements of the Rules.

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Volume 1	
Proposal	
A	Revised GIT results
B	Updated MAV Pole 1 - Economic Analysis
C	Covec Report on South Island demand
D	MMA Report on reserves risk
E	Transpower's consideration of submissions
F	Submissions received and Transpower's responses during the consultation period
Volume 2	
Consultation Paper	
A	Proposed GIT Results
B	Databook
C	Development plans for short-listed options
D	Options – Ranking
E	Options – Identification and Screening
F	MAV Pole 1 – Economic Analysis
G	Further information – PLEXOS results

PART A - The Proposal

This part presents Transpower's HVDC Grid Upgrade Proposal (the Proposal).

Transpower is seeking Electricity Commission approval to recover the full costs associated with implementing the Proposal.

Stage 1:

- Procuring, constructing and commissioning new HVDC converter station facilities including control systems at Haywards and Benmore that:
 - have nominal continuous ratings of around 700 MW at 350 kV; and
 - have AC filters suitable for bipole operation of around 1200 MW.
- Procuring and constructing seismic strengthening works for existing and new switchyards at Haywards and Benmore.
- Procuring, constructing and commissioning extended and new 220 kV switchyards to facilitate the connection of the new HVDC converter station facilities and (in preparation for Stage 2) new dynamic reactive power compensation facilities at Haywards.
- Procuring, constructing and commissioning extended 220 kV switchyards to facilitate the connection of the new HVDC converter station facilities at Benmore.
- Decommissioning and removal of existing HVDC control system facilities at Haywards and Benmore including:
 - Pole 2 control systems and valve base electronics; and
 - bipole control systems.
- Procuring, constructing and commissioning new HVDC control system facilities at Haywards and Benmore including:
 - Pole 2 control systems and valve base electronics;
 - bipole control systems; and
 - SCADA interfaces at the converter stations.
- Procuring, constructing and commissioning communication facilities to enable efficient operation of the bipole link.
- Procuring, constructing and commissioning new unit connection transformers for the existing C7, C8, C9 and C10 synchronous condensers at Haywards.
- HVDC transmission line works and activities required to facilitate the above.

Stage 2:

- Procuring, constructing and commissioning new dynamic reactive power compensation facilities at Haywards to enable bipole operation of at least 1200 MW.

Common to Stage 1 and Stage 2:

- Obtaining approvals under the Resource Management Act (including designations and consents) and easements and property purchases for the above.
- Any additional minor works and activities required to facilitate the above.

Timing

Transpower will work towards commissioning Stage 1 of the Proposal in 2012 and Stage 2 in 2014.

Costs

On commissioning of each stage of the Proposal, Transpower will recover the full costs associated with implementing that stage up to a total amount of \$728 million. This amount is the estimated “P90” level of costs to implement the Proposal, based on the timing above, expressed in New Zealand dollars exclusive of GST.

PART B - Justification

1 Introduction

1.1 Purpose

The purpose of the HVDC Grid Upgrade Proposal, submitted as part of Transpower's 2007 Grid Upgrade Plan (2007 GUP), is to obtain Electricity Commission approval to recover the full costs associated with implementing this investment.

The purpose of Part B of this document is to provide information for the Electricity Commission to assess compliance of this Proposal with the Electricity Governance Rules 2003 (Rules). This part also informs interested parties of Transpower's assessment of submissions received as part of the consultation process and its revised Grid Investment Test (GIT) analysis.

1.2 Background to the Proposal

Transpower has been considering the future of Pole 1 of the HVDC inter-island link (Pole 1) for some time, initially as part of Transpower's System Vision planning work. Subsequent to those initial investigations, Transpower submitted a Grid Upgrade Plan to the Electricity Commission in 2005 (2005 GUP), which included an investment proposal to replace Pole 1 (HVDC Investment Proposal). Consideration of the HVDC Investment Proposal was suspended in June 2006 pending clarification of how the GIT should be applied to such a situation. Transpower withdrew the HVDC Investment Proposal from consideration by the Electricity Commission today.

During late 2006 and early 2007, Transpower and the Electricity Commission held discussions to clarify those uncertainties and in March 2007 Transpower began an open and transparent process to consider whether it would be economic to replace Pole 1, pursuant to the requirements of the Rules. The approach, input assumptions and parameters and sensitivities to be used in applying the GIT were discussed with interested parties prior to any analysis being undertaken. That approach involved the development of a short list of options and publication of the key assumptions, methodologies and models to be used in the analysis, prior to application of the GIT.

Once the approach to applying the GIT had been established, Transpower initiated its formal HVDC Pole 1 Replacement Investigation Project pursuant to the requirements of the Rules. Independent of the HVDC Pole 1 Replacement Investigation Project, in September 2007 Transpower stood down Pole 1 pending further investigation and analysis into the risks that the aging technology posed, and possible remedial actions that could be undertaken in order to return the asset to service. Transpower engaged independent experts who advised that it would be possible to undertake sufficient remedial actions (at considerable cost and time) to bring Pole 1 up to an insurable state, but that due to environmental risks, Transpower should "only consider returning half of Pole 1 back into service, in a limited operation mode only, and for no more than 1-2 years, i.e. a return to full service should not be contemplated".

As a result of this advice and the fact that for the limited period Pole 1 could be recommissioned for, the expected benefits would not exceed the expected costs and hence it would not be economic, the decision was made to decommission half of Pole 1.

On the basis of a decommissioned Pole 1, Transpower applied the GIT to the HVDC Pole 1 Replacement Investigation Project. The results of that application of the GIT show that installing 700 MW converters at Benmore and Haywards (with related works) meets the requirements of the GIT.

Transpower has consulted on its proposed GIT application, and has reviewed its approach in light of submissions from interested parties. This document and its attachments incorporate changes made taking into account these submissions.

1.3 Document structure

1.3.1 Grid Upgrade Plan

This document forms Part V of the 2007 GUP.

Transpower has already submitted the following parts of the 2007 GUP to the Electricity Commission:

- Part I, the comprehensive plan for asset management, and Part II, investment contracts, on 21 September 2007;³
- Part III relating to the North Auckland and Northland Investment Proposal on 21 September 2007;
- Part IV relating to the West Coast Investment Proposal on 19 October 2007.

1.3.2 HVDC Grid Upgrade Project Investment Proposal

Part A of this document above contains the investment proposal.

Part B of this document describes the processes followed and information analysed by Transpower in reaching its decision to seek approval from the Electricity Commission to recover the full costs associated with implementing the Proposal set out in Part A. Accordingly, Part B of this document is not part of the Proposal itself, but contains justification for the Proposal.

Part B of this document contains:

- a description of the consultation process;
- discussion of which type of investment this Proposal is submitted against under the Rules, i.e. reliability or economic;
- a description of the process Transpower undertook and the information analysed to identify and consider all options with a view to producing a short list of options;
- a description of the process Transpower undertook and the information analysed to select the Proposal;
- illustration of how the Proposal meets the requirements of the Rules;
- consideration of timing of the Proposal;
- illustration of how the Proposal meets the wider policy objectives of the Government and Electricity Commission for transmission in New Zealand;
- a recommendation to the Electricity Commission to approve the Proposal; and
- discussion of how, post-approval, Transpower intends to manage the capital costs associated with implementing the Proposal.

1.4 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.

³ As required under Rule 12.3, Section III of Part F of the Rules.

2 Consultation Process

2.1 Transpower's proposed application of the Grid Investment Test

On 1 February 2008, Transpower released and publicised a consultation paper entitled 'Inter-Island HVDC Pole 1 Replacement Investigation' (Consultation Paper), a copy of which is included in Volume 2 with its attachments. The Consultation Paper sets out Transpower's provisional view that the 700 MW replacement option was the most economic option available. The Consultation Paper attached documents as set out in Volume 2 to this Proposal.

The documents were clarified on the 7 February 2008 and 17 March 2008. This period of consultation followed the open and extensive engagement with customers, and other interested parties, detailed below at section 4.2.

The Consultation Paper sets out Transpower's thinking on the proposed application of the GIT, at the time, to the Inter-Island HVDC Pole 1 Replacement Investigation and on why its proposed application was reasonable. Its analysis at that stage showed that the 700 MW option, which is now the Proposal, maximised the expected net market benefit of the options considered, compared to the Base Case, the expected net market benefit was positive and that this result was robust to a number of sensitivities.

Transpower published a report from the results of PLEXOS modelling carried out by McLennan Magasanik Associates (MMA) on 29 February 2008. One of four appendices attached to this report – published slightly later on 20 March 2008 – covered PLEXOS modelling of competition and consumer benefits. These reports were published primarily for information. Transpower has relied on neither report in its application of the GIT. Nonetheless, consistent with views of MEUG that having two models with similar results was helpful, Transpower believes that the results of these reports reinforce its conclusions, as explained in more detail below.

2.2 Consultation on Transpower's proposed application of the Grid Investment Test

Transpower's consultation on the Consultation Paper ran from 1 February 2008 until 5pm on Friday 4 April 2008, as agreed with the Electricity Commission.⁴

A consultation briefing was held on 22 February 2008, at which 33 people attended from industry participants including Transpower customers, consumer representatives, engineering firms, consultants, the Electricity Commission and the office of the Parliamentary Commissioner for the Environment. The briefing summarised the Consultation Paper⁵ and gave an early opportunity for interested parties to make comments to Transpower.

Transpower received letters from Meridian Energy on the 21 and 22 February and 18 March 2008. Transpower responded to these letters on 12, 20 and 28 March 2008. Transpower also received a letter from Contact Energy on 11 March 2008 to which it responded on 27 March 2008.

Transpower received further submissions from Contact Energy, Genesis Energy, the Major Electricity Users' Group and Meridian Energy on 4 April 2008.

All submissions from interested parties, and Transpower's responses, have been posted on Transpower's website at <http://www.gridnewzealand.co.nz/n282,110.html>. For ease of

⁴ See Agreed process and timeline for consultation of 13 December 2007 at <http://www.gridnewzealand.co.nz/n282,110.html>.

⁵ A copy of Transpower's presentation is available at <http://www.gridnewzealand.co.nz/n282,110.html>.

reference, Transpower has also included these documents as Attachment F to this document.

Attachment E summarises the issues raised by these submissions and their impact, if any, on Transpower's analysis (as reflected in the Attachment A, Revised GIT Results, to this document). Broadly, two submissions considered that the analysis was reasonable and two raised concerns with some aspects of the analysis. Transpower has considered these submissions fully and without preconceptions in determining the final proposal.

3 Type of investment

Under the Rules, Transpower may propose an investment that meets a defined need to the Electricity Commission for approval. Those investments are split into two different types - "reliability investments" and "economic investments". As economic investments are investments which, amongst other things, are not reliability investments, one must first assess whether an investment is a reliability investment within the terms of the Rules in order to decide which type of investment a project involves.

3.1 Definition of reliability investment

Reliability investments are defined under the Rules as follows:

*"investments made by **Transpower** in the **grid**, or alternative arrangements by **Transpower**, the primary effect of which is, or would be, to reduce **expected unserved energy**".*

The Rules then provide for a catch all of economic investment which is defined as:

*"investments in the **grid** that can be justified on the basis of the **grid investment test** under section III of part F and are not **reliability investments**".*

Accordingly, the first step is to determine whether an investment's primary effect is to reduce expected unserved energy. Expected unserved energy is defined under the Rules as follows:

*"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 and unplanned outages of **primary transmission equipment**".*

In turn, primary transmission equipment is defined in the Rules as follows:

*"any plant or equipment forming part of the **grid** which enables the bulk transfer of **electricity**, including without limitation transmission circuits, busbars and switchgear".*

Accordingly, for an investment to be a reliability investment it must pass the following four-limbed test:

- it must be an investment made by Transpower in the grid or an alternative arrangement by Transpower;
- it must have the primary effect of reducing expected unserved energy;
- the expected unserved energy must result from likely planned or unplanned outages; and
- the likely planned or unplanned outages must be to primary transmission equipment.

3.1.1 Investment in the grid

The "grid" is defined in the Rules as:

*"the system of transmission lines, substations and other works, including the **HVDC link** used to connect the **grid injection points** and **grid exit points** to convey **electricity** throughout the North Island and South Island of New Zealand".*

The Proposal is an investment by Transpower in the grid as it involves investment in the HVDC link.

3.1.2 Reducing expected unserved energy

If demand for electricity exceeds supply of electricity there will be unserved energy (i.e. energy that is unable to be transported to where it is required).

The HVDC link provides access to the South Island's large hydro generation capacity for North Islanders, which may be important for the North Island in peak winter periods. For South Islanders, the link provides access to the North Island's gas and coal generation, which may be important for the South Island during dry winter and summer periods. However, providing all currently commissioned generation in both the North and South Island's is available, both islands are self-sufficient at peak times, or in dry years, and hence the primary effect of the HVDC cannot currently be classified as reducing expected unserved energy.

3.1.3 Conclusion on type of investment

The Proposal is an investment in the grid but does not meet the second limb of the reliability investment test. Therefore, provided it meets the requirements of the GIT, the Proposal is an economic investment as defined in the Rules.⁶

4 Identification and consideration of Options

4.1 Alternative Projects

To obtain cost recovery of economic investments under the Rules, Transpower must apply the GIT reasonably. The investments being contemplated by the HVDC Pole 1 Replacement Investigation Project are economic investments (i.e. it is an investment in the grid, the main purpose of which is not to reduce expected unserved energy). For economic investments, the GIT requires a proposed investment to maximise the expected net market benefits compared with a number of alternative projects and result in expected net market benefits greater than zero.

Accordingly, to enable Transpower to compare a proposed investment with "alternative projects" under the GIT Transpower must first identify those options that fall within the definition of "alternative projects" under the Rules. "Alternative Projects" are defined in the Schedule F4 of the Rules as follows:

19. ... any alternative transmission augmentation projects and **transmission alternatives** to the **proposed investment**, including any variant of the **proposed investment** that involves a non-negligible change in the timing of that **proposed investment**, that are:

19.1. technically feasible;

19.2. reasonably practicable having regard to the matters set out in clauses 8.1 to 8.4;

⁶ It is possible at some time in the future, that investment in the HVDC link may meet the criteria to be classified as a reliability investment. In some circumstances, the generation expansion plans developed as a part of the GIT analysis presented in this document, show either or both North and South Islands becoming capacity (MW) constrained and hence no longer being self-sufficient. At the point where the HVDC link is required to meet peak capacity in one or other islands, it might be argued that the primary purpose would become reducing expected unserved energy. The implications of this change are not explored further in this document.

- 19.3. *reasonably likely to proceed if neither the **proposed investment** nor any other **alternative project** proceeds and unlikely to proceed if the **proposed investment** does proceed;*
- 19.4. *reasonably expected to provide similar benefits, in type but not necessarily in magnitude, to relevant nodes, as the **proposed investment**; and*
- 19.5. *reasonably expected to enable the deferment of investment of the type contemplated by the **proposed investment** for a period of 12 months or more.*

4.2 Option identification

4.2.1 Long list of options

A full description of the Options Identification process used to produce the long list of options is provided in Attachment E to the Consultation Paper (see Volume 2).

To qualify for the long list, options only needed to be technically feasible (i.e. meet the clause 19.1 criteria only (set out in section 4.1 above)) for consideration as an alternative project. For the long list of options, no attempt was made to determine whether an option was reasonably practicable or likely to proceed based on technical practicality or cost.

Transpower identified 83 options (including transmission and non-transmission options) that are technically possible for inclusion in the long list of options. Those options fell within four broad categories:

- an option with no new investment;
- HVDC options - the 66 HVDC options reflect different combinations of HVDC terminal locations in the North Island and South Island and differing HVDC pole capacities;
- HVAC options - the 8 HVAC options reflect replacing the HVDC with HVAC, over a limited number of locations; and
- other options - the 9 other options represent alternatives to replacing Pole 1 of the HVDC with either HVDC or HVAC equipment.

4.2.2 Options screening

A set of high level screening criteria was developed to eliminate those options that are not appropriate and, therefore, do not warrant further analysis. These criteria reflect the requirements of the definition of alternative projects set out in section 4.1 above in order for options to be included as alternative projects, along with requirements from the Government Policy Statement on Electricity Governance (GPS).

A full description of the screening criteria is provided in Attachment E to the Consultation Paper (see Volume 2), but in summary they are:

- A. Fit for purpose
 - a. Purpose - Interconnection of the two island markets
- B. Technical feasibility (Rules)
 - a. Complexity of solution
 - b. Reliability, availability and maintainability of the solution
 - c. Future flexibility - Grid Development Strategy
- C. Practicality of implementation
 - a. Solution implementable by required date (probability of proceeding) (Rules and GPS)

- b. Property and environmental risks
- c. Implementation risks
- D. Good electricity industry practice (GEIP)
 - a. Consistent with good international practice
 - b. Ensure safety and environmental protection
 - c. Accounts for relative size, duty, age and technological status
 - d. Prior industry experience with this technology
 - e. Low technology risks
- E. System security (additional benefit resulting from an economic investment)
 - a. Improved system security
 - b. System operator benefits (controllability)
 - c. Dynamic benefits (modulation features and improved system stability)
- F. Facilitating Renewables (GPS)
 - a. Transport energy
 - b. Balancing MW transfer

The options screening analysis identified 11 options from the long-list which met these criteria and these constitute the long-short list of options.

Transpower held a workshop ("Options Workshop") with interested parties on 8 June 2007 to discuss:

- the long-list of options;
- assessment criteria for reducing the long-list;
- the long-short list;
- the options ranking approach;
- the GIT approach; and
- the assumptions to be used in the analysis.

Approximately 35 people attended the Options Workshop representing generators, consumer representatives, government officials, the Electricity Commission and other interested members of the general public. The workshop was chaired by Mr Tony Baldwin, an independent facilitator within the industry.

At the Options Workshop there was general agreement that the long list, assessment criteria and long-short list were appropriate. It was requested that a life extension option be included on the long-short list, but otherwise it was considered complete.

Accordingly, life extension options aside, Transpower confirmed the long-short list of options for consideration in the options ranking analysis was appropriate and complete.

Following the Options Workshop, Transpower commissioned further investigation into life extension options. As a part of those investigations, advice was received with respect to the insurability and environmental risks associated with continuing to operate the Pole 1 assets. That advice led Transpower to conclude that it would be imprudent to continue to operate the Pole 1 assets in other than a limited mode, for a limited time. For that reason, life extension options are no longer included as potential options in the Pole 1 replacement investigation. Separate investigations continue into recommissioning one half-pole for limited operation, for system security reasons, but any outcome from those investigations will not affect the Pole 1 replacement investigation.

A more detailed summary of the assessment of the long list of options against the specified criteria is provided in Attachment E to the Consultation Paper (see Volume 2).

4.2.3 Options ranking

The options ranking analysis was a high level economic analysis, the purpose of which was to consider whether the long-short list of options could be reduced to a short list, prior to application of the GIT. This was undertaken because the detailed analysis required in the GIT would be extremely time consuming for all 11 options on the long-short list. It seemed

likely that some options would be highly unlikely to pass the GIT based on a high level economic analysis.

The approach and application of ranking options are fully described in Attachment D to the Consultation Paper (see Volume 2), but a summary follows.

The options ranking approach was to:

- identify a suitable Base Case;
- apply a simplified GIT analysis to each long-short list option;
- determine the expected net market benefit of the 10 long-short list options versus the Base Case using the simplified GIT analysis;
- rank the 10 long short list options based on expected net market benefit of the simplified GIT analysis; and
- if possible, identify a sensible cut-point and determine a short list of options to be taken forward for detailed GIT analysis.

The Base Case for the options ranking analysis was determined on the basis that any HVDC Pole 1 replacement would be justified as an economic investment. In line with the essence of economic investments, the most appropriate and practicable Base Case is to “do-nothing” and for options to be considered against the counterfactual of doing nothing.

Therefore, Transpower considered that the option not to replace Pole 1 of the HVDC should be the Base Case for the options ranking analysis. It was also assumed that Pole 2, which reaches the end of its economic life in 2025, would be replaced with like-for-like equipment. Transpower used this assumption as it is conservative, in that if anything, it would not favour a Pole 1 replacement, plus it avoids the uncertainties associated with that replacement decision itself.

The options ranking analysis applied a simplified GIT approach to the long-short list options. The simplified GIT approach considered a targeted subset of the major variables in the GIT analysis:

- considered medium demand growth only;
- considered a simplified set of costs and benefits;
- used GEM for generation expansion modelling, with SDDP-derived dispatch costs; and
- included limited sensitivity analysis.

In summary the simplified GIT approach used for the options ranking analysis was applied as follows:

Table 4-1: Simplified GIT approach used for the options ranking analysis

Base Case:

Existing Pole 2 only

compared to:

HVDC alternatives:

Existing Pole 2 plus new 300 MW link at BEN-HAY in 2012
 Existing Pole 2 plus new 500 MW link at BEN-HAY in 2012
 Existing Pole 2 plus new 700 MW link at BEN-HAY in 2012
 Existing Pole 2 plus new 1000 MW link at BEN-HAY in 2012
 Existing Pole 2 plus new 500 MW link at BEN-BPE in 2012
 Existing Pole 2 plus new 700 MW link at BEN-BPE in 2012
 Existing Pole 2 plus new 1000 MW link at BEN-BPE in 2012
 Existing Pole 2 plus new 500 MW link at ROX-HAY in 2012
 Existing Pole 2 plus new 700 MW link at ROX-HAY in 2012
 Existing Pole 2 plus new 1000 MW link at ROX-HAY in 2012

over the following range of assumptions:

Demand (Commission draft 2007 SoO demands):

Medium

Market development scenarios (MDS)⁷ (Commission draft 2007 SoO scenarios):

MDS 1 - High Gas

MDS 2 - Mixed Technologies

MDS 3 - Primary Renewables

MDS 4 – South Island Surplus Renewables

Market cost and benefits:

Generation expansion costs from GEM

Dispatch costs from SDDP

HVDC alternative capital costs

HVDC alternative O&M costs

AC augmentation capital costs

AC augmentation O&M costs

Market development scenarios using the following weightings:

MDS 1 High Gas 15%

MDS 2 Mixed Technologies 15%

MDS 3 Primary Renewables 50%

MDS 4 South Island Surplus 20%

Other GIT parameters:

Analysis period: 30 years

Discount rate: 7%

HVDC charge: \$40/MW

Reference date for costs: 30 April, 2007

Exchange rate approach: +/- 20 business days around 30 April, 2007

Inflation: 3%

Terminal benefits: annuities used for all investments and no costs/benefits after analysis period included

Sensitivities:

No South Island Surplus scenario

Low demand growth

High demand growth

Discount rate 4%

Discount rate 10%

The options ranking analysis was undertaken prior to advice that Meridian Energy and Rio Tinto Aluminium had reached agreement on a long term supply contract and Transpower's introduction of a fifth market development scenario, 90% renewables by 2025, in the analysis. Transpower does not consider that either of these changes, later reflected in the GIT assumptions, affects the resultant short list of options.

Transpower held a workshop ("HVDC Update Briefing") with interested parties on 25 October 2007 to discuss the options ranking results, along with other issues. Approximately 20 people attended the HVDC Update Briefing representing generators, consumer representatives, government officials, the Electricity Commission and other interested members of the general public. The HVDC Update Briefing was chaired by Mr Tony Baldwin, an independent facilitator within the industry.

Transpower presented the results of the options ranking analysis and there was discussion with respect to the results. There was general agreement that the options ranking approach was reasonable and that the short of list of options identified for consideration in the GIT was

⁷ Transpower used the term "market development scenarios" as used in the GIT for this document and its attachments. The term is related to, and is used at many other times interchangeably with, the term "generation scenarios".

appropriate. There was further discussion about whether a life extension option should be included on the short list of options.

Accordingly, life extension options aside, Transpower confirmed the following short list of options:

Table 4-2: Short list of options

Option No.	Description
Base Case	No Pole 1 replacement
1	HVDC 500 MW pole at BEN-HAY
2	HVDC 700 MW pole at BEN-HAY
3	HVDC 1000 MW pole at BEN-HAY

At that time, Transpower had commissioned further investigation into life extension options, as mentioned in Section 4.2.2. The outcome of those investigations and subsequent investigations led Transpower to conclude that it would be imprudent to continue to operate the Pole 1 assets in other than a limited mode, for a limited time. For that reason, life extension options were no longer included as potential options in the Pole 1 replacement investigation.

4.3 Description of Short List Options

The detailed development plans for and a full description of each short list option consulted on, including a description of the approach used in deriving the development plans are set out in Attachment C to the Consultation Paper (see Volume 2). The development plan for each short list option, including that for the base case option, consists of a staged development plan for the HVDC equipment, plus a list of AC augmentations that would be required to fully enable the HVDC capacity installed.

Transpower has refined and updated these short-listed development plans in light of further available information from the version consulted upon. Tables 4-3 to 4-6 below describe each of the short list options in detail:

4.3.1 Base Case – No Pole 1 replacement

Table 4-3 Base Case Option Development Timetable

Stage	HVDC Investment
Stage 1	Electrode and HVDC transmission line works for continuous mono-polar operation, and replacement of cable terminal bushings
	Refurbishment and unit connection of three Haywards Synchronous condensers
	Low order harmonic filter at Haywards
	Seismic strengthening at Haywards and Benmore sites
Stage 2	Pole 2 valve base electronics and control system replacement

4.3.2 Option 1 – 500 MW pole at BEN-HAY

Table 4-4 Option 1 Development Timetable

Stage	HVDC Investment
Stage 1	New 500 MW, 350 kV, converter pole terminating at Benmore and Haywards including new Pole 1 and bipole control system
	Pole 2 valve base electronics and control system replacement
	Harmonic filters at Benmore and Haywards suitable for bipole operation of around 1200 MW
	Seismic strengthening and AC switchyard development for 500 MW option at Benmore and Haywards
	Electrode and HVDC Transmission line works for 500/700 MW operation, and replacement of cable terminal bushings
	Refurbishment and unit connection of Haywards Synchronous condenser C7 to C10
Stage 2	New condenser C11 or equivalent dynamic reactive power compensation facilities at Haywards 60 MVar

4.3.3 Option 2 – 700 MW pole at BEN-HAY

Table 4-5 Option 2 Development Timetable

Stage	HVDC Investment
Stage 1	New 700 MW, 350 kV, converter pole terminating at Benmore and Haywards including pole and bipole control systems
	Pole 2 valve base electronics and control system replacement
	Harmonic filters at Benmore and Haywards suitable for bipole operation of around 1200 MW
	Seismic strengthening and AC switchyard development for 700 MW option at Benmore and Haywards
	Electrode and HVDC Transmission line works for 700/700 MW operation, and replacement of cable terminal bushings
	Refurbishment and unit connection of Haywards Synchronous condenser C7 to C10
Stage 2	New synchronous condenser C11 or equivalent dynamic reactive power compensation facilities at Haywards 120 MVar
Stage 3	Additional filters suitable for 1400 MW operation
	Add one new HVDC submarine cable rated, 350 kV, 500 MW

4.3.4 Option 3 – 1000 MW pole at BEN-HAY

Table 4-6 Option 3 Development Timetable

Stage	HVDC Investment
Stage 1	New 1000 MW, 350 kV, converter pole terminating at Benmore and Haywards including pole and bipole control systems
	Pole 2 valve base electronics and control system replacement
	Harmonic filters at Benmore and Haywards suitable for bipole operation of around 1200 MW
	Seismic strengthening and AC switchyard development for 1000 MW option at Benmore and Haywards
	Electrode refurbishment for 1000/700 MW operation.
	HVDC Transmission line works for 700/700 MW operation, and replacement of cable terminal bushings
	Refurbishment and unit connection of Haywards Synchronous condenser C7 to C10
Stage 2	New synchronous condenser C11 or equivalent dynamic reactive power compensation facilities at Haywards 120 MVar
Stage 3	Additional filters suitable for 1400/1700 MW operation
	Add one new HVDC submarine cable rated, 350 kV, 500 MW
Stage 4	New synchronous condenser C12 or equivalent dynamic reactive power compensation facilities at Haywards 120 MVar
	HVDC Transmission Line works for BEN-HAY 1000/700 MW bipole operation

In relation to the Project (i.e., the 700 MW options above) Transpower intends to carry out the following related works as ongoing “business as usual” projects (non-Part F) and are not included within this Proposal (i.e. would proceed with or without this Proposal):

- Decommissioning of the existing Pole 1 converter stations and associated equipment at Haywards and Benmore;
- Reconfiguration of 110kV switchyard at Haywards;
- DC electrode refurbishment at Te Hikowhenua (North Island) and Bog Roy (South Island); and
- Cable terminal roof bushings at Oteranga Bay and Fighting Bay.

4.3.5 Description of AC augmentations

Transpower has considered which AC augmentations would be required for each short-listed option, for each level of demand considered (high, medium and low) and for each market development scenario. A detailed description of the approach is set out in Attachment C to the Consultation Paper (see Volume 2). These are only treated as modelled projects for the purposes of this analysis and none are included in the Proposal.

Table 4-7 below sets out the full list of North Island AC augmentations identified as being required in at least one of the market development scenarios considered.

Table 4-7 North Island AC augmentation list

North Island AC Augmentation	
<i>Name</i>	<i>Description of augmentation</i>
BPE-TKU	Duplexing of BPE-TKU 1&2 circuits raises rating to 492/404 MVA each
TKU-WKM	Duplexing of TKU-WKM 1&2 circuits raises rating to 492/404 MVA each
ATI-OHK	Reconductoring of the ATI-OHK circuit: raises rating from 358/333 to 716/666 MVA
OHK-WRK	Reconductoring of the OHK-WRK circuit: raises rating from 358/333 to 716/666 MVA
PPT-WKM	Reconductoring of the PPT-WKM circuit: raises rating from 448/421 to approximately 764/694 MVA
PPT-WRK	Reconductoring of the PPT-WRK circuit: raises rating from 448/421 to approximately 764/694 MVA
BPE-HAY	Duplexing of BPE-HAY 1&2 circuits: raises the rating from 335/307 to 650-750 MVA
HAY-TF	New Haywards interconnector T4
BPE-TNG	Thermal upgrade raises the rating to 382/347 MVA
RPO-TNG	Thermal upgrade raises the rating to 382/347 MVA
BRK-SFD	Thermal upgrade raises the rating to at least 332/289 MVA
BRK-SFD-DUPLEX	Reconductoring of BRK-SFD 1,2, & 3 circuits raises rating to at least 500/470 MVA each
CAP100-LNI	Install 100 MVAR of Capacitor banks at one of: BPE or HAY 220kV substations
SVC100-LNI	Install 100 MVAR of Dynamic Reactive (capacitive) support at one of: BPE or HAY 220kV substations

Table 4-8 below sets out the full list of South Island AC augmentations identified as being required in at least one of the market development scenarios considered.

Table 4-8 South Island AC augmentation list

South Island AC Augmentation	
Name	Description of augmentation
AVI-WTK	Duplex just the AVI-WTK section of AVI-WTK-LIV 220kV circuit (9km)
AVI-WTK-LIV	Duplex the AVI-WTK and WTK-LIV 220kV circuits (42 km total) : increases rating from 323/293 to 646/586 MVA and reduces resistance
BEN-AVI	Thermal upgrade of BEN-AVI 1&2 220kV circuits (18km each) : raise simplex op. temp - increases rating from 246/202 to 310/278 MVA each
CAP100-MSI	Install 100 MVAR of Capacitor banks at one of : ASB or LIV 220kV substations
CAP100-USI	Install 100 MVAR of Capacitor banks at one of : TWZ, ISL or KIK 220kV substations
GDE-BUS	Install GDE busbar schemes
ROX-NSY-LIV	Duplex the ROX-NSY (94 km) and NSY-LIV 220kV (48 km) circuit : increases rating from 246/202 to 492/404 MVA and reduces resistance
SVC100-USI	Install 100 MVAR of Dynamic Reactive (capacitive) support at one of : TWZ, ISL or KIK 220kV substations
WTK -LIV	Duplex just the WTK-LIV section of AVI-WTK-LIV 220kV circuit (33km)

A full description of which of these augmentations is required in each of the demand and market development scenario combinations is given in Attachment C to the Consultation Paper (see Volume 2).

5 Transpower's application of the Grid Investment Test

5.1 The Grid Investment Test

Under Rule 14.4, the Electricity Commission may approve proposed investments where Transpower has applied the GIT reasonably. Clause 4 of Schedule F4 of the Rules (the schedule of the Rules which contains the GIT) states that:

*"A **proposed investment** satisfies the **grid investment test** if the **Board** is reasonably satisfied that:*

- 4.1. *for a **proposed investment** that is necessary to meet the reliability standard set out in clause 4.2 of the **grid reliability standards**:*
 - 4.1.1. *the **proposed investment** maximises the **expected net market benefit** or minimises the **expected net market cost** compared with a number of **alternative projects**; and*
 - 4.1.2. *if sensitivity analysis is conducted, a conclusion that a **proposed investment** satisfies clause 4.1.1 is sufficiently robust having regard to the results of that sensitivity analysis; or*
- 4.2. *for any other **proposed investment**:*
 - 4.2.1. *the **proposed investment** maximises the **expected net market benefit** compared with a number of **alternative projects**;*
 - 4.2.2. *the **expected net market benefit** of the **proposed investment** is greater than zero; and*
 - 4.2.3. *if sensitivity analysis is conducted, a conclusion that a **proposed investment** satisfies clauses 4.2.1 and 4.2.2 is sufficiently robust having regard to the results of that sensitivity analysis".*

As set out at section 3.1 above, the investment set out in the Proposal is not necessary to meet the grid reliability standards. As such, the Proposal falls to be considered as an economic investment within the scope of clause 4.2 of the GIT. To satisfy the GIT therefore, the Proposal must:

- maximise the expected net market benefit compared with a number of alternatives, in a robust manner with respect to sensitivity analysis; and
- result in an expected net market benefit greater than zero, in a sufficiently robust manner with respect to sensitivity analysis.

5.2 Methodology and assumptions

Attachment B to the Consultation Paper (see Volume 2) sets out in detail Transpower's methodology and assumptions for applying the GIT. Transpower addresses in this section a number of areas in which industry participants have made submissions at either (or in some cases both) the early customer engagement phase of consultation or the recent GIT consultation process, namely:

- generation expansion modelling approach;
- demand growth assumptions; and
- market development scenarios.

5.2.1 Generation expansion modelling approach

Generation expansion modelling arises in this GIT analysis because different HVDC link sizes (i.e. the different short list options) may lead to different investments in generation, in both the North and South Islands and, therefore, generation expansion plans are required for each short-listed option considered.

Modelling how generation will develop, under a market-led generation environment, such as in New Zealand can be a contentious and difficult area. Depending on the form of market-based expansion used it may rely on assumptions of market behaviour, which over a long period of time may be very different to how the market evolves. The use of these same assumptions may also mean that the generation expansion plan diverges significantly from a supply side least cost expansion.

Transpower's analysis in this proposal uses a form of market-led generation expansion modelling where new generation investment decisions are made based on price signals as may be observed by market participants. Such signals include the capital cost of different generation technologies (after accounting for tax effects, depreciation), nodal price differences and industry tariffs including the HVDC charge, allocated to South Island generators under the transmission pricing methodology (TPM).

As this is the first time Transpower has used generation expansion modelling for GIT analysis, Transpower consulted widely on its approach. The GIT analysis uses the Commission's published GEM model, but separately, the same analysis was undertaken by MMA using PLEXOS, a proprietary generation expansion model. Results from the PLEXOS analysis are reported for information at Attachment G to the Consultation Paper (see Volume 2).

There was much discussion at the Options Workshop, HVDC Update Briefing and other forums held, with respect to generation expansion modelling. In particular, early versions of the GEM model were formulated with an N-2⁸ capacity constraint in a manner which appeared to build more new generation than the market would likely deliver. Discussion focussed on which of two general approaches were most appropriate:

⁸ Note that the terms N-1 and N-2 do not reflect the traditional use of those terms in terms of grid planning but these are a parameter that is used in GEM with respect to a capacity constraint. N-2 is effectively a reference to N-2 generation plants, not transmission assets.

- security constrained modelling, where generation expansion occurs as required to meet peak MW; and
- revenue adequacy modelling, where generation expansion only occurs once a new generator is assured of adequate revenue from sales into the national market to be commercially viable.

The Electricity Commission considered this issue and in a letter to Transpower on 31 August 2007, stated that:

Transpower has had various discussions with participants over the last three months about the inputs for the application of the grid investment test (GIT) to the HVDC Pole 1 replacement investigation project (HVDC project).

These have included whether the models used to produce the generation scenarios should include settings that provide revenue adequacy for generators or those that provide adequate generation to meet security requirements.

The Commission discussed this at its 24/25 July 2007 and 28/29 August 2007 meetings. The Commission's view, as confirmed at its 28/29 August 2007 meeting is that, *"for the purposes of developing credible generation scenarios for the application of the GIT to transmission investments, it is reasonable and credible to assume that adequate generation will be introduced to meet peak and energy security margins...it is not necessary to specify the mechanism(s) through which adequate generation will emerge"* (for example, whether market mechanisms will deliver the new generation, or whether market intervention occurs to facilitate the new generation).

Transpower, having carefully considered all submissions received, considers that applying a security-constrained model is a reasonable application of the GIT.

Further analysis by Electricity Commission staff on the use of capacity constraints in generation expansion modelling led them to further indicate, in a letter to Transpower of 2 November 2007:⁹

While the Commission still considers this matter as under review, in the interests of assisting Transpower to progress its preparation of an HVDC investment proposal, the Commission has taken the step of advising Transpower that the current view of the Commission is that using an N-1 capacity constraint in GEM is preferable to (ie, more reasonable than) using an N-2 capacity constraint when applying the GIT.

Transpower, having regard to the submissions received, considered that applying an N-1 constraint in GEM was an appropriate constraint to be applied in the proposed GIT analysis.

Meridian Energy's submission of 4 April 2008 on Transpower's application of the proposed GIT requested that:

"The impact of the capacity constraint on all scenarios is identified by removing the constraint in GEM and re-running each scenario."

Transpower undertook this analysis. Three cases were considered:

- no constraint applied – as suggested by Meridian Energy;
- N-1 constraint applied as used in the GIT;

⁹ The letter from the Electricity Commission also cautioned that Transpower is required to reach its own view, but offered some guidance on the issue of security constrained modelling. Transpower has fully considered the matter and sets out its reasoning and views in this document.

- N-2 constraint applied as used in early analysis.

The outcomes of this analysis are fully reported in section 4.6 of Attachment A – Revised GIT Results to this document.

The analysis shows that the N-1 capacity constraint results in generation expansion plans under the prudent peak demand forecast, whereby demand is met whilst meeting the reserves requirement, with the largest unit out of service.

Under the no capacity constraint case, prudent demand will not be met from 2013 on. From around 2017, there will not be sufficient capacity to run the system with reserves intact, which increases the risk of load shedding. From around 2023 there is just enough capacity to meet peak demand but with no allowance for reserves at all – not even for frequency keeping. Such a level of generation is clearly not sustainable.

The Electricity Commission has also, more generally, analysed the impact on security of supply of running GEM with and without the capacity constraint. The Commission used a probabilistic model that took GEM market development scenarios as inputs and assessed the periods where the system would operate at N-security, i.e. running with too few reserves to deal with the loss of largest unit.

The Commission's analysis showed that the number of half-hourly trading periods, where there is insufficient capacity to cover the loss of the largest unit rises to 2,000 by the end of the horizon, using an N capacity constraint - approximately 20% of the year. The historical level is at around 5-6 half-hourly trading periods per year. The Commission found that this level was maintained when using the model with an N-1 capacity constraint. The Commission also found that this reduces even further to below 1 half-hourly trading period using an N-2 capacity constraint.

Based on all of the analysis undertaken, including the work in response to Meridian Energy's submission, Transpower considers that the N-1 capacity constraint is the most realistic assumption for the purposes of this analysis, most importantly because it maintains the current level of reliability and security.

Ignoring an N-1 constraint by running the model with no constraint applied results in a significant, unrealistic lack of new generation built in the system. Running the model with an N-2 constraint builds more generation than using the N-1 constraint. Given that the results using N-1 were consistent with current levels of reliability, the results suggest that, unless the preference for reliability changes significantly, the market would not be likely to deliver N-2 security.

Transpower's overall assessment of the GEM model is that it is suitable for this HVDC GIT economic analysis and this was supported by a recent review by Dr Grant Read, which can be found at:

<http://www.electricitycommission.govt.nz/opdev/modelling/gem/documentation>

Transpower also applied the PLEXOS model to this analysis (which Dr Read's review also considered a reasonable model for the purposes of this HVDC GIT analysis) and the results of that analysis, which are for information only, are set out in Attachment G to the Consultation Paper (see Volume 2). While Transpower has not relied on the PLEXOS model to produce its GIT results, it is reassuring, consistent with the submissions by Genesis and MEUG, that it has produced similar results to Transpower's own GIT analysis.

5.2.2 Demand growth assumptions

Transpower has used the Electricity Commission's draft 2007 Statement of Opportunities demand forecasts for this GIT analysis. These are included in Appendices B and C of Attachment B – Databook to the Consultation Paper (see Volume 2). Transpower considered whether to use these forecasts or its own demand forecasts published in its 2007 Annual Planning Report (APR) for the purposes of this GIT analysis. Having sought feedback from industry participants, Transpower considered that, while application of its own

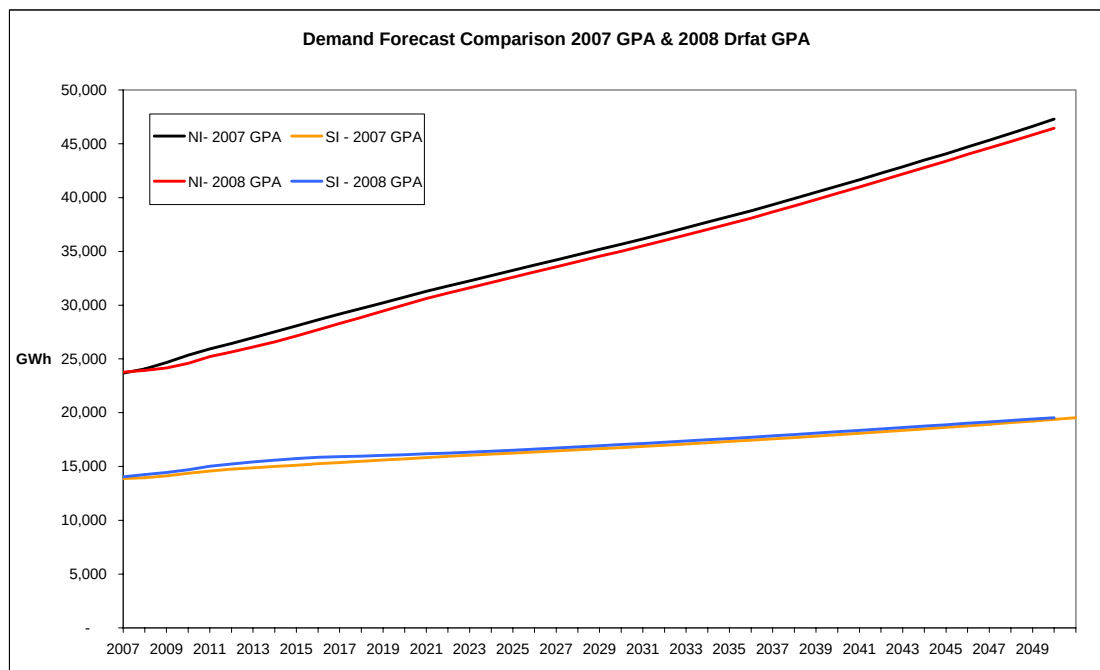
demand forecasts may have also been reasonable, the forecasts suggested by the Commission were reasonable for the purposes of the proposed analysis.

During consultation on Transpower's proposed application of the GIT, submissions suggested that since the Commission had published draft 2008 Statement of Opportunity demand forecasts, that these should be considered.

The chart below shows the Electricity Commission's draft 2008 demand forecasts (GWh) by island against the draft 2007 demand forecasts which were used in the GIT analysis. Overall, the national demand forecast has fallen by around 1% in the current proposed draft 2008 forecasts.

The allocation between islands has changed a little more significantly with the draft 2008 demand forecasts showing slightly more demand in the South Island than in the North Island, in other words, there is a higher allocation to the South Island.

Figure 5-1: Comparison of Demand Forecasts – 2007 GPA and draft 2008 GPAs



Transpower has not undertaken any specific analysis using the draft 2008 demand forecasts, as it believes the results would be captured by the further sensitivity outlined below in response to a Meridian Energy submission. The results of that analysis indicate that the Proposal would still meet the requirements of the GIT. Transpower therefore concludes that use of the draft 2008 Statement of Opportunities demand forecast would still result in this Proposal passing the GIT.

Meridian Energy raised issues with regard to the demand forecasts in the recent consultation. Meridian's main contention is that the Transpower demand forecasts understate demand growth in the South Island, resulting in more generation being available for transfer on the HVDC than would actually be available. Meridian Energy considers that Transpower's forecasts therefore overstate the value of replacing Pole 1.

Transpower's response to Meridian Energy's various submissions are contained in Attachment E to this document. The main point Meridian Energy make is that demand growth in South Island in recent years has been much higher than Transpower reflects in its

forecasts and that a forecast based on actual demand growth over the last 10 years would be more appropriate.

Transpower commissioned Covec to consider Meridian's proposition. Covec's report, South Island Electricity Load Growth¹⁰, is included as Attachment C to this document. Covec concluded that the recent high South Island demand growth has mainly been attributable to growth from dairy farming and that there are emerging constraints which are likely to mean that the recent high demand growth will not be sustained. The constraints include the competition for water resources and an increasing trend towards the use of bio-energy systems on dairy farms.

Nevertheless, Transpower has undertaken two new sensitivity studies to consider the effect on the GIT results if the recent high South Island demand growth did continue:

- High South Island growth - South Island demand growth is extrapolated, based on recent historical data (1997-2007), out over the full period of analysis; and
- 10 year high South Island growth - South Island demand growth extrapolated as above based on the historical data out over approximately the first 8 years at which time it over 4 years reverts to mean demand growth rates.

Although the expected net market benefit of replacing Pole 1 was reduced, in both sensitivities, the Proposal was still the preferred option and still had a positive expected net market benefit.

Having considered submissions received on the demand growth assumptions, sought expert advice on South Island demand growth and having undertaken further sensitivity studies, Transpower is satisfied that the demand forecasts used in the HVDC analysis are reasonable and fit for purpose.

5.2.3 Market development scenarios

Transpower discussed with Electricity Commission staff the market development scenarios and weightings to be used in the HVDC analysis. The Commission staff suggested a set of market development scenarios.

Having sought feedback from industry participants, Transpower considered that the suggested market development scenarios were reasonable for use in the analysis.

Establishing weightings to be applied to the market development scenarios is somewhat subjective, but some observations can be made which assist establishing reasonable weightings:

- Scenarios with higher proportions of renewables are likely, as only these scenarios enable the electricity sector to contribute its share toward reducing emissions of greenhouse gases in line with New Zealand's Kyoto commitments.
- The South Island surplus scenario should be considered unlikely, given recent announcements that Meridian Energy and Rio Tinto now have a supply agreement through to 2030.
- A more detailed and complete description of the reasoning Transpower applied in deriving the weightings can be found in section 5.6.4 of Attachment A – Revised GIT Results and with that in mind, Transpower derived and used the following market development scenarios and weightings to calculate the expected net market benefit of each short list option:

• High gas discovery (MDS 1)	20%
• Mixed technologies (MDS 2)	10%
• Primary renewables (approx 75%) (MDS 3)	15%
• South Island surplus renewables (MDS 4)	5%
• 90% renewables by 2025 (MDS 5)	50%

¹⁰ See Attachment C to the Proposal.

More description of the market development scenarios used in Transpower's GIT analysis and the weightings is provided in the table below:

Table 5-1: Summary of market development scenarios, weightings and descriptions

Scenario	Description	Weighting
High Gas Discovery (MDS 1)	Timely and extensive exploration for gas leads to a relatively unrestricted supply of natural gas at prices similar to today's. Several new gas-fired power stations are constructed. Low carbon prices lead to less renewable generation. It is assigned a moderate probability, reflecting uncertainty around gas discoveries.	20%
Mixed Technologies (MDS 2)	Low carbon price lead to less renewable generation. A mixture of generation technologies is the result, including new coal-fired generation in the North Island after 2020, as well as geothermal, wind, and hydro. Thermal peakers support intermittent generation. Demand-side measures also contribute to peak management. The coal-fired units at Huntly remain in operation until 2030 but are replaced with new fossil generation. Carbon emissions will increase significantly in this scenario.	10%
Primary Renewables (MDS 3)	High carbon prices discourage the development of fossil-fuel-based generation. Combined with a constrained gas supply, this leads to the development of renewable options. Geothermal, hydro and wind generation all feature strongly. In the later part of the scenario, both renewable and thermal projects are added to provide peaking capacity in the North Island (including pumped and peaking hydro schemes, and gas- or oil-fired thermal units). Demand-side measures also contribute to peak management. The coal-fired units at Huntly Power Station remain in operation until 2030.	15%
South Island Surplus Renewables (MDS 4)	This is a variant of the 75% Renewables scenario, and is similar in many respects (with a strong emphasis on geothermal, wind, and hydro generation). The key difference is that in the SI Surplus variant, the Tiwai Point aluminium smelter ceases operations with a gradual phase-out from 2014 to 2019. The results include increased northward power flows, and delays in generation build relative to the 75% Renewables scenario.	5%
90% renewables (MDS 5)	Government policies strongly discourage the development of fossil-fuel-based generation, and raise the proportion of renewable electricity generation to 90% by 2025. The coal-fired units at Huntly are decommissioned between 2013 and 2017 and replaced by renewable generation. Geothermal, hydro and wind generation all feature strongly, with biomass-fired cogeneration, marine, and coal with carbon sequestration added later in the scenario. In the later part of the scenario, both renewable and thermal projects are added to provide peaking capacity in the North Island. Demand-side measures also contribute to peak management.	50%

In its submission on Transpower's proposed application of the GIT, MEUG did question whether Transpower's reasoning for the scenario weightings was sufficient and this is also addressed in section 5.6.4 of Attachment A – Revised GIT Results, along with some sensitivities showing the effect of applying different weightings. As those sensitivities show, the GIT outcome is robust to variations in scenario weightings, favouring the same option in each case.

5.3 Cost refinements

Since publishing its proposed GIT analysis for consultation, Transpower has refined and updated the estimated scope and costs for the options in light of further available

information. As a result, Transpower's GIT analysis has used slightly different costs to those used in its proposed analysis.

In summary, the overall development plans for each of the options considered in the GIT have changed by, in \$2007 million:

Table 5-2: Change in costs of development plans

	\$2007 million (not discounted)	PV, \$million	Expected net market benefit change (compared to Base Case), PV \$million
Base Case	+\$36	+\$24	-
Option 1	+\$32	+\$21	+\$3
Option 2	+\$30	+\$20	+\$4
Option 3	+\$15	+\$14	+\$10

The change in relativities of these costs does mean that the expected net market benefit calculations change, as shown in the right hand column. These changes are reflected in the revised GIT results, but as can be seen, they are not material to the GIT outcomes or conclusions.

5.4 Results

The weight-averaged expected net market benefit for each short list option is set out in Table 5-3 below.

Table 5-3: Overall results of application of the Grid Investment Test

Item	Base Case No Pole 1 replacement	Option 1 500 MW Pole 1	Option 2 700 MW Pole 1	Option 3 1000 MW Pole 1
Present Value 2007\$M				
Generation fixed costs (A)	7,000	6,847	6,769	6,800
Generation variable costs (B)	9,499	9,392	9,356	9,291
HVDC costs (C)	59	325	436	554
AC augmentation costs (D)	45	47	48	49
Terminal benefit (E)	5,858	5,712	5,660	5,661
Total cost (A+B+C+D+E)	22,461	22,323	22,269	22,355
Expected Net Market Benefit	-	138	191	106

These results show that Option 2, building a 700 MW Pole 1 at Benmore and Haywards, has the highest expected net market benefit of the short list options, being some \$53 million in 2007 present value terms higher than the next highest short list option, building a 500 MW

Pole 1 at Benmore and Haywards. Transpower notes that there is analysis suggesting that omitting reserve costs significantly underestimates the expected net market benefit of investment, in particular Option 2, compared to the Base Case (see 5.8.1 below).

Without including these benefits, the expected net market benefit of Option 2 is \$191 million and, being greater than zero, Transpower concludes that Option 2, therefore, meets the requirements of clauses 4.2.1 and 4.2.2 of the GIT (as quoted in section 5.1 above).

Transpower has gone on to consider the sensitivity of this result to changes in key variables and parameters to assess the robustness of this result (see clause 4.2.3 of the GIT).

5.5 Sensitivity analysis

Table 5-4 below sets out a summary of weight-averaged sensitivity studies. These show that the ranking of the short list options is stable to a range of sensitivities. All sensitivities show Option 2, the 700 MW replacement option, having the highest positive expected net market benefit.

Table 5-4: Sensitivity of expected net market benefit of the short list options

\$2007 million	Base Case No Pole 1 replacement	Option 1 500 MW Pole 1	Option 2 700 MW Pole 1	Option 3 1000 MW Pole 1
Base results	-	138	191	106
Sensitivity:				
Discount rate, 4%				
Discount rate, 10%	—	446	600	514
HVDC capital 80%	—	-7	4	-76
HVDC capital 120%	-	191	267	205
10 yr avg x-rate	-	84	115	6
HVDC O&M 0.2%	-	135	174	83
HVDC O&M 1.0%	-	143	199	116
Base – med demand, 90% renewables only	-	300	395	292
N-2 cap constraint	-	531	672	509
Generation capital	-	312	375	260
No HVDC charge	-	305	352	271
Base – med demand, Option 2 only	-	-	221	-
ROX termination	-	-	211	-
BPE termination	-	-	204	-

5.6 Conclusions of Transpower's application of the Grid Investment Test

Option 2, a 700 MW Pole 1 replacement terminated at Benmore and Haywards, satisfies the GIT because:

- it maximises the expected net market benefit when compared with the alternative projects;
- it has a positive net market benefit; and

- it is robust having regard to the results of a sensitivity analysis.

It is noted that whilst the expected net market benefit of Option 2 is \$187 million, this is averaged over five market development scenarios and uses a 7% discount rate.

The net market benefit of Option 2 for the 90% renewables by 2025 scenario, which is most consistent with the government's New Zealand Energy Strategy, is \$348 million, using a 7% discount rate. If a 5% discount rate is used, consistent with the New Zealand Energy Strategy, the net market benefit of Option 2, for the 90% renewables by 2025 scenario, would be approximately \$700 million.

These results are robust to the wide range of sensitivity analysis carried out by Transpower. It therefore fulfils the criteria of clause 4.2 of the GIT.

5.7 Timing of the Proposal

The quantitative analysis in section 7 of Attachment A - Revised GIT Results, to this document shows that the net benefits for the various stages of Option 2 are:

- Stage 1 – similar between 2012 – 2014, and then net benefits decrease after 2014;
- Stage 2 – similar between 2012 – 2018, and then net benefits decrease after 2018; and
- Stage 3 – not required before 2018 and in thermal scenarios, potentially after 2030.

This Proposal seeks approval to recover the costs for implementing Stage 1 and Stage 2. Stage 3 is not included in this Proposal and will form the basis of a separate proposal, when the need for Stage 3 is nearer.

Transpower proposes to commission Stage 1 in 2012 and Stage 2 in 2014.

5.7.1 Stage 1 timing

Given that the quantitative analysis for investment in Stage 1 shows that it is close to breakeven between 2012 and 2014, it is necessary to consider other factors in deciding when to aim for commissioning within this band.

Generation option value

Meridian Energy and Contact Energy consider that there is a significant option value in delaying the commissioning of Stage 1. For example, Meridian Energy considers such a value exists due to considerable uncertainty in generation costs, and generation build plans, of market participants, and the greater relative costs of generation than transmission.¹¹

Transpower accepts such an option value exists, but does not believe that it exists to the extent suggested. Transpower considers that there is a more significant countervailing option value. This results from early commissioning of Stage 1 creating options for generators which would not be there otherwise. Transpower believes that it is widely accepted that, as the lead times of transmission investment exceed that of generation investment, an efficient generation investment market requires transmission investment to lead generation investment.

Uncertainty over continued Pole 1 limited operation

Transpower notes that the HVDC plays an important role in improving security of supply in dry years, by enabling southwards transfer of electricity for North Island generators when there are low inflows into the South Island hydro schemes. The potential difficulties the New

¹¹ Meridian Energy's other arguments regarding deferral benefits and demand forecasts are addressed in Transpower's quantitative analysis in section 7 of Attachment A to this document.

Zealand electricity supply system faces this coming 2008 winter have highlighted the importance of having more than the existing Pole 2 transfer capacity available at such times. Transpower's insurers have agreed to insure the existing Pole 1 for limited operation with annual reviews. There is no certainty that it will be available even for limited operation beyond 2009.

Further, the equipment is old and susceptible to terminal failure at any time.

From this point of view, Transpower considers it would be prudent to aim for as early a commissioning for Stage 1 as possible.

Susceptibility to Pole 2 failure

The existing Pole 2 is aging and there is an inherent, increasing risk of it failing. A replacement Pole 1 would mitigate the consequences for security of supply of a Pole 2 failure. Although the critical failure of Pole 2 is a low probability event, it would have a high impact. This suggests that it would be prudent to aim for as early a commissioning for Stage 1 as possible.

Increased resilience to high impact, low probability events

A larger HVDC, in bipole configuration, will increase the flexibility of system operations to deal with other high impact, low probability events that could occur elsewhere in the electricity supply system. This will improve the overall reliability of supply. Therefore from this point of view, Transpower considers it would be prudent to aim for as early a commissioning for Stage 1 as possible.

Enhanced ability to develop ancillary markets

Replacing Pole 1 will offer opportunities to develop the market for ancillary services (such as frequency keeping, reserves and balancing markets) and lower the cost of these services overall. Some such developments are already being contemplated by the Electricity Commission. From this point of view, Transpower considers it would be prudent to aim for as early a commissioning for Stage 1 as possible, as otherwise potential benefits to be derived from these enhanced markets will be foregone.

Earlier development of support required for intermittent renewable sources

The development of renewable generation in the medium term is likely to include a substantial proportion from intermittent sources. As the proportion of intermittent generation in the system increases, so to does the need for the supporting generation required to ensure a reliable electricity supply. The HVDC will play an important role in ensuring that support does not have to be physically located in the same island as the intermittent generation. It is possible that a smaller link could restrict the development of intermittent renewable generation from this point of view. This also suggests that it would be prudent to aim for as early a commissioning for Stage 1 as possible.

Constructability risk

There is a risk that construction could take longer than forecast. Given the way costs increase if the replacement Pole 1 is commissioned after 2014, it would be imprudent to aim for 2014, as there would be a higher risk that these costs would be incurred.

Conclusion on Stage 1 timing

Overall, these considerations lead Transpower to the conclusion that the potential costs of commissioning the Proposal in 2012, as opposed to 2014, are far outweighed by the potential benefits of commissioning in 2012.

Transpower's Proposal therefore targets commissioning Stage 1 in 2012.

5.7.2 Stage 2 timing

Transpower's quantitative analysis also shows that the optimal timing for commissioning Stage 2 timing is close to breakeven between 2012 and 2018.

Stage 2 consists of a new synchronous condenser which is to be placed on the same site as the existing Pole 1. It is estimated that Stage 2 will take approximately 18 months to construct, as it consists of decommissioning/demolishing the existing Pole 1,¹² clearing the site and constructing the new equipment. Transpower recommends that this work does not commence until Stage 1 of this project is successfully commissioned, in order to maximise the possibility that more than 700 MW of HVDC transfer capacity between the islands will be available until then.

Most of the arguments discussed above for the earliest possible commissioning of Stage 1 of the Proposal, also apply to Stage 2. Transpower recommends aiming for the earliest possible commissioning of Stage 2 for those same reasons.

Given the estimated 18 month construction time for Stage 2, and the imperative to keep the existing Pole 1 operating in its limited operation mode, if possible, Transpower therefore proposes targeting commissioning of Stage 2 in 2014.

If it is not possible to maintain the existing Pole 1 operating in its limited operation mode until Stage 1 of the Proposal is commissioned, Transpower recommends building Stage 2 as early as possible. This Proposal is submitted on the basis of commissioning Stage 2 in 2014, but if it turns out to be plausible to commission it earlier, Transpower will discuss that possibility with the Commission at the time.

5.8 Other benefits favouring the Proposal

While outside Transpower's application of the GIT in whole or in part, a number of factors reinforce Transpower's view that Pole 1 of the HVDC link should be replaced and that the Proposal is the best option available. These factors include:

- Reserves modelling;
- Strategic benefits;
- Enabling wind diversification;
- Cost effectiveness of carbon abatement;
- Wholesale competition benefits;
- Retail competition benefits;
- Consumer benefits;
- System stability improvement;
- Transient stability;
- Frequency control / stabiliser; and
- Other benefits of HVDC dynamic performance.

Transpower considers each of these factors in turn below.

5.8.1 Reserves modelling

Genesis Energy expressed concern in its submission on Transpower's proposed GIT application that the GEM and SDDP models do not include the modelling of instantaneous

¹² Outside the scope of this Proposal, see section 4.3 above.

reserves. In particular, Genesis Energy queried whether the modelling scheduled enough capacity (particularly in the Base Case) to meet reserve energy requirements.

Transpower considered this issue early in the HVDC Pole 1 Replacement Investigation Project and while agreeing with Genesis Energy that not modelling reserves is likely to “under-schedule” capacity in the Base Case, that this was reasonable for the purposes of analysing this economic investment.

As Genesis Energy noted, the PLEXOS analysis did include the modelling of reserves. It is also noted that the expected net market benefit of replacing Pole 1, in the PLEXOS analysis, is higher than in Transpower’s analysis.

In response to Genesis Energy submission, Transpower asked MMA to undertake further analysis to ascertain how much of the PLEXOS net benefit could be explained by reserves modeling. To do this, MMA compared results with and without reserves modelling. Their report is attached to this Proposal as Attachment D. In summary, they found that the expected net market benefit, under medium demand growth, for the 700 MW replacement option, varied as follows if reserves were not modelled:

Table 5-5: Additional benefits as a result of modelling reserves for each market development scenario

Market development scenario	Additional benefits as a result of modelling reserves (\$M)
High Gas	\$26
Mixed Technologies	\$43
Primary renewables	\$64
SI Surplus	\$51
90% renewables by 2025	\$46
Weighted average	\$44

MMA also undertook the same analysis using the expansion plan obtained using GEM for the 90% renewables by 2025 scenario only. Their results show that without modelling reserves there was a reduction in the net market benefits of the 700 MW replacement of \$34 million, which is consistent with their own results.

This supplementary MMA analysis supports Transpower's supposition that the GEM/SDDP modelling, without reserves, is conservative. The analysis suggests that the GEM/SDDP modelling underestimates the expected net market benefit of the Proposal by approximately \$30 - \$50 million.

5.8.2 Strategic benefits

Transpower considers that this Proposal also provides a number of benefits, not fully reflected in the Grid Investment Test results, including:

- enabling the development of renewable generation in the South Island by ensuring a reliable connection between the South and North Island;
- enabling development of ancillary markets (such as frequency keeping, reserves and balancing markets) to support increased generation from intermittent renewable sources;
- increasing resilience of the National Grid to high impact, low probability events by increasing the flexibility of system operation;
- improving security of supply in dry years, by enabling greater southwards transfer of electricity from North Island generators when there are low inflows into the South Island hydro schemes; and
- mitigating the consequences for security of supply of a Pole 2 failure, noting that the existing Pole 2 is aging and there is an inherent, increasing risk of it failing.

5.8.3 Enabling wind diversification

As more wind farms are built in the North Island, the non-firm nature of this resource is likely to put a strain on the rest of the system from a reliability perspective. When the wind is not blowing, there still needs to be sufficient capacity to cover demand. Over time, an additional reserve market may emerge to back up the intermittency of wind. With a larger link capacity than a 700 MW monopole, there is potential for more South Island hydro capacity to be built, resulting in less reliance on wind capacity in the North Island. Furthermore, if more South Island wind capacity is built as a result of the larger link, the geographical diversity may help smooth out the intermittency of supply and improve overall reliability of supply.

In a recent joint study between Meridian Energy and Imperial College, London into the system integration impacts of wind generation in New Zealand¹³, it is reported that the additional capacity costs that wind generation impose on overall energy costs will be reduced once HVDC capacity is increased from 1000 MW to 1500 MW capacity.

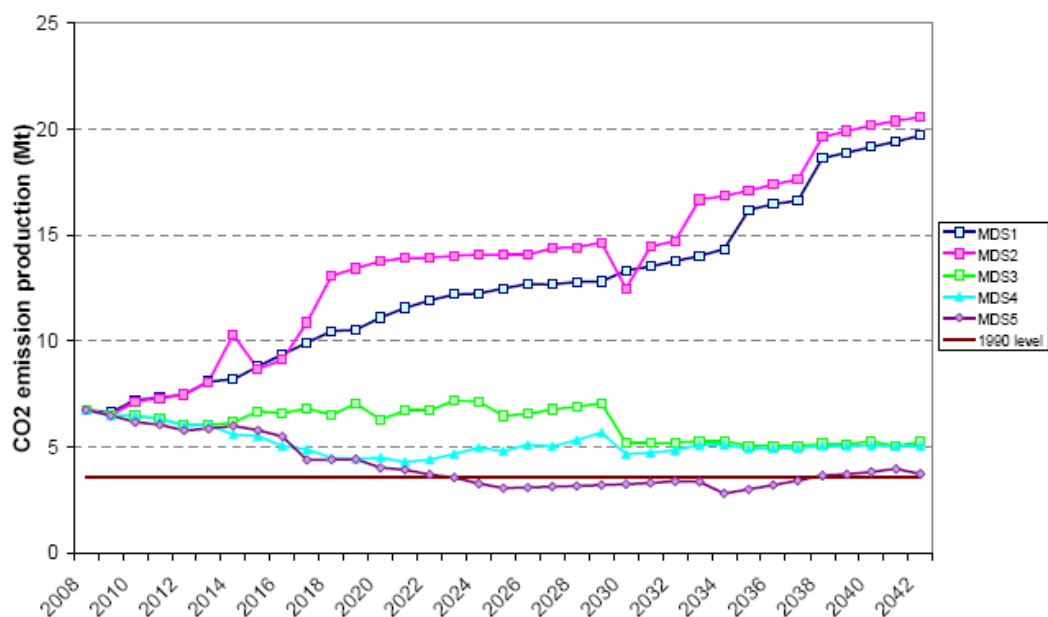
The study finds that the additional capacity cost of wind generation decreases by approximately \$0.5 per MWh once Pole 1 is replaced. Using the wind generation estimates included in the report, this equates to a saving of approximately \$14 million, as a present value, between 2010 and 2020 alone.

The \$0.5 per MWh decrease in capacity related cost is achieved over a decade (2010-2020) where the generation from wind power triples. Capacity related costs also increase the following decade (2020-2030) with the explanation being even higher wind penetration. Thus, the impact from the extra HVDC capacity is likely to be even higher than \$14 million estimated benefits quoted in this study.

5.8.4 Cost effectiveness of emission abatement

MMA's PLEXOS analysis shows that the Government's emission abatement target to return to 1990 CO₂ production levels by 2025 would probably only be achievable for the stationary energy sector under market development scenario 3, 4 or 5, as shown in Figure 5-2 below.

Figure 5-2: Market Development Scenario by CO₂ emission production



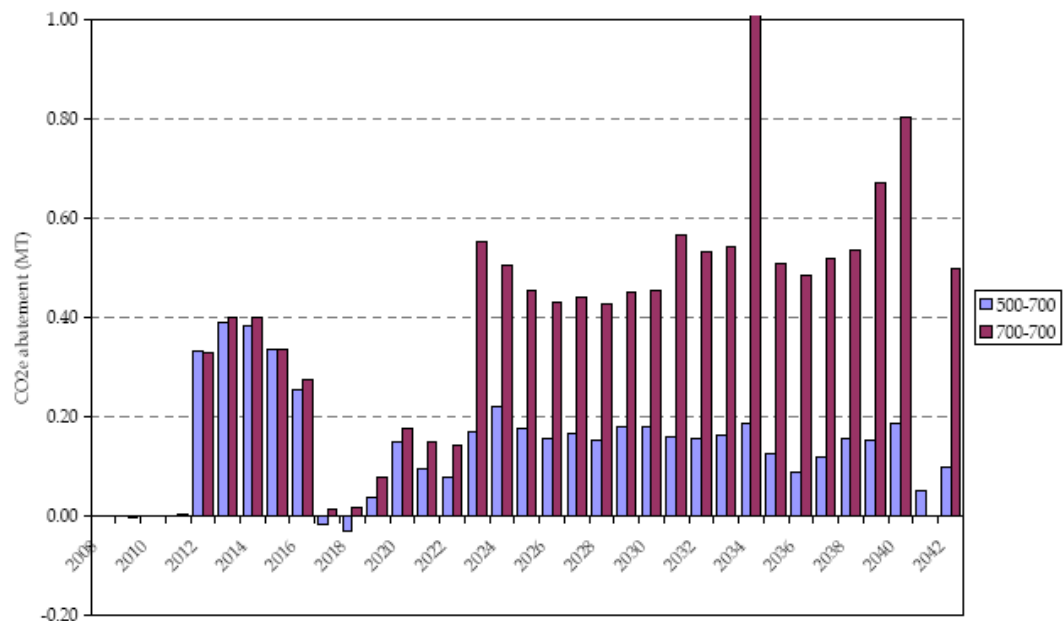
¹³ <http://www.meridianenergy.co.nz/AboutUs/News/Economic+virtues+of+future+wind+generation.htm>

The 1990 target could be met in 2025 in all cases (the Base Case and all options), although it cannot be sustained for more than five years under the Base Case and 500 MW option. The 700 MW option is the most cost-effective CO₂ emission abatement alternative, as it produces fewer emissions than the other options.

Figure 5-3 shows the emission abatement from the 500 MW and 700 MW options relative to the Base Case, for the 90% renewables by 2025 scenario and for medium demand growth. From 2024 onwards, emission abatement under the 700 MW option is nearly double the abatement from the 500 MW option. This is largely driven by the additional North Island wind that is built in the 700 MW option, compared with other thermal and DSR technologies chosen under the 500 MW option. In all but the High Gas scenario, the emission costs are lower and hence the emission abatement is higher under the 700 MW option than the 500 MW option.

It should be noted that the emission abatement benefits have already been included in the GIT analysis, with the value of abatement assumed to be equal to the carbon price assumed. However, if carbon prices were higher than assumed in this analysis, the Proposal would offer even more benefit than attributed in the GIT analysis.

Figure 5-3: Emission abatement – MDS 5, medium growth



5.8.5 Competition benefits

Whilst it is intuitive that providing a link between the North Island and South Island should enable greater competition between generators in both islands, it is difficult to calculate the benefits that result from that enhanced competition.

Transpower employed MMA to consider the effect of the various Pole 1 replacement options on competition benefits and consumer benefits. A summary of their findings can be found in Appendix B to this report and their full report is included as Attachment G to the Consultation Paper (see Volume 2). Although the GIT does allow competition benefits to be included provided they are quantified, given the exploratory nature of this work Transpower has chosen not to include them in the GIT result for this proposal.

Competition benefits only arise in situations where one or more competitors in a market are in a position to exercise market power and they exercise that power in a manner that results

in inefficient outcomes, compared to a situation where they could not exercise that power. Hence, to model competition benefits in a market requires assumptions to be made about the extent of potential market power and the market behaviour of those competitors when they exercise that power.

For the purpose of this project, that requires assumptions to be made about the ownership of new generation built and how competitors would exert market power, e.g. by withdrawing some generation to enable more of their less efficient and more expensive generation to run

In the analysis undertaken, some surprising results emerged - both positive and negative competition benefits were found, depending on the market development scenario.

That may be explained by the observation that, when the North Island becomes capacity constrained, a lot of new generation is built in the North Island, particularly in the Base Case. Hence the North Island has a very competitive market in the Base Case and by expanding the HVDC and reducing the amount of new generation in the North Island, the level of competition is potentially reduced.

Whilst this may help explain the outcomes observed, it does highlight how important the assumptions are and it raises a question about whether enough work has been undertaken to robustly conclude the extent of competition benefits for the HVDC options considered. Different assumptions about new generation ownership and market behaviour, would likely produce different outcomes.

For information, a summary of the competition benefits for individual scenarios and for high, medium and low demand, for the 700 MW replacement option, were as follows:

Table 5-6: Competition benefits by generation and demand scenario.

Competition benefits (\$2007 m)	Demand scenario		
	High	Med	Low
High Gas	-\$55	-\$40	-\$119
Mixed technologies	-\$13	-\$22	-\$33
Primary renewables	\$171	-\$57	-\$194
SI surplus	\$213	-\$526	-\$481
90% renewables by 2025	\$101	\$188	\$111

Applying the weightings used in the GIT, this gives a competition benefit to the Proposal of approximately \$42 million compared to the Base Case. As discussed above, these results are explainable.

Transpower is encouraged by the MMA analysis, as it produces explainable results for the assumptions made, but considers that other ownership/market behaviour combinations would need to be modelled to draw robust conclusions about competition benefits.

Whilst this analysis may not support the existence of positive competition benefits for the Proposal, Transpower would still expect a positive competition benefit emerge with further modelling. It seems intuitive that linking the North Island and South Island enhances competition nationally.

5.8.6 Consumer benefits

Consumer benefits are benefits to consumers of electricity and in general are related to the competitiveness of a market and the resulting efficiency of the market. In an efficient market, consumers could expect that electricity prices would be close to long run marginal costs to produce electricity, whereas in an inefficient market, electricity prices could be well above long run marginal costs. The cost differences related to these market inefficiencies are largely wealth transfers between generators and consumers. These wealth transfers are not

considered in the GIT.¹⁴ Nevertheless Transpower would expect the Electricity Commission to have a preference for competitive markets which deliver consumer benefits.¹⁵

MMA also considered a range of consumer benefits at the same time as considering competition benefits. Their conclusions are summarised in Appendix B and are described fully in Attachment G to the Consultation Document – Volume 2. In brief:

HVDC constraints

Congestion on the HVDC can place generators in the constrained region in a position of market power, so in general, the fewer constraints on the HVDC, the better from this point of view.

Generally, the results indicate that there are fewer constraints if Pole 1 is replaced than if it is not. Additionally constraints decrease as replacement Pole 1 capacity increases.

Market concentration/competitiveness

Market concentration was assessed using an adjusted Herfindahl-Hirschman Index (HHI). The HHI is calculated using the following formula:

$$HHI^{adj} \equiv \sum_{i=1}^m s_i (s_i + s_c / m)$$

where s_i is the market share of the i -th unconstrained firm ($i = 1, \dots, m$) and s_c is the total market share of the constrained firms.

Markets with many competitors and small market shares are less concentrated and have a smaller HHI than markets with few competitors with large market shares.

A smaller HHI is preferred. MMA found that the HHI drops over time whether Pole 1 is replaced or not. In all cases though, the commissioning of a replacement Pole 1 in 2012 reduces the HHI and generally results in a lower HHI over time than if Pole 1 had not been replaced, i.e. the replacement of Pole 1 ensures the electricity market is less concentrated.

Price Mark-ups

The Lerner index was used to calculate how price mark-ups (amount a generator bids over and above their marginal cost) change with HVDC link size. The Lerner Index is calculated as:

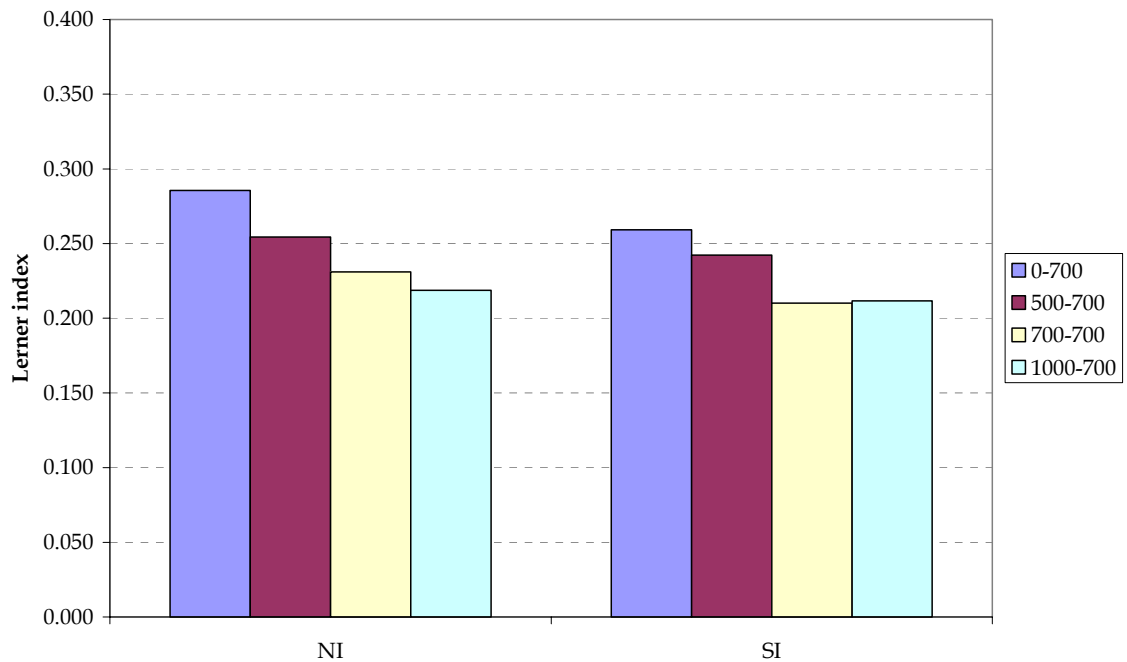
Lerner Index: $LI = (\text{bid price} - \text{short run marginal cost}) / \text{bid price}$

The Lerner index for each year is calculated based on the average bid prices from the Nash-Cournot simulations and the average short run marginal cost from the non-competition simulations.

The figure below shows that the weighted average Lerner index ranged from 0.2 to 0.3 across all augmentation scenarios in both North Island (NI) and South Island (SI). A Lerner index of zero would imply that there is no market power in the system, so a lower index is preferred.

¹⁴ However, any associated deadweight loss due to levels of generation being lower than optimal could be.

¹⁵ See the Government Policy Statement on Electricity Governance, e.g., clause 80.

Figure 5-4: Average Lerner index for North Island and South Island

As seen, the Lerner index indicates that the price mark-ups decrease as link size increases.

Nodal price changes

Nodal prices were calculated at Penrose and Islington, over time, for each option.

The table below shows the annual average price differential between the specific nodes in the North Island and South Island for the same scenario and level of demand. Increasing the capacity of the HVDC link reduces the price differential between the North Island and the South Island, with the price in the South Island typically increasing more than the decrease in price in the North Island.

Table 5-7: Price differential between North and South Islands, 90% renewables by 2025, medium demand

HVDC option	Average annual price differential post augmentation (\$/MWh)
0-700	25.9
500-700	8.0
700-700	6.6
1000-700	6.3

5.8.7 Retail competition

While the presence of an HVDC link affects competition on the wholesale market, it also affects retail competition in as much as it effectively increases the geographic market in which retailers can operate.

Electricity generation and retail are vertically integrated in New Zealand and the retail arm of these vertically integrated companies offers the generator a natural hedge for its generation

output. Retail competition is not considered to be “as vigorous as it could be¹⁶” with only three retail companies offering contracts in the majority of the South Island¹⁷.

Currently, it is common practice for a retailer to offer contracts in the island in which its parent company has generation located. For example, Genesis Energy only offers retail contracts in the North Island¹⁸ where all of its generation is located. One of the reasons for this is likely to be the risk of price separation between islands in the absence of the link or at times of constraint.

Compared with the Base Case, all options 1-3 will lead to a lower risk of price separation between the islands. This may make it more attractive for retailers to offer contracts to consumers on the “other” island. Furthermore, it may enable retailers that already offer retail agreements on the “other” island, to offer more competitive prices as their hedging costs are reduced.

Finally, a bipole link (i.e. options 1-3) will lead to a reduction in the amount of time the South Island price is separated from the North Island price. It will therefore be relatively more attractive to invest in generation in the South Island. Such investments, if made by generators currently not present in the South Island, may result in increased retail competition.

Conclusion

The consumer benefit analysis demonstrates that, in general, competitiveness is increased with a replacement Pole 1 and that competitiveness increases as the replacement link size increases.

Overall, there is expected to be a transfer of wealth from consumers to generators in the South Island, and from generators to consumers in the North Island, upon the building of the replacement link. The analysis suggests replacement of Pole 1 is likely to result in benefits to consumers.

This analysis does not include sensitivity analysis, which would improve the robustness of the results. The trends, however, do indicate that replacing Pole 1 of the HVDC link will enhance the competitiveness of the New Zealand electricity market and the benefits to consumers.

5.8.8 System stability improvement

The HVDC controls will incorporate several power and current modulation functions which exploit the high degree of controllability inherent in the HVDC link. The net market benefit derived from the special control functionality provided by the Proposal is difficult to quantify but forms an essential part for maintaining the stability and economic operation of the grid. Investment in a replacement Pole 1 (options 1-3) will provide additional modulation capacity to respond to AC system events over and above possible with the Base Case.

5.8.9 Frequency control/stabiliser

The HVDC frequency stabiliser provides a temporary fast reaction to frequency changes in either or both islands following system disturbances. This assists in arresting the frequency drop as a result of system disturbances. Without this function, more reserves or load shedding would need to be available to ensure the frequency is kept within defined frequency limits. This has a consequential flow-on effect in terms of increased costs for generators and consumers.

¹⁶ Draft Government Policy Statement on Electricity Governance, para 132, 29 Feb 2008.

¹⁷ Christchurch and Central Canterbury are the exception with four retailers offering contracts.

¹⁸ <http://www.consumer.org.nz/powerswitch/>

In the event that Haywards is separated from the upper North Island during high DC transfer north, over frequency is limited by the emergency over frequency control on the HVDC until the HAY islanded constant frequency control can be manually switched on.

The HVDC link can control the frequency in the Wellington area if it is separated from the upper North Island while being supplied from DC transfer.

Having an increased capacity over the Base Case provides increased head room required for frequency stabilisation functions to operate and to improve power system stability.

5.8.10 Other benefits of HVDC dynamic performance

In addition to the above known benefits of HVDC other new benefits, such as from improved frequency keeping and extending automatic generation control between the two islands, may result from the Proposal.

Transpower has not finalised the methodology for the cost/benefit analysis of such features. It has, therefore, not quantified the benefits of implementing such solutions in this Proposal. However, if it considers such potential benefits are likely, even if their value is difficult to estimate at this stage.

These benefits flow from (a) the increase in inter-island capacity and (b) the bipole link that will result from the Proposal:

- The increase in inter-island capacity will provide many benefits including an increased head room required for dynamic modulation for improving power system stability, enhancing the ability to block dispatch renewable generation via HVDC across the two islands. This will also provide a better means of catering for fluctuating generation sources and/or demand across the two islands.
- Having two poles in the Proposal instead of a monopole will provide self cover in the event of a pole outage reducing the need for additional spinning reserves and/or shedding large blocks of customer load.

5.8.11 Summary of other benefits

Transpower considers that the Proposal leads to a wide variety of benefits not accounted for in its GIT application. Transpower has not relied on these benefits in deciding to make this Proposal, but considers that these benefits reinforce the view that the outcome of its GIT analysis is consistent with wider policy objectives.

6 The Proposal meets the Rule requirements

Rule 14.4 sets out two criteria that a proposed economic investment must meet in order for Transpower to obtain approval from the Electricity Commission to recover the costs associated with implementing it, namely:

- Transpower's application of the GIT must be reasonable; and
- Transpower has followed any agreed consultation process.

Transpower also considers that the Proposal is consistent with GEIP, as were all the short-listed options.¹⁹

6.1 Transpower's application of the Grid Investment Test

Transpower considers that its application of the GIT, described above and in the attached documents, is reasonable.

6.2 Compliance with agreed consultation process

Rule 14.2 requires the Electricity Commission and Transpower to agree a timetable for consultation and approval of economic investments. In the absence of agreement, the Electricity Commission may stipulate such a timetable.

Additionally, the Electricity Commission must consult with Transpower on the process for consultation and persons who the Electricity Commission thinks are:

"representative of the interests of persons likely to be substantially affected by economic investments and content of draft grid upgrade plans".

The Electricity Commission and Transpower agreed a timetable and process for consultation on, and approval of, the Proposal to Transpower on 6 November 2007. This was replaced by a revised process and timeline on 13 December 2007.²⁰ Transpower has complied with the process and timeline to date, and will work with the Electricity Commission to achieve the remaining agreed process and timeline.

6.3 Compliance with criteria for approval

As set out above, Transpower has applied the GIT reasonably and complied with the agreed process for consultation as required by the Rules for the Proposal. Transpower therefore considers that the Proposal satisfies the requirements of the Rules for approval by the Electricity Commission of a proposed economic investment to recover the costs associated with implementing it.

¹⁹ Transpower considered GEIP at the identification and screening of options stage (see section 4 above).

²⁰ Both are available at <http://www.gridnewzealand.co.nz/n282,110.html>.

7 The Proposal is consistent with wider policy objectives

In addition to the Rules requirements set out above, the Proposal is being submitted within the context of a wider regulatory framework.

Set out in this section is a brief assessment of the Proposal against the:

- purpose of section III of Part F of the Rules;
- Government Policy Statement on Electricity Governance (GPS); and
- principal objectives and specific outcomes under the Electricity Act 1992 (the Act).

7.1 The purpose of section III of Part F

Transpower submits that the objectives of Part F of the Rules are relevant to the Electricity Commission's consideration of the proposal.

Table 7-1: Alignment of the Proposals with the objectives of section III of Part F of the Rules

Rule (purpose of Part F)		Would approval of the Proposal contribute to this purpose?
2.1	Facilitate Transpower's ability to develop and implement long term plans (including timely securing of land access and resource consents) for investment in the grid	The investigation into the need for the Proposal, or other investment, has been a part of Transpower's long-term plan for the grid and has been included in: ◦ Transpower's 'Future of the National Grid' document of 2003; ◦ Transpower's 2005 GUP; and ◦ all of Transpower's Annual Planning Reports (the first being in 2006).
2.2	Assist participants to identify and evaluate investments in transmission alternatives	The development of the Proposal, particularly the extensive consultation process, has allowed and assisted participants to identify and propose transmission alternatives.
2.3	Facilitate efficient investment in generation	The Proposal will facilitate efficient investment in generation nationally and in the South Island in particular.
2.4	Facilitate any processes pursuant to Part 4A of the Commerce Act 1986	Any proposed investment that follows the Part F processes will achieve this.
2.5	Enable the cost of approved investments to be recovered through the transmission pricing methodology applied in transmission agreements	Any proposed investment that follows the Part F processes will achieve this.

7.2 The Government Policy Statement

Under section 172O(1) of the Electricity Act 1992, one of the functions of the Commission is to give effect to GPS objectives and outcomes. The current GPS is that issued in October 2006.

Table 5-2 below considers how the Proposal would contribute to giving effect to the relevant policies as laid out in the GPS.

Table 7-2: Alignment of the Proposals with the GPS (directly relevant policies only)

Government Policy Statement (directly relevant policies only)	Would approval of the Proposal contribute to this policy?
Renewable Energy	
Encouraging the development of renewable energy resources is a key part of the Government's strategy for managing climate change and long term energy security. To further this aim the Government's objectives in relation to renewable energy, are that: - undue barriers to investment in renewables should be reduced or removed - the efficient uptake of renewable generation should be promoted and - the national transmission grid should be planned and made available so as to facilitate the potential contribution of renewables to the electricity system and in a manner that is consistent with the Government's climate change and renewables policies.	The Proposal will enable efficient levels of renewable generation, in the South Island by increasing transfer capacity, and in the North Island by increasing options for balancing with South Island plant.
Security of Supply	
Key components of security of supply are that: - Hydro and thermal generating capacity and fuels are appropriately managed, to deal with the risks of extended dry hydro periods better than we have in the past - The national grid and distribution lines meet specified reliability objectives. (Transmission and distribution issues are covered in separate sections)	The Proposal allows for greater quantities of electricity to be transferred between the North and South Islands (inter-island transfer capacity). This improves security of supply in relation to dry year risks by enabling increased southward flows. The Proposal is consistent with the Grid Reliability Standards.
Transmission - objectives for the provision of transmission services	
80 The Government's objectives for the provision of transmission services are that: - the services are provided in a manner consistent with the Government's policy objectives for electricity and in particular that grid reliability should be maintained at a level required by residential, commercial and industrial users and the Government's economic development objectives - the transmission grid should be adequately resilient against the effects of low probability but high impact events having regard to the load which could be disrupted and the duration of any disruption - where practical, the transmission grid should provide adequate supply diversity to larger load centres having regard to the load which could otherwise be disrupted and the duration of any disruption - competition in generation and retail is facilitated and transmission constraints are minimised	The Proposal is consistent with and assists the Government's policy objective of delivering electricity to all classes of consumers in an efficient, fair, reliable, and environmentally sustainable manner. The Proposal is consistent with the Grid Reliability Standards. The Proposal improves the resilience of the grid in that it allows greater inter-island transfer capacity. This increases the number of management options available to Transpower in the event of low probability, high impact events. The probability of an outage preventing any inter-island transfer will be significantly reduced. While the Proposal does not directly serve a major load centre, it does improve reliability for North Island centres including Auckland and Wellington, and in dry years South Island centres including Christchurch, by increasing inter-island transfer capacity. The Proposal facilitates competition in generation by enabling new generation in the South Island in particular. The Proposal will reduce constraints to power flow between the islands. This will in turn facilitate competition in generation and retail by creating a more national market.



	the national transmission grid should be planned and made available so as to facilitate the potential contribution of renewables to the electricity system and in a manner that is consistent with the Government's climate change and renewables policies	The Proposal will enable efficient levels of renewable generation, in the South Island by increasing transfer capacity, and in the North Island by increasing options for balancing with South Island plant. The Proposal's consistency with the Government's climate change and renewables policies is well illustrated by fact that its net benefit almost doubles under the 90% renewables by 2025 scenario relative to that weighted across all scenarios, and doubles again under a lower discount rate.
	the efficiency of transmission services should be continuously improved so as to produce the services grid users and consumers want at least cost, and	The Proposal provides a net market benefit and a higher benefit than alternatives, demonstrating that it meets grid users' and consumers' needs at least overall economic cost.
	stakeholders and the public are kept well-informed about how security of supply is to be maintained throughout the development and consideration of any grid upgrade plans.	This document and its attachments, the preceding meetings and consultation and Transpower's Annual Planning Reports have ensured the public are well-informed on security and investment issues.
Transmission - Investment in and maintenance of the transmission network		
87B	The grid upgrade plan should also be consistent with statement of opportunity forecasts and wider government energy policy including applicable policies on renewable generation and climate change.	In developing the Proposal, Transpower has had regard to the Electricity Commission's draft 2007 forecasts. The Proposal is consistent with wider government energy policy including applicable policies on renewable generation and climate change, as outlined in this section.
87C	Grid upgrade plans should demonstrate the rationale for all expenditure (operation, maintenance and capital), taking into account the prescribed reliability standards and good industry practice for power system operation. The plans should demonstrate that the proposed expenditure is required to meet reliability standards and/or deliver the greatest net benefit after taking into account transmission alternatives and government energy policy requirements.	This Proposal demonstrates the rationale for the costs of the Proposal, taking into account good electricity industry practice. The Proposal is consistent with the Grid Reliability Standards. The Proposal delivers the greatest net benefit after taking into account transmission and non-transmission alternatives. This section outlines how the Proposal contributes to government energy policy requirements.
87D	In the development of grid upgrade plans; the Government's objective is that: - Transpower should undertake the detailed planning role (including the assessment of both transmission and non transmission alternatives); and - the Electricity Commission should review and approve grid upgrade plans that meet the criteria set out in the Electricity Governance Rules and reject applications that fail them.	The process of developing this Proposal is consistent with these roles.
87F	The Electricity Commission should ensure that affected parties are fully consulted on grid upgrade plans.	Transpower has followed the consultation process agreed with the Electricity Commission in developing this Proposal.
87G	In developing and considering grid upgrade plans, Transpower and the Electricity Commission should seek to maintain business confidence by making it clear that adequate grid reliability will be maintained.	Transpower has undertaken a detailed assessment of the Proposal and it will not detrimentally affect the reliability of the grid. This will assist in maintaining business confidence. The benefits of the Proposal in terms of security of supply can be expected to improve business confidence. For possible investors in renewable generation, the Proposal will improve business confidence as their investment options will be increased.



Transmission - planning ahead

88BB The risks to maintaining grid reliability resulting from uncertainties in demand forecasting and easements should be conservatively managed.

Transpower believes that this statement of government policy focuses on reliability rather than economic investments.

Nevertheless, Transpower will continue to monitor demand growth and, if necessary, refine the physical scope of works, design or timing of the Proposal, with Electricity Commission agreement as necessary.

88C This should help the essential process of maintaining stakeholder confidence in ongoing security of electricity supply even if, at times, there is some loss of flexibility around investment choices and some additional cost for electricity consumers.

Transpower is always concerned with stakeholder confidence and has developed this document and attachments to ensure that this confidence is maintained.

The Proposal achieves this without loss of flexibility around investment choices or additional cost for electricity consumers. Indeed, the Proposal will significantly increase flexibility around generation investment choices and is expected to reduce costs for electricity consumers.

Transmission - transmission alternatives

As part of the consideration of transmission investments, the Electricity Commission should ensure that transmission alternatives are considered to the extent practicable subject to the following conditions:

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- only alternatives which have a high probability of proceeding and where grid reliability can be maintained by contingency measures if the alternative is delayed or does not proceed should be considered;
 - alternatives which are only likely to proceed if they are assisted financially by the Government or relevant body should not be considered unless the Government or relevant body has agreed to provide such assistance.

Transpower believes that this statement of government policy focuses on reliability rather than economic investments.

Nevertheless, in reaching the Proposal Transpower has considered a wide range of transmission and non-transmission options. Transpower has assessed the proposal against two transmission alternatives, and did not consider that any non-transmission options were practicable. Transpower took the GPS into account in its option screening process.

The alternatives considered satisfied the two conditions specified here.

7.3 The Electricity Act 1992

Transpower submits that the following objectives, outcomes and functions of the Electricity Commission and corresponding assessments are relevant to its consideration of the proposal.

Table 7-3: Assessment of the Proposal against the principal objectives and specific outcomes of the Electricity Commission

172N	Principal Objectives of the Electricity Commission	Would approval of the Proposal contribute to this purpose?
172N(1)	The principal objective of the Commission in relation to electricity are:	By increasing transfer capacity, the Proposal will allow electricity to be dispatched at lower overall cost.
	- to ensure that electricity is produced and delivered to all classes of consumers in an efficient, fair, reliable and environmentally sustainable manner; and - to promote and facilitate the efficient use of electricity.	In addition to this, the Proposal will improve the reliability and security of supply to the South Island in dry years. The Proposal will also facilitate least cost renewable generation investment, which will help ensure that electricity is produced in a sustainable and efficient manner.
172N(2)	Consistent with those principal objectives, the Commission must seek to achieve, in relation to electricity, the following specific outcomes:	
	- energy and other resources are used efficiently; - risks (including price risks) relating to security of supply are properly and	The Proposal allows for the efficient use of energy and resources, as demonstrated by the result of Transpower's GIT analysis. The Proposal improves security of supply and is



efficiently managed;	consistent with the grid reliability standards. The Proposal will reduce price risks by reducing the frequency of inter-island constraints and enabling efficiencies in ancillary service procurement.
incentives for investment in generation, transmission, lines, energy efficiency, and demand-side management are maintained or enhanced and do not discriminate between public and private investment.	The proposal will enhance incentives for investment in generation by providing more (and hence some cheaper) investment options to generators, and by providing greater access to markets and balancing services and fewer constraints. The Proposal will not introduce discrimination between public and private investment.
delivered electricity costs and prices are subject to sustained downward pressure	The Proposal will facilitate investment in least cost generation, especially in the South Island, and can be expected to reduce ancillary service costs and the price impacts of constraints. This will, in the long term, ensure downwards pressure on electricity prices.
the electricity sector contributes to achieving the Government's climate change objectives by...removing barriers to investment in new generation technologies, renewables, and distributed generation.	The Proposal facilitates investment in renewable generation in the South Island by increasing inter-island transfer capacity, which in turn avoids constraints that may otherwise discourage this investment.

Table 7-4: Assessment of the Proposal against the functions of the Electricity Commission

1720	Functions of the Electricity Commission	Would approval of the Proposals contribute to this purpose?
1720 (1)	give effect to GPS objectives and outcomes	The Proposal will not give effect to all GPS objectives and outcomes, but will contribute significantly to some key GPS objectives and outcomes, as outlined in Table 7-2 above.

7.4 Summary of Consistency with Wider Objectives

The Proposal is consistent with, and will assist in achieving, the Electricity Commission's wider policy objectives as set out in the Electricity Act, section III of Part F of the Rules and the GPS.

8 Costs of Proposal

Transpower seeks approval of the Proposal and approval to recover the lesser of actual costs or the estimated 90th percentile of project costs (P90 cost). The P50 cost (mid-range) is estimated to be \$620 million and the P90 cost (upper range) of the Proposal is estimated to be \$728 million. This section sets out how Transpower has estimated the P50 and P90 costs and describes the difference between the expected costs used in the GIT analysis and the P50 and P90 costs.

Method of calculating P50 and P90 costs

Transpower applies a Monte Carlo simulation technique to estimate the P50 and P90 costs, whereby the cost of the Proposal is simulated a large number of times, each time changing a number of variables related to the cost within an expected range. A distribution of the resultant project costs is plotted and the P50 cost is the 50th percentile of those project costs (and therefore represents a mid-range cost estimate for the Proposal) and the P90 cost is the 90th percentile of those project costs (and therefore represents an upper range cost estimate for the Proposal with 10% probability of exceedance).

The following inputs and variables are considered in deriving the P50 and P90 costs:

- **Estimated capital costs.** The estimated capital costs are the estimated costs of 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 capital costs do not include contingencies. The estimated capital costs are in Reference date dollars.
- **Reference date.** Transpower prepared estimated capital costs as at 30 April 2007. 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, Transpower has assumed a commissioning date of 30 April 2012 for Stage 1 and 30 April 2014 for Stage 2. These commissioning dates are assumed to be the dates at which accumulated costs for the project would be included in Transpower's regulated asset base and from which costs would start to be recovered through the Transmission Pricing Methodology. Note that the evolving nature of the regulatory regime under the Commerce Act may introduce some uncertainty into this assumption. The consequences of that uncertainty are further discussed in section 10 below.
- **Scope contingency.** Transpower also estimates scope contingencies, which are added to the estimated capital costs, 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 capital cost plus scope contingency equals the **expected cost** of the project or various components of it and this is the cost used in GIT analyses. For the purpose of simulation modelling scope contingencies are not varied, but rather are treated as a fixed percentage of estimated capital costs, added to the estimated capital cost. They may vary in dollar terms because of changes in other input variables. This is consistent with the use of Expected costs used in the GIT analysis. In this proposal the percentage allowance for scope contingencies varies from item to item between 8% and 40%, with an overall average of 14%.
- **Price accuracy.** 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 Transpower seeks tenders, the prices offered may reflect a tighter supply situation and therefore be higher than at other times; and
- commodity price movements. Tender prices for some capital items include escalators linked to market price variations in significant elements of that item eg metals such as steel and copper. As with exchange rate variations, Transpower 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, Transpower is exposed to commodity price movements up until contracts are signed and so an estimate is made of the potential cost variation this might cause.

Transpower has modelled commodity price risk by expressing the accuracy of estimates as a triangular distribution for the purposes of the simulation modelling with the minimum and maximum variations varying by item, but between -10% and +10% to -22% and +22% respectively. The point estimate of costs is given as the most likely outcome, and lower and upper bounds are expressed as percentages of the midpoint.

The market pressure risks referred to above are considered separately and treated in the same manner as scope contingency for the purposes of the simulation modelling, i.e. they are added to the estimated capital costs but are not varied in the simulation runs.

- **Exchange rates.** Transpower's 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.

Transpower does 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.

Point estimates of capital cost were based on the average exchange rate 20 business days either side of 30 April 2007. For the simulation runs exchange rates have been sampled from daily exchange rates over the period 1 July 1996 to 12 September 2007. This approach assumes that the simulated exchange rates and cross-rates have a similar mean and variance to historical rates.²¹

- **Inflation.** Transpower modelled inflation by drawing from a uniform distribution in a range from 2% to 4%, with a mean of 3%.
- **Real interest rates.** Transpower modelled real interest rates, used in the calculation of interest during construction, by drawing from a uniform distribution in a range from 4.2% to 6.2%, with a mean of 5.2%. The nominal interest rate is the real interest rate plus the inflation rate, equating to a mean nominal interest rate of 8.2% in this instance. This is approximately Transpower's current cost of debt.

²¹ Over a large number of simulations the exchange rate will be close to the 10-year average rate which is reflected in the mean cost figures.

Results of P50 and P90 cost calculations

The expected cost of the Proposal, as estimated in 2007, is \$470 million. This cost includes an average scope contingency of 14% and represents Transpower's estimate of the cost of purchasing, constructing and commissioning the Proposal. Transpower will not start recovering the costs of a stage of this Proposal until it is commissioned, i.e. 2012 for Stage 1 and 2014 for Stage 2. The cost Transpower will look to recover at that time is higher, due to financing costs incurred throughout the construction period and inflation. Transpower's P50 estimate of the cost it will look to recover from commissioning is \$620 million. A P90 cost has also been estimated, being an upper range cost that Transpower would look to recover from commissioning. The P90 cost allows for uncertainties between now and commissioning, in capital costs, exchange rates, interest rates and inflation. The estimated P90 cost for the Proposal is \$728 million and Transpower is seeking approval to recover the lesser of actual costs or the P90 cost. By definition, there is a 10% probability of exceedance of this cost based on the modelling assumptions set out above. If there are changes to modelling assumptions that are materially different to those used then the P90 cost may also be exceeded. In either case, Transpower would apply for approval for the revised costs of the project in accordance with Rule 17.2.

Table 8-1: Costs for Stages 1 and 2, \$million

Category	Estimated capital cost	Expected cost	Estimated P50 cost	Estimated P90 cost
Stage 1	381	436	573	676
Stage 2	31	34	47	52
Total	412	470	620	728

(*) As defined above and as used in GIT economic analysis.

To determine a P90 cost for this approval request, Transpower has developed a distribution of likely project costs using Monte Carlo simulation techniques, as previously described.

The following table shows how the expected cost is related to the estimated P50 cost of the Proposal. The P50 cost is estimated to be \$620 million and this is the mid-range estimate of the cost Transpower will seek to recover, following commissioning of the Proposal in 2012 (and 2014). Note that the P50 is the median from the cost distribution and is not the mean.

Table 8-2: P50 cost for the Proposal, \$million

Category	Expected Cost	Price Contingency	Exchange Rate Variation	Interest During Construction	Inflation	Estimated P50 Cost
Stage 1	436	0	19	39	79	573
Stage 2	34	0	1	3	9	47
Total	470	0	20	42	88	620

Applying the Monte Carlo simulation technique, as discussed above, the P90 cost is estimated to be \$728 million. Please note that the 90th percentile outcomes for each individual variable are shown in the table below, but that these do not simply add to become the overall P90 cost as reported in the right-hand column. This table shows, when compared to Table 8-2 above, the general source of the variation between the P50 and P90 costs.

Table 8-3: P90 cost for the Proposal, \$million



Category	Expected Cost	Price Contingency	Exchange Rate Variation	Interest During Construction	Inflation	Estimated P90 Cost
Stage 1	436	66	48	51	109	676
Stage 2	34	2	3	4	11	52
Total	470	68	51	55	120	728

Summary of estimated P50 and P90 cost

Transpower therefore estimates the P50 cost of the Proposal to be \$620 million and the P90 cost of the Proposal to be \$728 million.

9 Recommendation

On the basis of this investment proposal contained within the 2007 Grid Upgrade Plan, Transpower **recommends** that the Electricity Commission **approve the HVDC Grid Upgrade Proposal as defined in Part A of this document** on the grounds that:

- Transpower's application of the GIT is reasonable; and
- Transpower has followed the agreed consultation process.

10 Post Approval

This section describes what Transpower's approach to project managing and reporting and to change management will be following approval by the Electricity Commission of the Proposal as defined in Part A of this document.

10.1 Project management and reporting

Transpower will continue to have appropriate project management techniques in place to manage project costs and risks, including:

- Undertaking independent periodic audits of its project management, procurement and commercial processes for the Transpower Board. These audits are aimed at demonstrating that project controls are in place and there is a process to identify areas where Transpower can improve its processes and performance.
- Tracking and reporting project progress on Transpower's website, and sending the Electricity Commission copies of those reports.
- Reporting periodically to the Transpower Board on progress against both expected costs and cost with contingencies, and reasons for any divergence (e.g. exchange rate fluctuations), allowing for indexed escalation or deflation of linked costs.
- Ensuring quality assurance is applied in planning, designing, and manufacturing, commissioning, testing and maintaining Transpower's assets in accordance with good electricity industry practice.

10.2 Change management

Transpower will continually look for opportunities to minimise project costs and maximise market benefits where practicable, considering reliability standards, good electricity industry practice, timing delays, requirements under the Resource Management Act 1991 and any other relevant matters.

Design

Following approval of the Proposal, Transpower may refine the design of this Proposal to reduce costs, increase benefits or resolve practical or safety issues as they arise. Should any such design refinement fall outside the physical scope of works defined in Part A, Transpower will advise the Electricity Commission as soon as reasonable and consider seeking an amendment of project scope under Rule 17.2.

Two particular design issues that may arise are:

- Transpower will include short-term overload capacity as a desirable characteristic of the new converter and will value overload capacity when assessing tenders.
- Transpower has not included in the Proposal overhauls and replacement of control, excitation, protection and starting systems for the synchronous condensers at Haywards. It is continuing to investigate the need and costs of this work, and expects these investigations to taken 6-12 months to complete.

Once each of these is progressed, Transpower will, if necessary, discuss with the Electricity Commission whether this work remains within scope, requires amendment to this Proposal, or requires a separate proposal.

Commissioning dates

Transpower will proceed to commission the Proposal to the target dates set out in Part A, allowing for sound legal, environmental, commercial and safety processes.

Should the Electricity Commission's approval of the Proposal be challenged through judicial review, Transpower may suspend the project pending the outcome of such review.

Transpower will keep the industry and Electricity Commission informed of expected commission dates as described under reporting above.

Costs

Transpower is seeking Electricity Commission approval to recover the full costs associated with implementing the physical works defined in Part A up to an amount reflecting the current estimate of the P90 cost to implement the Proposal.

Where it is likely that costs will exceed, in a material respect, this estimated P90 cost, Transpower will advise the Electricity Commission as soon as reasonable and consider seeking an amendment of the approved amount under Rule 17.2.

While Transpower has endeavoured to provide a reasonable estimate of the P90 cost to implement the Proposal, Transpower notes that there is significant uncertainty in estimating the range of variation in factors affecting costs and their likelihoods. The consequence of this is that the "P90" cost for which approval is sought may have a probability of being exceeded of more or less than 10%.

One particular cost issue that may arise is that, depending on how the regulatory regime under the Commerce Act evolves, Transpower may only be able to add assets to its regulated asset base at the end of a 1 April to 31 March year. If this occurs and Stage 1 is commissioned in April 2012, then Transpower may not be able to start recovering the costs until 2013. Further interest during construction costs would accrue, which have not been included in these cost estimates and which are not reflected in the amount Transpower is seeking approval for. If such an event does occur and Transpower could in consequence exceed the approved amount, Transpower will advise the Electricity Commission as soon as reasonable and consider seeking an amendment of the approved amount under Rule 17.2.

Unforeseen events

In addition to the above, Transpower will continually review factors material to the justification of this project, including generation developments and demand growth. If it becomes apparent that in consequence changes to the physical scope of works, design or timing of the Proposal would be of national benefit, and any such changes fall outside the scope of the Proposal as defined in Part A, Transpower will discuss with the Electricity Commission and consider seeking an amendment of project scope under Rule 17.2.

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	Annual Planning Report
Base Case	The “do nothing” option, a counterfactual for other options to be considered against.
Climate Bill	Climate Change (Emissions and Renewable Preference) Bill, 187-1, introduced on 4 December 2007.
Consultation Paper	Document published by Transpower on 1 February 2008 setting out Transpower’s provisional view that the 700 MW replacement option was the most economic option available.
economic investment	Investments in the grid that can be justified on the basis of the Grid Investment Test under section III of part F, Electricity Governance Rules, and are not reliability investments.
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	Good Electricity Industry Practice.
GEM	Generation Expansion Model , a model for generation expansion modelling developed by the Electricity Commission.

GIT **Grid Investment Test.** 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.

GPS **Government Policy Statement on Electricity Governance.**

Grid Development Strategy A 40-year development strategy used by Transpower to provide a framework within which to consider and propose upgrades to the National Grid.

GUP **Grid Upgrade Plan.** A plan for grid expansions, replacements and upgrades, developed in accordance with rule 12 of section III of part F, Electricity Governance Rules.

HHI **Herfindahl Hirschman Index,** a measure of market concentration.

HVAC **High Voltage Alternating Current**

HVDC **High Voltage Direct Current**

Inter-Island HVDC Pole 1 Replacement Investigation Project Investigation by Transpower to consider the feasibility of different replacement options that has resulted in this Proposal.

Lerner Index The Lerner index is a measure of price mark-ups (amount a generator bids over and above their marginal cost). The Lerner Index is calculated as:
Lerner Index: $LI = (\text{bid price} - \text{short-run marginal cost}) / \text{bid price}$

Matlab A modelling program used by Transpower to undertake Monte Carlo analysis

MAV **Mercury Arc Valve**

modelled projects Transmission augmentation projects and non-transmission projects, other than the proposed investment and alternative projects, which are likely to occur in a market scenario, are reasonably expected to occur in that market development scenario within the time horizon for assessment of the market benefits and costs of the proposed investment and alternative projects, and the likelihood, nature and timing of which will be affected by whether

	the proposed investment or any alternative project proceeds.
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.
NZES	New Zealand Energy Strategy 2050, published by Ministry of Economic Development, October 2007.
P90 cost	Estimated 90 th percentile of project costs.
PLEXOS	A proprietary power market model suitable for short, medium and longer term studies including generation expansion planning. It can furthermore model market behaviour to assess competition benefits.
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.
SCADA	Supervisory Control and Data Acquisition.
SDDP	S tochastic D ual D ynamic P rogramming, a hydro-thermal dispatch model with representation of the transmission network used for short, medium and long term operation studies.
Transpower	Transpower New Zealand Limited, owner and operator of New Zealand's high-voltage electricity network (the National Grid).
Transpower's System Vision	Intended to drive Transpower strategies and policies for the long-term growth and management of the transmission system. It includes the two related initiatives of Grid Vision and System Operation Vision.

Appendix B Summary of competition and consumer benefits analysis

The GIT allows competition benefits to be included as a market benefit, provided they can be separately identified and calculated. Whilst it seems intuitive that providing a link between the North Island and South Island enables greater competition between generators in both islands, it is not straightforward to calculate the benefits that result from that enhanced competition.

Transpower employed McLennan Magasanik Associates (MMA) to consider the effect of the various Pole 1 replacement options on competition and consumer benefits. Their full report is set out at Appendix 4 to Attachment G to the Consultation Paper (see Volume 2). Transpower has not included any competition benefits in its application of the Grid Investment Test.

However, the results are plausible and do provide at least directional information on the effect on consumers if Pole 1 of the HVDC link is replaced compared to not being replaced.

B.1 Competition benefits

Competition benefits for each replacement option were determined as follows:

- calculate non-competition benefits by comparing outcomes between the base case and replacement options assuming generators bid in at their true marginal cost;
- calculate total benefits by comparing outcomes between the base case and replacement options assuming some market power is exerted; and
- calculate competition benefits by subtracting the non-competition benefits from total benefits.

The modelling of competition benefits was undertaken using PLEXOS. PLEXOS' Nash-Cournot game-theoretic model was used to assess the impact of future bidding behaviour of market participants with market power.

Market power is exerted by participants lowering the capacity offered into the market to increase prices and thereby maximise profit.

The magnitude of competition benefits depends on a number of factors including:

- the choice of company ownership for new generation projects;
- the capacity expansion plan, in particular the mix of renewable and thermal technologies in the North Island;
- the choice of price elasticity of demand; and
- the rules assumed to govern the degree to which renewable generation can participate in the game.

In the analysis undertaken, some initially surprising results emerged. Competition benefits were found to be both positive and negative, depending on the market development scenario.

Market power was assumed to be exerted by withdrawing some existing thermal capacity and/or new renewable capacity in the North Island. This withdrawn capacity was replaced with more costly thermal generation. The resulting fuel and emission cost increases represent reductions in productive efficiency. The more renewable generation withdrawn, the greater the reduction in productive efficiency, as the difference between renewable and thermal fuel costs is greater than between different thermal technologies.

If more renewable generation is withdrawn under a replacement option than under the Base Case, then the cost of the replacement option also increases more than under the Base Case and negative competition benefits are observed. Typically, in the Base Case in

each scenario, more new thermal generation is built in order to satisfy the North Island capacity constraint, and market power is exerted by existing thermal generators rather than new renewable generators. Also, the additional capacity built to satisfy the capacity constraint is always greater than or equal to the additional capacity on the HVDC link, due to the peak contribution factors assigned to various new entrants. Hence, once capacity constraints become binding, there is more competition in the North Island in the Base Case, than in the alternatives where Pole 1 is replaced.

The 90% renewables by 2025 market development scenario is an exception, due to the greater emphasis on renewable generation. Without Pole 1 being replaced, more North Island renewable generation is built. In this analysis, this new renewable generation is assumed to be owned by a single new competitor. Their market share in the North Island increases to 25% by 2030 and 30% by 2040, and its ability to exert market power increases. In this scenario, there is significantly more North Island renewable capacity withdrawn if Pole 1 is not replaced, and therefore the cost increases are greater in the Base Case and this results in positive competition benefits for the replacement options.

A summary of the competition benefits for individual scenarios and for high, medium and low demand, for the 700 MW replacement option, were as follows:

Competition benefits (\$2007 m)	Demand scenario		
	High	Med	Low
High Gas	-\$55	-\$40	-\$119
Mixed technologies	-\$13	-\$22	-\$33
Primary renewables	\$171	-\$57	-\$194
SI surplus	\$213	-\$526	-\$481
90% renewables by 2025	\$101	\$188	\$111

Applying the weightings used in the GIT, this gives a competition benefit of approximately \$42 million. These results are explainable, as discussed above, but they make it difficult to conclude whether replacing Pole 1 would have any positive competition benefit.

Transpower is encouraged by the MMA analysis, as it produces explainable results for the assumptions made, but considers that other ownership/market behaviour combinations would need to be modelled to draw robust conclusions about competition benefits.

Whilst this analysis may not support the existence of positive competition benefits for the Proposal, Transpower would still expect a positive competition benefit emerge with further modelling. It seems intuitive that linking the North Island and South Island enhances competition nationally.

B.2 Consumer benefits

With respect to consumer benefits though, Transpower considers some conclusions can be drawn.

This consumer benefits analysis considered the following:

- HVDC constraints;
- market concentration/competitiveness;
- price mark-ups; and
- nodal price changes.

B.2.1 HVDC constraints

More congestion on the HVDC will result in more periods where generators will be in a position to exert market power.



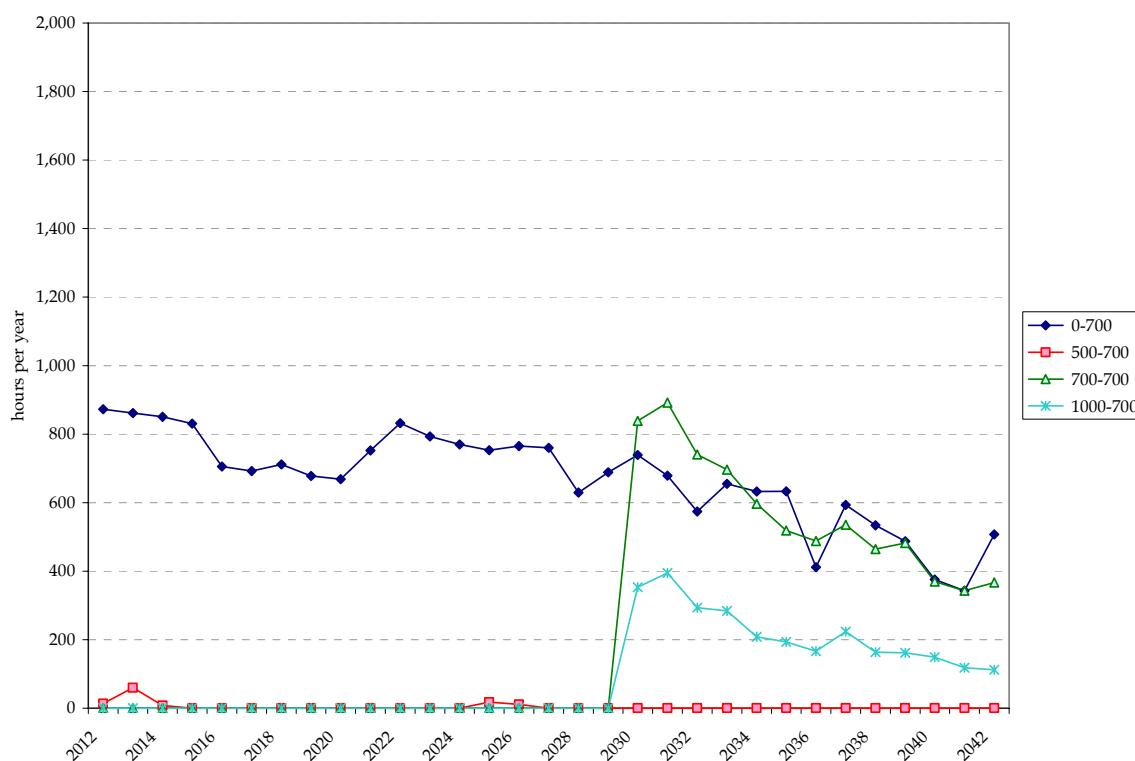
The following diagrams show how congestion on the HVDC changes over time for two market development scenarios. Congestion on both the existing Pole 2 and the replacement Pole 1 is shown.

In the High Gas scenario two new South Island lignite plants are built in 2030, to take advantage of the additional HVDC capacity in the 700 MW and 1000 MW replacement options, but not in the 500 MW replacement option. This additional South Island generation capacity results in more congestion after 2030 in the 700 MW and 1000 MW options, than in the 500 MW option, despite the larger link capacity.

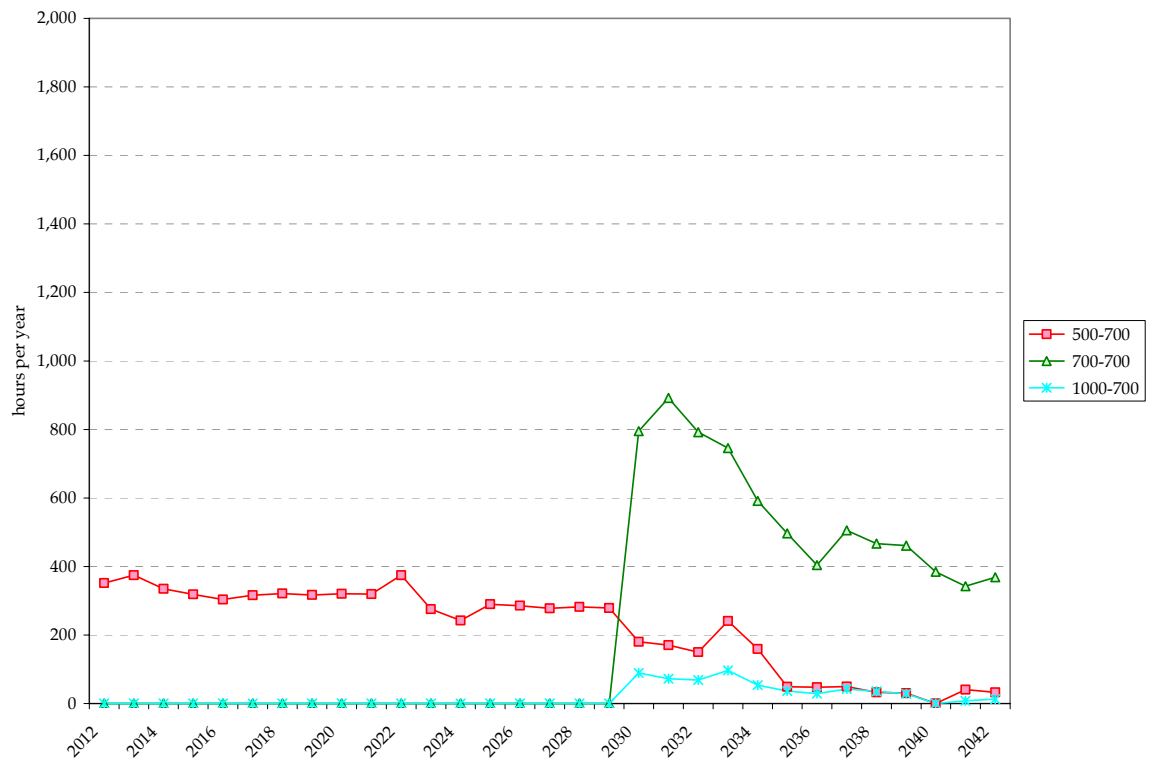
Generally though, it can be seen that:

- There is less congestion if Pole 1 is replaced, than if it is not
- Congestion decreases as replacement Pole 1 capacity increases

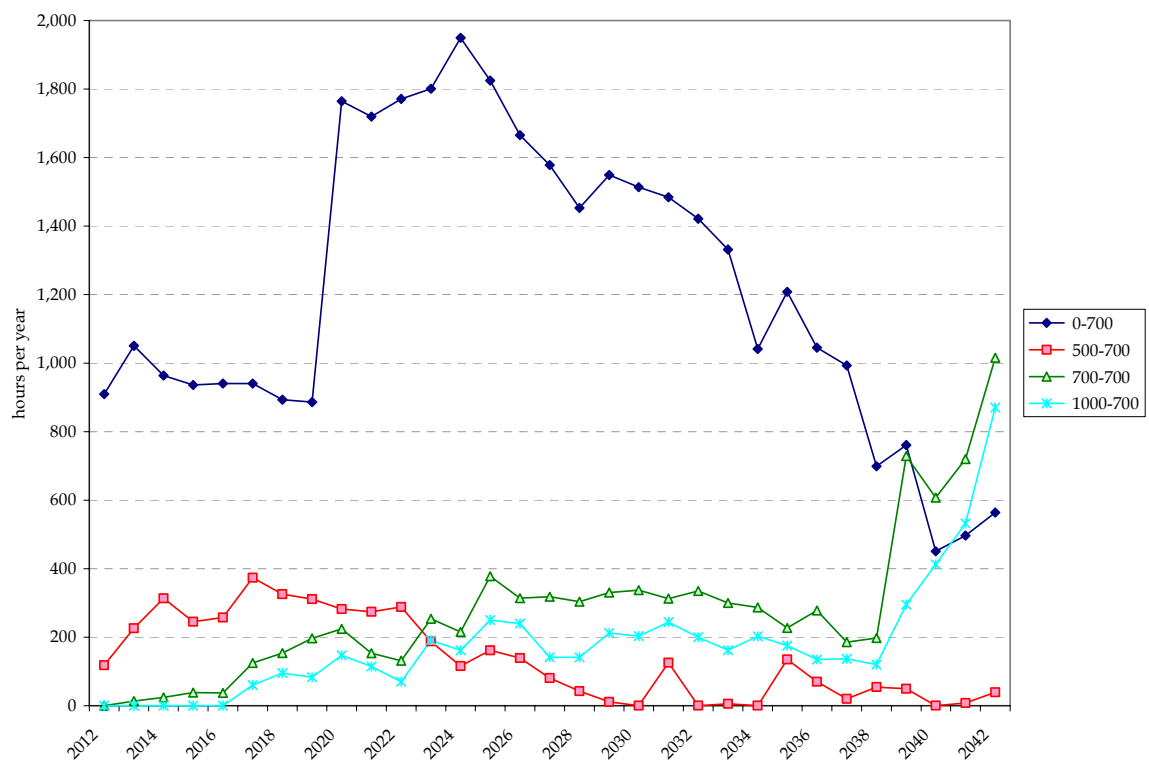
Pole 2 congestion – hours per annum, High Gas, medium demand



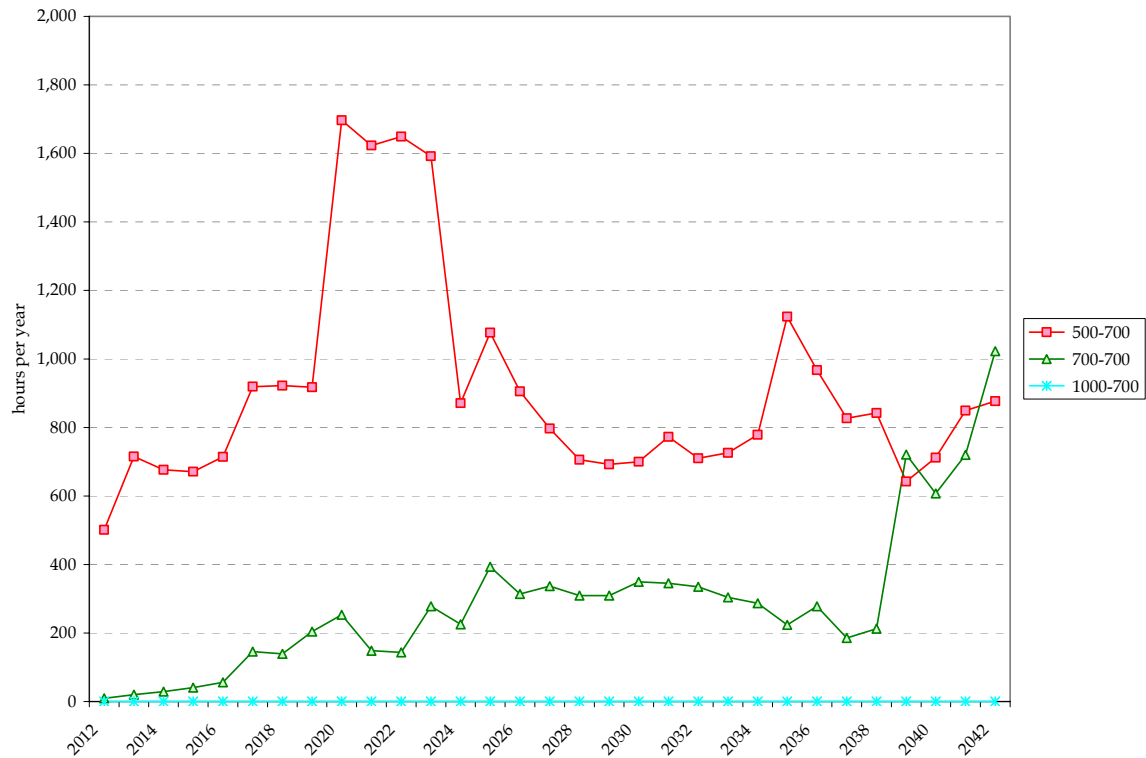
Pole 1 congestion – hours per annum, High Gas, medium demand



Pole 2 congestion – hours per annum, 90% renewables by 2025, medium demand



Pole 1 congestion – hours per annum, 90% renewables by 2025, medium demand



B.2.2 Market concentration/competitiveness

Market concentration was assessed using the adjusted Herfindahl-Hirschman Index (HHI), defined as:

$$HHI^{adj} \equiv \sum_{i=1}^m s_i (s_i + s_c / m)$$

where s_i is the market share of the i -th unconstrained firm ($i = 1, \dots, m$) and s_c is the total market share of the constrained firms.

Constrained firms are defined as those with plant whose output depends on the primary energy available at the moment (wind, geothermal, run-of-river hydro units, cogeneration units) and not on an operating decision regarding how much of the stored primary energy to use (hydro plants with reservoirs and thermal plants).

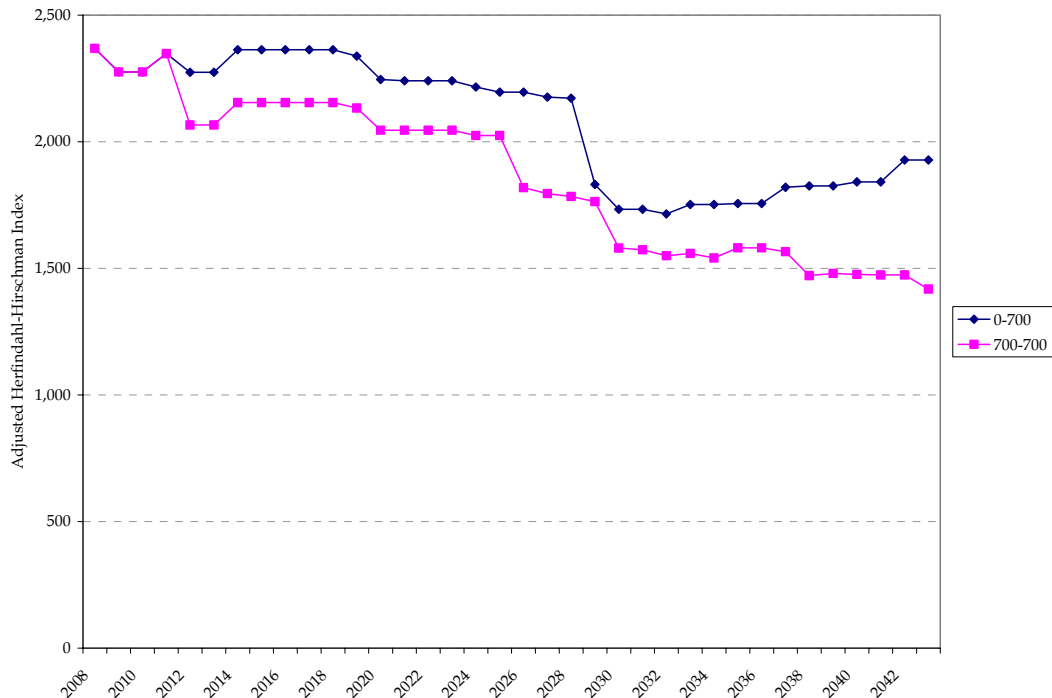
Since some of the firms have both constrained and unconstrained generation, their total capacity is divided in two parts, one constrained and one unconstrained.

The HHI is used by the US Department of Justice. According to their merger guidelines, the US Department of Justice will regard a market in which the post-merger HHI is below 1000 as "unconcentrated," between 1000 and 1800 as "moderately concentrated," and above 1800 as "highly concentrated." A merger potentially raises "significant competitive concerns" if it produces an increase in the HHI of more than 100 points in a moderately concentrated market or more than 50 points in a highly concentrated market. A merger is presumed "likely to create or enhance market power or facilitate its exercise" if it produces an increase in the HHI of more than 100 points in a highly concentrated market.

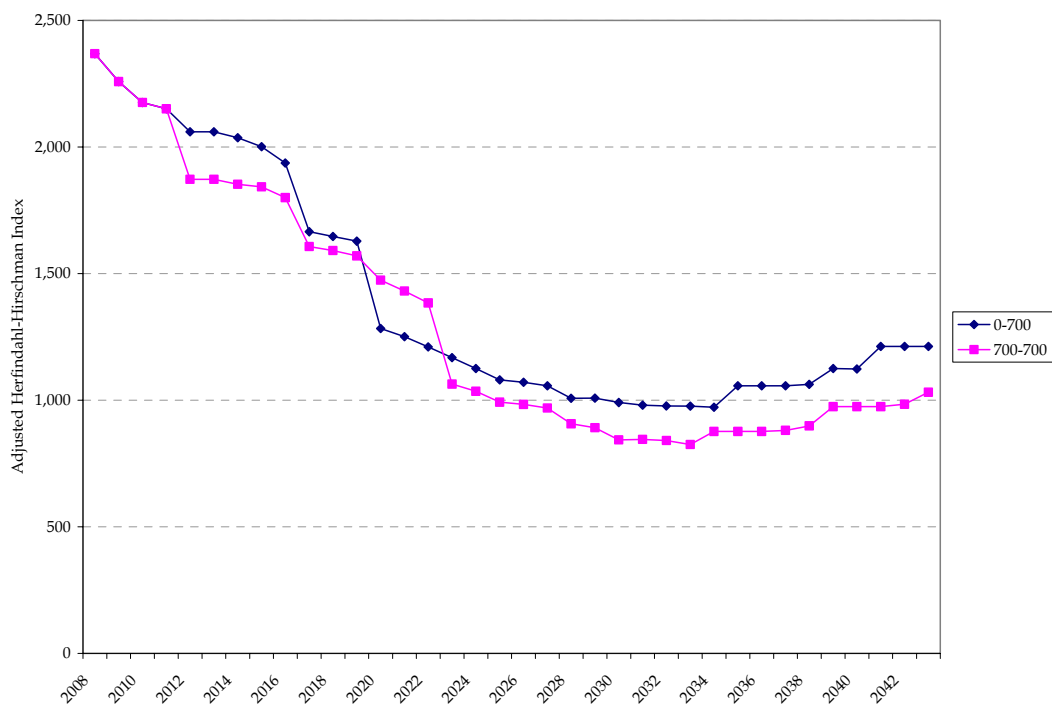
The figures below show how the HHI changes in both the North and South Islands for the High Gas and 90% renewables by 2025 scenarios.

As can be seen, the HHI drops over time whether Pole 1 of the HVDC is replaced or not. In all cases though, the commissioning of a replacement Pole 1 in 2012 reduces the HHI and generally results in a lower HHI over time than if Pole 1 had not been replaced.

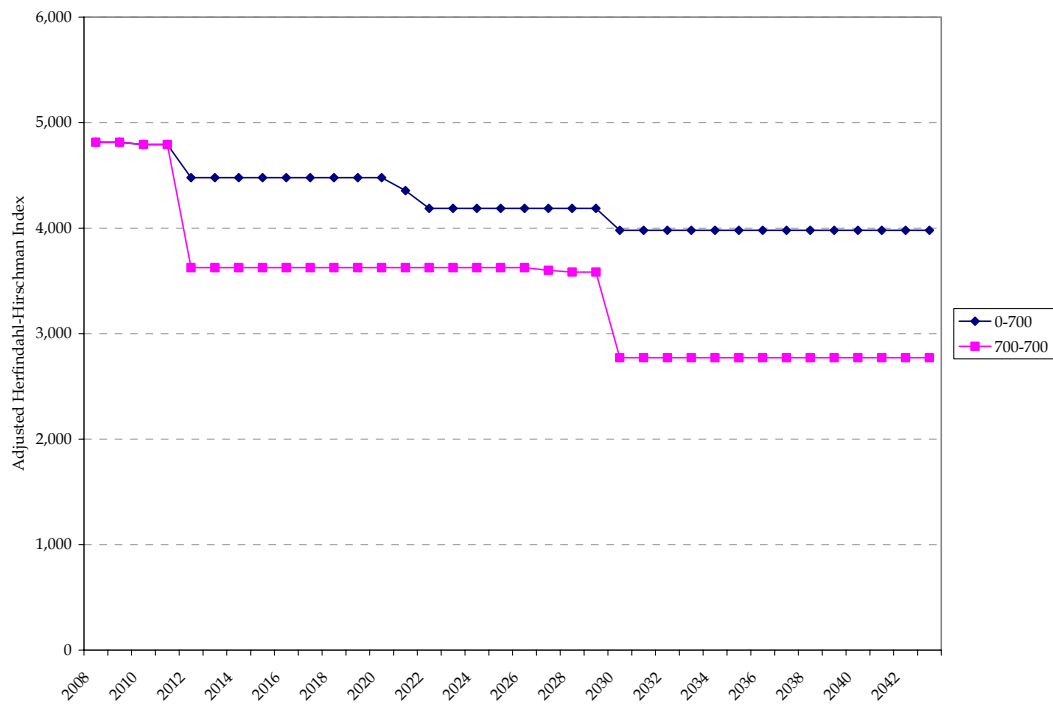
Adjusted HHI in North Island for High Gas scenario



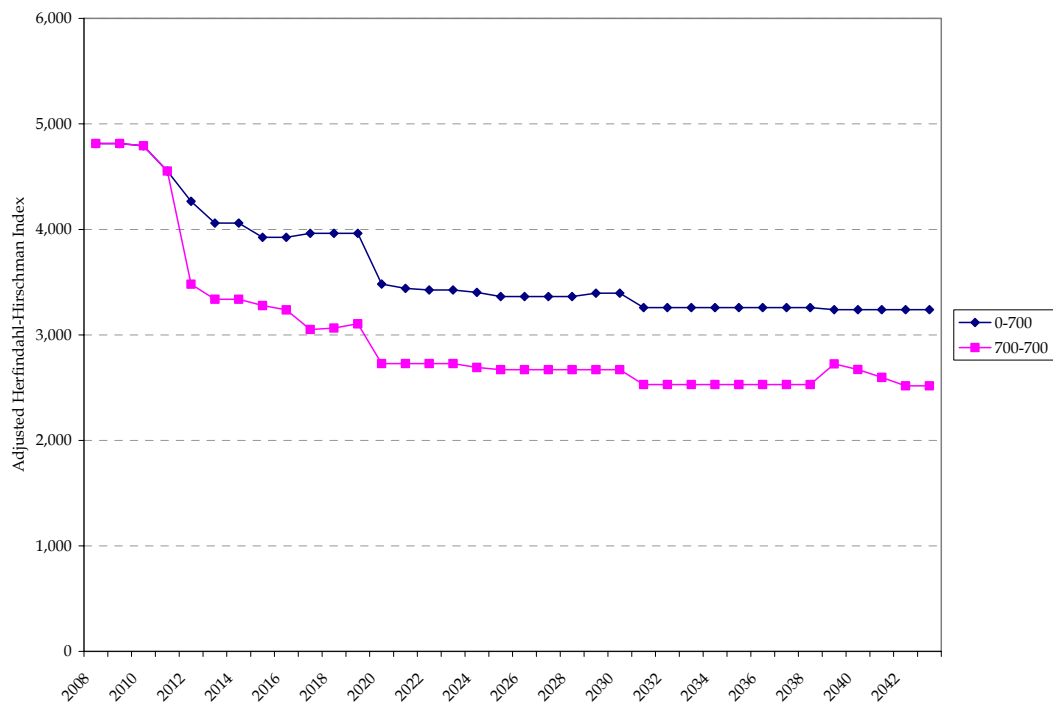
Adjusted HHI in North Island for 90% renewables by 2025 scenario



Adjusted HHI in South Island for High Gas scenario



Adjusted HHI in South Island for 90% renewables by 2025 scenario



B.2.3 Price mark-ups

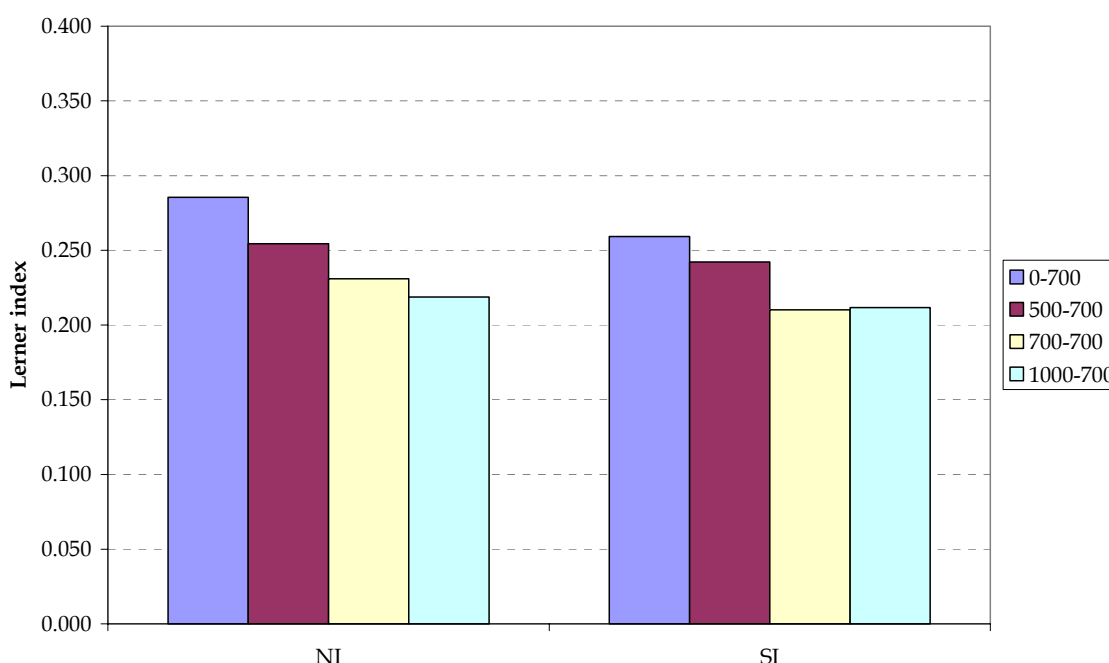
The Lerner index is used to calculate how price mark-ups (amount a generator bids over and above their marginal cost) change with HVDC link size. The Lerner Index is calculated as:

Lerner Index: $LI = (\text{bid price} - \text{short run marginal cost}) / \text{bid price}$

The Lerner index for each year is calculated based on the average bid prices from the Nash-Cournot simulations and the average short run marginal cost from the non-competition simulations. Then, the average Lerner index is calculated as the simple average of the Lerner indices for each year.

The figure below shows that the weighted average Lerner index ranged from 0.2 to 0.3 across all augmentation scenarios. A Lerner index of zero would imply that there is no market power in the system. The moderately low Lerner index values are a reflection of the price elasticity of demand assumed in the Nash-Cournot game, which was estimated based on the back cast study undertaken for 2005.

Average Lerner index



As seen though, the Lerner index indicates that the price-mark-ups decrease as link size increases.

B.2.4 Nodal price changes

The figures below show the North Island and South Island nodal price projections (at Penrose and Islington) for the 90% renewables by 2025 scenario with medium demand growth, based on the Nash-Cournot game.

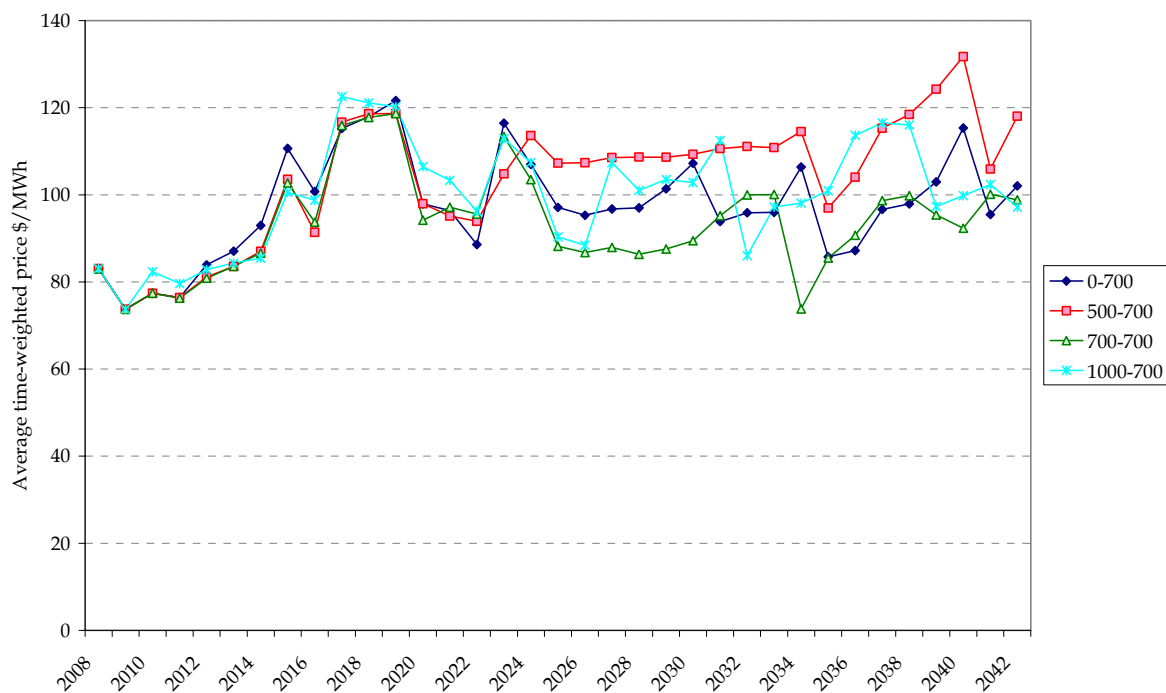
This analysis indicates that, in the 90% renewables by 2025 scenario, prices in the North island are projected to rise from their current levels of around \$80/MWh to between \$90 and \$120/MWh from around 2015, reflecting fuel price increases and carbon price increases. The variability in pool price under each augmentation alternative is largely driven by changes in the generation technologies selected by the capacity expansion plan. Similar variability and relativities are observed in prices projected assuming perfect competition.



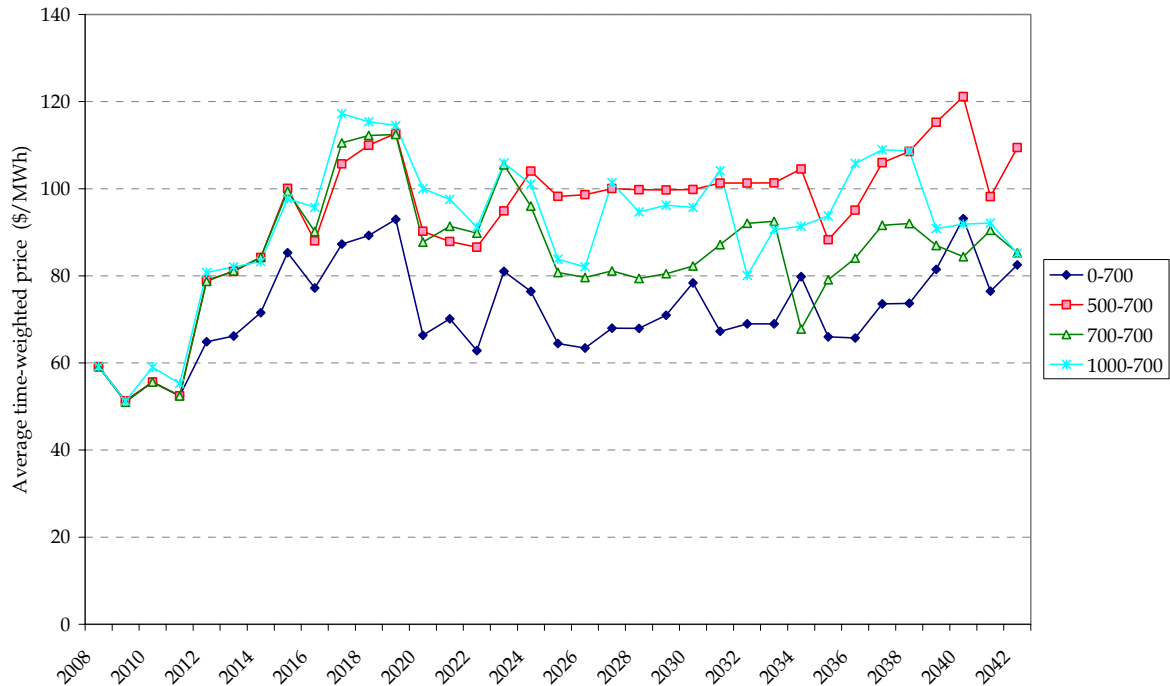
South Island prices follow a similar pattern. The greater spread in South Island prices between the various options reflects the price differential between the two islands, and hence the degree of congestion on the HVDC link.

The table below shows the annual average price differential between the North Island and South Island for the same nodes and scenario. Increasing the capacity of the HVDC link reduces the price differential between the NI and the SI, with the price in the SI typically increasing more than the decrease in price in the NI.

North Island nodal price (Penrose), 90% renewables by 2025, medium demand



South Island nodal price (Penrose), 90% renewables by 2025, medium demand

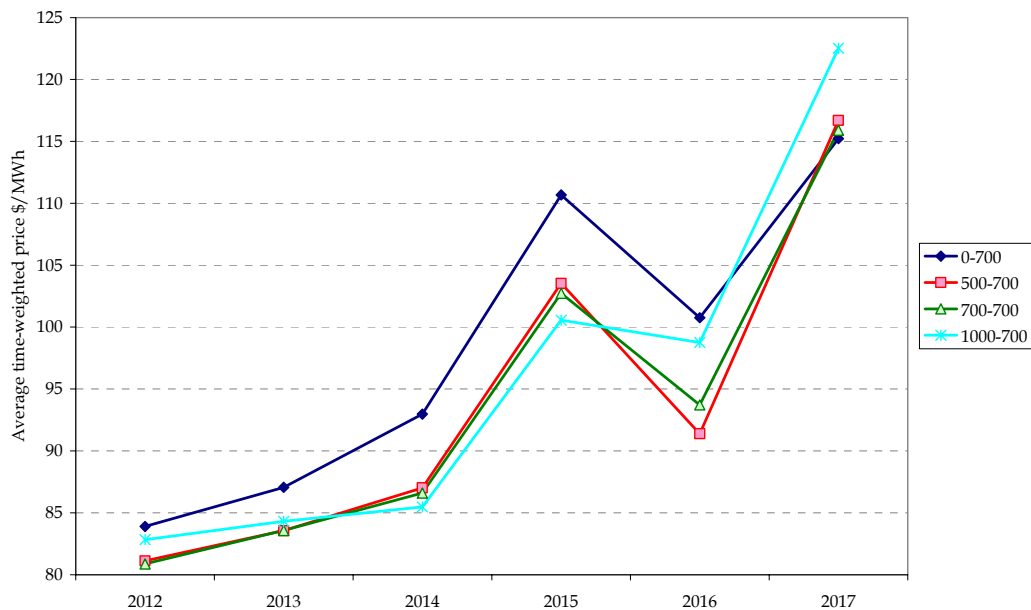


Price differential between North and South islands, 90% renewables by 2025, medium demand

HVDC option	Average annual price differential post augmentation (\$/MWh)
0-700	25.9
500-700	8.0
700-700	6.6
1000-700	6.3

Investing in a 700 MW Pole 1 replacement will increase the price in the South Island by 20% on average (\$15/MWh), relative to the South Island price if no replacement link is built. The North Island price decreases over time, relative to the North Island price without replacement, with an average decrease of 4%. For the first five years after replacement of Pole 1, the impact of HVDC augmentation on North Island price is most noticeable, with average North Island prices reducing as shown below. Beyond 2017, variations in capacity expansion plans swamp any clear relationship between North Island price and the size of the HVDC link.

North Island nodal price (Penrose) immediately after augmentation, 90% renewables by 2025, medium demand



Overall, there is a transfer of wealth from consumers to generators in the SI, and from generators to consumers in the NI, upon the building of the replacement link.

B.3 Conclusion

Although, the results of the competition benefit analysis are inconclusive, the consumer benefit analysis demonstrates that, in general, competitiveness is increased with a replacement Pole 1 and that competitiveness increases as the replacement link size increases.

Overall, there is expected to be a transfer of wealth from consumers to generators in the South Island, and from generators to consumers in the North Island, upon the building of the replacement link. The analysis suggests replacement of Pole 1 is likely to result in benefits to consumers.

This analysis does not include sensitivity analysis, which would improve the robustness of the results. The trends, however, do indicate that replacing Pole 1 of the HVDC link will enhance the competitiveness of the New Zealand electricity market and the benefits to consumers.

Appendix C

Since publishing its proposed GIT analysis for consultation, Transpower has refined and updated the scope and estimated costs for the options in light of further available information. As a result, Transpower's GIT analysis has used slightly different costs to those used in its proposed analysis.

The tables below set out the works to be undertaken in the Base Case and under each short list option with the estimated costs associated with each stage of the Base Case and each option. The cost items for Option 2 are (a) items in the Proposal and (b) modelled projects, i.e., investments that Transpower expects are likely to occur but for which Transpower is not seeking cost recovery as part of this Proposal.

These tables update the information in Appendix A to Attachment B – Databook to the Consultation Paper (see Volume 2).

These costs are reproduced in the companion spreadsheet "Final HVDC GIT results.xls", along with the streaming of these costs. For the Electricity Commission, this spreadsheet is available on the enclosed CD. For others, the spreadsheet is available at <http://www.gridnewzealand.co.nz/n282,110.html>.

The GIT analysis set out in Attachment A to this document has used the expected costs listed below. Expected costs are the estimated capital costs plus a contingency for scope accuracy. This contingency is to allow for unexpected variations in the design scope and an allowance, based on experience, for items not considered in the design.

Table 10-1 Base Case development timetable and costs

Stage	HVDC Investment	Expected cost NZ\$ million
Stage 1	Electrode and HVDC transmission line works for continuous mono-polar operation, and replacement of cable terminal bushings Refurbishment and unit connection of three Haywards Synchronous condensers Low order harmonic filter at Haywards Seismic strengthening at Haywards and Benmore sites	55
Stage 2	Pole 2 valve base electronics and control system replacement	25
Total		80

Table 10-2 Option 1 (500 MW) development timetable and costs

Stage	HVDC Investment	Expected cost NZ\$ million
Stage 1	New 500 MW, 350 kV, converter pole terminating at Benmore and Haywards including new Pole 1 and Bipole control system Pole 2 valve base electronics and control system replacement Harmonic filters at Benmore and Haywards suitable for bipole operation of around 1200 MW Seismic strengthening and AC switchyard development for 500 MW option at Benmore and Haywards Electrode and HVDC Transmission line works for 500/700 MW operation, and replacement of cable terminal bushings Refurbishment and unit connection of Haywards Synchronous condenser C7 to C10	388
Stage 2	New condenser C11 or equivalent dynamic reactive power compensation facilities at Haywards 60 MVar	29
Total		417

Table 10-3 Option 2 (700 MW) development timetable and costs

Stage	HVDC Investment	Expected cost NZ\$ million
Stage 1	New 700 MW, 350 kV, converter pole terminating at Benmore and Haywards including pole and bipole control systems Pole 2 valve base electronics and control system replacement Harmonic filters at Benmore and Haywards suitable for bipole operation of around 1200 MW operation Seismic strengthening and AC switchyard development for 700 MW option at Benmore and Haywards Electrode and HVDC Transmission line works for 700/700 MW operation, and replacement of cable terminal bushings Refurbishment and unit connection of Haywards Synchronous condenser C7 to C10	445
Stage 2	New synchronous condenser C11 or equivalent dynamic reactive power compensation facilities at Haywards 120 MVar	34
Stage 3	Additional filters suitable for 1400 MW operation Add one new HVDC submarine cable rated, 350 kV, 500 MW	125
Total		604

Table 10-4 Option 3 (1000 MW) development timetable and costs

Stage	HVDC Investment	Expected cost NZ\$ million
Stage 1	New 1000 MW, 350 kV, converter pole terminating at Benmore and Haywards including pole and bipole control systems Pole 2 valve base electronics and control system replacement Harmonic filters at Benmore and Haywards suitable for bipole operation of around 1200 MW Seismic strengthening and AC switchyard development for 1000 MW option at Benmore and Haywards Electrode refurbishment for 1000/700 MW operation. HVDC Transmission line works for 700/700 MW operation, and replacement of cable terminal bushings Refurbishment and unit connection of Haywards Synchronous condenser C7 to C10	547
Stage 2	New synchronous condenser C11 or equivalent dynamic reactive power compensation facilities at Haywards 120 MVar	34
Stage 3	Additional filters suitable for 1400/1700 MW operation	125

Add one new HVDC submarine cable rated, 350 kV, 500 MW

Stage 4	New synchronous condenser C12 or equivalent dynamic reactive power compensation facilities at Haywards 120 MVar	71
	HVDC Transmission Line works for BEN-HAY 1000/700 MW bipole operation	
Total		777



T R A N S P O W E R

HVDC Grid Upgrade Project

Proposal

Attachment A

Revised Grid Investment Test Results

Doc reference: Inter-island HVDC Pole 1 Replacement Investigation/DC/Consult/Grid
Investment Test Results/001/Rev C

May 2008

Document Revision Control

Document Number/Version	Description	Date
001/Rev A	Grid Investment Test Results	2008-02-01
001/Rev B	Clarification to 4.4 and 5.5.7, consistent with changes to main consultation document and Databook respectively Amendment to B.3 explaining trend variations Correction of minor spelling mistakes	2008-03-17
001/Rev C	Minor revision to GIT results due to revision of HVDC costs Overall results now reflect 20 year result plus terminal benefit, as required by GIT Some sensitivity results changed to include results from all scenarios rather than just one Additional sensitivities carried out in response to submissions received Additional information added in response to submissions received	2008-05-02

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1 Introduction

1.1 Purpose

The purpose of this document is to present and explain the results from Transpower's revised application of the Grid Investment Test (GIT), undertaken as a part of the HVDC Pole 1 Replacement Investigation Project.

1.2 Glossary/terminology

A glossary of terms and acronyms used in this GIT Results paper 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 Application of the Grid Investment Test

2.1 Compliance with the Grid Investment Test

Under Rule 14.4, the Electricity Commission may approve proposed investments where Transpower has applied the GIT reasonably. Clause 4 of Schedule F4 of the Rules contains the GIT which states that:

*"A **proposed investment** satisfies the **grid investment test** if the **Board** is reasonably satisfied that:*

*4.1. for a **proposed investment** that is necessary to meet the reliability standard set out in clause 4.2 of the **grid reliability standards**:*

*4.1.1. the **proposed investment** maximises the **expected net market benefit** or minimises the **expected net market cost** compared with a number of **alternative projects**; and*

*4.1.2. if sensitivity analysis is conducted, a conclusion that a **proposed investment** satisfies clause 4.1.1 is sufficiently robust having regard to the results of that sensitivity analysis"; or*

*4.2. for any other **proposed investment**:*

*4.2.1. the **proposed investment** maximises the **expected net market benefit** compared with a number of **alternative projects**;*

*4.2.2. the **expected net market benefit** of the **proposed investment** is greater than zero; and*

*4.2.3. if sensitivity analysis is conducted, a conclusion that a **proposed investment** satisfies clause 4.2.1 and 4.2.2 is sufficiently robust having regard to the results of that sensitivity analysis".*

As set out at section 3.1 of the Proposal, investment in the HVDC falls within the requirements of clause 4.2 above (i.e. it is an economic investment) and, therefore, to satisfy the GIT must:

- maximise the expected net market benefit compared with a number of alternative projects, in a robust manner with respect to sensitivity analysis; and
- result in an expected net market benefit greater than zero, in a robust manner with respect to sensitivity analysis.

3 Document framework

The remainder of this document is split into three main parts:

- Section 4 discusses the generation expansion plans which emerged as outputs from Transpower's use of the GEM model. As discussed in Attachment B – Databook to the Consultation Paper (see Volume 2), the most significant market benefit arising from the HVDC link is the effect it has on the amount and mix of generation required nationally. Smaller HVDC link sizes constrain generation expansion in both the North and South Islands and hence a key element in this GIT analysis is formulating possible generation expansion plans for various link sizes.
- The purpose of this is to demonstrate that GEM is producing credible generation expansion plans and that the differences between the expansion plans for various input assumptions are reasonable.
- Sections 5 and 6 present the GIT results themselves – a comparison of the expected net market benefit for the options under various demand growth and generation scenario conditions and the sensitivity of the expected net market benefit to various other parameters. Further sensitivities in response to submissions received are also included in these sections.
- Section 7 discusses the optimal timing for commissioning of the project.

4 Generation expansion plans

This section discusses the generation expansion plans output from using the GEM model in order to analyse whether the results are reasonable and form a sound basis for the economic analysis.

This section is structured as follows:

- Introduction;
- Variation of generation build mix by market development scenario (also referred to as MDS in this paper);
- Inter-Island balance and HVDC link size;
- Forecast HVDC flows compared to historical flows;
- CO₂ emissions;
- Revenue adequacy of new generation; and
- Conclusion on reasonableness of generation expansion plans.

4.1 Introduction

To be reasonable, generation expansion plans would need to:

- meet demand;
- show reasonable trends as input variables change; and
- not over-build or under-build new generation.

The major input variables that differ between GEM runs and the generation expansion plans are:

- 5 market development scenarios;
- 3 demand forecasts; and
- 4 HVDC link sizes.

Attachment B – Databook to the Consultation Paper (see Volume 2) includes a detailed description of each of these variables.

This GIT analysis considers all combinations of these major variables and hence a generation expansion plan has been derived for all $5 \times 3 \times 4 = 60$ combinations. The generation

expansions plans are unchanged from those consulted on but the GIT results themselves have changed due to changes in costs. The GIT results (expected net market benefit of each option) are a weighted average of the net market benefit from each combination.

The 60 generation expansion plans are illustrated individually, in the following manner:

- Appendix C to this document shows installed national MW generation, over time, by generation technology
- Appendix D shows national GWh generated, over time, by generation technology
- Appendix F shows HVDC transfers, MW, over time, for both north flow and south flow

Transpower has published GEM output files to accompany the Consultation Paper, which are available on the Grid New Zealand website at:

<http://www.gridnewzealand.co.nz/n282,110.html>

These also detail each of the 60 runs and are a listing of new generation installed, generation plant by generation plant. Details of each plant (location, size, generation technology) are given, along with the year in which it is commissioned.

4.2 Variation of generation build mix by market development scenario

The market development scenarios used reflect differing views of what new generation technologies may be built in the future, based mainly on the relative costs of fuel and carbon emissions.

It is to be expected that fewer thermal generation plants (both gas and coal) will be built under scenarios with a renewable emphasis, as the costs of fuel and carbon charges are higher in those scenarios than in the scenarios with a thermal generation emphasis. Similarly, more gas plant should be built under the High Gas Discovery scenario, as gas availability is higher and gas price and the carbon charge are less.

Example graphs of the different fuel mix that result from the different scenarios are shown in Figure 4-1 and Figure 4-2.

Figure 4-1: Fuel Mix Example for 700 MW link

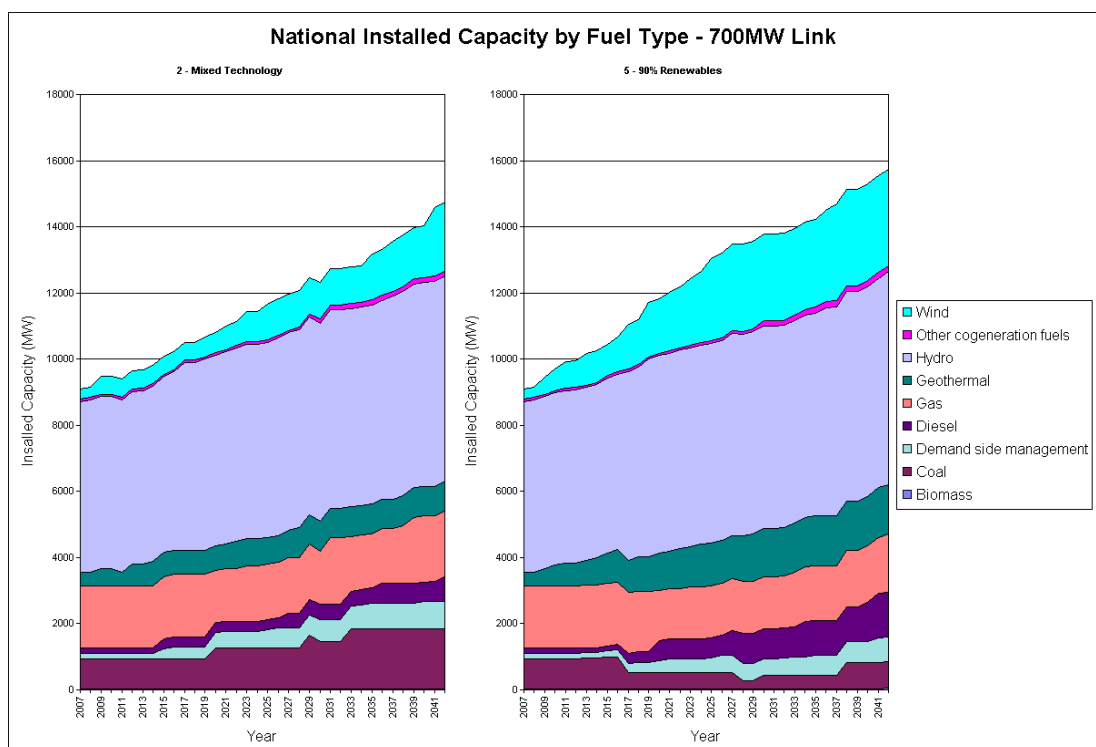
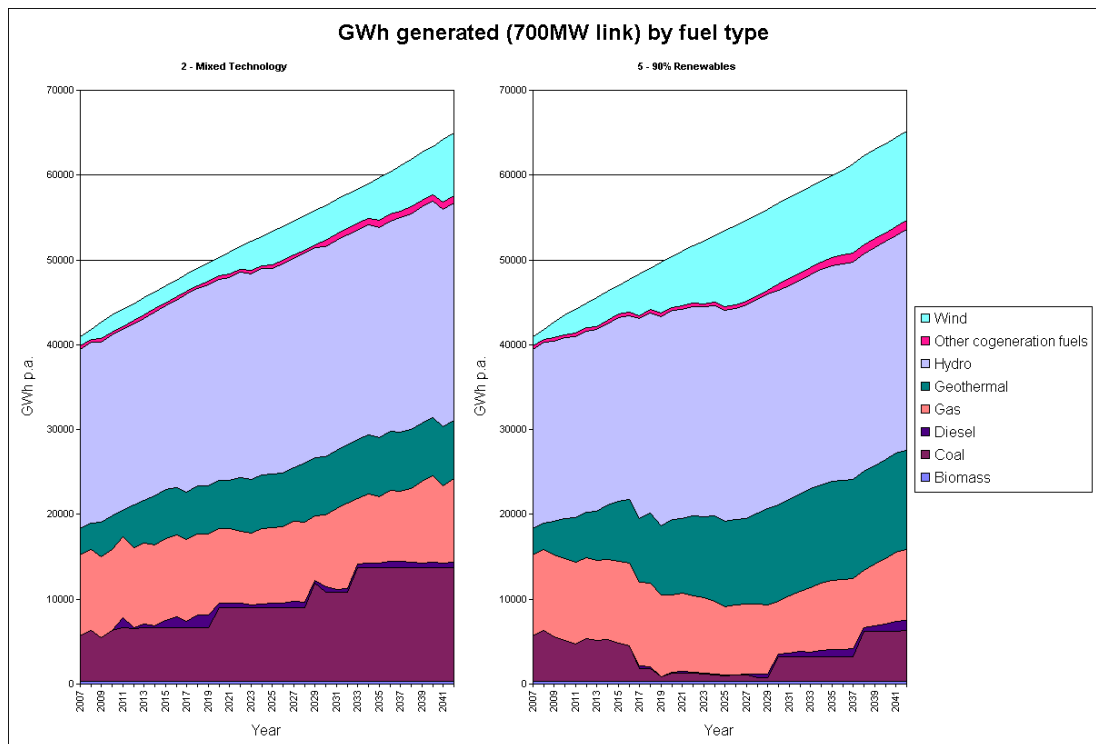
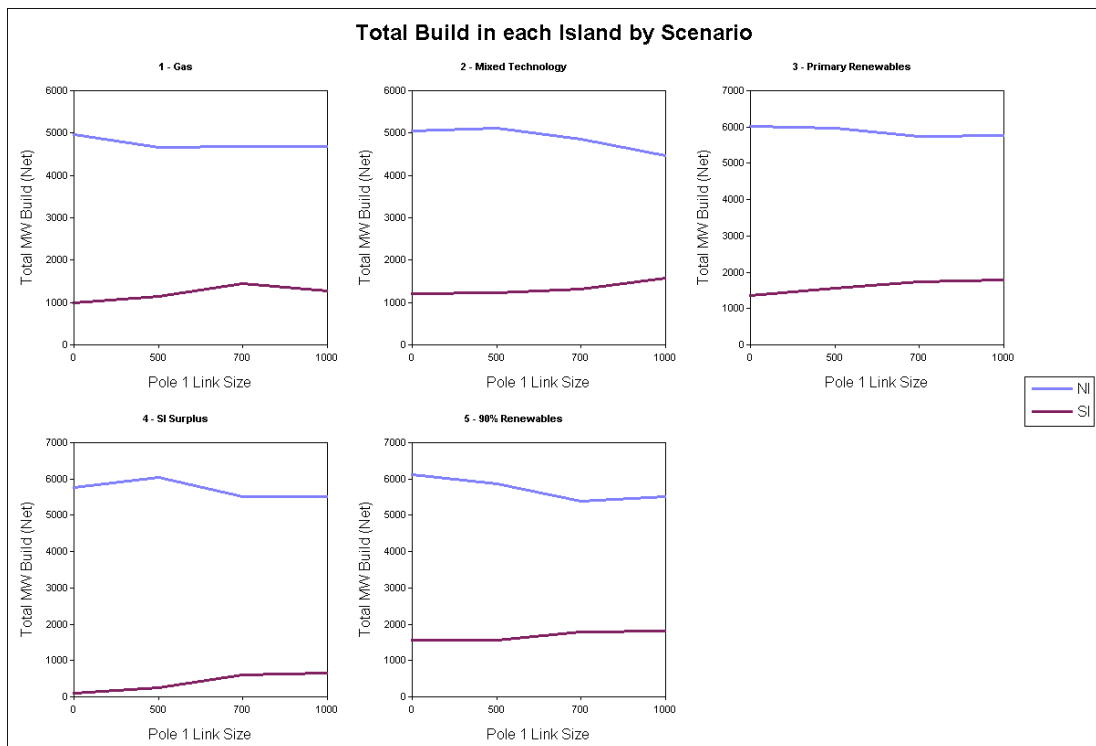


Figure 4-2: Fuel Mix Example for 700 MW link

A full set of these graphs, for the 60 runs reflected in the calculation of expected net market benefit, is included in Appendix C and Appendix D.

The following trends are evidenced:

- All market development scenarios show the same steady growth in total demand except for the South Island surplus scenario which reflects the decommissioning of the Tiwai Point Smelter.
- The 90% renewables by 2025 scenario clearly contains the greatest and earliest build of wind generation.
- The High Gas Discovery scenario shows the least build of wind generation.
- The High Gas Discovery has a much higher proportion of new gas generation being built than in the other scenarios.
- The Mixed Technologies scenario, the only other non-renewables scenario, shows steadily increasing coal generation build and consumption.
- The 90% Renewables by 2025 scenario has the sharpest decrease in coal consumption before 2020, but then reflects an increase in coal consumption from 2030. This increase reflects new carbon sequestration technologies and such new coal generation is relatively "clean".
- Increasing use is made of diesel peaking generation in all scenarios except in the Mixed Technologies scenario to provide firm capacity to cover wind generation (and to provide dry year security).
- Geothermal power is utilised more in the renewables scenarios, increasing until around 2025 and remaining steady thereafter.
- In general, as shown in the Appendix F diagrams, as new South Island generation increases compared to North Island generation, utilisation of the HVDC link increases.
- Wind forms a greater fraction of installed capacity than of energy production because of its lower utilisation than other baseload technologies.

Figure 4-3: Total build by Island for each market development scenario by HVDC link size

4.3 Inter-Island Balance and HVDC Link Size

The capacity of the HVDC link limits the generation build in the South Island. For this reason, scenarios generally show more South Island build for higher link capacities and this is evidenced in the graphs in Appendix C. There is some variation, as HVDC link capacity is only one of many determiners of the generation build mix.

Figure 4-3 shows the cumulative new installed capacity by link size for each of the North and South Islands. In general, these graphs show the expected pattern of increased South Island build for increased HVDC link size. North Island build decreases correspondingly.

Note that, particularly in the renewables scenarios, the amount of South Island build flattens out and there is basically no increase in new South Island generation build between 700 MW and 1000 MW.

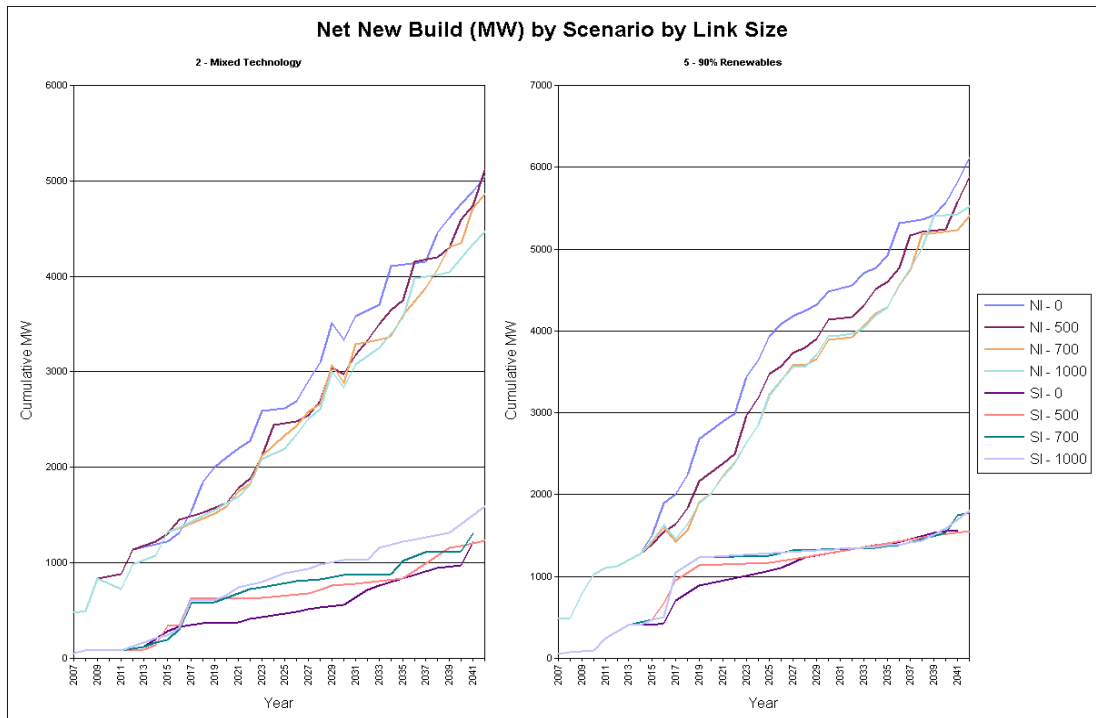
Two effects contribute to this:

- All cost effective South Island generation can be built with a 700 MW link. The higher capability of a 1000 MW link to enable more South Island generation build is not utilised. This is reflected in the GIT results where, in general, the 700 MW option is more economic than the 1000 MW option.
- The North Island capacity constraint becomes binding and forces new generation to be built in the North Island in any case.

The timing of the new generation build is shown in Figure 4-4. For market development scenarios 2 and 5 it illustrates the amount of capacity built in both islands over time for four different Pole 1 link sizes:

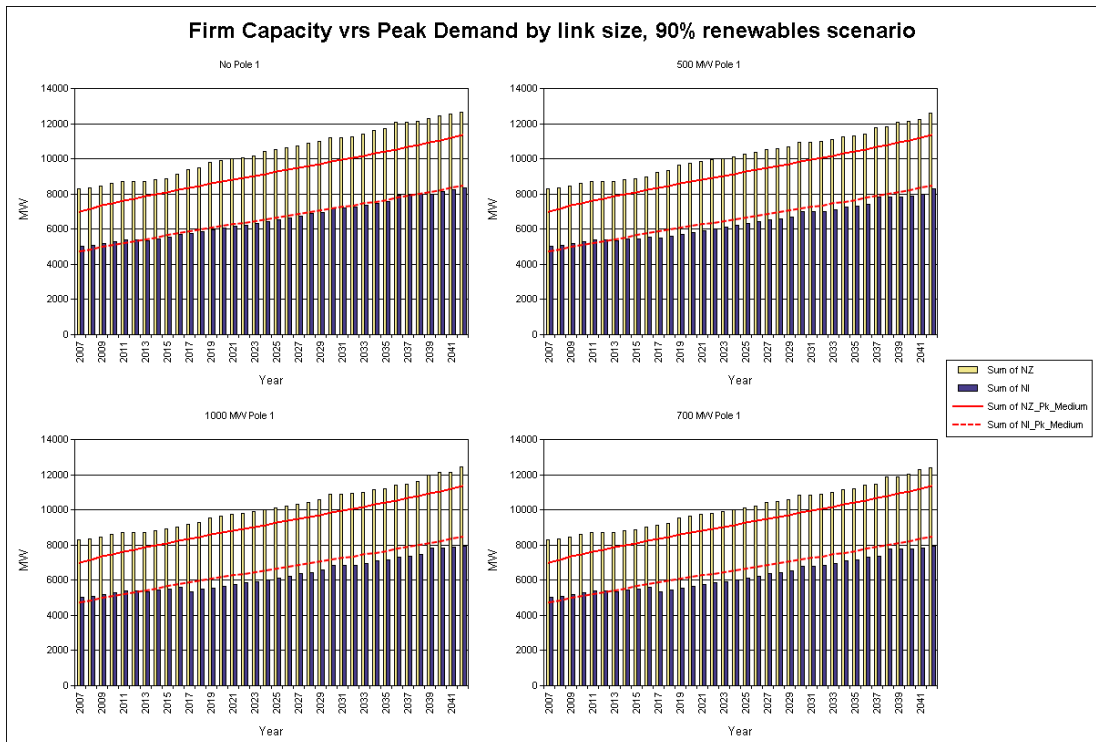
- 0 MW (i.e. the base case);
- 500 MW (i.e. Option 1);
- 700 MW (i.e. Option 2); and
- 1000 MW (i.e. Option 3).

Figure 4-4: new build by market development scenario



The same issue is illustrated from a different perspective in Figure 4-5 where firm North Island and national peak capacity are contrasted with demand for different HVDC link sizes. With no replacement Pole 1 there is no guarantee of the HVDC link being able to transfer at peak to meet North Island demand and so North Island capacity must grow to match demand. With a replacement Pole 1, HVDC transfer is reliable and new generation may be built in the South Island.

Figure 4-5: Firm Capacity build and peak demand



4.4 Forecast HVDC flows compared to historic flows

During the consultation of the GIT, Meridian Energy and Contact Energy raised whether forecast HVDC flows were consistent with historic flows.

The figures below show expected HVDC north transfers (Figure 4-6) and south transfers (Figure 4-7) for the 90% renewables by 2025 scenario and for a 700 MW replacement Pole 1. The estimates are based on SDDP runs using different hydro years.

Wet years will lead to larger north flows (and lower south flows) while dry years will have the opposite impact.

Figure 4-6: HVDC transfers, GWh per annum, south to north, 700MW replacement Pole 1, 90% renewables by 2025 scenario

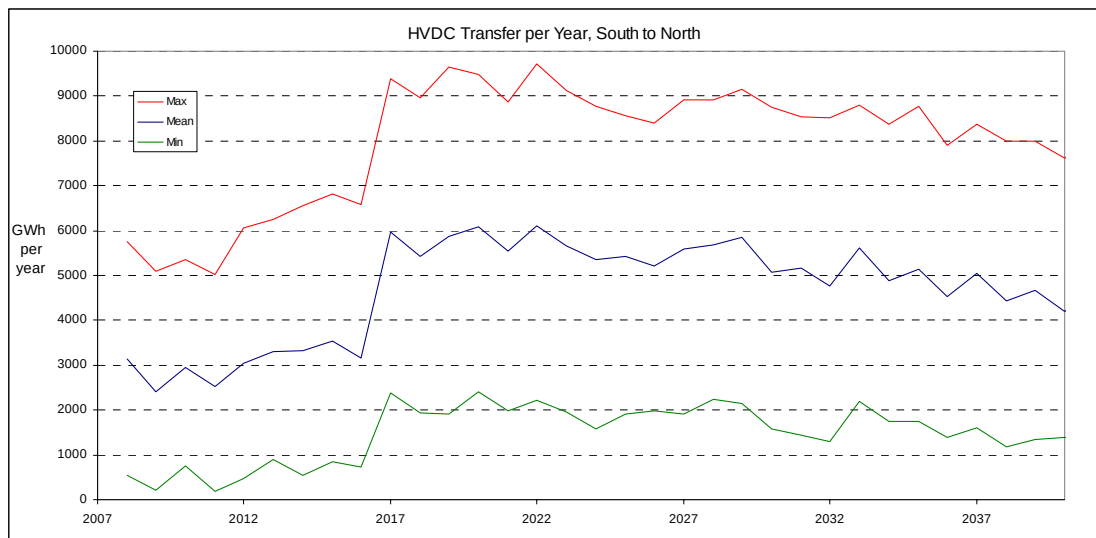


Figure 4-7: HVDC transfers, GWh per annum, north to south, 700MW replacement Pole 1, 90% renewables by 2025 scenario

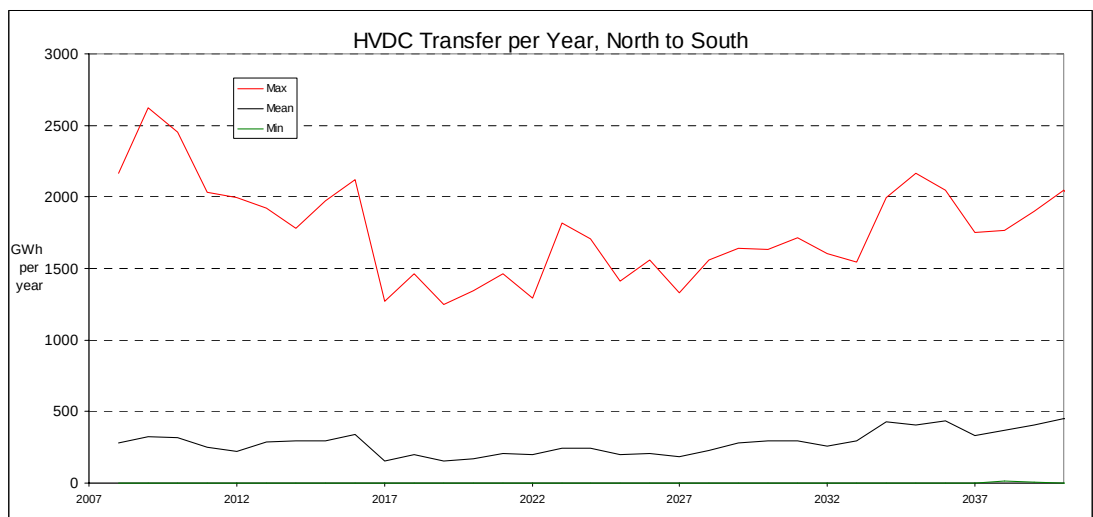
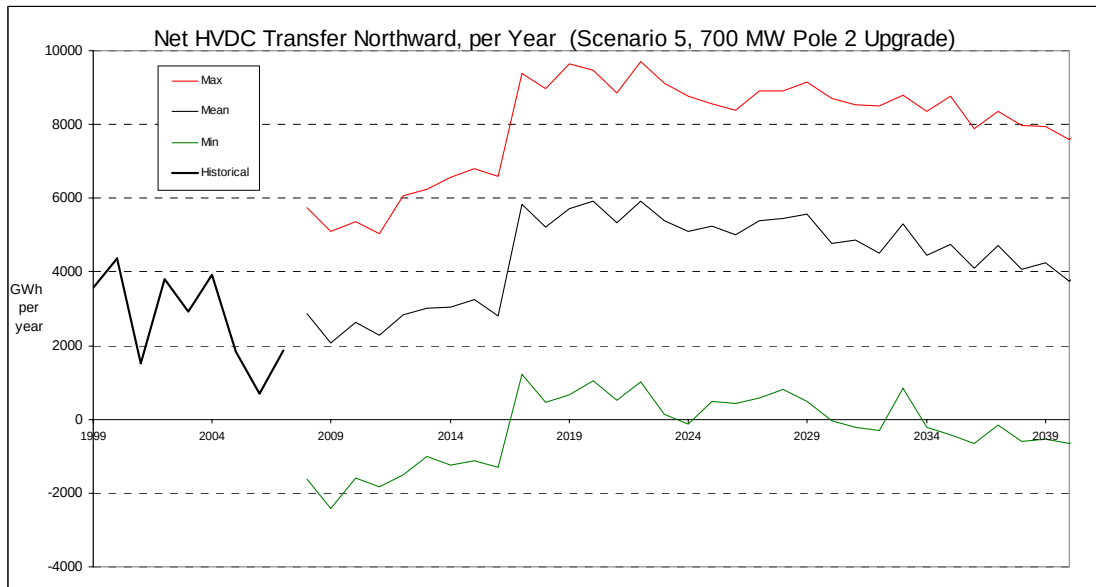


Figure 4-8 shows both the historical net transfers¹ and the forecasted net transfers as from the figures above.

¹ Corresponding to the transfers shown in Meridian Energy's letter to Transpower of 22 February 2008, available on www.gridnewzealand.co.nz

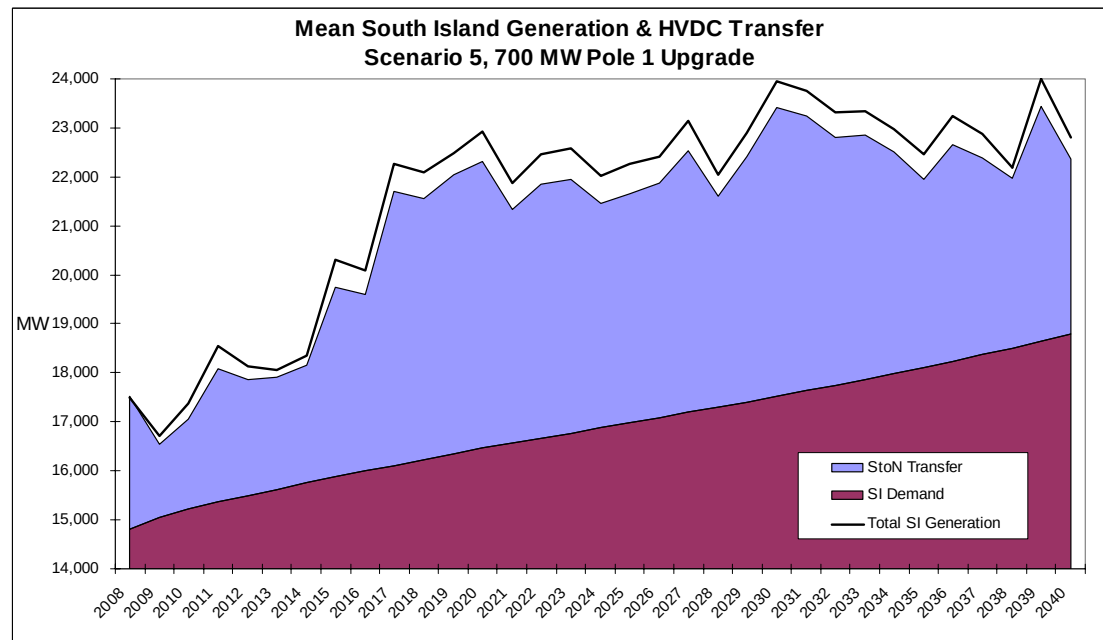
Figure 4-8: Net HVDC transfers, GWh per annum, 700MW replacement Pole 1, 90% renewables by 2025 scenario



As illustrated, the GIT analysis undertaken by Transpower is forecasting a growth in net north transfers through until about 2020 and then a gradual decline. There is a significant jump in transfers forecast in the period 2015-2020, corresponding with significant new generation being commissioned in the South Island as discussed later.

Also, there is a jump between the last historical year, 2007, and the first modelled year, 2008. Correcting from the fact that 2007 was a year with just 90% of the average inflow², the likely 2007 transfer level is likely to closely match the forecasted 2008 net transfer level.

Figure 4-9: Graph of SI generation, HVDC transfers south to north and SI demand, GWh per annum, 700MW replacement Pole 1, 90% renewables by 2025 scenario



² See Transpower response 16 in Attachment E to the Proposal.

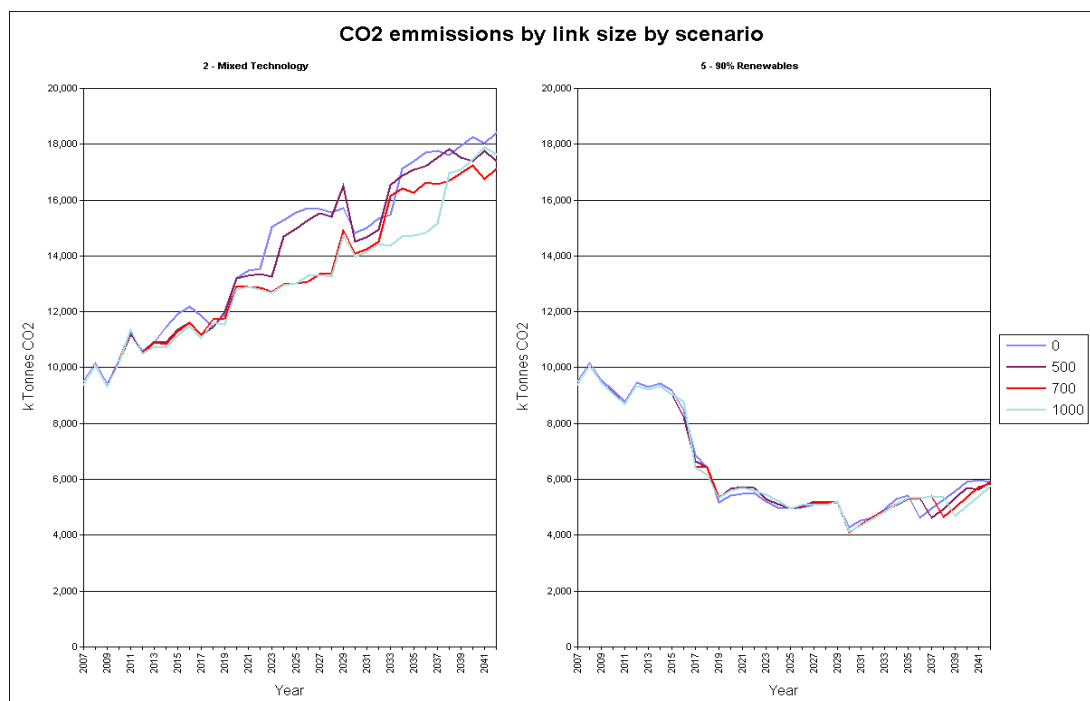
To further illustrate the efficacy of these numbers, Figure 4-9 shows South Island generation over the same time period, being the black line. South Island demand is the burgundy area of the graph, with HVDC transfers south to north being the balance (less losses).

4.5 CO₂ Emissions

Figure 4-10 below shows the trends for CO₂ emissions for different market development scenarios and HVDC link sizes.

In general, the renewable scenarios show emissions falling, while the fossil fuel burning scenarios show an increase over time. In the renewable scenarios, particularly the “90% renewables” there is little variation with HVDC link size as most new generation must be zero carbon emitting regardless of location. In the fossil fuel burning scenarios a larger HVDC link leads to relatively low emissions as South Island renewable generation is preferred over North Island gas generation, which is the only possibility in the absence of a replacement Pole 1.

Figure 4-10: CO₂ emissions by scenario



4.6 Revenue adequacy of new generation

Transpower has not undertaken analysis to consider the revenue adequacy of the new generation built in each market development scenario. Although this was originally discussed, once it was recognised that over time the North Island was moving toward being capacity constrained, it became clear that to model revenue adequacy would require assumptions to be made about the market place that should deliver this capacity³. Rather, focus has been on whether a reasonable amount of capacity has been built.

The Electricity Commission has also considered this issue and in a letter to Transpower on 31 August 2007, stated:

³ Note however, that MMA did consider the revenue adequacy of new thermal generation in their analysis. Their conclusions are available in section 3.1.4 of Volume 2 – Attachment G. In summary, they found that new baseload thermal plant was likely to be economic, even with the imposition of a capacity constraint and without consideration of capacity payments.

Transpower has had various discussions with participants over the last three months about the inputs for the application of the grid investment test (GIT) to the HVDC Pole 1 replacement investigation project (HVDC project).

These have included whether the models used to produce the generation scenarios should include settings that provide revenue adequacy for generators or those that provide adequate generation to meet security requirements.

The Commission discussed this at its 24/25 July 2007 and 28/29 August 2007 meetings. The Commission's view, as confirmed at its 28/29 August 2007 meeting is that, *"for the purposes of developing credible generation scenarios for the application of the GIT to transmission investments, it is reasonable and credible to assume that adequate generation will be introduced to meet peak and energy security margins...it is not necessary to specify the mechanism(s) through which adequate generation will emerge"* (for example, whether market mechanisms will deliver the new generation, or whether market intervention occurs to facilitate the new generation).

Transpower, having carefully considered all submissions received, considered that applying a security-constrained model would be a reasonable application of the GIT for the purposes of its application of the GIT on which it has consulted. Meridian Energy raised the issue again during the latest consultation process, in response to which Transpower has carefully considered which approach is appropriate in this case.

Further analysis by Electricity Commission staff on the use of capacity constraints in generation expansion modelling has led them to further indicate, in a letter to Transpower of 2 November 2007:⁴

While the Commission still considers this matter as under review, in the interests of assisting Transpower to progress its preparation of an HVDC investment proposal, the Commission has taken the step of advising Transpower that the current view of the Commission is that using an N-1 capacity constraint in GEM is preferable to (ie, more reasonable than) using an N-2 capacity constraint when applying the GIT.

Feedback during discussions with interested parties was that the generation expansion plans emerging from GEM with an N-2 capacity constraint were not realistic. Too much new generation was being built, compared to what the market could commercially sustain.

Transpower has considered whether to apply an N-1 or N-2 capacity constraint for the purposes of this analysis. Figure 4-5 above demonstrates that when using an N-1 capacity constraint, the "generation margin", i.e. the amount of excess firm generation over demand, stays relatively constant over the analysis period. This indicates that the GEM model using a N-1 capacity constraint is not providing results which are premised on the over-building of generation capacity. For the purposes of this proposed application of the GIT, Transpower considers using an N-1 constraint is reasonable. In any event, as set out below, Transpower has applied a sensitivity of applying a N-2 capacity constraint to this analysis (section 5.5.6).

Further to this analysis, Meridian Energy maintained in its submission on Transpower's application of the GIT that "...use of a capacity constraint...will bring on generation earlier than the current market will deliver...and...overvalue the replacement of Pole 1 of the HVDC link." Meridian Energy requested that "Transpower demonstrate the level of VoLL implied by the peak capacity constraint" and that the "...impact of the capacity constraint on all scenarios is identified by removing the constraint in GEM and re-running each scenario."

⁴ The letter from the Electricity Commission also cautioned that Transpower is required to reach its own view, but offered some guidance on the issue of security constrained modelling. Transpower has fully considered the matter and sets out its reasoning and views in this document.

When assessing revenue adequacy, it is important to remember that running GEM without the capacity constraint only considers the energy market. Revenue adequacy for generators in reality would be income from energy *and* reserve provision minus costs (CAPEX and OPEX), so GEM is missing one part of generators' income if the capacity constraint is not used. The capacity constraint adds costs on a MW basis needed to ensure the level of reserves. This corresponds to the income available to the providers of these reserves, though this is done at the prudent peak demand level rather than at the expected peak demand.

Overall, using GEM without the capacity constraint as a proxy for revenue adequate generation would be misleading in Transpower's view. However, Transpower has undertaken such an analysis with fuller details to be found in Section 5.6.2.

Based on this analysis, the charts below show the firm capacity results, the first with no constraint and the second with the N-1 capacity constraint applied. The results are shown for Option 2, 700 MW Pole 1 replacement, under market development scenario 5 (MDS 5).

Figure 4-11: Firm capacity vs. peak load, no constraint GEM run

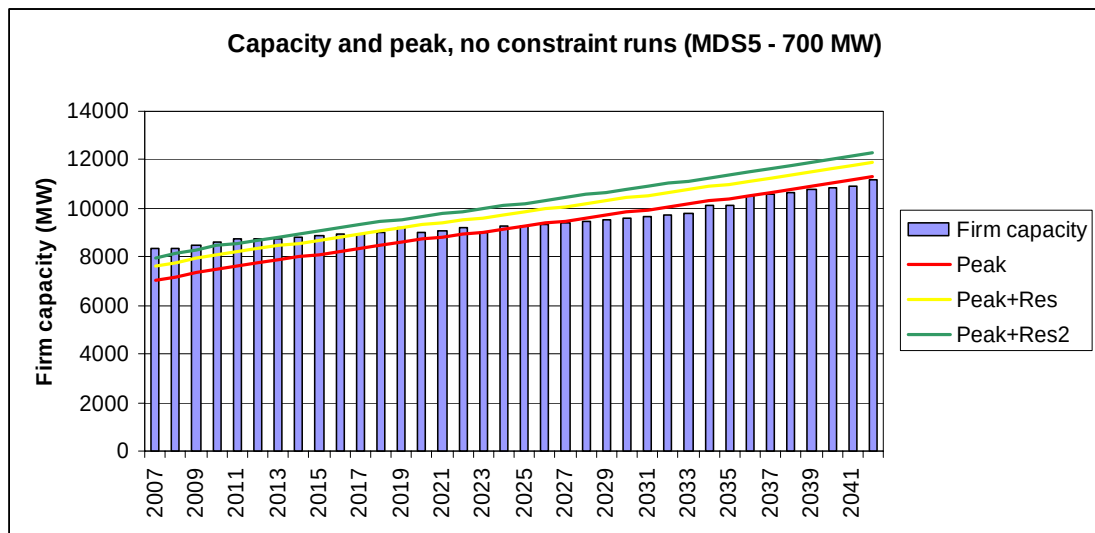
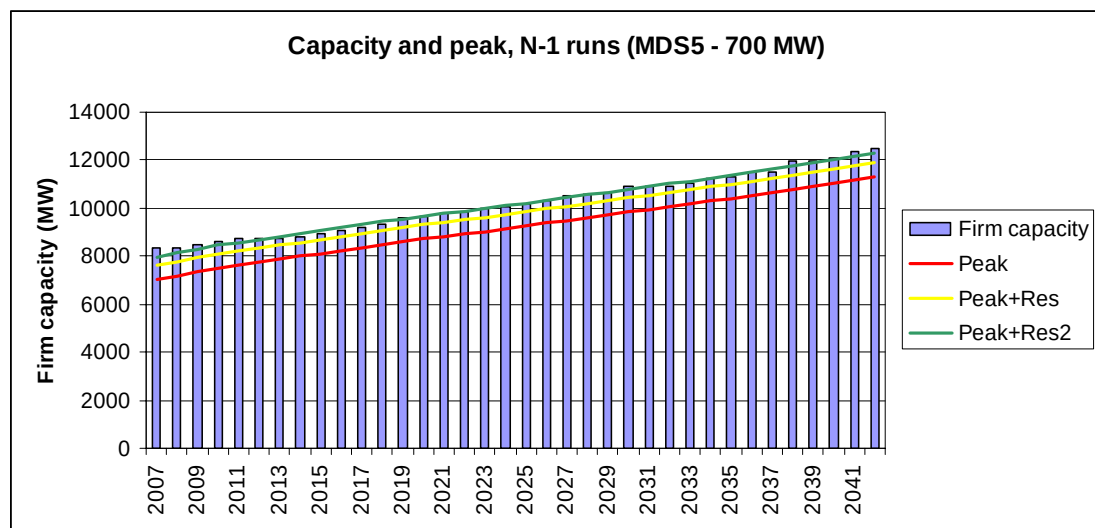


Figure 4-12: Firm capacity vs. peak load, N-1 constraint GEM run



The bars show the firm capacity while the red lines show the prudent peak forecast (10% probability of exceedence) for the normal demand growth scenario. The prudent peak corresponds to the peak load conditions forecast to occur once every ten years. The yellow

line adds the reserve requirements needed to cover loss of largest units on both islands as well as 100 MW frequency keeping reserves. The green line is higher as it also assumes that the largest unit is out of service.

It can be seen that with the N-1 constraint applied, under the prudent peak demand forecast, demand can be met whilst meeting the reserves requirement even with largest unit out of service.

Under the no constraint case, supply will not meet prudent demand from 2013 onwards when largest unit is out. From around 2017, there will not be sufficient capacity to run the system with reserves intact even with largest unit available and this increases the risk of load shedding. From around 2023, there is just sufficient capacity to meet peak demand but no allowance for reserves – not even for frequency keeping.

In summary, the two charts show that using the N-1 constraint maintains a sufficient capacity margin, while using no constraint does not.

The Electricity Commission has also, more generally, analysed the impact on security of supply of generation expansion plans obtained from running GEM with and without the capacity constraint. The Commission used a probabilistic model that took GEM market development scenarios as inputs and assessed the periods where the system would operate at N-security, i.e. running with too few reserves to deal with the loss of largest unit.

Figure 4-13: Number of trading periods with N-operation or worse on the North Island with no capacity constraint in GEM⁵

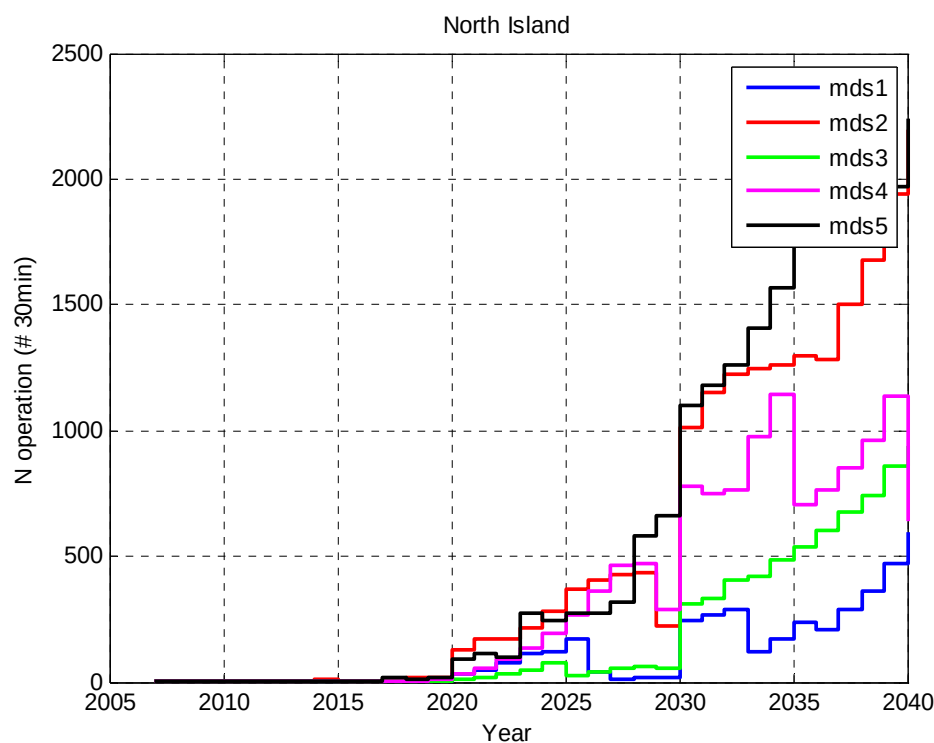


Figure 4-13 to Figure 4-15 show the results of the analysis. Figure 4-13 shows that the number of half-hourly trading periods, where there is insufficient capacity to cover the loss of the largest unit rises to 2,000 by the end of the horizon. That is approximately 20% of the year. The historical level is at around 5-6 of the half-hourly trading periods a year. This level is maintained when using the N-1 constraint as seen in Figure 4-14. Transpower expects the current level of reliability and security would not reduce below the current level in the future.

⁵ Source: EC presentation at TAG meeting – November 1, 2007

Figure 4-14: Number of trading periods with N-operation or worse on the North Island with N -1 capacity constraint in GEM⁶

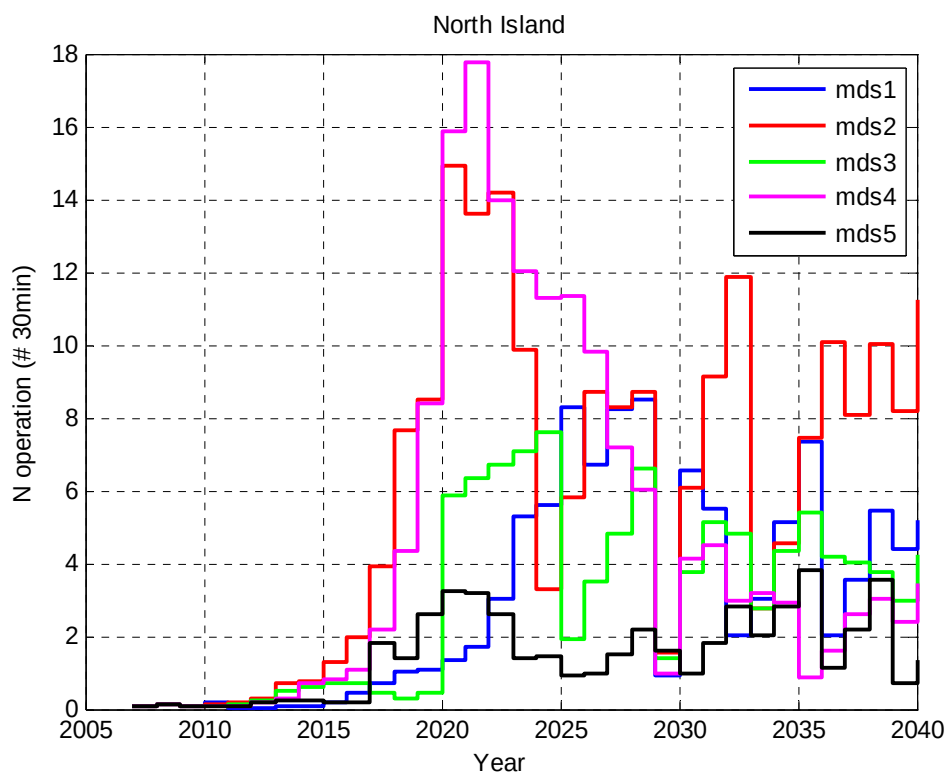
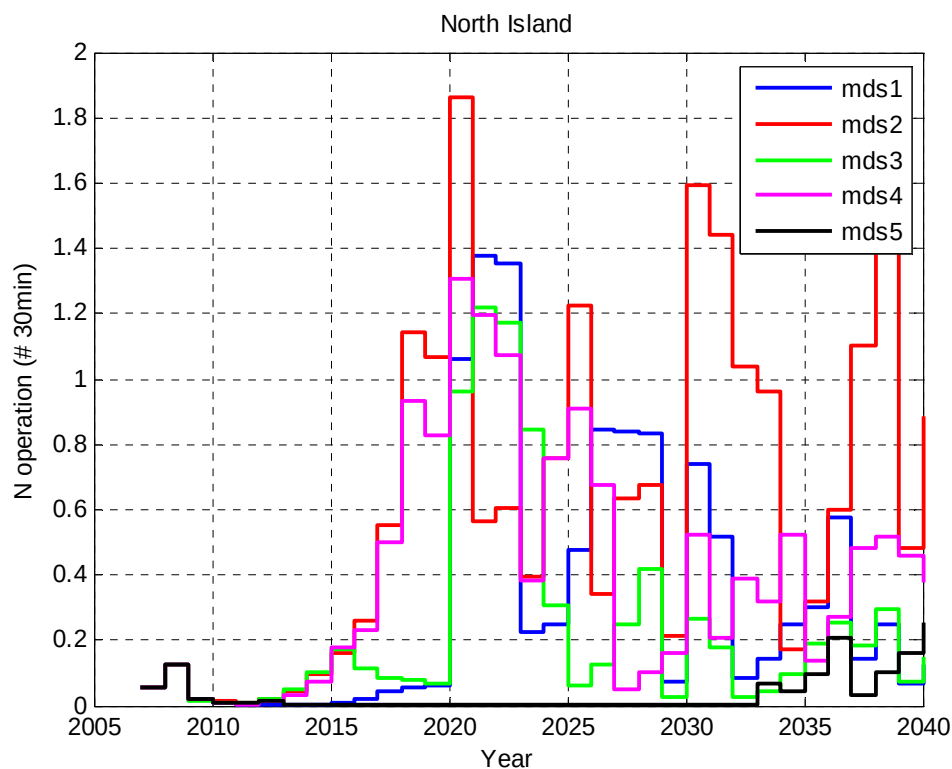


Figure 4-15: Number of trading periods with N-operation or worse on the North Island with N -2 capacity constraint in GEM⁷



⁶ Source: EC presentation at TAG meeting – November 1, 2007

⁷ Idem

Whilst the N-2 constraint improves the reliability over the current level as seen in Figure 4-15, Transpower has chosen the N-1 constraint for this GIT application since this best reflects current security requirements⁸.

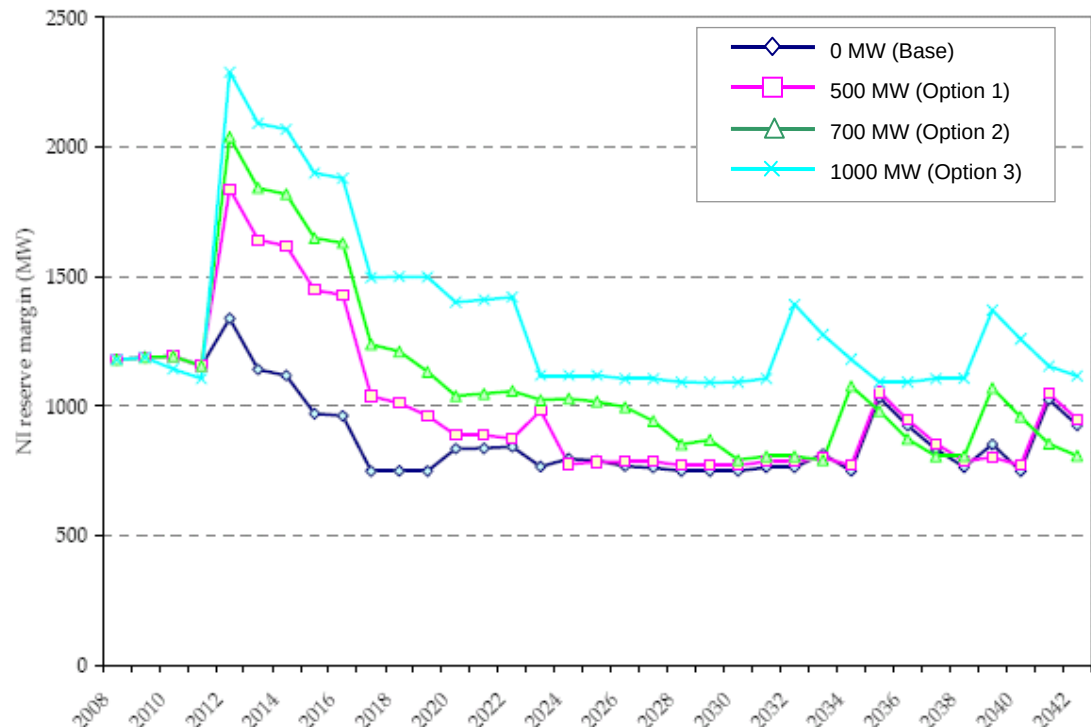
In response to the submissions raised, Transpower requested further analysis be carried out by MMA⁹. MMA ran the generation expansion part of PLEXOS, both with and without the capacity constraints. Because PLEXOS co-optimises energy and reserve, the capacity expansion plan is still likely to build some reserve capacity to ensure that the requirements for instantaneous reserves can be met for each of the 17 load blocks used in the modelling. In that respect, it is different from GEM. However, the amount of capacity built will still be lower without the N-1 constraints imposed because:

- The N-1 capacity constraints are formulated to ensure that the prudent peak demand can be met with reserves intact. The load forecasts used in the LT Plan are based on median peak demand projections rather than the prudent peak demand (with the latter expected to be exceeded one out of ten years only), and consequently the perceived need for additional capacity in the model will be less.
- The LT Plan assumes average deratings for wind and hydro units and does therefore not reflect the non-firm nature of these resources. The N-1 capacity constraint accounts for this non-firm capacity by assuming a peak contribution factor. For wind, this is assumed to be 20%, and for run-of-river hydro, a peak contribution factor of 65% is assumed.

The impacts on North Island capacity margins when having the constraints are shown in Figure 4-16 below. For comparison, the capacity margins when running the model without the constraints are shown in

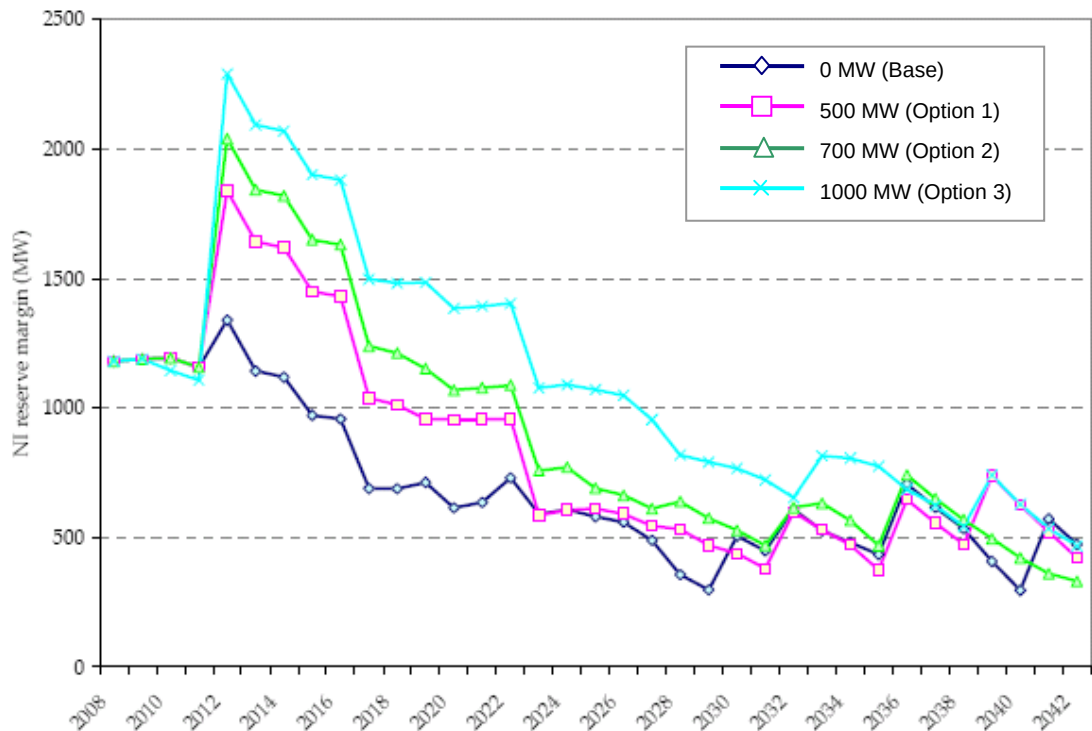
Figure 4-17.

Figure 4-16: North Island capacity margin with N-1 capacity constraint



⁸ Note that the terms N-1 and N-2 does not reflect the traditional use of those terms in terms of grid planning but is a parameter that is used in GEM to calibrate the results to something realistic.

⁹ See section 3.1 of Attachment G of Volume 2.

Figure 4-17: North Island capacity margin without including the capacity constraint

Without capacity constraints, the reserve margin reduces over time to approximately 500 MW or less than half the level at the start of the horizon. With this low reserve margin, prudent peak demand in the North Island would not be able to be supplied in the event that the largest HVDC link was out of service. Due to reliability concerns, it is highly unlikely that the system would ever operate with such a low reserve margin.

Given the analysis shown above, Transpower concludes that such modelling produces unrealistic generation expansion plans and that an N-1 capacity constraint is more realistic. Transpower expects that a market that delivers that amount of capacity will be in place. Transpower therefore considers it reasonable to use generation expansion based on the N-1 constraint for the purposes of its GIT analysis.

4.7 Conclusion on reasonableness of generation expansion plans

The general trends between scenarios, between demand growth scenarios and between varying HVDC link sizes are as expected. Transpower concludes that GEM is producing reasonable generation expansion plans and that these generation expansion plans are suitable for assessing the economics of replacing Pole 1 of the inter-island HVDC link.

5 Expected Net Market Benefit results

As discussed in the Consultation Paper (see Volume 2) and other attachments, the following options have been analysed:

- Base Case – no Pole 1 replacement. HVDC capacity is existing Pole 2 only – a 700 MW monopole.
- Option 1 – a 500 MW Pole 1 replacement terminated at Benmore and Haywards.
- Option 2 – a 700 MW Pole 1 replacement terminated at Benmore and Haywards.
- Option 3 – a 1000 MW Pole 1 replacement terminated at Benmore and Haywards.

These options have been analysed over a range of three demand growth assumptions and five market development scenarios.

The numbers reported here, and their presentation, differ slightly from those reported in the Consultation Paper for the following reasons:

- The Rules require GIT results (expected net market benefit) to be calculated for a twenty year period from commissioning with any significant costs and benefits after that being reported as a terminal benefit. The Consultation Paper showed the results for the 30 year expected life of the assets (see footnote 2 of the revised Consultation Paper¹⁰ included as Volume 2). This change in presentation does not change the reported expected net market benefits.
- The estimated costs for the options have continued to be refined and updated in light of further available information and more detailed design considerations. As a result, Transpower's GIT analysis has used slightly different costs to those used in its proposed analysis.
- Where relevant and where possible, the sensitivity results now reflect a weighted average over all scenarios, rather than for a selected scenario.
- Further sensitivities have been added in response to submissions received during the consultation.

5.1 Overall GIT results

The weight averaged expected net market benefit for each short list option is:

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

Net Market Benefit	Base Case No Pole 1 replacement	Option 1 500 MW Pole 1	Option 2 700 MW Pole 1	Option 3 1000 MW Pole 1
Present Value 2007\$M				
Generation fixed costs (A)	7,000	6,847	6,769	6,800
Generation variable costs (B)	9,499	9,392	9,356	9,291
HVDC costs (C)	59	325	436	554
AC augmentation costs (D)	45	47	48	49
Terminal benefit (E)	5,858	5,712	5,660	5,661
Total cost (A+B+C+D+E)	22,461	22,323	22,269	22,355
Expected Net Market Benefit	-	138	191	106

These results show that Option 2, building a 700 MW Pole 1 at Benmore and Haywards has the highest expected net market benefit of the short list options, being some \$53 million in 2007 present value terms higher than the next highest short list option, building a 500 MW Pole 1 at Benmore and Haywards.

This value includes the terminal benefits shown in line (E). These are the costs and benefits (primarily generation fixed and variable costs) forecast to arise after 20 years from commissioning of a replacement Pole 1, to the end of the 30 year expected life of that replacement. The terminal benefits are significant in this case and Transpower has therefore included them in the calculation of expected net market benefit, consistent with clause 27 of

¹⁰ Or footnote 1 to the original Consultation Paper (version Rev A).

Schedule F4. For ease of presentation, all results in this document are shown as the expected net market benefit over 30 years and included the terminal benefit (E).

The expected net market benefit of Option 2 is \$191 million and, being greater than zero, Transpower concludes that Option 2, therefore, meets the requirements of clauses 4.2.1 and 4.2.2 of the GIT.

Transpower has gone on to consider the sensitivity of this result to changes in key variables and parameters to assess the robustness of this result (see clause 4.2.3 of the GIT).

In terms of presentation in the remainder of this document, please note that:

- net market benefits highlighted in red indicate a result that satisfies the GIT; and
- net market benefits highlighted in orange indicate the highest net market benefit of the options, but that the result does not satisfy the GIT.

The results reported in this document are the expected net market benefits only. The details behind these numbers are contained within a spreadsheet, which is available on the Grid New Zealand website:

<http://www.gridnewzealand.co.nz/n282,110.html>.

5.2 GIT results by demand growth scenario

Table 5-2 shows the GIT results by demand growth scenario, weight averaged over the market development scenarios:

Table 5-2: Results of application of the Grid Investment Test by demand scenario

Net Market Benefit	Base Case No Pole 1 replacement	Option 1 500 MW Pole 1	Option 2 700 MW Pole 1	Option 3 1000 MW Pole 1
Present Value 2007\$M				
Low demand	-	26	1	-110
Medium demand	-	145	221	128
High demand	-	213	243	214

These results indicate that each short list option has a higher expected net market benefit as demand growth increases. This is reasonable, because as demand growth increases, the requirement for new generation would increase and the potential generation expansion savings from increased North Island access to South Island generation options would increase.

As seen, Option 2 is the most economic for medium and high demand growth assumptions, but for low demand growth, a smaller HVDC link would be more economic in terms of the GIT, although only marginally.

Furthermore, Option 2 is still more economic than the base case in the low demand case.

5.3 GIT results by market development scenario

Table 5-3 shows the GIT results by market development scenario, weight averaged over the demand growth scenarios.

Table 5-3: Results of application of the Grid Investment Test by generation scenario

Net Market Benefit	Base Case No Pole 1 replacement	Option 1 500 MW Pole 1	Option 2 700 MW Pole 1	Option 3 1000 MW Pole 1
Present Value 2007\$M				
High Gas	-	-77	-114	-198
Mixed technologies	-	13	208	111
Primary renewables	-	120	90	-21
SI Surplus	-	62	75	-41
90% renewables by 2025	-	261	352	278

These results indicate that:

- Option 2 has the highest expected net market benefit in three of the five market development scenarios.
- It would not be economic in terms of the GIT to replace Pole 1 of the HVDC link under the High Gas generation scenario. This seems reasonable because in that scenario much of the new generation is built in the North Island, where the gas supplies are assumed to be. South Island gas discoveries could change that, but none of the market development scenarios reflect such a possibility.
- The short list options are most economic under the 90% renewables by 2025 scenario. This is reasonable, as that scenario benefits the most from access to the renewables generation options in the South Island.

5.3.1 Variability in the MIP model results

There are some natural phenomena associated with the use of mixed integer program (MIP) which are worth being aware of. They contribute to a variability in the results, which is at first unexpected, and if not understood and allowed for when interpreting the results and trends can lead to erroneous conclusions about the results.

These effects are described in Appendix B and the reason for considering them is to assist with interpreting the results.

5.4 GIT results by demand growth scenario and generation scenario

Table 5-4 shows the GIT results broken down by both demand growth scenario and generation scenario.

Significant conclusions to note are:

- Of the 15 combinations shown, a short list option would satisfy the GIT in 11 of them.
- Of those 11 combinations, Option 2 is the most economic in 7 of them.
- The trends in moving from low to medium to high demand are consistent.
- The trends between market development scenarios are more variable, but these variations are likely to be due to the likes of the MIP effect (see Appendix B).
- The highest expected net market benefits, across all demand scenarios, result from the 90% renewables by 2025 generation scenario.

Table 5-4: Results of application of the Grid Investment Test by demand growth scenario and generation scenario

Net Market Benefit		Base Case No Pole 1 replacement	Option 1 500 MW Pole 1	Option 2 700 MW Pole 1	Option 3 1000 MW Pole 1
Present Value 2007\$M					
Low demand	High Gas	-	-175	-281	-391
	Mixed technologies	-	-98	-193	-344
	Primary renewables	-	1	-132	-238
	SI Surplus	-	92	37	-0
	90% renewables by 2025	-	132	189	76
Medium demand	High Gas	-	-63	-88	-172
	Mixed technologies	-	4	281	176
	Primary renewables	-	107	101	-25
	SI Surplus	-	54	75	-73
	90% renewables by 2025	-	278	383	306
High demand	High Gas	-	-42	-71	-125
	Mixed technologies	-	168	269	267
	Primary renewables	-	299	259	217
	SI Surplus	-	73	111	68
	90% renewables by 2025	-	312	372	353

5.5 GIT Sensitivities

Transpower carried out the following sensitivities to consider the robustness of the GIT result as part of its proposed GIT application. Compared with the sensitivity results from the Consultation Paper (see Volume 2), these results have been updated consistent with the GIT results above. Again, these changes to numbers and presentation have not materially affected the results of this analysis.

In addition, further sensitivities have been carried out in response to submissions received during the consultation. They follow in section 5.6.

5.5.1 Discount Rate – 4%

To test this sensitivity, the discount rate used to calculate the present values is 4%, rather than the 7% used for the base GIT analysis.

These results should be compared to the results using a 7% discount rate in sections 5.1, 5.2 and 5.3.

Table 5-5: Results of application of the Grid Investment Test - 4% discount rate sensitivity

Net Market Benefit	Base Case No Pole 1 replacement	Option 1 500 MW Pole 1	Option 2 700 MW Pole 1	Option 3 1000 MW Pole 1
Present Value 2007\$M				
Weighted for demand and generation	-	446	600	514
Weighted for generation				
Low demand	-	245	271	133
Medium demand	-	466	658	566
High demand	-	555	660	656
Weighted for demand				
High Gas	-	59	52	-17
Mixed technologies	-	243	625	479
Primary renewables	-	410	427	300
SI Surplus	-	308	386	271
90% renewables by 2025	-	667	888	822

Significant conclusions to note are:

- The expected net market benefit improves considerably for lower discount rates and the short list options are economic in terms of the GIT, even under low demand growth conditions.
- The ranking of the short list options changes such that in only one combination (low demand in the High Gas scenario) does Option 2 not have the highest expected net market benefit. Note that this is not considered a particularly likely outcome and has only a 3% weighting in terms of calculating expected net market benefit.
- One option produces a positive expected net market benefit for every demand growth scenario and every generation scenario.

It is noted that the analysis behind the New Zealand Energy Strategy to 2050 reflects a discount rate of 5%.

5.5.2 Discount Rate – 10%

To test this sensitivity, the discount rate used to calculate the present values is 10%, rather than the 7% used for the base GIT analysis.

These results should be compared to the results using a 7% discount rate in sections 5.1, 5.2 and 5.3.

Table 5-6: Results of application of the Grid Investment Test – 10% discount rate sensitivity

Net Market Benefit	Base Case No Pole 1 replacement	Option 1 500 MW Pole 1	Option 2 700 MW Pole 1	Option 3 1000 MW Pole 1
Present Value 2007\$M				
Weighted for demand and generation	-	-7	4	-76
Weighted for generation				
Low demand	-	-73	-115	-208
Medium demand	-	-5	20	-67
High demand	-	49	47	12
Weighted for demand				
High Gas	-	-133	-175	-261
Mixed technologies	-	-86	21	-53
Primary renewables	-	-16	-59	-155
SI Surplus	-	-51	-66	-173
90% renewables by 2025	-	67	98	26

Significant conclusions to note are:

- The expected net market benefit of the short list options deteriorates significantly at higher discount rates. Option 2 becomes breakeven.
- The ranking of the short list options does not change.

It is noted that there does not appear to be a lot of support for a discount rate higher than 7% in the GIT. Almost all arguments against using 7% are in favour of a lower discount rate.

5.5.3 HVDC Capital Costs

To test this sensitivity, the capital cost of the HVDC equipment is varied between 80% and 120% of the expected cost used by Transpower in the GIT analysis.

Table 5-7: Results of application of the Grid Investment Test - HVDC capital costs sensitivity

Expected Net Market Benefit	Base Case No Pole 1 replacement	Option 1 500 MW Pole 1	Option 2 700 MW Pole 1	Option 3 1000 MW Pole 1
Present Value 2007\$M				
80% capital cost	-	191	267	205
100% capital cost	-	138	191	106

Expected Net Market Benefit	Base Case No Pole 1 replacement	Option 1 500 MW Pole 1	Option 2 700 MW Pole 1	Option 3 1000 MW Pole 1
Present Value 2007\$M				
120% capital cost	-	84	115	6

Significant conclusions to note are:

- The expected net market benefit of the short list options is relatively sensitive to the capital cost of the HVDC itself.
- The ranking of the short list options does not change.
- All results show a positive expected net market benefit for Option 2.

5.5.4 Exchange rate

To test this sensitivity, the exchange rates used to calculate the capital cost of the HVDC equipment are varied from being an average calculated around +/- 20 business days of 30 April, 2007 (an agreed reference date) to an average calculated around the last ten years exchange rates.

Table 5-8: Results of application of the Grid Investment Test - exchange rate sensitivity

Expected Net Market Benefit	Base Case No Pole 1 replacement	Option 1 500 MW Pole 1	Option 2 700 MW Pole 1	Option 3 1000 MW Pole 1
Present Value 2007\$M				
+/- 20 business days of 30/04/07	-	138	191	106
10 year average	-	135	174	83

Significant conclusions to note are:

- The expected net market benefit of the short list options is not particularly sensitive to the exchange rate basis used.
- The ranking of the short list options does not change.
- All results show a positive expected net market benefit for Option 2.

5.5.5 HVDC Operating & Maintenance costs

To test this sensitivity, the operating and maintenance costs of the HVDC are varied between 0.2% of the expected capital cost and 1.0% of the expected capital cost. A value of 0.4% of the expected capital cost has been used in the GIT analysis.

Table 5-9: Results of application of the Grid Investment Test - HVDC operating cost sensitivity

Expected Net Market Benefit	Base Case No Pole 1 replacement	Option 1 500 MW Pole 1	Option 2 700 MW Pole 1	Option 3 1000 MW Pole 1
Present Value 2007\$M				
0.2%	-	143	199	116
0.4%	-	138	191	106
1.0%	-	122	168	75

Significant conclusions to note are:

- The expected net market benefit of the short list options is not particularly sensitive to the HVDC operating and maintenance costs.
- The ranking of the short list options does not change.
- All results show a positive expected net market benefit for Option 2.

5.5.6 Using a N-2 capacity constraint in the generation expansion modelling

To test this sensitivity, the N-1 capacity constraint in GEM is changed to be an N-2 capacity constraint.

The N-2 constraint was used in the Option Ranking process. As discussed in section 4.6 above, following industry feedback and further consideration, Transpower has used a N-1 constraint for this GIT analysis.

To assess the impact on the results in comparison with the Option Ranking work, this sensitivity was undertaken. It has been done for medium demand using GEM only. The operating costs assessed by SDDP in the main runs differ as GEM models the whole dispatch in less detail, though it includes all the hydrological years and not just 6 years as in the SDDP analysis.

Table 5-10 shows the results. As the modelling differ from the base GIT analysis, the normal demand results using GEM only have been shown in Table 5-11 for comparison.

Table 5-10: Using the N-2 capacity constraint sensitivity – GEM modelling only

Net Market Benefit	Base Case No Pole 1 replacement	Option 1 500 MW Pole 1	Option 2 700 MW Pole 1	Option 3 1000 MW Pole 1
Present Value 2007\$M				
High gas	-	130	136	-62
Mixed technologies	-	225	311	148
Primary renewables	-	100	237	66
SI Surplus	-	544	635	481
90% renewables by 2025	-	880	1094	946
Weighted	-	531	672	509

Table 5-11: Using the N-1 capacity constraint as comparison – GEM modelling only

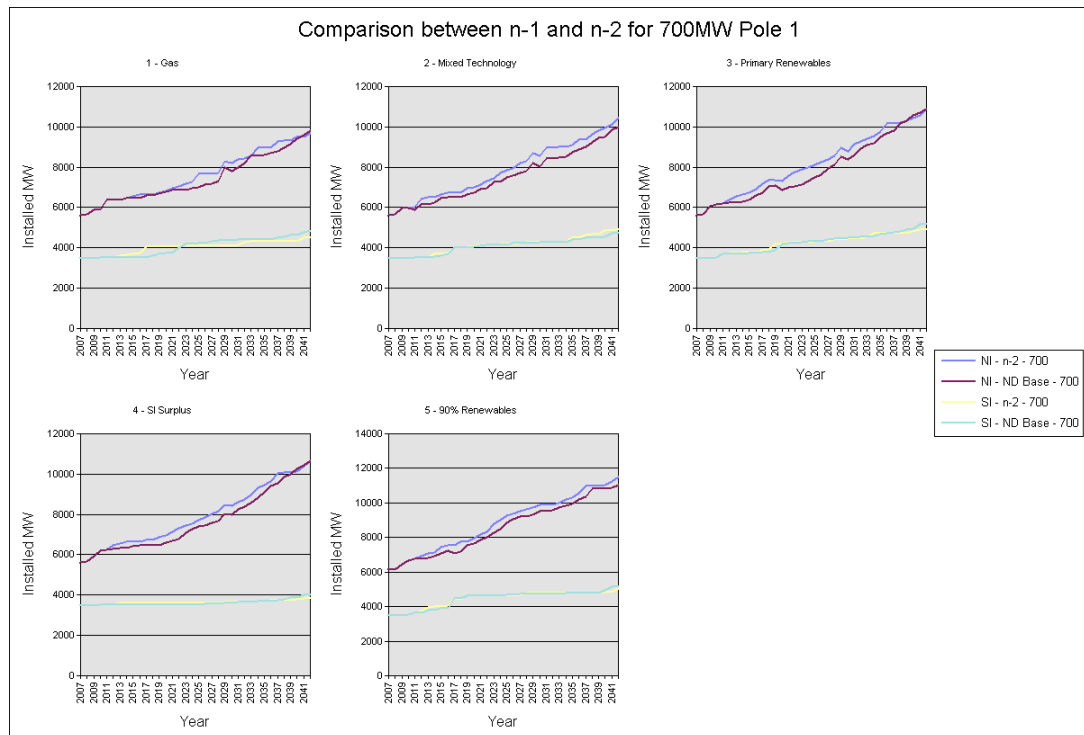
Net Market Benefit	Base Case No Pole 1 replacement	Option 1 500 MW Pole 1	Option 2 700 MW Pole 1	Option 3 1000 MW Pole 1
Present Value 2007\$M				
High gas	-	63	-41	-111
Mixed technologies	-	132	387	252
Primary renewables	-	199	167	33
SI Surplus	-	521	551	422
90% renewables by 2025	-	436	624	525
Weighted	-	300	395	292

Significant conclusions to note are:

- The expected net market benefit of the short list option is sensitive to the capacity constraint assumption used in the GEM model, with N-2 (higher reliability) resulting in significantly higher net market benefits.
- The ranking of the short list options does not change.
- All scenarios show a positive expected net market benefit for Option 2.
- Figure 5-1 illustrates that using an N-2 capacity constraint, there is a consistently higher new generation build than if N-1 capacity constraint is used in the generation expansion modelling.

A higher expected net market benefit for an N-2 capacity constraint is intuitive, because with an N-2 capacity constraint, more and earlier generation is needed and the South Island provides some of that additional capacity.

Subsequently, an analysis has been undertaken without any capacity constraints. The details can be found in sections 4.6 and 5.6.2.

Figure 5-1: Comparison between security levels

5.5.7 Generation capital

To test this sensitivity, the capital costs of various sorts of generation technology are varied, to test the sensitivity of the generation expansion modelling to generation capital cost.

Following industry feedback, Transpower considers it reasonable to vary the capital costs published by the Electricity Commission as part of the draft 2007 Statement of Opportunities (SoO) as follows¹¹:

- Geothermal capital costs +20%
- Wind capital costs -10%
- Hydro capital costs -10%

As for the N-2 capacity constraint sensitivity analysis, this sensitivity was undertaken for medium demand using GEM only. The operating costs assessed by SDDP in the main runs differ as GEM models the whole dispatch in less detail, though it includes all the hydrological years and not just 6 years as in the SDDP analysis.

Table 5-12 shows the results. As the modelling differ from the base GIT analysis, the normal demand results using GEM only have been shown in Table 5-13 for comparison.

¹¹ See also Attachment B – Databook to the Consultation Paper (Volume 2)

Table 5-12: Generation Capital Cost Change sensitivity – GEM modelling only

Net Market Benefit	Base Case No Pole 1 replacement	Option 1 500 MW Pole 1	Option 2 700 MW Pole 1	Option 3 1000 MW Pole 1
Present Value 2007\$M				
High gas	-	117	-41	-92
Mixed technologies	-	378	350	341
Primary renewables	-	103	164	2
SI Surplus	-	497	580	454
90% renewables by 2025	-	421	574	443
Weighted	-	312	375	260

Table 5-13: Capital cost as in base runs for comparison – GEM modelling only

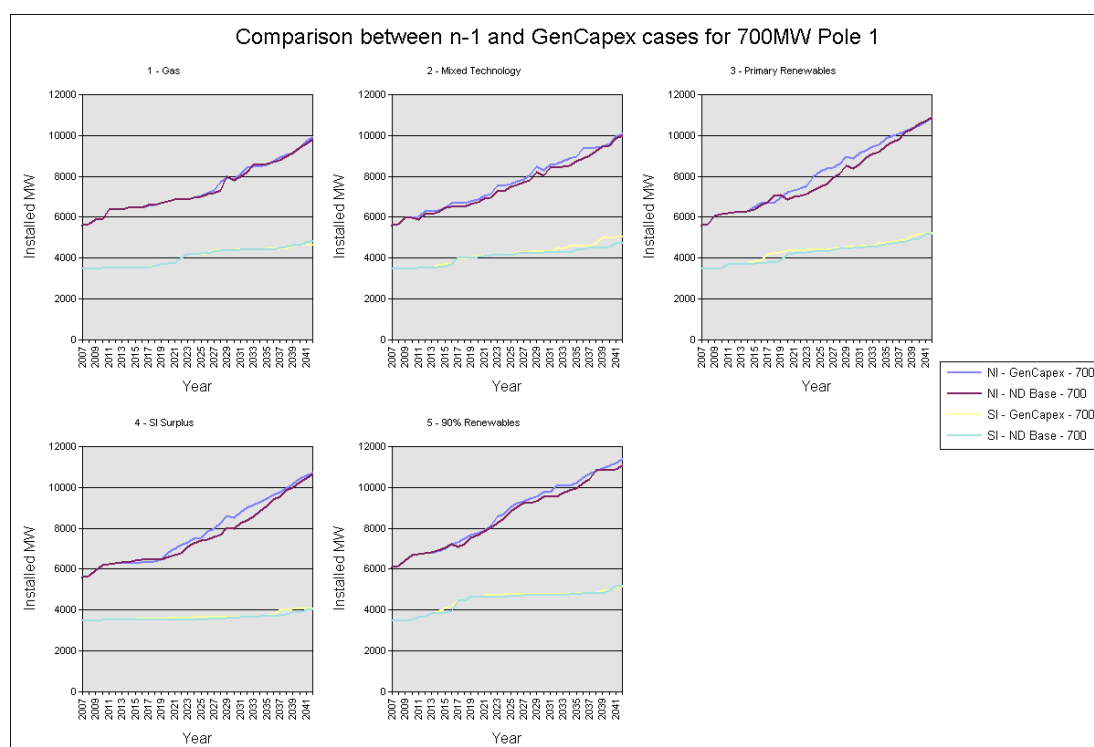
Net Market Benefit	Base Case No Pole 1 replacement	Option 1 500 MW Pole 1	Option 2 700 MW Pole 1	Option 3 1000 MW Pole 1
Present Value 2007\$M				
High gas	-	63	-41	-111
Mixed technologies	-	132	387	252
Primary renewables	-	199	167	33
SI Surplus	-	521	551	422
90% renewables by 2025	-	436	624	525
Weighted	-	300	395	292

Significant conclusions to note are:

- The expected net market benefit of the short list options is relatively insensitive to generation capital cost changes of this magnitude.
- The ranking of the short list options does not change.
- 4 out of 5 scenarios show a positive expected net market benefit for Option 2.

Since North Island generation costs (geothermal) increase and South Island generation costs (wind, hydro) decrease, slightly more South Island generation is built and the HVDC link becomes more valuable as the extra energy produced is exported to the North Island. More North Island generation is also added as the geothermal generation partly is replaced with generation with lower peak availability (such as wind). Therefore, more capacity is needed to satisfy the peak constraint in the model.

Subsequently, following submissions in the recent consultation, a sensitivity analysis with lower geothermal costs has been carried out. Details can be found in section 5.6.3.

Figure 5-2: Generation Capital change for 700 MW Pole 1

5.5.8 No HVDC charge on South Island generators

To test this sensitivity, the HVDC charge, currently paid by South Island generators, is removed. South Island generation costs therefore go down compared to North Island generation costs.

Table 5-14: No HVDC charge sensitivity – GEM modelling only

Net Market Benefit	Base Case No Pole 1 replacement	Option 1 500 MW Pole 1	Option 2 700 MW Pole 1	Option 3 1000 MW Pole 1
Present Value 2007\$M				
High gas	-	69	-3	-101
Mixed technologies	-	266	269	209
Primary renewables	-	180	166	34
SI Surplus	-	535	563	438
90% renewables by 2025	-	421	545	486
Weighted	-	305	352	271

This sensitivity was undertaken for medium demand using the GEM model only as in the previous two sensitivities. The results are shown in Table 5-14. For comparison, the GEM only results with the HVDC charge have been provided in Table 5-15 below.

Table 5-15: Run with HVDC charge for comparison – GEM modelling only

Net Market Benefit	Base Case No Pole 1 replacement	Option 1 500 MW Pole 1	Option 2 700 MW Pole 1	Option 3 1000 MW Pole 1
Present Value 2007\$M				
High gas	-	63	-41	-111
Mixed technologies	-	132	387	252
Primary renewables	-	199	167	33
SI Surplus	-	521	551	422
90% renewables by 2025	-	436	624	525
Weighted	-	300	395	292

Significant conclusions to note are:

- The expected net market benefit of the short list options is relatively insensitive to the costs of the HVDC being paid for by the South Island generators.
- The ranking of the short list options does not change.
- 4 out of 5 scenarios show a positive expected net market benefit for Option 2.

A higher expected net market benefit when including the HVDC charge is not intuitive. However, the detailed results behind the differences presented in the tables show the cost of the Base Case increases with the charge compared to the case without the charge. The same cost differences for Options 1, 2 and 3 are lower or negligible. This means that the benefits of Options 1, 2 and 3 for the 'No Charge' analysis relative to the 'No Charge' Base Case appear to be smaller than for the cases that include the charge.

5.5.9 Roxburgh and Bunnythorpe as termination points

This sensitivity compares the expected net market benefit arising from moving the termination points for a replacement Pole 1 from Benmore and Haywards to Roxburgh and Bunnythorpe respectively. AC augmentation costs and loss cost differences are all accounted for.

This sensitivity was undertaken for medium demand and Option 2 only. The tables below show the Roxburgh and Bunnythorpe results in the Option 2 column. This is for convenience only.

Table 5-16: Roxburgh/Bunnythorpe termination sensitivity

Net Market Benefit	Base Case No Pole 1 replacement	Option 1 500 MW Pole 1	Option 2 700 MW Pole 1	Option 3 1000 MW Pole 1
Present Value 2007\$M				
Benmore termination	-	-	221	-
Roxburgh termination	-	-	211	-

Table 5-17: Haywards/Bunnythorpe sensitivity

Net Market Benefit	Base Case No Pole 1 replacement	Option 1 500 MW Pole 1	Option 2 700 MW Pole 1	Option 3 1000 MW Pole 1
Present Value 2007\$M				
Haywards termination	-	-	221	-
Bunnythorpe termination	-	-	204	-

Significant conclusions to note are:

- A lower expected net market benefit results from moving the HVDC termination points in either island from their current location.
- The ranking of the short list options does not change.

All results show a positive expected net market benefit for Option 2.

5.5.10 Summary table of sensitivity results

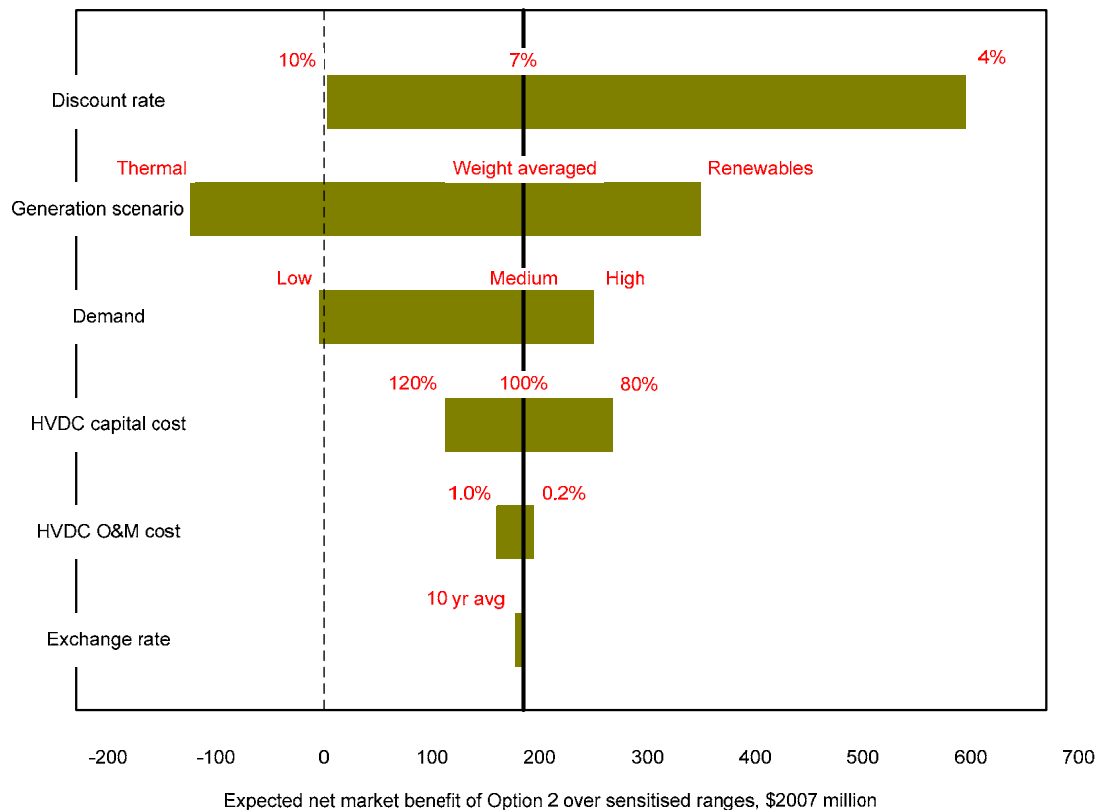
Table 5-18: Sensitivity of expected net market benefit of the short list options

\$2007 million	Base Case No Pole 1 replacement	Option 1 500 MW Pole 1	Option 2 700 MW Pole 1	Option 3 1000 MW Pole 1
Present Value 2007\$M				
Base results	-	138	191	106
Sensitivity:				
Discount rate, 4%	—	446	600	514
Discount rate, 10%	—	-7	4	-76
HVDC capital 80%	-	191	267	205
HVDC capital 120%	-	84	115	6
10 yr avg exchange rate	-	135	174	83
HVDC O&M 0.2%	-	143	199	116
HVDC O&M 1.0%	-	122	168	75
Base – med demand, GEM				
N-2 cap constraint, GEM	-	531	672	509
Generation capital, GEM	-	312	375	260
No HVDC charge, GEM	-	305	352	271
Base – med demand, Option 2				
ROX termination, Option 2	-	-	211	-
BPE termination, Option 2	-	-	204	-

This summary of weight averaged sensitivity studies show that the ranking of the short list options is stable to a range of sensitivities. All sensitivities show Option 2, the 700 MW replacement, having the highest positive expected net market benefit.

These results are also shown diagrammatically below, in order to demonstrate what the expected net market benefit is most sensitive to.

Figure 5-3: Sensitivity ranges of expected net market benefit



5.6 Further sensitivities in response to submissions received

Meridian Energy, Contact Energy and MEUG each raised issues in the most recent consultation period, which Transpower has addressed using further sensitivity analysis.

5.6.1 South Island demand growth

Meridian Energy raised several issues with regard to the demand forecast used in the HVDC GIT analysis. Transpower's response to each issue is detailed in the following section.

Allocation of forecast demand between Islands

From Meridian Energy's submission:

"Transpower's demand forecasts fail to acknowledge that the drivers of demand growth are economic as well as population growth. Instead their allocation of national demand growth between the North and South Island is based on population growth only."

"Transpower has undertaken no historical analysis to support the proposition that population growth is the primary driver relevant to allocate demand growth between the North and South Islands"

Both these issues are closely related and Transpower covers both in its response below.

The demand forecast used in Transpower's GIT analysis is that provided by the Electricity Commission in its May 2007 draft GPAs. Full details of the methodology used in deriving the demand forecast can be found in the Electricity Commission's National Demand Forecast Review report dated June 2006.¹²

In summary, the Electricity Commission produces the national demand forecast by applying an econometric model which uses the relationship between historical demand and key drivers such as GDP and population to forecast demand based on forecasts of these key drivers. This is widely acknowledged both in New Zealand and overseas as a sound method by which to forecast demand.

The Commission then allocates national demand between 13 regions to produce regional demand forecasts. Meridian Energy's assumption that the allocation of national demand forecast is based purely on population forecasts is erroneous as discussed below.

Whilst the regional residential demand forecast is produced by allocating out the national residential demand forecast to regions based on regional population forecasts obtained from Statistics NZ, the industrial and commercial component of the demand forecast is allocated out to a regional level based on long term regional GDP projections obtained from NZIER. The demand forecast, therefore, does not ignore regional economic growth as a driver for its regional allocation.

However, given that this approach assumes that the forecast growth in load will have the same energy intensity characteristics as exist in the historical data set at a regional level, the Commission made an additional adjustment to capture the trend within regions which result from short term changes in energy intensity. This is particularly relevant to the South Island where the recent growth in demand can be largely attributed to the rapid and high conversion rates of dairy farms and the resulting irrigation and processing facilities required to sustain it.

Transpower's view is that is far more robust to use regional demand forecasts derived from a mix of population and regional GDP projections as well as recent trends than to rely purely on extrapolating out the regional trend based on a relatively small set of data points, i.e. 10 years as has been proposed by Meridian Energy in its submission dated 4 April 2008. There is obviously a limit on the potential increase in energy intensity in the South Island.

In its report, South Island Electricity Load Growth¹³, COVEC concluded that there are emerging constraints on the growth of the dairy industry which would contribute to a reduction in its contribution to electricity demand growth in the South Island. These are namely the competition for water resources and an increasing trend towards the use of bio-energy systems on dairy farms.

Having analysed the North Island/South Island historical demand split, Transpower is satisfied that the demand forecast used in the HVDC analysis is reasonable and fit for purpose.

Table 5-19 shows the historical annual demand in GWh¹⁴ by island and the respective island proportion.

As illustrated in the table, the balance of demand distributed to island level has remained relatively constant through the last 10 years. The moderate increase in South Island demand relative to North Island in the last five years can be attributed to the growth in demand directly attributable to strong growth in the dairy sector which is driving demand for electricity via its processes and irrigation load.

¹² Available at <http://www.electricitycommission.govt.nz/opdev/modelling/gpas/May2007/Demand/index.html>.

¹³ See Attachment C to the Proposal.

¹⁴ Actual demand data has been derived from final metered billing data provided by EMS.

Table 5-19: Actual Annual Net Demand (GWh) by Island

Calendar Year	NI Demand	SI Demand	NI Ratio	SI Ratio
1997	20,629	11,796	64%	36%
1998	20,354	12,044	63%	37%
1999	21,080	12,259	63%	37%
2000	21,592	12,514	63%	37%
2001	21,507	12,730	63%	37%
2002	22,243	13,120	63%	37%
2003	22,166	13,309	62%	38%
2004	23,423	13,770	63%	37%
2005	23,246	13,783	63%	37%
2006	23,630	13,931	63%	37%
2007	23,949	14,243	63%	37%

The following table shows the expected forecast demand by island used in the HVDC GIT analysis¹⁵.

Table 5-20: Forecast Annual Net Demand (GWh) by Island

Calendar Year	NI Demand	SI Demand	NI Ratio	SI Ratio
2007	23,074	13,364	63%	37%
2008	23,612	13,569	64%	36%
2009	24,251	13,787	64%	36%
2010	24,829	13,956	64%	36%
2011	25,341	14,087	64%	36%
2012	25,849	14,200	65%	35%
2013	26,370	14,320	65%	35%
2014	26,909	14,443	65%	35%
2015	27,455	14,564	65%	35%
2016	27,966	14,671	66%	34%
2017	28,469	14,777	66%	34%

Whilst the allocation of demand in the South Island does reduce, it is not a significant reduction. The allocation of demand between islands remains relatively consistent with the historical split until 2012, at which time, the South Island allocation starts to drop away very slightly, reflecting the slower projected growth rate in population and regional GDP relative to the North Island. This is in line with Transpower's expectations that there is a limit to the accelerated growth in energy intensity in the South Island and the expectation that this will be reached within the next few years.

¹⁵ Please note that this demand forecast has been adjusted to net off embedded generation and losses. This has been done so that it is comparable with the historical data set which represents the net load at GXP level.

In its report, South Island Electricity Load Growth, COVEC concluded that there is a high correlation between three key variables: GDP, population, cow numbers and electricity demand. These three variables are also correlated with each others, so for practical purposes, just one (or at least not all three) is needed to forecast the demand. As stated above, the Commission's forecast actually uses 2 of these drivers – regional GDP and population projections – to forecast the allocation of demand at a regional level. These projections are more readily available than the expected future number of cows.

Given the high correlation between these variables and electricity demand growth, Transpower is of the view that the Commission's forecasts sufficiently model projected load growth in the South Island over the medium to long term.

A GEM sensitivity analysis with higher SI demand growth

From Meridian Energy's submission to the Consultation Paper (see Volume 2) requesting that, for the GIT analysis for a submitted proposal:

"The South and North Island demand forecasts are revised to be based on an extrapolation of historical demand growth and not allocated on the basis of population growth alone."

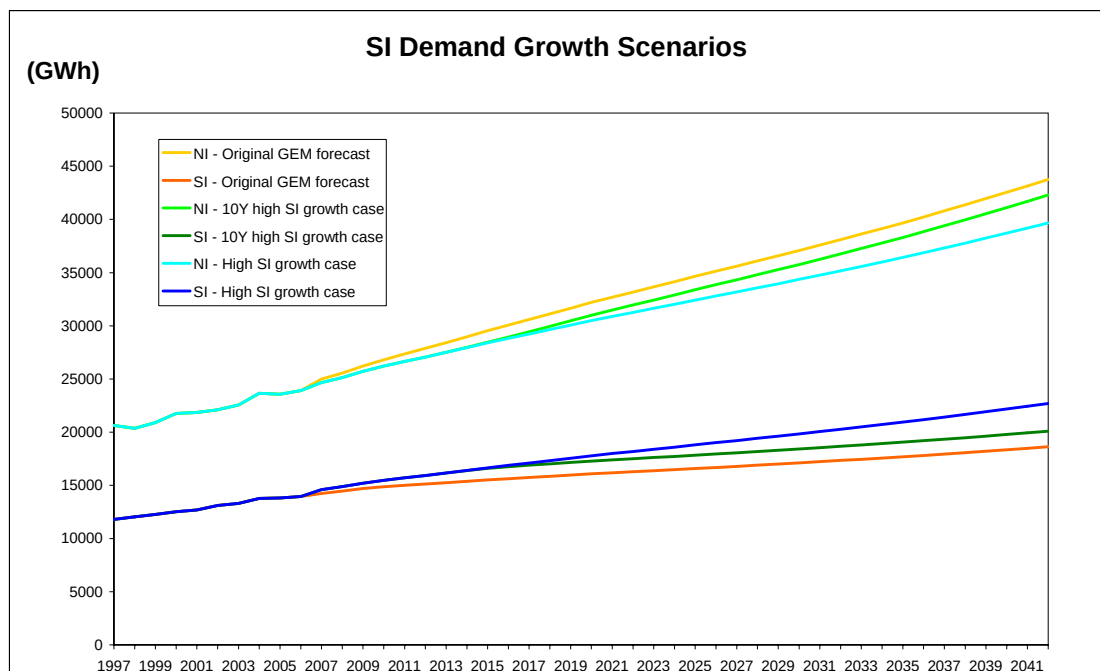
In response to this, Transpower re-ran the GEM model with two new forecasts:

- High SI Growth Case. South Island demand growth extrapolated, based on recent historical data (1997-2007), out over the full period of analysis.
- 10 Year High SI Growth Case. South Island demand growth extrapolated as above based on the historical data out over approximately the first 8 years at which time it over 4 years reverts to mean demand growth rates.

The national demand forecast was kept constant. To do so, North Island growth rates were reduced as South Island growth rates increased. All were based on the medium demand forecast.

The following chart shows the three demand forecasts used in this part of the analysis.

Figure 5-4: South Island Demand Growth Scenarios



The demand scenarios were run through GEM and the results of these sensitivities are shown in Table 5-21 below.

Table 5-21: GEM results on basis of new demand sensitivities

Net Market Benefit		Base Case No Pole 1 replacement	Option 1 500 MW Pole 1	Option 2 700 MW Pole 1	Option 3 1000 MW Pole 1
Present Value 2007\$M					
Original GEM forecast	High Gas	-	63	-41	-111
	Mixed technologies	-	132	387	252
	Primary renewables	-	199	167	33
	SI Surplus	-	521	551	422
	90% renewables by 2025	-	436	624	525
	Weighted Average	-	300	395	292
10 yr high SI growth	High Gas	-	-22	-138	-301
	Mixed technologies	-	21	20	-158
	Primary renewables	-	63	-9	-154
	SI Surplus	-	226	239	111
	90% renewables by 2025	-	459	633	500
	Weighted Average	-	248	301	157
High SI growth	High Gas	-	-65	-130	-292
	Mixed technologies	-	118	116	69
	Primary renewables	-	62	18	-135
	SI Surplus	-	169	117	-10
	90% renewables by 2025	-	425	515	411
	Weighted Average	-	229	252	133

It is hard to conclude too much from the results at an individual level. The highest South Island demand forecast (High SI growth) produces results more favourable to a lower capacity option as expected.

As explained earlier, Transpower considers it unlikely that South Island demand will continue to grow at recent historical levels for the reasons outlined above. Transpower therefore considers it is not appropriate to place significant weight on these results.

In any event, the 700 MW option presents highest expected net market benefit when weighted over all scenarios under all demand forecasts, thus further demonstrating that the proposed option is robust.

5.6.2 Capacity Constraint in GEM

Meridian Energy requested that:

“The impact of the capacity constraint on all scenarios is identified by removing the constraint in GEM and re-running each scenario.”

The following analysis shows how the capacity constraint in GEM impacts the GIT results. Three cases are shown:

- no constraint applied – as suggested by Meridian Energy in its 4 April submission;
- N-1 constraint applied as used in the GIT; and
- N-2 constraint applied as used in the option ranking process.

Whilst the N-2 constraint was used in the ranking of the options and considered appropriate to assess the relativity of options, further analysis suggested that applying an N-1 constraint in GEM was a more appropriate constraint to be applied in the GIT analysis.

Implications on net market benefit

The table below show the net market benefit of the different options when using the different capacity constraints in GEM. Note that the results are based on GEM estimates of generation operating costs rather than SDDP estimates and that results are based on the medium demand forecast.

Table 5-22: Net market benefit when using different capacity constraints in GEM

Net Market Benefit Scenario weighted	Base Case No Pole 1 replacement	Option 1 500 MW Pole 1	Option 2 700 MW Pole 1	Option 3 1000 MW Pole 1
Present Value 2007\$M				
No constraint	-	257	144	25
N-1	-	300	395	292
N-2	-	531	672	509

As seen, the net market benefit increase in line with the rigour of the constraint.

For the N-1 and N-2 cases, the results by scenario can be found in section 5.5.6. For the ‘no constraint’ case, the results are shown in Table 5-23.

Table 5-23: Net market benefit per scenario for the no constraint case using GEM only

Net Market Benefit	Base Case No Pole 1 replacement	Option 1 500 MW Pole 1	Option 2 700 MW Pole 1	Option 3 1000 MW Pole 1
Present Value 2007\$M				
High gas	-	-55	-185	-297
Mixed technologies	-	53	-44	-125
Primary renewables	-	-4	-149	-235
SI Surplus	-	92	-14	-46
90% renewables by 2025	-	292	210	209
Weighted	-	144	41	-5

The SDDP model was also run for both the ‘no constraint’ case and the N-1 case. The table below show the net market benefits of those cases where the dispatch cost part has been assessed by SDDP rather than GEM.

Table 5-24: Net market benefits under different constraints based on GEM/SDDP

Net Market Benefit	Base Case No Pole 1 replacement	Option 1 500 MW Pole 1	Option 2 700 MW Pole 1	Option 3 1000 MW Pole 1
Present Value 2007\$M				
No constraint	-	144	41	-5
N-1	-	145	221	128

The resulting net market benefits show the same relativity between options.

The amount of unserved energy occurring is higher in the 'no constraint' case since there is effectively less capacity available. The table below shows the NPV of the cost of unserved energy in 2007 \$million.

Table 5-25: NPV Unserved Energy Costs (2007 \$million) under different constraints

Expected Unserved Energy	Base Case No Pole 1 replacement	Option 1 500 MW Pole 1	Option 2 700 MW Pole 1	Option 3 1000 MW Pole 1
Present Value 2007\$M				
No constraint	111	85	67	83
N-1	67	66	55	59

Implications on system security

The previous results are based on a 5 load block modelling in both GEM and SDDP, where the peak load block is averaging the 7.14% of the highest expected load. Approximately half of the time, load is expected to be higher than this average and capacity build based on the average figure would fall short of the actual need. In addition, there is no reserve requirement modelled in either GEM or SDDP and the introduction of a capacity constraint in GEM was a simple and straightforward method of capturing the additional generation required in the absence of accurate peak load modelling and reserve requirements.

The charts showed in section 4.6 show the impact of the modelling on the available capacity to meet peak demand. Transpower considers that using the N-1 constraint in GEM provides the most likely and realistic outcomes.

5.6.3 Sensitivities on geothermal costs

In a letter to Transpower¹⁶ dated 11 March 2008, Contact Energy requested a sensitivity analysis assuming lower geothermal capital costs, as they estimated that the ones used in the GIT analysis was overstated by around 20-24%.

In response to this, Transpower undertook a sensitivity analysis assuming -20% capital costs for all geothermal projects plus a lower growth in costs for the generic projects, giving them a higher discount than the 20% suggested by Contact Energy.¹⁷

The focus in the sensitivity analysis was to look at the differences between the total generation costs (CAPEX + OPEX) only, i.e. costs of the HVDC Options 1-3 and the AC development plans required to enable the market development scenarios are assumed

¹⁶ See <http://www.gridnewzealand.co.nz/n282,110.html>

¹⁷ See Transpower's letter of 27 March 2008 to Contact Energy.

unchanged.¹⁸ Hence, the total generation cost impact is assumed to equal the impact on the overall GIT result. As the 1000 MW option (Option 3) was significantly less economic compared with Options 1-2, the sensitivity analysis was not undertaken for this option.

The table below shows the results based on a 7% discount rate. It can be seen that the impact on generation costs difference between base case (no replacement) and Options 1 and 2 are between \$0 and \$100 million with a weighted average around \$40 million for both options. These changes would not affect the GIT ranking and hence Transpower considers that even if the geothermal costs were lowered in line with Contact Energy's suggestion, that a 700 MW Pole 1 replacement would still meet the requirements of the GIT.

Table 5-26: Scenario specific costs from the lower geothermal costs case 2007 \$million

Difference in generation costs compared with base case (0 MW)		GIT results	-20% geo costs	Difference
Per scenario		Present Value 2007\$M		
High Gas	0 MW option	0	0	0
	500 MW option	-330	-296	34
	700 MW option	-351	-352	-1
Mixed Technology	0 MW option	0	0	0
	500 MW option	-414	-332	82
	700 MW option	-781	-682	99
Primary renewables	0 MW option	0	0	0
	500 MW option	-475	-455	20
	700 MW option	-575	-565	10
SI surplus	0 MW option	0	0	0
	500 MW option	-796	-795	1
	700 MW option	-955	-948	7
90% renewables	0 MW option	0	0	0
	500 MW option	-698	-647	51
	700 MW option	-1000	-944	56

Table 5-27: Scenario weighted results from the lower geothermal costs case

Difference in generation costs compared with base case (0 MW)	0 MW option	500 MW option	700 MW option
Weighted results	Present Value 2007\$M		
GIT results	0	-567	-782
-20% geo costs	0	-524	-743
Difference	0	44	40

¹⁸ Transpower expects that HVDC costs would be unaffected, and that any effect on AC augmentation costs would not impact materially on the HVDC GIT analysis.

The table below shows an example on the impacts on the new generation build schedules - in this case for using market development scenario 5 (90% renewables by 2025) for the 700 MW replacement Pole 1 (Option 2).

Both the build years from the GIT analysis and the build years with the geothermal costs proposed by Contact Energy are shown, as well as the difference.

Table 5-28: Impact on geothermal project investment years by lowering costs

Plant	GIT	New	Difference (years)
Ngawha 2	2009	2009	0
Kawerau	2009	2009	0
Mokai 3	2008	2008	0
Rotokawa Exp.	2010	2010	0
Tukairangi Road	2013	2010	3
Te Mihi	2011	2011	0
Generic Geo 1	2014	2012	2
Generic Geo 2	2015	2014	1
Generic Geo 3	2016	2016	0
Generic Geo 4	2018	2018	0
Generic Geo 5	2020	2020	0
Generic Geo 7	2022	2022	0
Generic Geo 8	2024	2024	0
Generic Geo 9	2029	2026	3
Generic Geo 10	2028	2028	0
Generic Geo 11	2032	2030	2

It can be seen that the impact of lowering geothermal generation capital costs on build year is minor, if any.

In Meridian Energy's submission to the proposed GIT application, they requested:

"Sensitivity analysis is performed on MDS5 to show how the impact of Huntly units 3, 4 and P40 being replaced with North Island geothermal and wind, instead of South Island hydro and wind."¹⁹

This relates to the sensitivity analysis as Meridian Energy recommended:

"Meridian recommends that this is achieved by splitting MDS5 into two 90% scenarios in which capital costs between hydro, wind and geothermal generation are varied. Contact's suggestion to reduce geothermal costs by 20% is a pragmatic solution to achieve this outcome."

Table 5-26 above shows that the 500 MW case (Option 1) becomes \$51 million less economic and the 700 MW case (Option 2) becomes \$56 million less economic when compared with the base case in MDS 5 on the basis of medium demand growth.

Transpower expects the demand weighted impact to be quite similar to the \$51 million and \$56 million stated above. Transpower expects that lower demand growth is likely to result in a lesser impact on the results while a higher demand growth is likely to result in a roughly corresponding bigger impact.

¹⁹ It should be noted that P40 is not taken out of service. The Huntly Gas unit taken out in the scenarios is the "natural gas fuelled" parts of Huntly blocks 1-4.

Splitting the existing market development scenario 5 (90% renewables), which has a weighting of 50% in the GIT, into two – each of 25% total weight (one being the existing and one being similar to the geothermal cost sensitivity study carried out above) will affect the proposed GIT results in the following way:

- 500 MW (Option 1) will have its scenario weighted net market benefit reduced by \$13 million (or 25% of \$51 million); and
- 700 MW (Option 2) will have its scenario weighted net market benefit reduced by \$14 million (or 25% of \$56 million).

Amending the proposed GIT results from Table 5-1 with these numbers, the overall results are presented in the table below.

Table 5-29: Overall results of application of the Grid Investment Test with low geothermal costs in half of the 90% renewables scenario

Item	Base Case No Pole 1 replacement	Option 1 500 MW Pole 1	Option 2 700 MW Pole 1
Present Value 2007\$M			
Expected Net Market Benefit	-	125	177

Transpower considers that its GIT results are robust to these sensitivities.

5.6.4 Impact of revising generation scenario weightings

In their submission, MEUG queried the basis Transpower used for assigning a 50% weighting to the 90% renewables by 2025 scenario:

“The 50% weighting on the “90% renewables by 2025” scenario because it²⁰ “*should be considered likely, given it is government policy*” is a very flimsy reason. MEUG do not think the “90% renewables by 2025” target should be accepted without very good reason.”

Transpower has considered this comment and offers the following further explanation. The weightings Transpower has applied in the GIT analysis are:

Market development scenario	Weight
MDS1 - High gas	20 %
MDS2 - Mixed technologies	10 %
MDS3 - Primary renewables	15 %
MDS4 - South Island surplus	5 %
MDS5 - 90% renewables by 2025	50 %

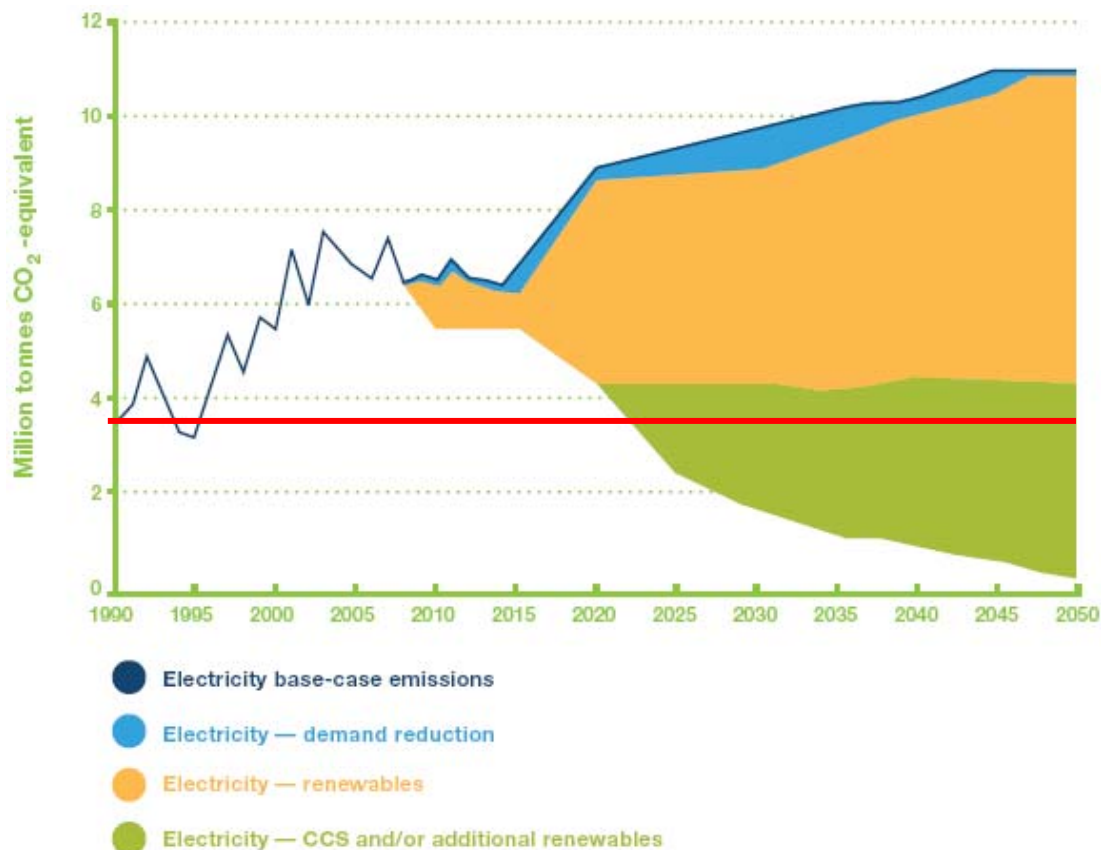
New Zealand is a signatory to the Kyoto Protocol and quoting from a Ministry for the Environment document (September 2007), “*Projected Balance of Emissions Units During the First Commitment Period of the Kyoto Protocol*”:

“*New Zealand has committed to reducing its average net emissions of greenhouse gases over the first commitment period to 1990 levels or to take responsibility for the difference*”.

Forecast electricity sector emissions are shown in the graph below which has been taken from the New Zealand Energy Strategy to 2050 document (page 36). It can be seen that the 1990 emission level – marked with a red line – was around 3.5 Mt CO₂e per annum.

²⁰ Transpower HVDC GIT consultation report, paragraph 5.1.5, 7 February 2008

Figure 5-5: Historical emission and potential emission paths as presented in the New Zealand Energy Strategy to 2050



Source: Ministry of Economic Development

Figure 5-6 is from the MMA analysis²¹, where expected CO₂e emissions for each market development scenario were calculated based on PLEXOS simulations. Only the 90% renewables by 2025 scenario achieves the Kyoto target and even in that scenario, it is 10 years too late. This assumes that the electricity sector is only to reduce emissions to its own starting point. Other sectors, e.g. agriculture and transport, may find it difficult to even stabilize reductions, not to mention reducing them and therefore it is possible the electricity sector may be called upon to reduce even further.

Currently, the European Union is working towards a 20% reduction compared with the 1990 level and has signalled willingness to accept a 30% reduction if other industrialized countries agree as well. This is in line with the latest recommendations from the Intergovernmental Panel on Climate Change (IPCC)²² and at the UNFCCC²³ meeting at Bali (COP-13) meeting late in 2007 New Zealand supported the statement that industrialized countries would have to cut emissions 25-40% below 1990 levels by 2020 to limit the damage from climate change.

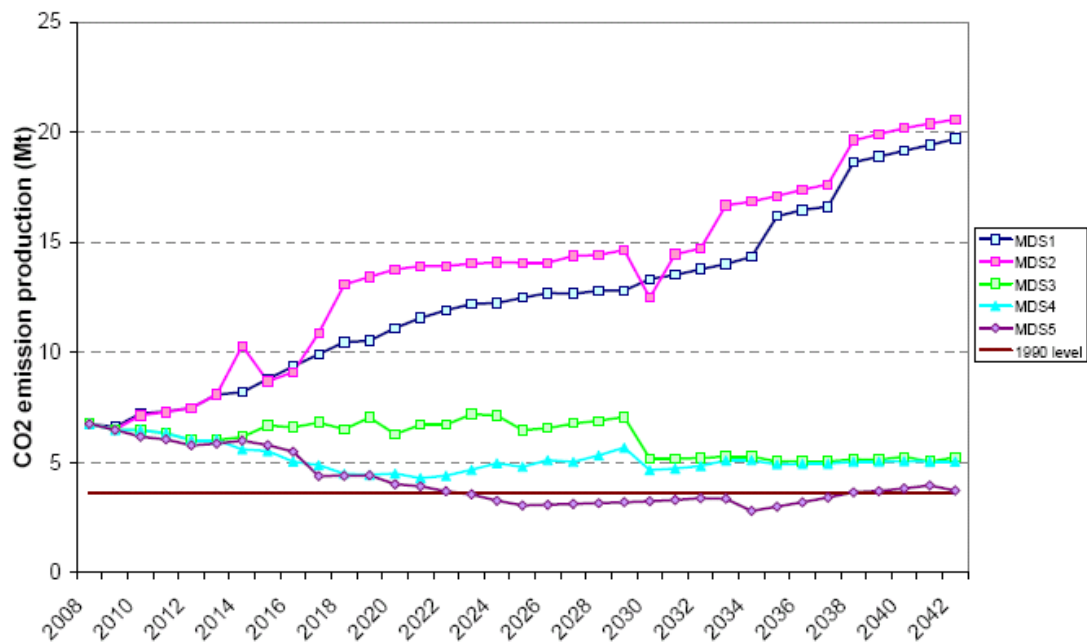
The European Union, furthermore, is considering a target to reduce emissions by 60-80% by 2050. A future scenario with a New Zealand emission target for the electricity sector well below 3.5 Mt CO₂e is therefore just as likely as assuming the future emission level equals the current Kyoto obligation level.

²¹ See Attachment G to the Consultation Paper (Volume 2).

²² See "Contribution of Working Group III to the Fourth Assessment Report of the Intergovernmental Panel on Climate Change, Technical Summary", pages 39 and 90, and Chapter 13, page 776

²³ United Nations Framework Convention on Climate Change

Figure 5-6: Projected emissions per market development scenario (MDS) based on the medium demand forecast



In light of these (current and possible future) emission objectives, Transpower questions whether the High Gas (MDS1) and Mixed Technologies (MDS2) emission paths (20 Mt CO₂e in 2040) warrant any significant weighting. These have been given a lower weighting – 30% in total, as in the draft 2007 GPAs, but it could be argued that even this total weighting is high. The lower emission scenario – the High Gas (MDS1) has been assigned a higher weighting of 20% and the Mixed Technologies scenario (MDS2), a 10% weighting. In the draft 2007 GPAs, they were assigned a 15% weighting each.

In the draft 2007 GPAs the renewables scenarios were assigned a 70% weighting – 50% for the primary renewables scenario and 20% for the South Island surplus scenario. However, since that time, the new Rio Tinto contract with Meridian Energy was announced which lowered the likelihood of the Tiwai load being phased out – at least in the shorter to medium term. The South Island surplus scenario was therefore reassigned a probability of 5% only.

The 90% renewables by 2025 goal was introduced as a part of the New Zealand Energy Strategy to 2050 late in 2007. The first GIT modelling results indicated that the Primary renewables scenario fell short of both emission targets (as discussed above) and the renewables goal (the primary renewables scenario resulted in an 80% renewables share at most). As a result, a fifth scenario was added to the four already being considered. Given that this is the only scenario that complies with New Zealand's renewables goal and the current Kyoto obligations, the scenario was assigned a high weight - 50%. There is no scenario that explores the possibility that further emission reductions may be needed by the electricity sector, which also supports this high weighting. The Primary renewables scenario was assigned the remaining 15% weight.

Transpower acknowledges that assessing the weighting to be used is a difficult task, which relies on judgment, but Transpower considers that while its reasoning is brief, it is reasonable.

As a sensitivity though, Transpower has calculated the impact of using different scenario weightings, for comparison. The table below shows how expected net market benefit changes for various weightings.

The first column shows the expected net market benefit using Transpower's assumptions, as discussed above and as applied in the GIT analysis.

In the second column, the high weighting for the 90% renewables by 2025 scenario is reduced and all scenarios are given an equal weighting. Option 2 is still preferred and still has a positive expected net market benefit.

In the third column, the weighting for the SI surplus scenario is reduced to zero and the other four scenarios are given equal weightings. This equates to renewables scenarios being given a weight of 50% and thermal scenarios a weight of 50%. As seen, Option 2 is still preferred and still has a positive expected net market benefit.

In the fourth column, the original weightings between thermal and renewables scenarios are reintroduced, but the high weighting is given to the primary renewables scenario, which includes 70-80% renewables. As seen, Option 2 is still preferred and still has a positive expected net market benefit.

In the fifth column, the weighting for the South Island surplus scenario is again reduced to zero, the thermal scenarios are given a weighting of 50% and the renewables scenarios are given a weighting of 50%, but now the primary renewables scenario is given a high probability and the 90% renewables by 2025 scenario a low probability. As seen, Option 2 is still preferred and still has a positive expected net market benefit.

Table 5-30: Sensitivity analysis of applying different scenario weightings

Scenario		Weighting			
High gas	20%	20%	25%	20%	25%
Mixed technologies	10%	20%	25%	10%	25%
Primary renewables	15%	20%	25%	50%	40%
SI surplus	5%	20%	0%	5%	0%
90% renewables by 2025	50%	20%	25%	15%	10%
Expected net market benefit		Present Value 2007\$M			
Option 1 - 500 MW Pole 1	138	76	79	88	58
Option 2 - 700 MW Pole 1	191	122	134	99	95
Option 3 – 1000 MW Pole 1	106	26	43	1	-2

In summary, Transpower considers that while its reasoning for the weightings it has applied in the GIT is brief, it is reasonable. But as illustrated, even if Transpower's reasoning for preferring a high weighting on the 90% renewables by 2025 scenario is ultimately not accepted, several other weighting versions still give the same GIT result.

5.6.5 Expected impact of changes in market assumptions

MEUG raised the issue about how changed market conditions since the proposed application of the GIT, most of which was done late 2007, would be likely to affect the GIT results. They mentioned in particular the decommissioning of New Plymouth and the new Rio Tinto contract. The expected impact on the GIT results of these two events, and several others, is discussed in the following.

Generation changes:

Two major projects changes occurred too late to incorporate in the analysis: the Waikato wind farm planned by Contract Energy and the potential permanent closure of New Plymouth power station due to asbestos.

For the Waikato wind farm, 300 MW of wind projects already exists, none of which appear that early in the scenarios. So adding a 650 MW as yet another option would make little difference. If it goes ahead, it will probably delay other North Island wind farms, such as those in Northland. The impact, overall, will thus be minor compared with the difference in net market benefits between the options.

The closure of New Plymouth now rather than in 2020 assumed in the GIT modelling will either lead to a replacement power plant, e.g. an open cycle gas turbine (OCGT) plant such as Whirinaki, or a higher need for the HVDC link. Given that 200 MW of OCGT already has been committed at Stratford as replacement by Contact Energy, the likely impact is minor overall. Any impact would favour larger link sizes.

Contact Energy stated the costs of the 200 MW OCGT power plant as \$250 million or \$1250/kW capacity. This is significantly more expensive than the \$800/kW assumed for OCGT power plants in the draft 2007 SoO and thus the numbers used in GEM to produce the generation expansion plans. The use of potentially too low costs of peaking capacity in the modelling may overestimate the amount of North Island peaking capacity and underestimate the HVDC flows. This may underestimate the value of the Proposal.

Demand changes:

Market development scenario 4 (South Island surplus) covers the possibility of the Tiwai Point aluminium smelter ceasing operations with a gradual phase-out from 2014 to 2019. The new Rio Tinto contract with Meridian Energy, which covers delivery of around 600 MW continuously to the Tiwai smelter until 2022, reduces the likelihood of this possibility. Given the low weighting attributed to this scenario (5%), Transpower doubts the new contract would have a significant effect on the outcome of this analysis.

Fuel prices:

Oil prices are currently²⁴ in excess of US\$115/bbl compared with the US\$60/bbl assumption used for the GIT analysis. The oil price is used both directly for the oil-fired power plants (New Plymouth and Whirinaki) and as driver for the LNG price, which historically has been linked to the oil price. As the New Zealand domestic natural gas price is assumed to converge towards the international liquefied natural gas (LNG) price, the short-run marginal cost (SRMC) of the natural gas fired units, mainly the combined cycle gas turbines (CCGTs), have been underestimated. For this aspect of the GIT analysis, there are two important: will prices remain at this level and, if so, what is the likely impact on HVDC analysis?

The assumption of US\$60/bbl is supported by the forecast by the International Energy Agency's 2007 edition of their World Energy Outlook, which has long-term prices around that range. However, the International Energy Agency is generally considered as being conservative, so that price level may be in the lower end.

Prices above the US\$60/bbl level and the assumed link to gas prices will lead to more renewable generation. The level of oil prices therefore tends to suggest that greater weightings should be attached to the renewables scenarios. As these scenarios that give the highest benefits of the HVDC link, such a shift in assumptions would reinforce the need for investment.

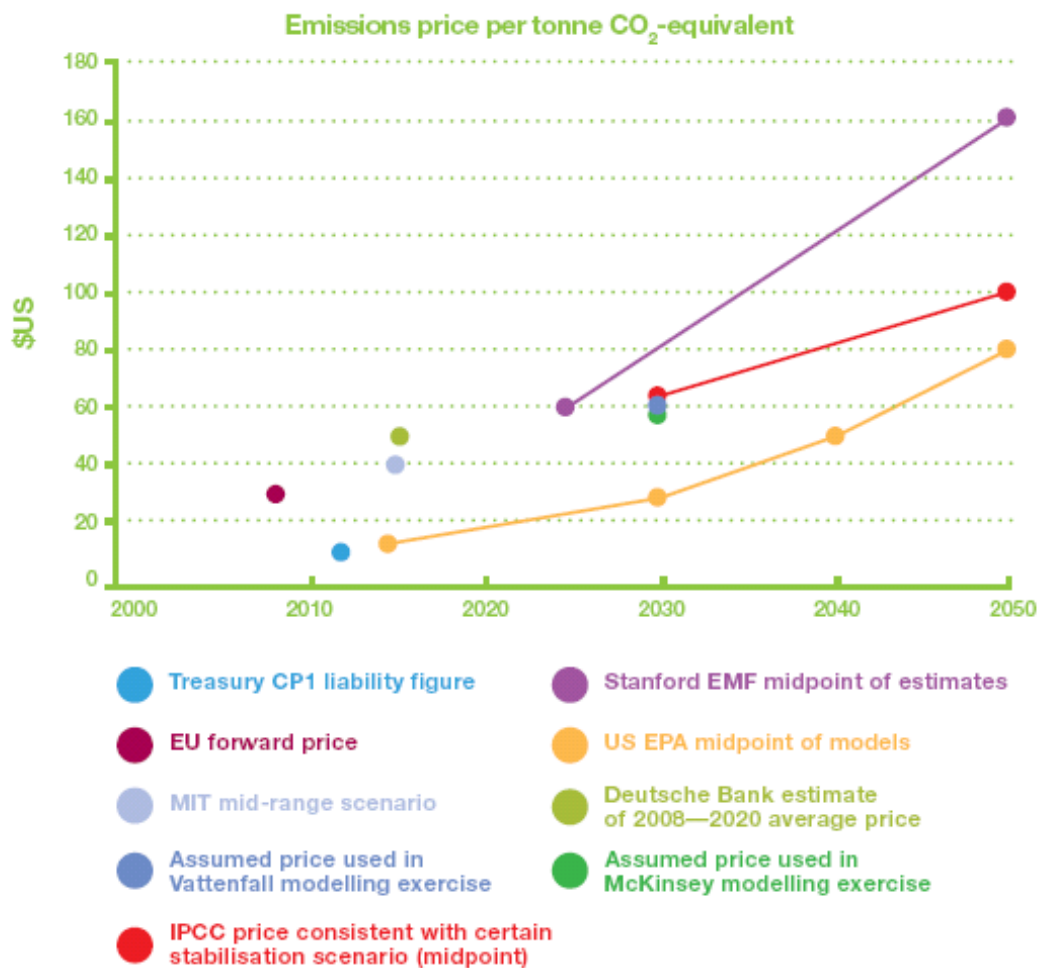
Carbon prices

Recent prices in the European emission trading market have been around 25 Euro/tonne or 50 NZ\$/tonne for the period 2008-2012. Certified Emission Reductions (CER) (international projects) were cheaper, selling at around 15 Euro/tonne or 30 NZ\$/tonne.²⁵ Carbon prices for New Zealand are most likely to line up with the CER price. To the extent the amount of reductions that can be purchased abroad is limited, the local carbon prices will exceed the CER price as it is unlikely cheaper domestic reductions can be found to meet the Kyoto obligations.

The following figure is taken from the New Zealand Energy Strategy to 2050 page 30. There are a range of estimates, but they suggest that carbon prices will increase. If this happens, there will be a larger benefit from investment in the HVDC link.

²⁴ As of end of April 2008.

²⁵ See e.g. <http://www.nordpool.com/marketinfo/co2-allowances/allowances.cgi>

Figure 5-7: Emission price estimates as presented in the New Zealand Energy Strategy to 2050

Source: Ministry for the Environment

5.6.6 Expected impact of new GPAs

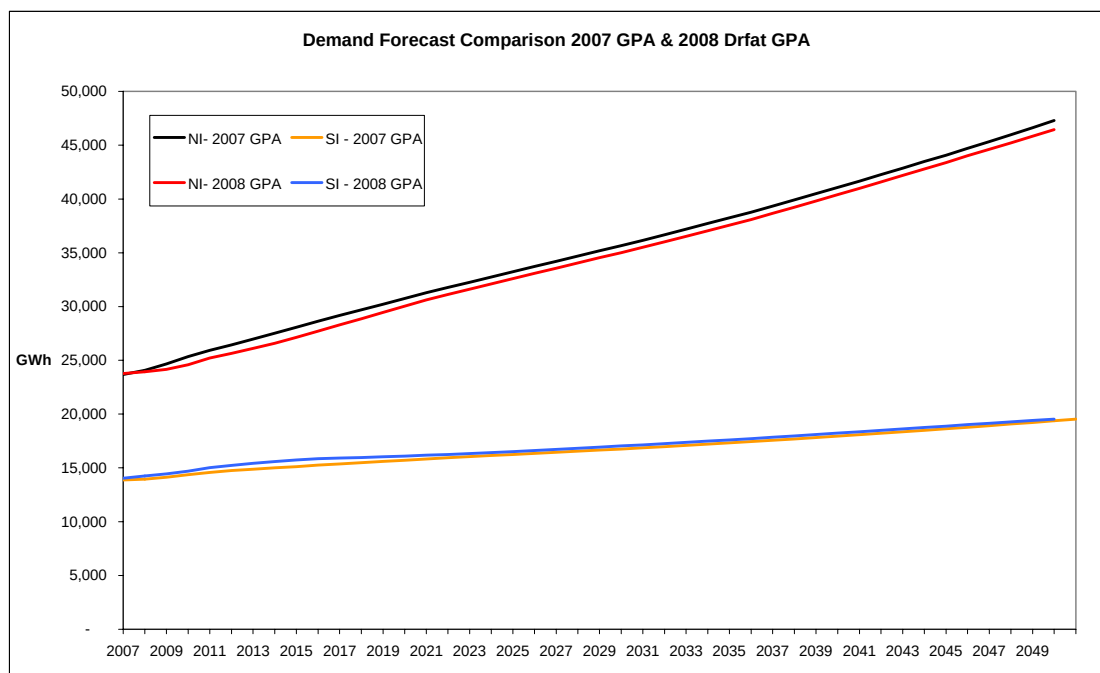
In its submission, MEUG suggested checking the demand forecast against the draft 2008 GPAs:

“These were reasonable at the date the EC advised such to Transpower. They may need updating following feedback to the EC on the recent Grid Planning Assumptions (GPA) consultation paper. MEUG expects any changes to be within the sensitivity range considered by Transpower. However a materiality check against the final GPA demand forecasts may be prudent.”

The chart below shows the Electricity Commission's draft 2008 demand forecasts²⁶ (in GWh) by island against the 2007 demand forecasts which were used in the GIT analysis. Overall, the national demand forecast has fallen by around 1% in the current proposed draft 2008 forecasts.

The allocation between islands has changed a little more significantly with the draft 2008 demand forecasts showing slightly more demand in the South Island than in the North Island. In other words, there is a higher allocation to the South Island.

²⁶ Given the 2008 SoO has not been published in its final form yet

Figure 5-8: Comparison of Demand Forecasts – 2007 GPA and draft 2008 GPAs

Transpower has not undertaken any specific analysis using the draft 2008 demand forecasts, as it believes the results would be captured by the further sensitivity outlined above at section 5.6.1 in relation to South Island demand forecasts. The results of that analysis indicate that the Proposal would still meet the requirements of the GIT. Transpower therefore concludes that use of the draft 2008 Statement of Opportunities demand forecast would still result in this Proposal passing the GIT.

As the results show in that analysis, the proposed investment is still the most economic under all demand scenarios. Given that these extreme demand cases return the highest positive net market benefit to the proposed option, Transpower is confident that a sufficient range of demand forecasts have been modelled to ensure the result is robust.

When it comes to the other assumptions in the draft 2008 GPAs, it is assumed that several of the recent market developments discussed in Section 5.6.5 will be incorporated. It is not expected that any of those will affect the GIT results significantly.

6 Conclusion of the Grid Investment Test analysis

Option 2, a 700 MW Pole 1 replacement terminated at Benmore and Haywards, satisfies the GIT because:

- it maximises the expected net market benefit when compared with the alternative projects;
- it has a positive net market benefit; and
- it is robust having regard to the results of a sensitivity analysis.

It is noted that whilst the expected net market benefit of Option 2 is \$187 million, this is averaged over five market development scenarios and uses a 7% discount rate.

The net market benefit of Option 2 for the 90% renewables by 2025 scenario, which is most consistent with the government's New Zealand Energy Strategy, is \$352 million, using a 7% discount rate. If a 5% discount rate is used, consistent with the New Zealand Energy Strategy, the net market benefit of Option 2, for the 90% renewables by 2025 scenario, would be approximately \$700 million.

These results are robust to the wide range of sensitivity analysis carried out by Transpower.

7 Optimal timing

Transpower has analysed the optimal timing of Option 2 including the timing of its Stages 1 and 2. Stage 1 will bring the capacity of the HVDC link up to 1000 MW balanced load while the addition of Stage 2 will increase the capacity to 1200 MW unbalanced (500/700 MW).

The section is structured as follows:

- Analysis of the optimal timing of Stages 1 and 2 combined;
- Analysis of the optimal timing of Stage 2;
- Analysis of the optimal timing of Stage 3; and
- Conclusion.

7.1 Timing of Stages 1 and 2 combined

7.1.1 Methodology and assumptions

The analysis is based on the methodology from Attachment F to the Consultation Paper (see Volume 2), with the following changes:

- The Base Case reflects the current half Pole 1 being available for emergency operation (winter quarter, 200 MW max, north transfers only).
- Contact Energy's New Plymouth plant has been decommissioned but 200 MW Stratford OCGT capacity is added in 2009.
- The PLEXOS GIT analysis showed higher expected net market benefits than Transpower's GIT analysis, at least partially because instantaneous reserves are modelled in PLEXOS. A bipole HVDC arrangement provides reserve capacity to cover loss of the other pole whenever the link is not fully utilized. To reflect this effect, the SDDP analysis has been undertaken limiting the north flow to 500 MW with monopole operation²⁷ in non-winter months and 700 MW in winter months.

7.1.2 Results

The table below shows the impact on the generation system costs of deferring Stage 1 and Stage 2 of the Pole 1 replacement to 2014, 2016 or 2018 for each of the scenarios.

Table 7-1: Impact of timing of investment on generation costs by market development scenario and weighted average

Case	High Gas	Mixed Tech.	Primary Renew.	SI Surplus	90 pct Renew.	Weighted
Replacement in 2012	0	0	0	0	0	0
Replacement in 2014	44	85	69	31	28	43
Replacement in 2016	32	85	67	32	151	102
Replacement in 2018	45	348	99	72	176	150

These additional system costs should be compared with the benefits from deferring the investment arising from a capital deferral. These benefits are shown below.

²⁷ This is currently the upper transfer level of Pole 2 observed when running as monopole. Transfer levels occasionally go above 500 MW in a few trading periods, but as the peak load block in SDDP correspond to more than 7% of the time, 500 MW has been used as proxy for the max flow limitation in that load block.

Table 7-2: Deferral benefits for different investment timing

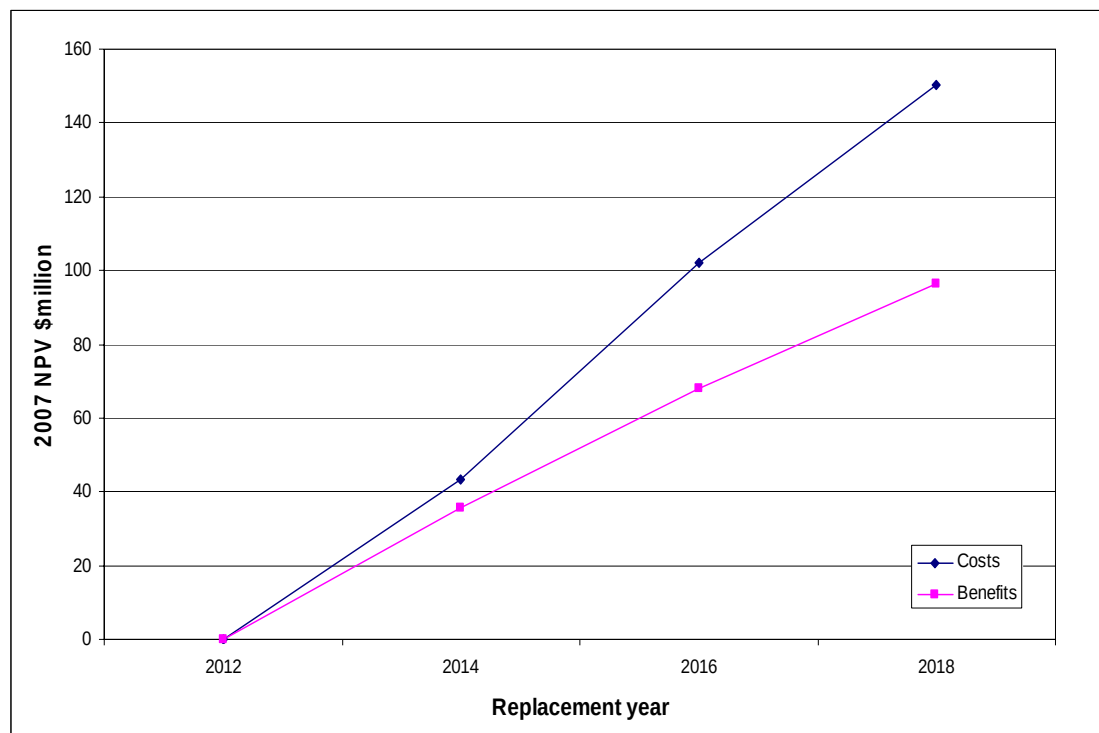
Case	Reference	Deferred	Difference
Replacement in 2012	440	440	0
Replacement in 2014	440	401	38
Replacement in 2016	440	366	73
Replacement in 2018	440	336	104

The benefits above include a deferral of operating and maintenance costs for the replacement Pole 1, but do not reflect an increase in operating and maintenance costs for the existing Pole 1. This cost may be in the order of \$2 million per annum, although this number may rise the longer a replacement Pole 1 is deferred.

The present value estimates of these operating costs are:

- Replacement in 2012: 0 \$M
- Replacement in 2014: 2.8 \$M
- Replacement in 2016: 5.2 \$M
- Replacement in 2018: 7.3 \$M

Lowering the deferral benefit accordingly, the trade-off between deferral benefits and additional system costs is shown in Figure 7-1.

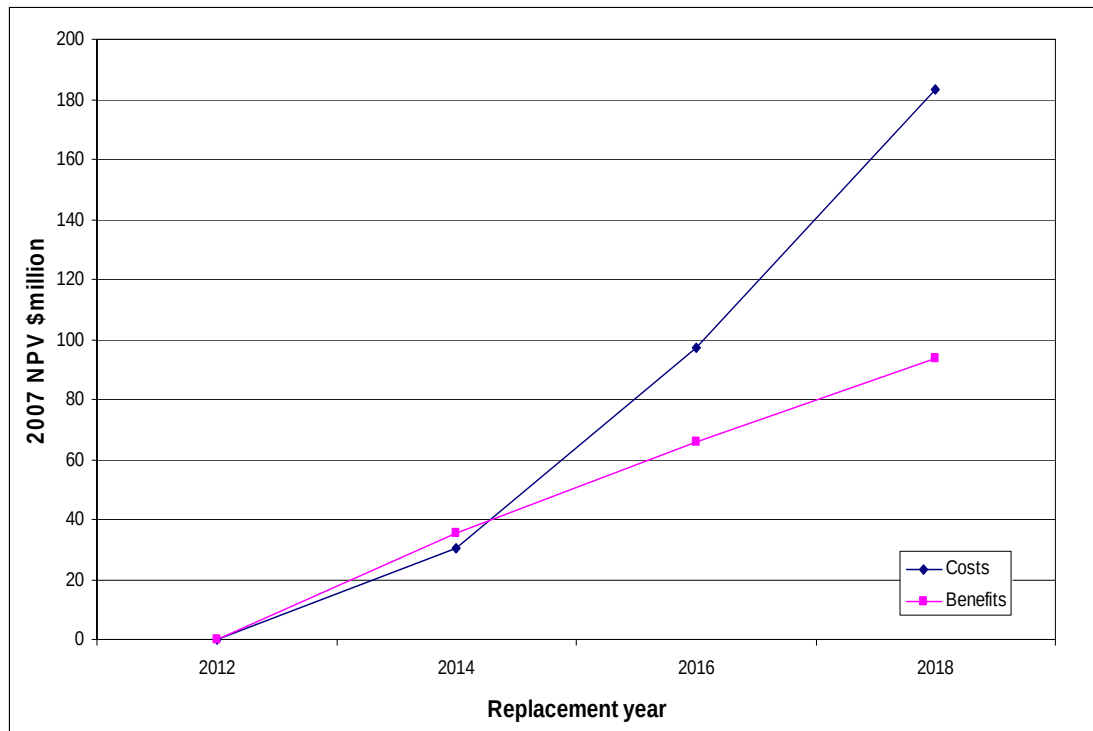
Figure 7-1: Comparison of benefits from deferring investment in a replacement Pole 1, with system costs arising from deferral – Transpower analysis

It can be seen that if stage 1 and 2 were commissioned later than 2012, the extra system costs increase faster than the benefits from deferring the expenditure. For the period 2012-2014 the growth rates are approximately the same throughout. Comparing the previous tables shows that the conclusions are the same for market development scenarios 2, 3 and 5. For the other two scenarios, there will be a net benefit of deferral.

The Appendix F analysis included some variability which partly arises from the fact that only 6 hydro sequences were analysed in SDDP. Therefore, a sensitivity analysis has been undertaken where the detailed grid modelling was turned off in SDDP. Instead, HVDC link and AC losses were calculated using historical percentages. This simplification allows all available 74 hydro sequences to be analysed.

Figure 7-2 shows the trade-off when the change in system costs are based on the average over 74 inflow sequences in SDDP but with a more simplified grid.

Figure 7-2: Comparison of benefits from deferring investment in a replacement Pole 1, with system costs arising from deferral – more hydro sequences in SDDP



Again, the growth rates between 2012 and 2014 are approximately the same. In this case however, the growth in costs is faster over time. This is because the cost impact is asymmetric (the increase in cost in very dry years is greater than the reduction in cost in very wet years) and more severe dry hydro inflow sequences evaluated here compared with the 6 less extreme samples used in the first instance.

7.1.3 Further considerations regarding asymmetric risk of costs

A similar analysis was undertaken by MMA with the PLEXOS model and is shown in figure 3-8 in their "Market benefit analysis of short-listed HVDC options" report.²⁸ For comparison, it has been included as Figure 7-3. As seen, the shape of the curves corresponds well with those of Figure 7-1 and Figure 7-2.

Figure 7-4 is an updated version of the MMA figure referred to overleaf which apart from the costs associated with an average inflow year, also shows the range of outcomes from the total of 10 hydro samples analysed in PLEXOS.

²⁸ See Attachment G to the Consultation Paper (see Volume 2).

Figure 7-3: Comparison of benefits from deferring investment in a replacement Pole 1, with system costs arising from deferral – MMA analysis

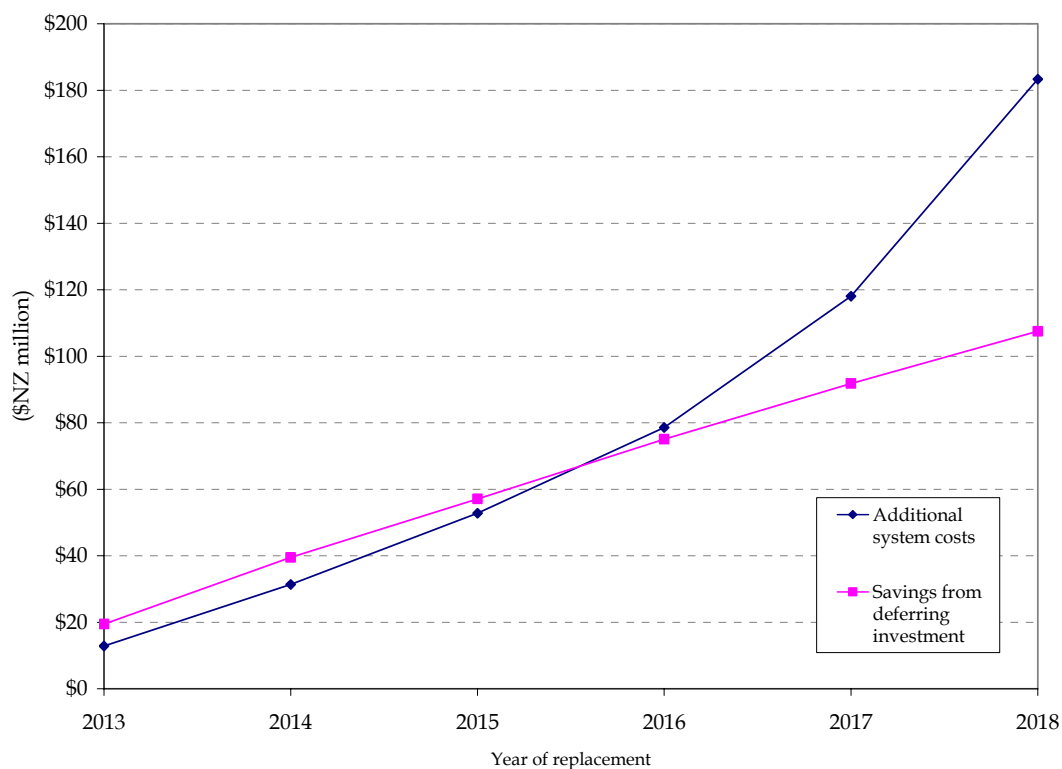
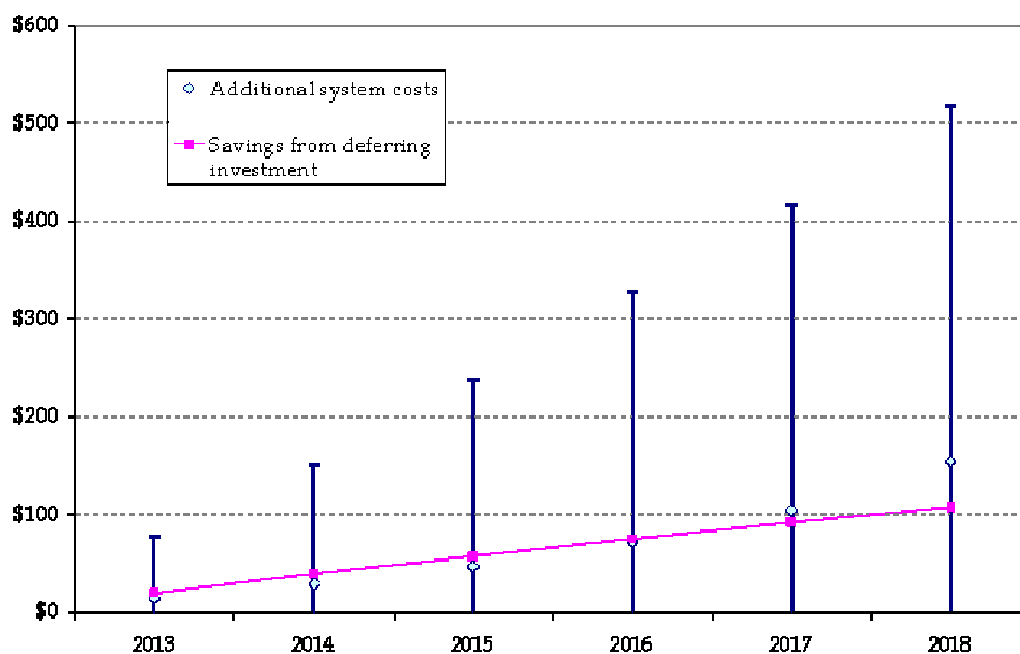


Figure 7-4: Comparison of benefits from deferring investment in a replacement Pole 1, with system costs arising from deferral – MMA analysis, showing spread over various hydrological conditions

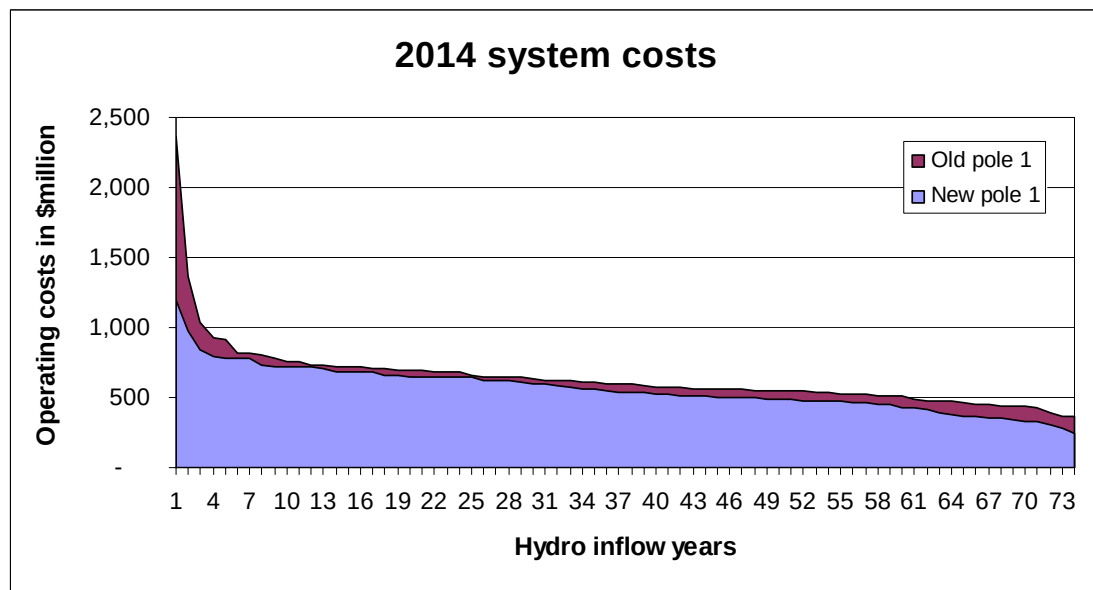


Again, the average results in Figure 7-4 (blue diamond marks) correspond well with the GEM/SDDP results from Transpower's analysis shown earlier.

As this graph also shows, there is a significant variation in additional system costs, depending on the hydro sample. For 2014, for instance, there is a risk of \$100 million additional costs. Given only 10 hydro samples have been analysed by MMA, this corresponds to approximately a 10% likelihood of these extra costs. For 2018, this value at risk has increased to almost \$500 million.

The asymmetric risk of cost outcomes as result of hydrological conditions is illustrated further below. It is based on the 90% renewables scenario and looks at the system costs (fuel costs and costs of unserved energy) for a case where a new Pole 1 is available in 2014²⁹ versus a case where only the current half pole in emergency operation is available to supplement Pole 2.

Figure 7-5: System costs for 2014 for various hydro years based on SDDP runs



As the figure shows, average cost difference for that year is not that significant, but there is a risk of more than \$1 billion extra costs in a dry year with the old Pole 1 (emergency operation only) compared with a situation with a new pole being available that year.

If the current Pole 1 for some reason (catastrophic failure or lack of insurance) suddenly was no longer would be available, the more years to a planned replacement, the higher the costs would be. Similarly, loss of Pole 2 for one to two months during winter could, in certain years, be very costly for New Zealand if the only available alternative was the current half pole in emergency operating mode.

Transpower considers that there was no need to re-run Stage 1 timing by itself, as the costs and benefits of Stage 1 are much greater than Stage 2, and hence, the results for Stage 1 alone are likely to be similar.

7.2 Stage 2 timing

The following analysis assumes Stage 1 (1000 MW balanced bi-pole operation) takes place in 2012 and Stage 3 takes place in 2018 (1400 MW balanced operation). Transpower considers it reasonable to do this, given that:

- 2012 is the target date to commission Stage 1 (see section 5.7 of the Proposal); and
- 2018 is the earliest that Stage 3 is likely to be required (see section 7.3 below).

²⁹ Transpower chose one year post-2012 as an example to demonstrate the impact of hydrology. Results are not expected to differ much for the years immediately before and after.

The analysis assesses the optimal timing of Stage 2 (1200 MW unbalanced operation) by varying the commissioning year of this stage between 2012 and 2018.

7.2.1 Benefits of deferral

Stage 2 consists of the following costs and when Transpower estimates that they may be incurred compared with a commissioning year Y:

Table 7-3: Stage 2 costs and streaming

Item	Cost \$M	Y-2	Y-1	Y
New condenser C11	33.91	20%	80%	0%

Based on these numbers, the deferral benefit of waiting with Stage 2 until 2014, 2016 or 2018 can be calculated using 2012 as the reference.

Table 7-4: Timing of costs and deferral benefits

Timing	Timing 2012	Timing 2014	Timing 2016	Timing 2018
2008	0.0	0.0	0.0	0.0
2009	0.0	0.0	0.0	0.0
2010	6.8	0.0	0.0	0.0
2011	27.1	0.0	0.0	0.0
2012	0.0	6.8	0.0	0.0
2013	0.0	27.1	0.0	0.0
2014	0.0	0.0	6.8	0.0
2015	0.0	0.0	27.1	0.0
2016	0.0	0.0	0.0	6.8
2017	0.0	0.0	0.0	27.1
2018	0.0	0.0	0.0	0.0
NPV	26.2	22.9	20.0	17.5
Difference	0.0	-3.3	-6.2	-8.8

From the last row, it can be seen that there is a benefit of NPV \$3.2 million of deferring stage 2 from 2012 to 2014 growing to \$8.6 million for deferral till 2018.

7.2.2 System costs of deferral

Transpower has assessed the additional costs of waiting with Stage 2 using GEM model runs. The results were as follows:

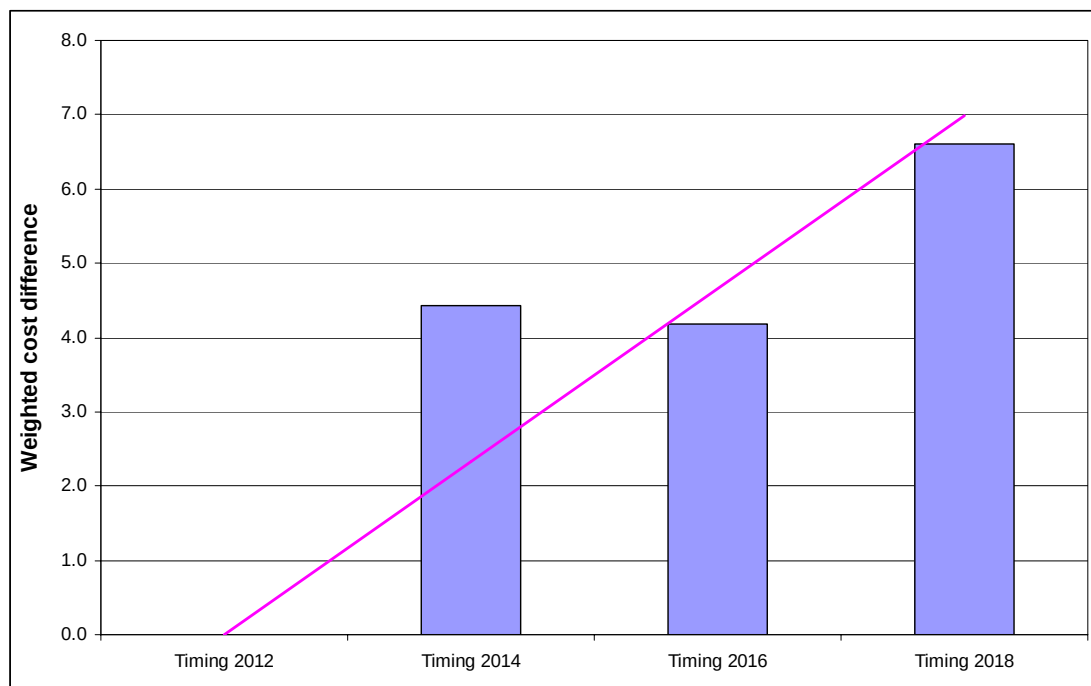
Table 7-5: System costs of deferral

NPV of cost changes in \$2007 million	Timing 2012	Timing 2014	Timing 2016	Timing 2018
Weighted cost difference	0.0	4.4	4.2	6.6
Linear trend	0.0	2.3	4.7	7.0

The first line shows the scenario-weighted cost difference (again in comparison with 2012 commissioning of Stage 2). Due to the noise in the modelling results, which can affect

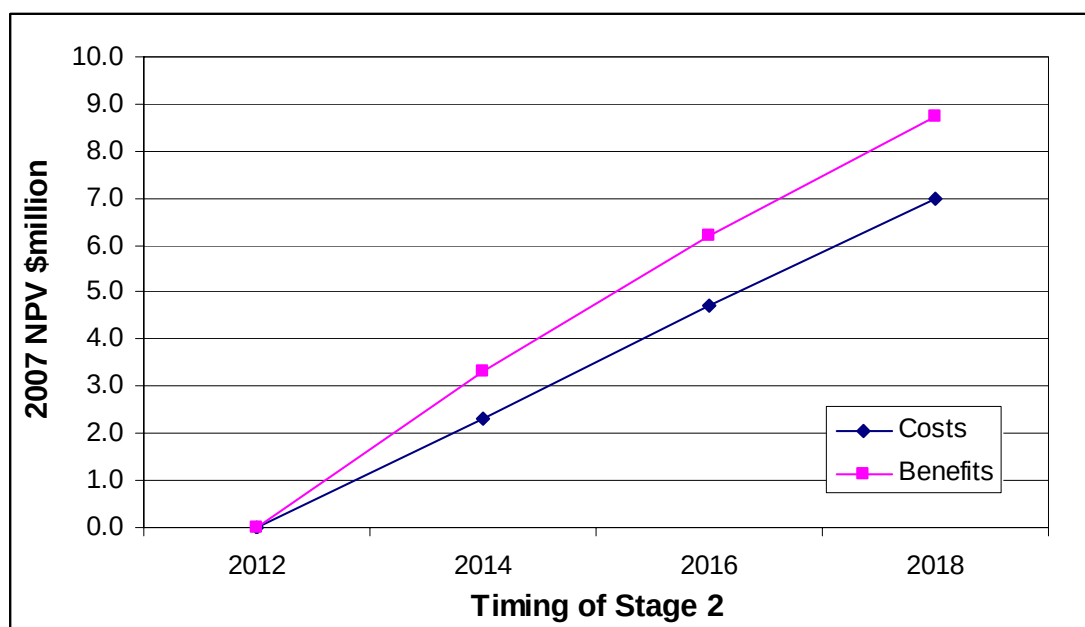
results at this scale, the linear trend may be a better estimate of the likely impact. Hence, Transpower calculated the linear trend by estimating the best fit line through the modelled results. It is shown as the second line in the table and as the line in the figure below.

Figure 7-6: Modelled system costs and linear trend of these



The growth of costs and benefits can be seen in the Figure 7-7 below.

Figure 7-7: Comparing costs and benefits of Stage 2 timing



Comparing the costs with the deferral benefits, it can be seen that costs and benefits are comparable and hence, the timing of Stage 2 is not decisive as benefits and costs grow with about the same rate.

7.3 Stage 3 timing

Transpower has not undertaken analysis of the optimal timing of Stage 3 to the same level of detail as for Stages 1 and 2, as it is a modelled project rather than part of the Proposal. Expected HVDC flow in various scenarios however indicated that timing of commissioning around 2018 was likely (see the HVDC flow charts in Appendix F). Transpower has costed Stage 3 on that basis.

MMA has analysed the timing of Stage 3 in more detail. Their report “Market Benefit analysis of short listed HVDC options”³⁰ shows in Table 3-6 that:

- the actual timing is likely to be 2018 at the earliest (as result of market development scenario 2);
- the timing is later for market development scenarios 5 and 1, 2023 and 2030 respectively; and
- it is optimal not to add Stage 3 within the assessment period in market development scenarios 3 and 4.

MMA identified around \$27 million in extra benefits in waiting before fixing Stage 3 until it is better known where generation is built and how fast demand is growing over fixing Stage 3 to 2018 as in the Proposal. These benefits are likely to be larger for Stage 3 than Stages 1 and 2, everything else being equal, as the uncertainty is greater given the commission date is later.

7.4 Conclusions on timing

Transpower’s quantitative analysis indicates that the optimal timing of each stage of the Proposal is as follows:

- for Stage 1, timing is between 2012 and 2014;
- for Stage 2, timing is between 2012 and 2018; and
- for Stage 3, timing is likely to be 2018 or later.

Transpower considers further the timing of each stage of the Proposal in section 5.7 of the Proposal document.

³⁰ Included as Attachment G of the Consultation Paper (see Volume 2)

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 (GIT), in accordance with rule 19, Schedule F4, Part F Section III, Electricity Governance Rules (EGRs).
Base Case	The “do nothing” option, a counterfactual for other options to be considered against.
CCGT	Combined Cycle Gas Turbine
Consultation Paper	Document published by Transpower on 1 February 2008 setting out Transpower’s provisional view that the 700 MW replacement option was the most economic option available.
economic investment	Investments in the grid that can be justified on the basis of the Grid Investment Test under section III of part F, Electricity Governance Rules (EGRs), and are not reliability investments.
EGRs	Electricity Governance Rules. In the context of this document, it generally refers to Part F Transport, Section III Grid Upgrade and Investments, 28 June 2007.
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.
GEM	Generation Expansion Model , a model for generation expansion modelling developed by the Electricity Commission.
GIT	Grid Investment Test. A test for reliability investments and economic investments in the grid developed in accordance with rule 6 of section III of Part F, Electricity Governance Rules (EGRs). The specific rules defining the Grid Investment test, as developed according to the process in rule 6 of section III, are set out in Schedule F4 of section III of Part F.
Grid Planning Assumptions	Principles for these are contained in Rule 10 Electricity Governance Rules. The Rule provides that assumptions should cover a reasonable range of credible forecasts and scenarios; should have a length of outlook commensurate with consideration of future investment in long-life transmission assets; and should be

as accurate as possible.

High Gas Discovery scenario	Refer to Table 5.1 of HVDC Grid Upgrade Project Proposal
HVDC	H igh V oltage D irect C urrent
HVDC Pole 1 Replacement Project Investigation	Investigation by Transpower to consider the feasibility of different replacement options that has resulted in this Proposal.
LNG	L iquified N atural G as
LT Plan	L ong T erm P lan
Mixed Technologies scenario	Refer to Table 5.1 of HVDC Grid Upgrade Project Proposal
modelled projects	Transmission augmentation projects and non-transmission projects, other than the proposed investment and alternative projects, which are likely to occur in a market scenario, are reasonably expected to occur in that market development scenario within the time horizon for assessment of the market benefits and costs of the proposed investment and alternative projects, and the likelihood, nature and timing of which will be affected by whether the proposed investment or any alternative project proceeds.
New Zealand Energy Strategy	The New Zealand Energy Strategy to 2050 sets out the government's vision for a reliable and resilient system to deliver a sustainable, low emissions energy services.
OCGT	O pen C ycle G as T urbine
PLEXOS	A proprietary power market model suitable for short, medium and longer term studies including generation expansion planning. It can furthermore model market behaviour to assess competition benefits.
Rules	The Electricity Governance Rules 2003.

SDDP	Stochastic Dual Dynamic Programming , a hydro-thermal dispatch model with representation of the transmission network used for short, medium and long term operation studies.
SRMC	Short Run Marginal Cost
Transpower	Transpower New Zealand Limited, owner and operator of New Zealand's high-voltage electricity network (the national grid).
90% Renewable by 2025 scenario	Refer to Table 5.1 of HVDC Grid Upgrade Project Proposal

Appendix B Variability in the model results

B.1 MIP solution effect

The GEM model is formulated and solved as a mixed integer program (MIP).

Ordinary linear programs (LP) solve a series of linear equations to find an optimal result. The consequence is usually that, as a particular variable changes, the optimal result changes continuously and relatively easy-to-understand trends in the results emerge.

Mixed integer programs also solve series of linear equations, but have extra constraints, because some of the variables cannot have linear outcomes, but rather are constrained to be integral, typically either 0 or 1.

In the case of GEM, many of the new generation plants that the model can choose from are the integers. These are given in particular sizes (in MW) and the model can only choose whether to build the plant or not. It is an integer (no built = 0 and build = 1) decision. The model cannot choose whether to build new generation plant and choose the size (in MW).

As a result of this, there is a lumpiness associated with the results which can make interpretation more difficult.

The way MIP solves also differs to LPs.

An LP simply solves the equations to derive an answer. Except for very large problems (GEM if formulated as an LP would not be considered large), an LP will find the optimal solution to the problem.

A MIP considers as many integer solutions to the problem as possible and reports the best answer as the results, though this may not be the true optimum. It forms a lower bound based on a relaxed solution and an upper bound given by the best integer solution found. The user sets a gap (usually as a %) and the program then iterates till it finds an integer solution (upper bound) within that gap from the current lower bound, or time runs out.

With respect to this HVDC analysis, the following gaps, in \$million were observed as outputs from GEM:

Gap of GEM run (in \$M)

	0 MW	500 MW	700 MW	1000 MW	Avg
MDS1	42.4	34.7	39.9	49.1	41.5
MDS2	78.5	58.3	57.7	59.0	63.4
MDS3	17.6	15.8	12.5	13.0	14.7
MDS4	25.2	13.5	10.0	10.7	14.8
MDS5	75.7	88.2	75.3	92.2	82.8
Avg	47.9	42.1	39.1	44.8	
Weighted	58.1	59.9	53.8	64.3	

The gaps differ as the time that could be used to solve the problem typically ran out. Compared with the total system costs, a gap of \$15 million indicates that the presented solution is within 0.1% of the optimal solution.

As it can be seen, these gaps vary in magnitude from the theoretical linear optimum, across market development scenarios and between HVDC Pole 1 replacement options.

This natural phenomenon of MIP, hereafter called the MIP phenomena, means there is a variability in the answers which needs to be considered in interpreting the results.

From the above table the gap between market development scenarios varies between about \$15million and \$80million, for HVDC Pole 1 replacement options it varies between about \$40million and \$50million.

The fact that the gap for MDS3 and MDS4 is approximately \$15m and for MDS5 is \$80m does not mean that the MDS5 result is not as good. The MDS5 result may be the best possible answer to the problem, but it is also possible that there is a better answer, but the program did not find it.

In general, GEM was unable to find a better integer solution in the final stage of the optimisation, which allowed for more than 8000 seconds (or 1.5 million iterations). This indicate that it is very likely that the solution is much closer to the optimum than the gap illustrates but insufficient time was given to prove this.

The sizes of the gaps when looking at averages for the options show that no option is favoured by more than a \$10 million lower gap than the other options. Hence the MIP effect should not raise any concerns about the conclusions of the analysis. The greater variability is between the market development scenarios, where scenarios 2 and 5 proved to be the harder ones to prove optimality for. But that trend was the same for all transmission options.

B.2 Optimisation criteria effect

Another modelling effect that can have an impact on the interpretation of the results is the fact that the optimisation criterion in GEM differs from the optimisation criterion in the GIT.

This is not a modelling error but an actual design feature. Generation will not appear in the future based on a national cost-benefit analysis but due to generator incentives, which are the ones that have been modelled. It is something to be aware of when interpreting results and could be the explaining factor in rare cases of counterintuitive results.

GEM models market led generation expansion and generators are assumed to invest, if they can get a post-tax return on investment equal to 8% which is a proxy for the WACC (Weighted Average Cost of Capital) for a commercial company. Basically, it calls for investments to be made if the NPV of the resulting post-tax cash flow based on an 8% discount rate is positive.

The GIT on the other hand looks at pre-tax market benefits and costs, as taxes are wealth transfers and therefore should be excluded from a national cost benefit analysis. Furthermore, a 7% discount rate for NPV calculation has been mandated to be used in the GIT.

Putting the tax issue to one side for a moment, the table below shows that the difference in discount rate alone is enough to create results that may seem counter-intuitive.

Cashflow analysis

Year	Option 1	Option 2
2008	-30	-15
2009	12	7.5
2010	12	7.5
2011	12	7.5
2012	12	7.5
7% NPV	\$9.95	\$9.72
8% NPV	\$9.02	\$9.11

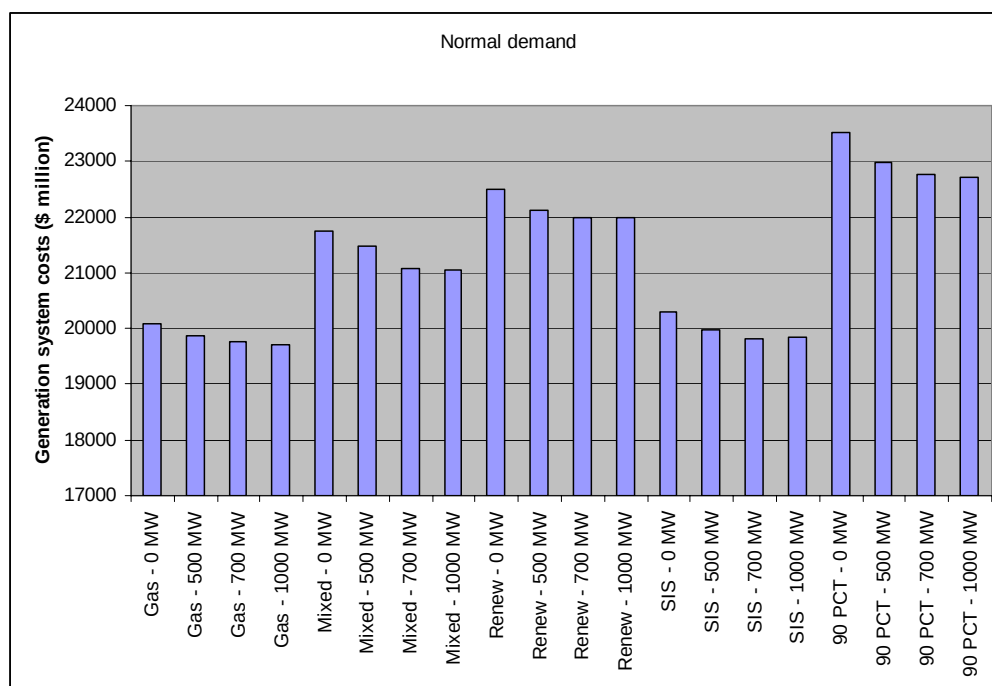
It can be seen that when looking at an investment, say Option 1, which is better than the alternative when using an 8% discount rate, it may look opposite if assessed with a 7% discount rate. Adding the fact that taxes (and the HVDC charge) are included in the GEM optimisation but not in the GIT results, further increase the chance that some reported solutions in the GIT appear suboptimal compared with others.

B.3 Overall implications for the results

For the reasons stated and other sources of uncertainty, the model results are not the optimal answers but approximations. The results described above and below show that the results do behave as expected when the various transmission options are considered.

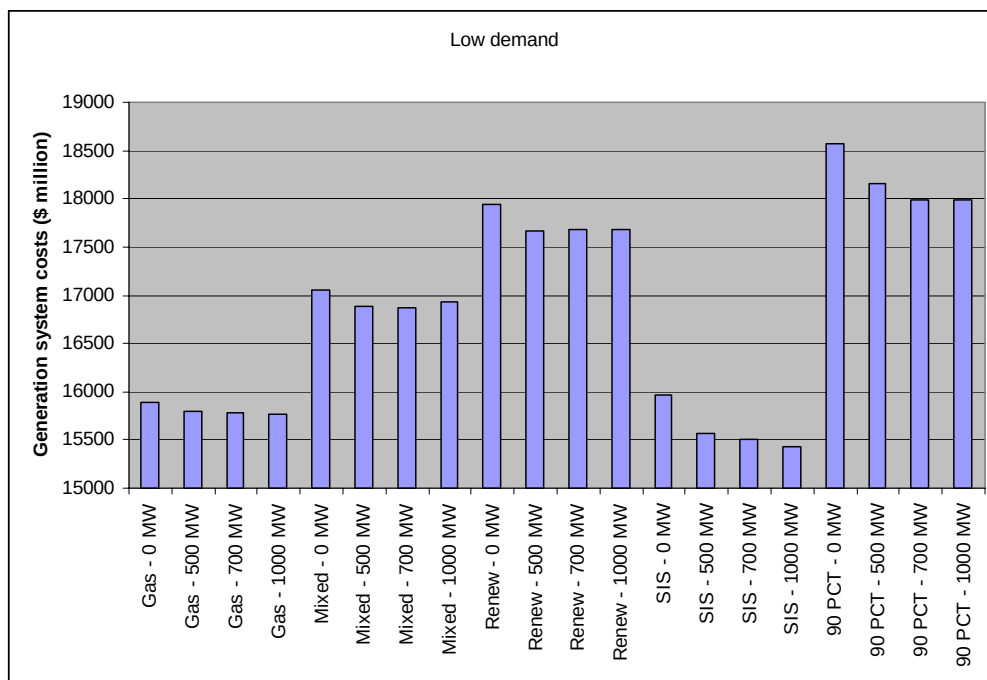
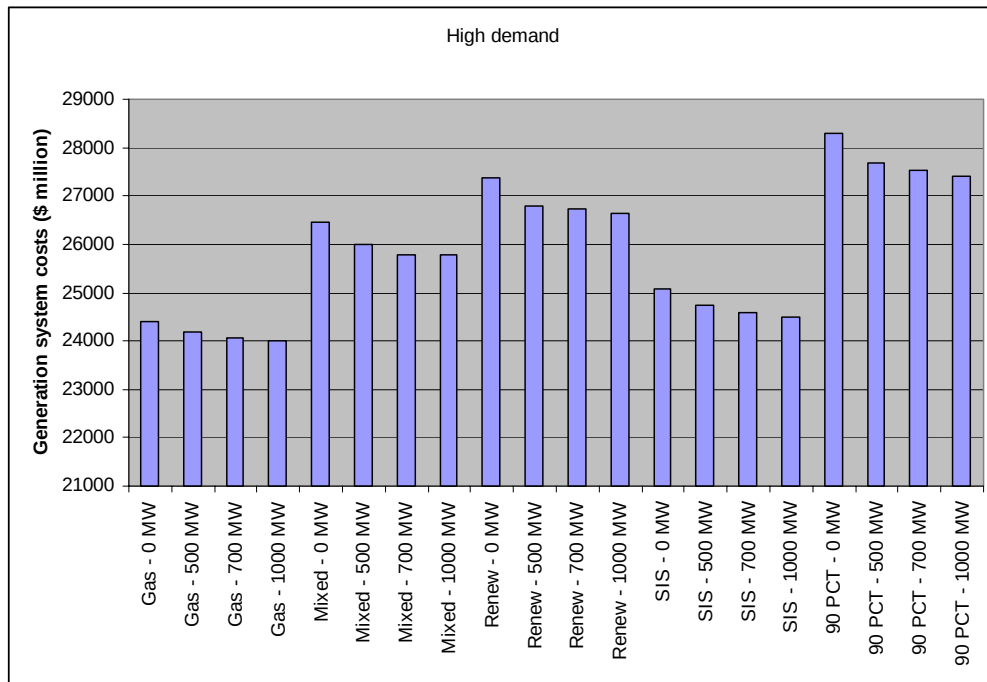
The graphs show the NPV of the total costs of electricity generation including new investments based on a 7% discount rate. Costs in the transmission system are not considered (though the HVDC charge was taken into account in the generation expansion plans). Generation capital costs and fixed operating costs are from GEM and the variable operating costs are from SDDP.

For a fixed generation scenario, a larger HVDC link will enable a cheaper solution to be found as the national system is less constrained. In the worst case, a just as good solution as in a lower capacity option (same generation expansion plan and generation dispatch) can always be found.

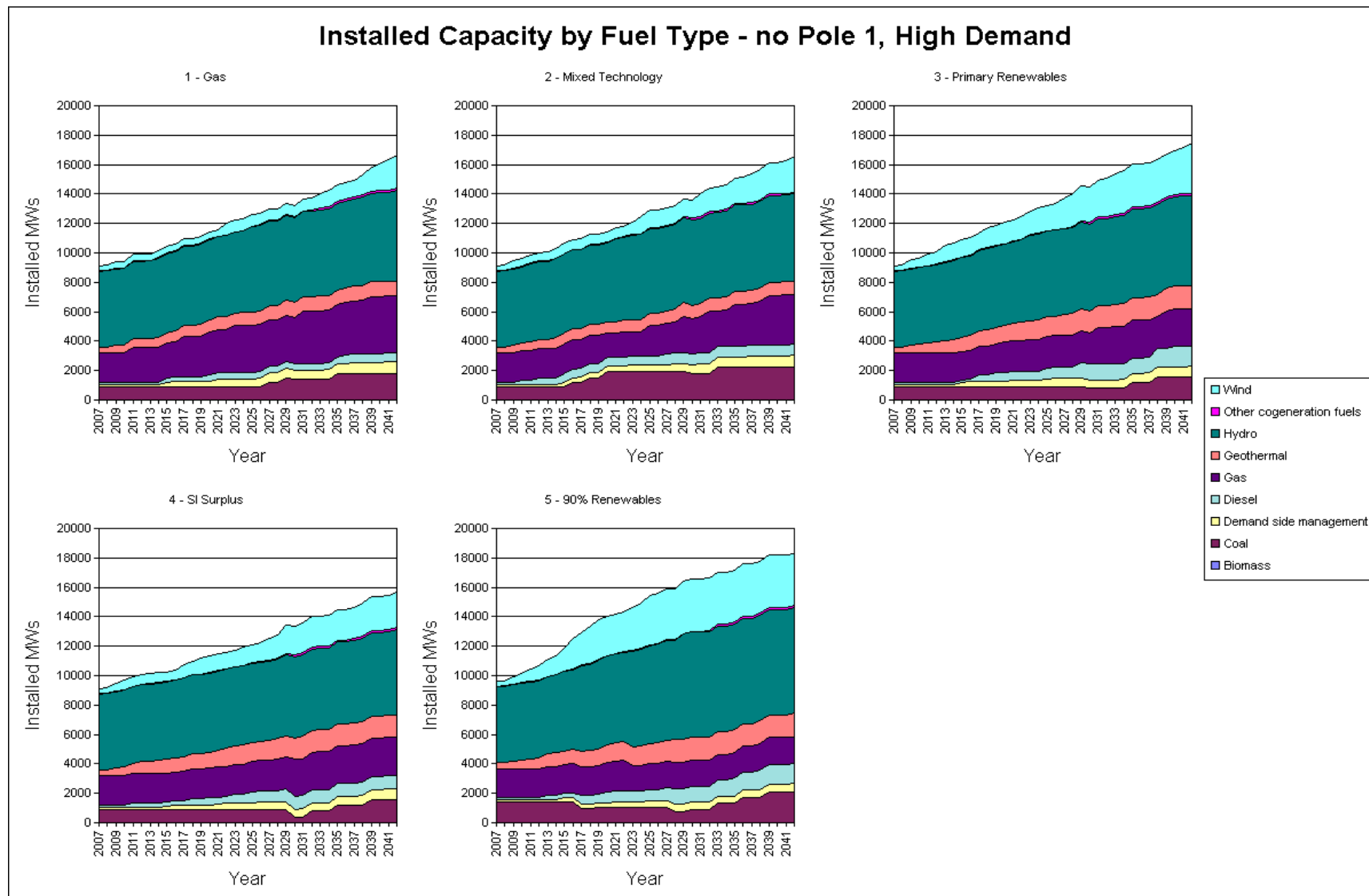


For the normal demand cases, it can be seen that the expected trend appears for the various market development scenarios apart from a minor jump in the SIS (South Island surplus) scenario when going from 700 MW (Option 2) to 1000 MW (Option 3). This small deviation can be explained by the effects described above. Overall, the graph gives comfort in the results from GEM and SDDP used in the analysis.

The following figures show the trends for the low and high demand cases. For the high demand cases, the expected trend appear for all market development scenarios but for the low demand cases, there is one case, the Mixed Technology scenario when going from 700 MW (Option 2) to 1000 MW (Option 3), which deviates more significantly from the trend.

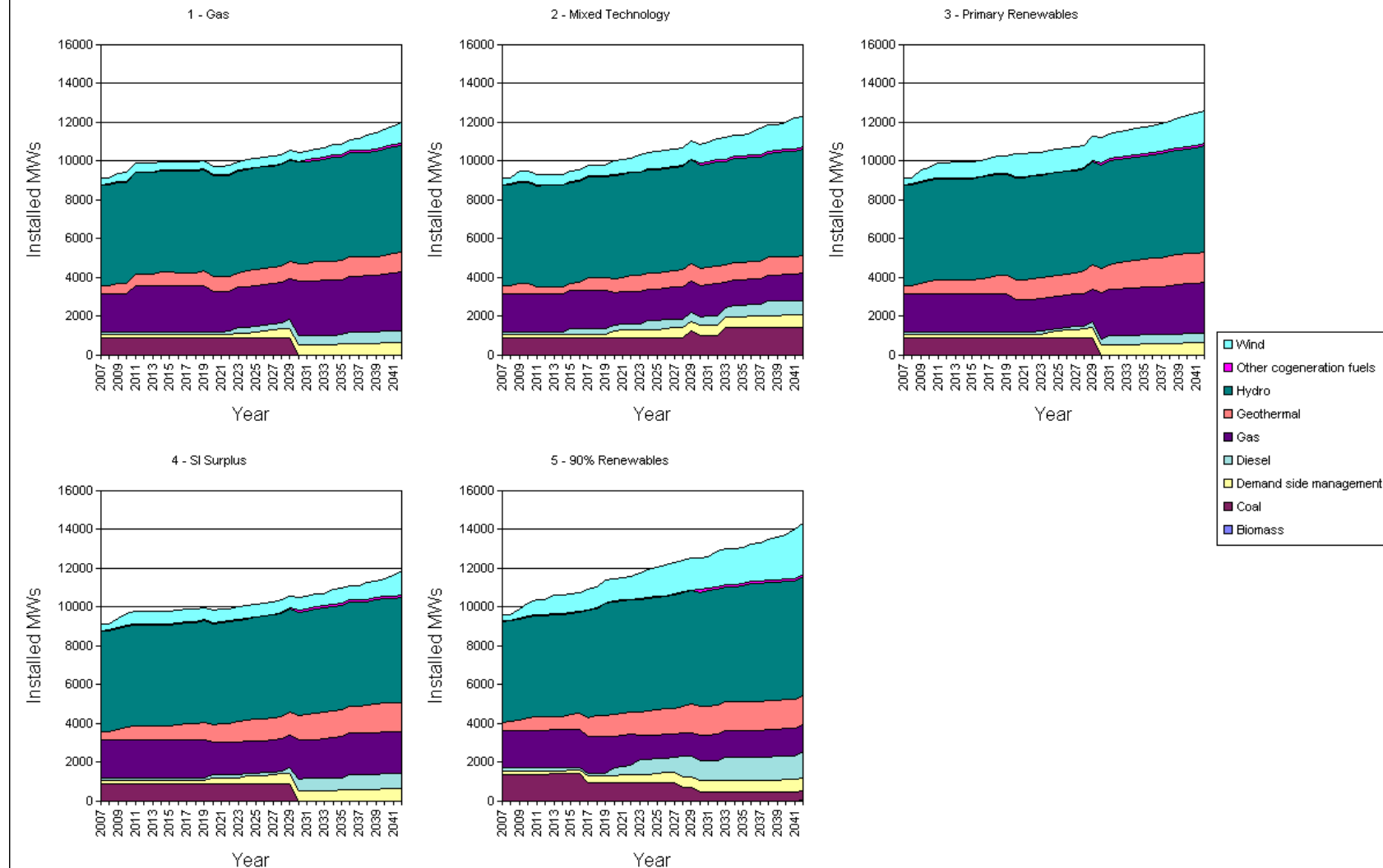


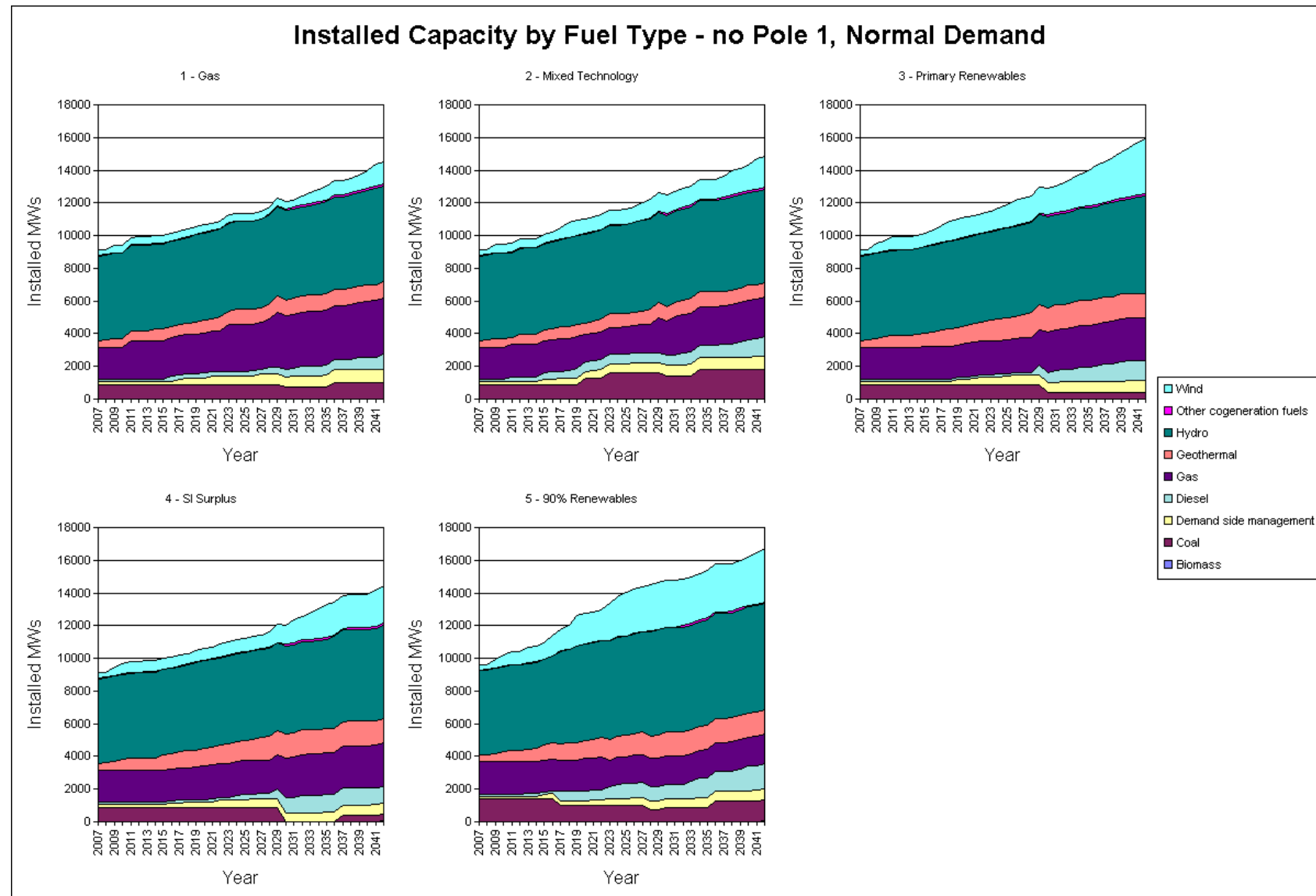
Appendix C National generation, MW, for various demand paths, market development scenarios and HVDC options





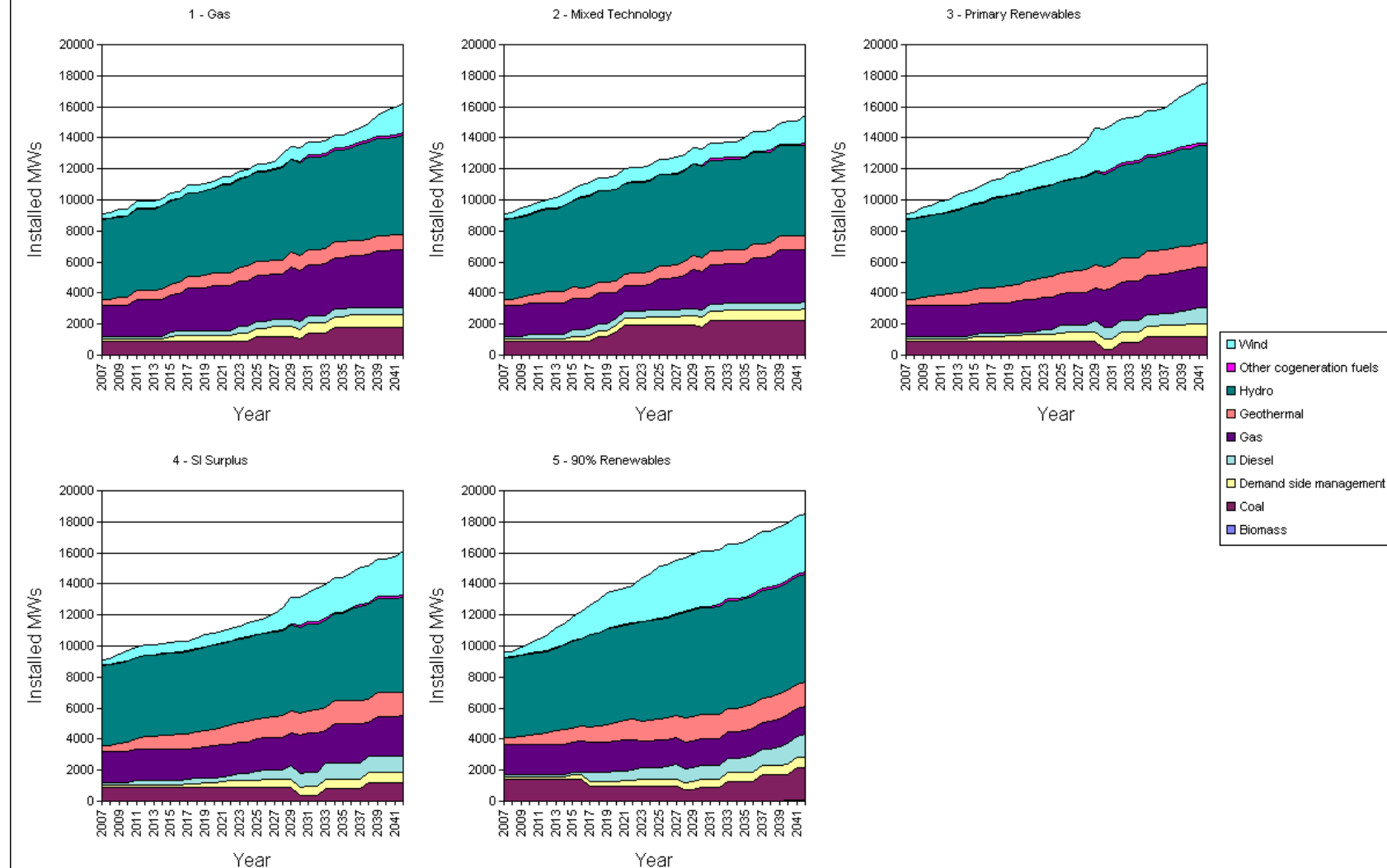
Installed Capacity by Fuel Type - no Pole 1, Low Demand

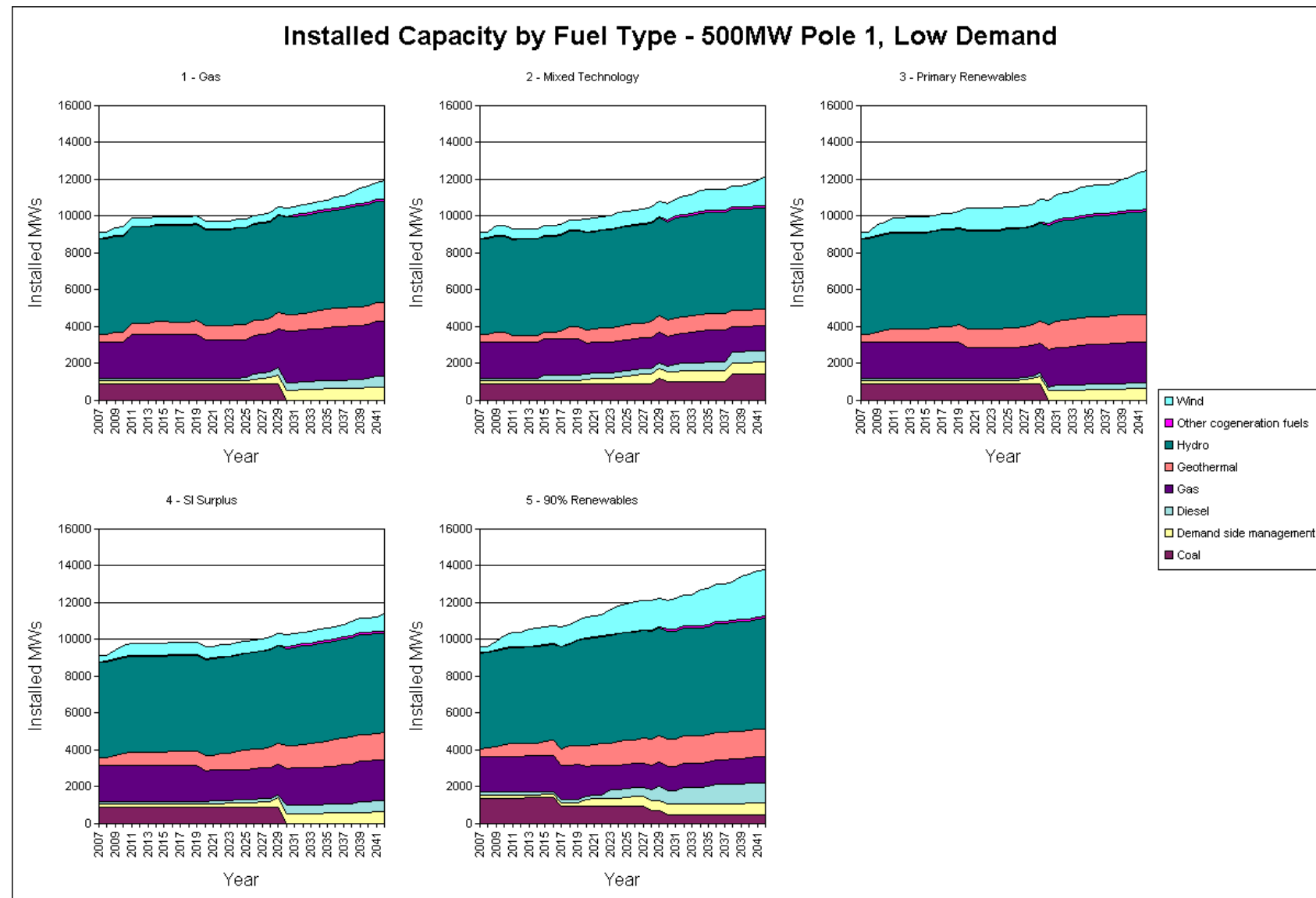


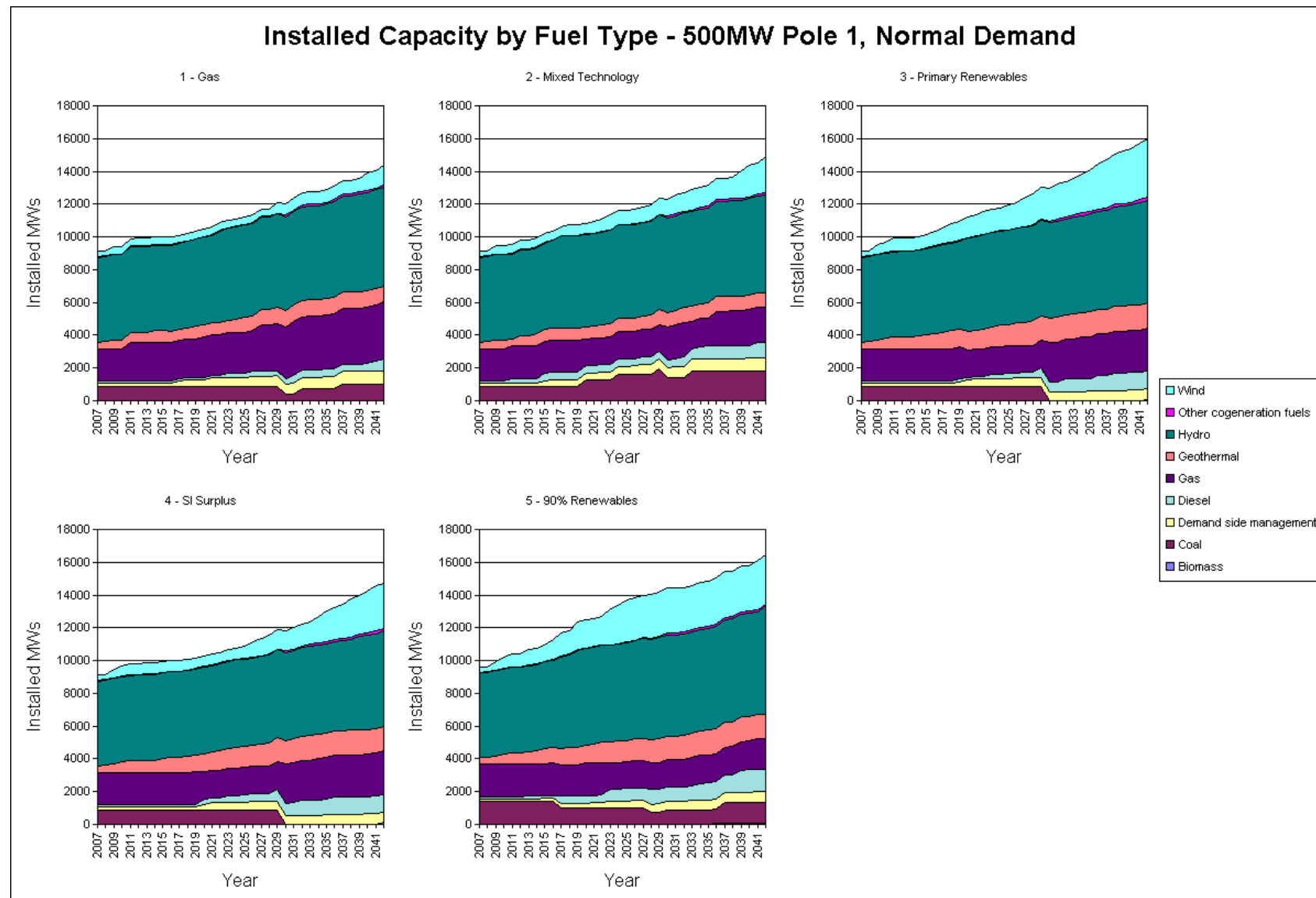




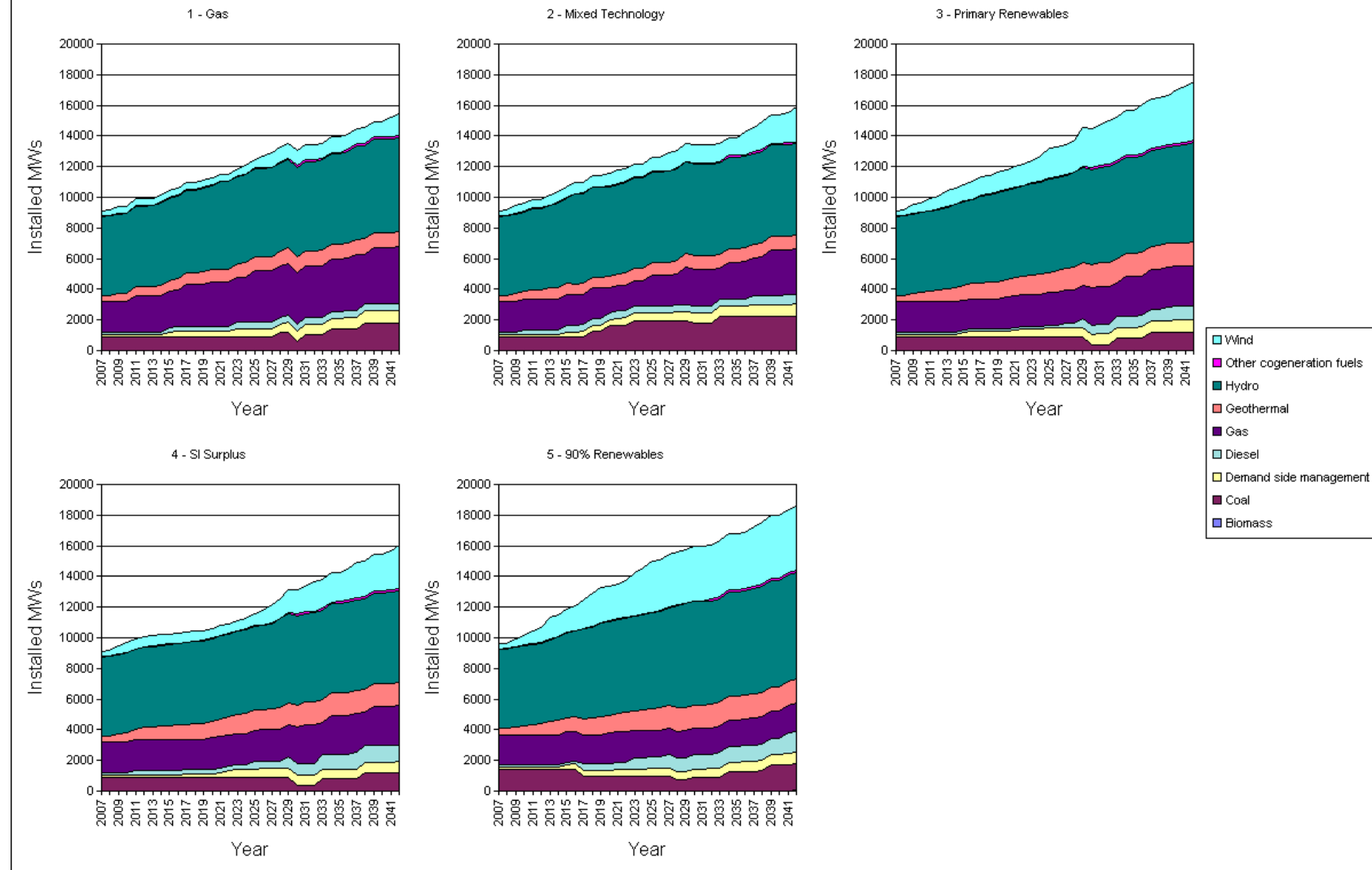
Installed Capacity by Fuel Type - 500MW Pole 1, High Demand

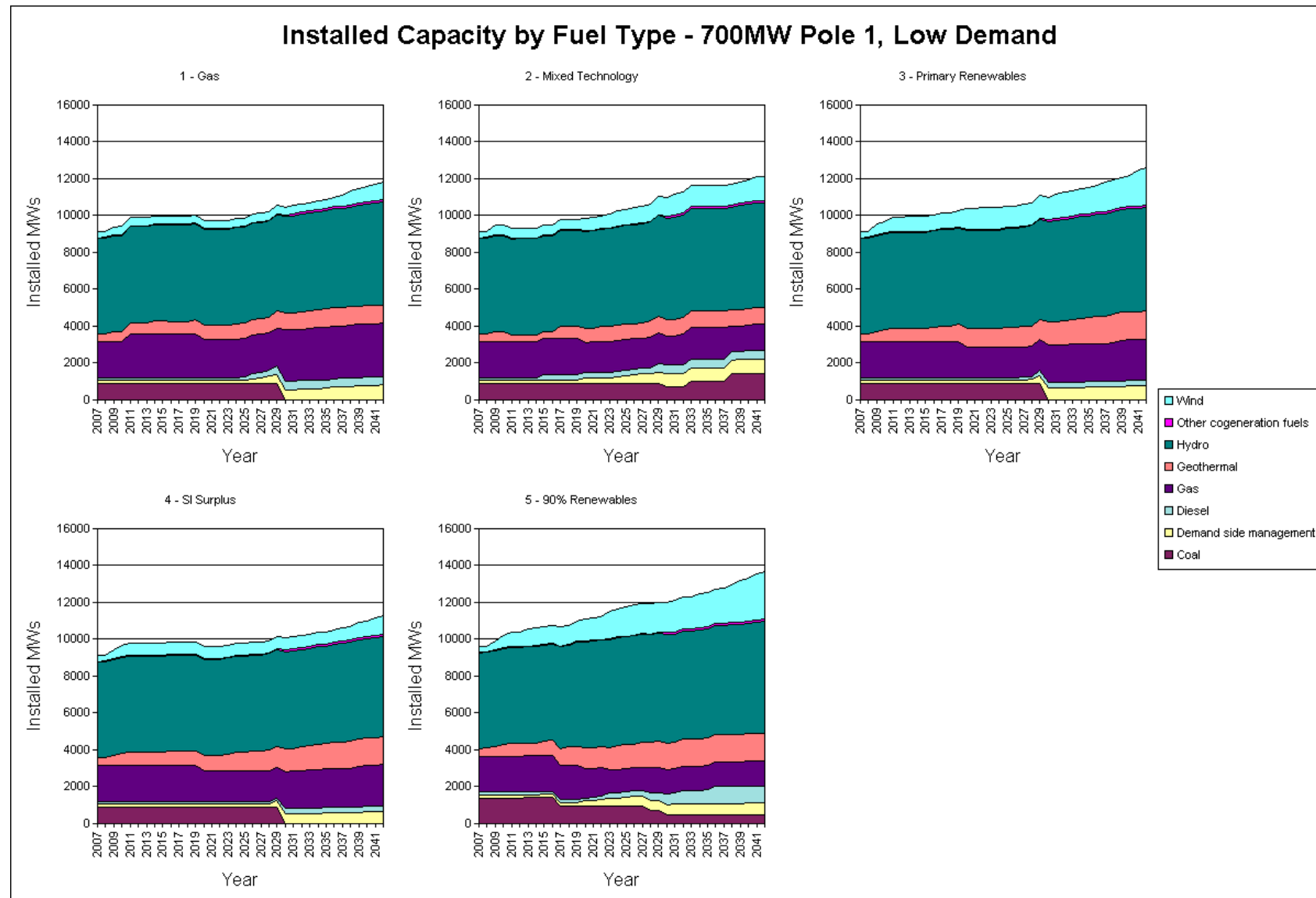


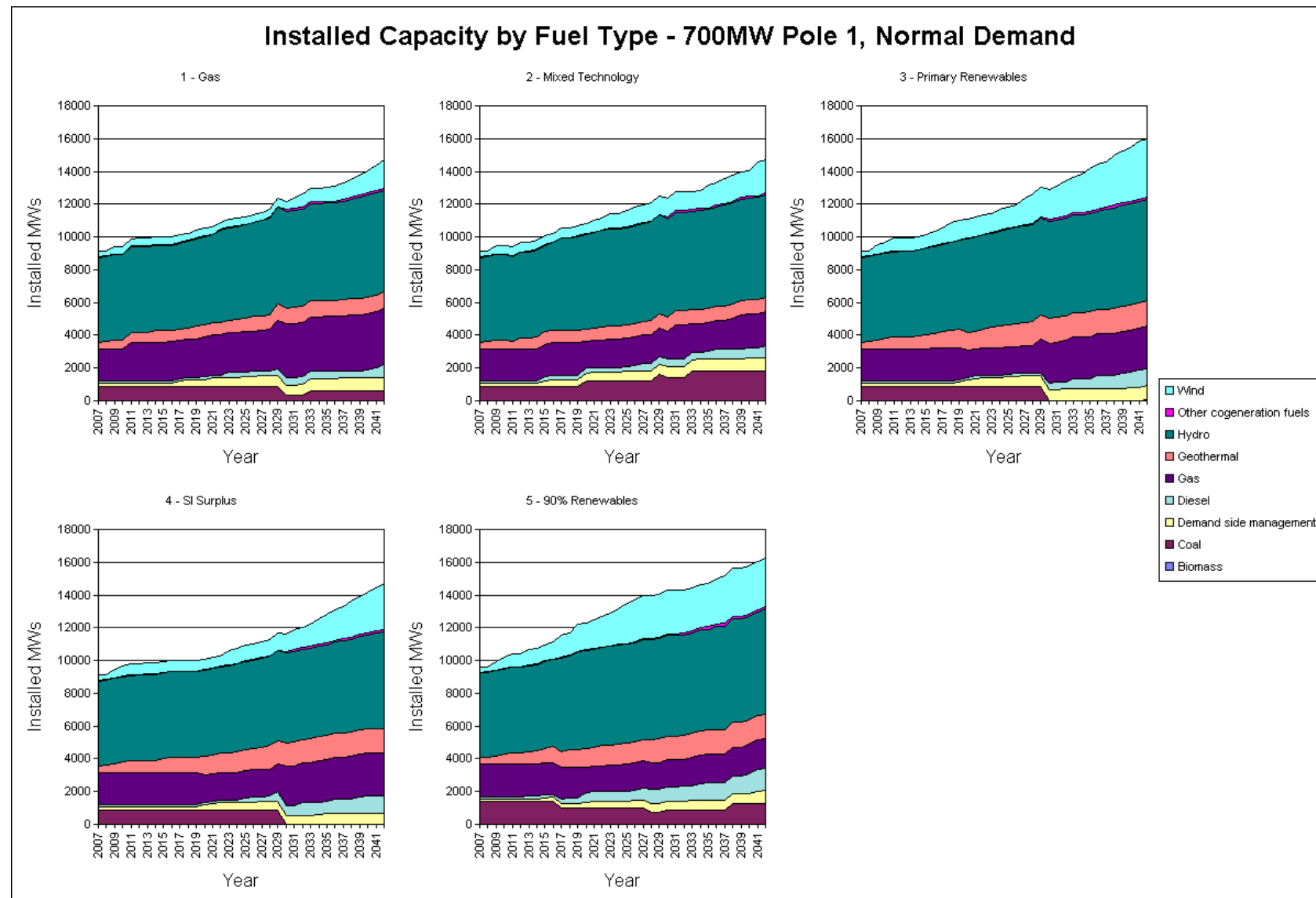




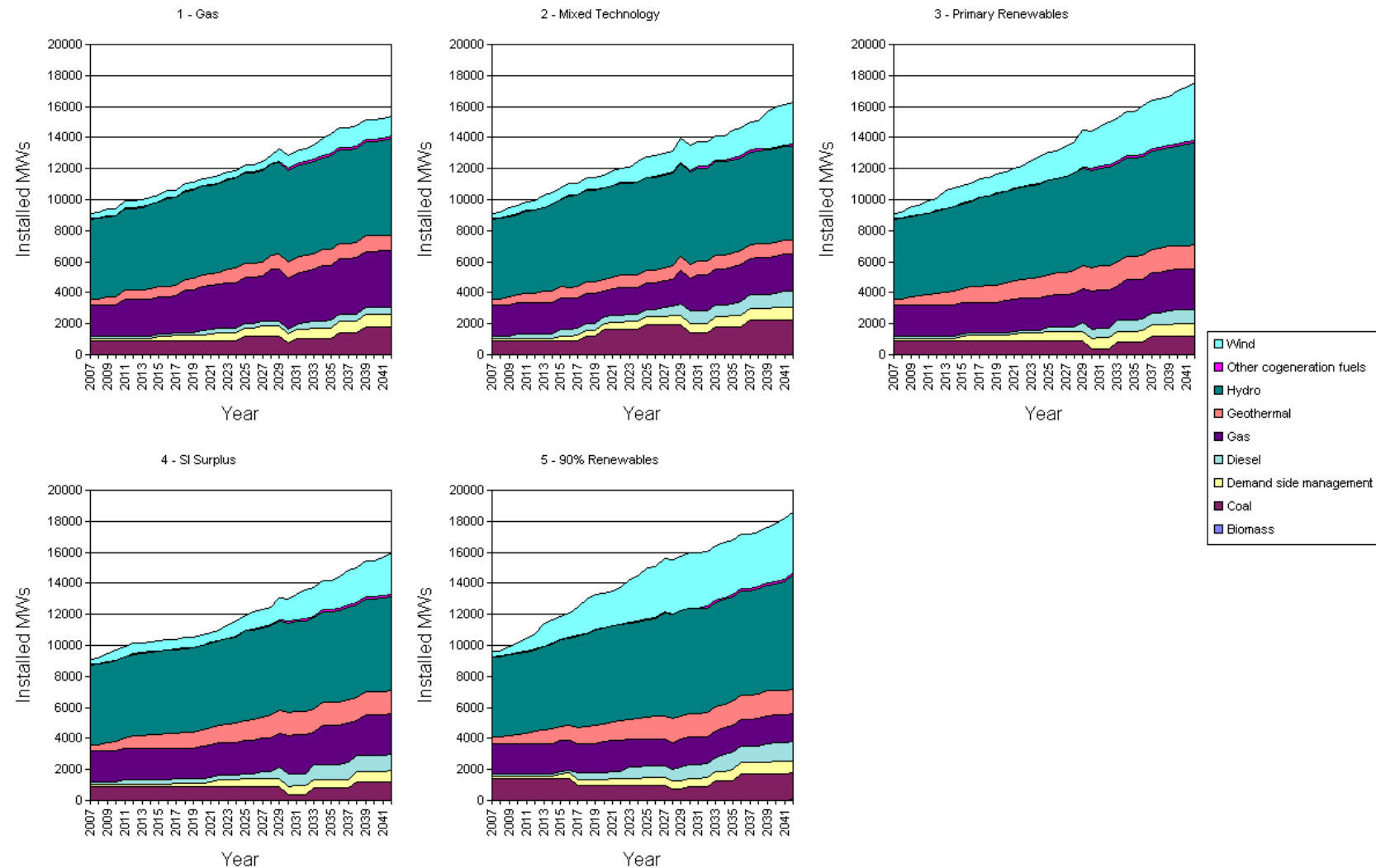
Installed Capacity by Fuel Type - 700MW Pole 1, High Demand





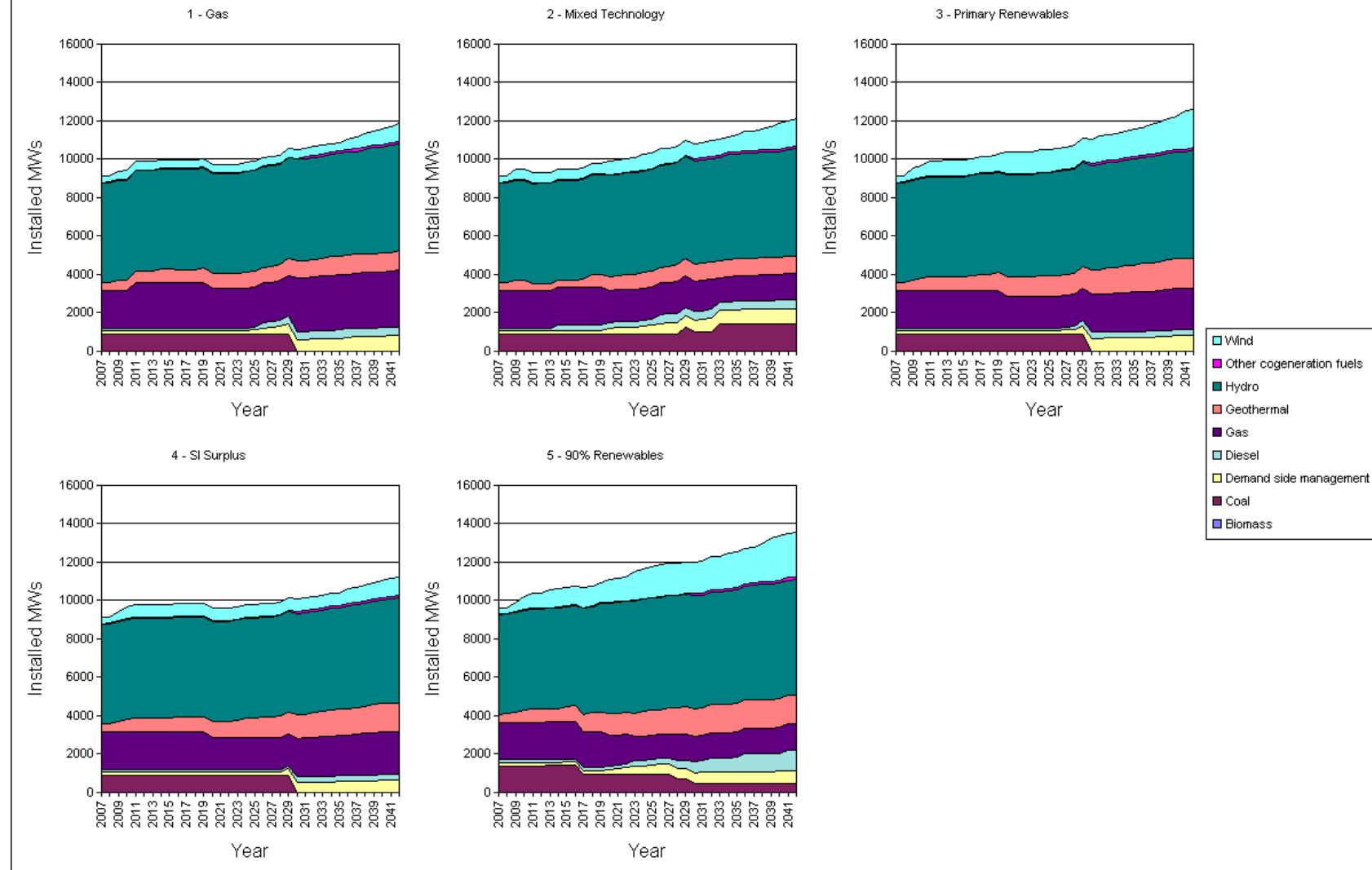


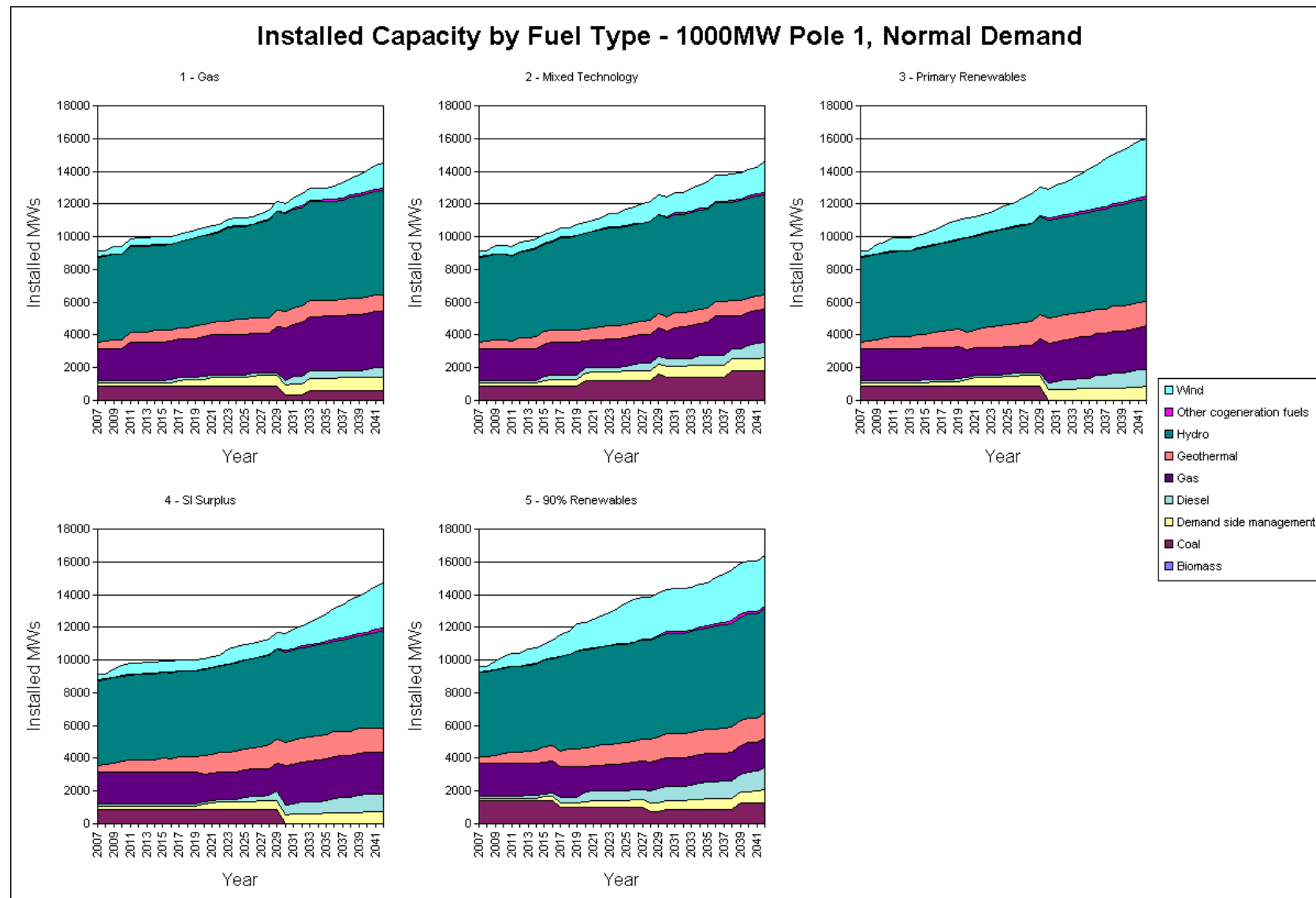
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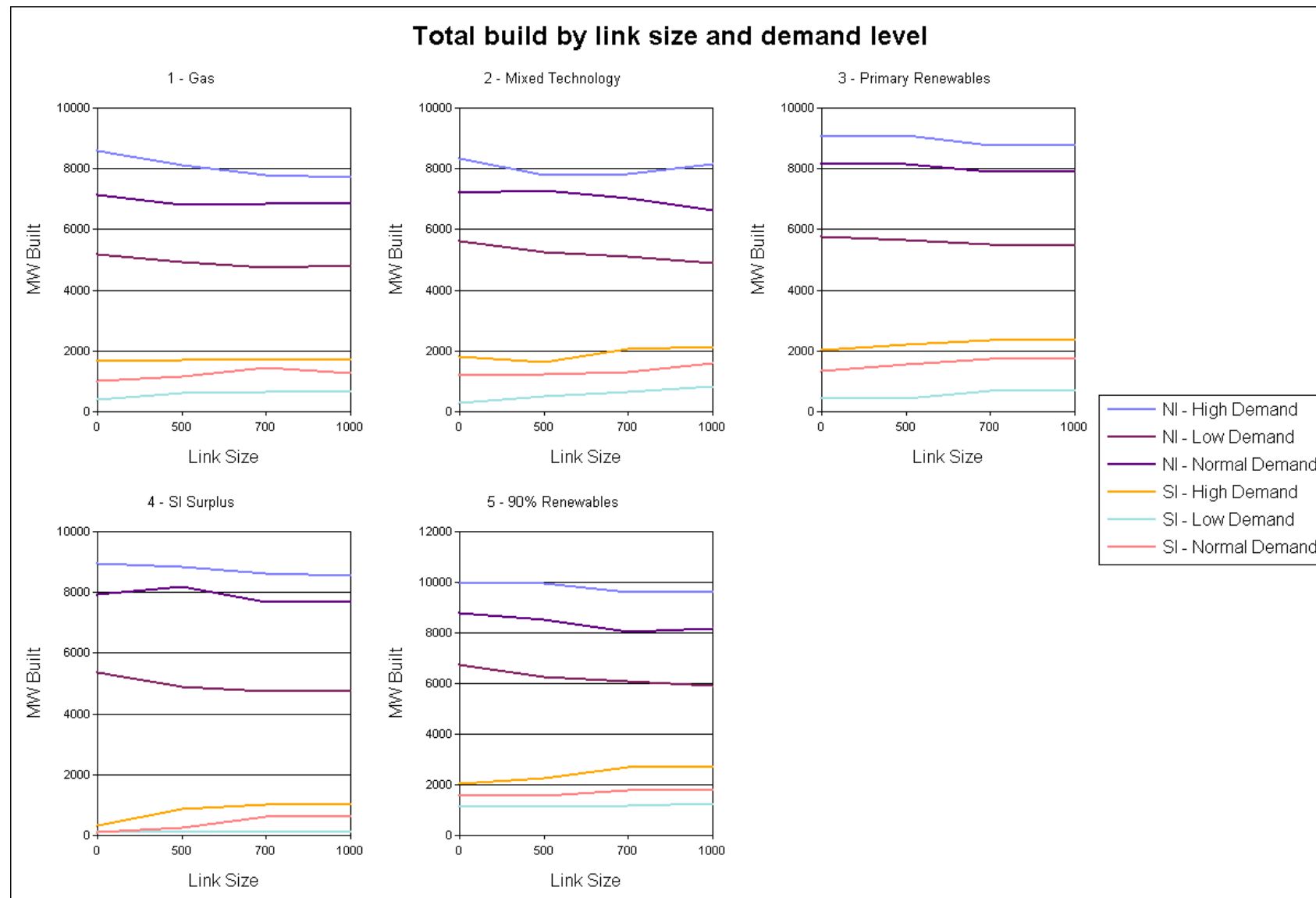


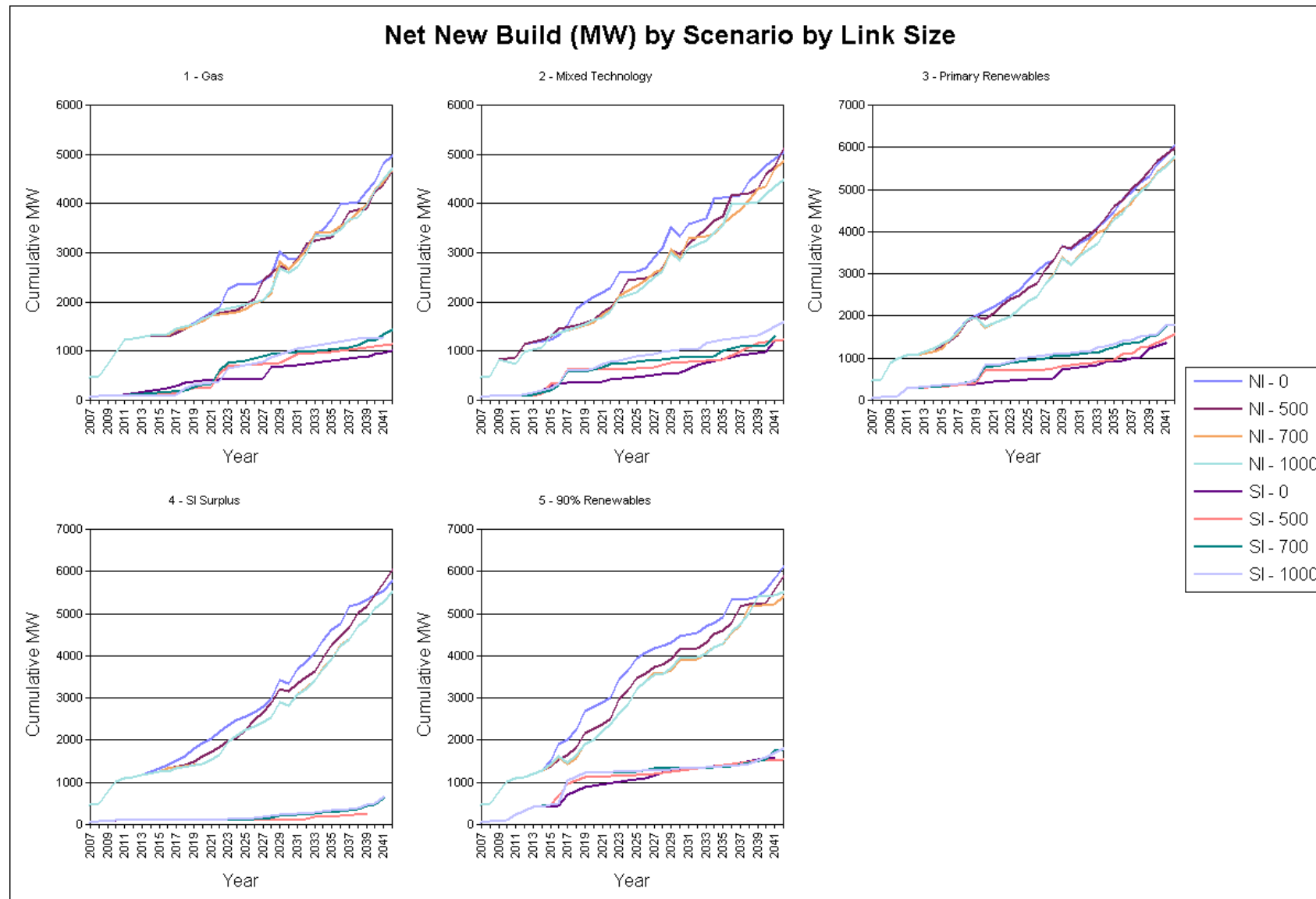


Installed Capacity by Fuel Type - 1000MW Pole 1, Low Demand



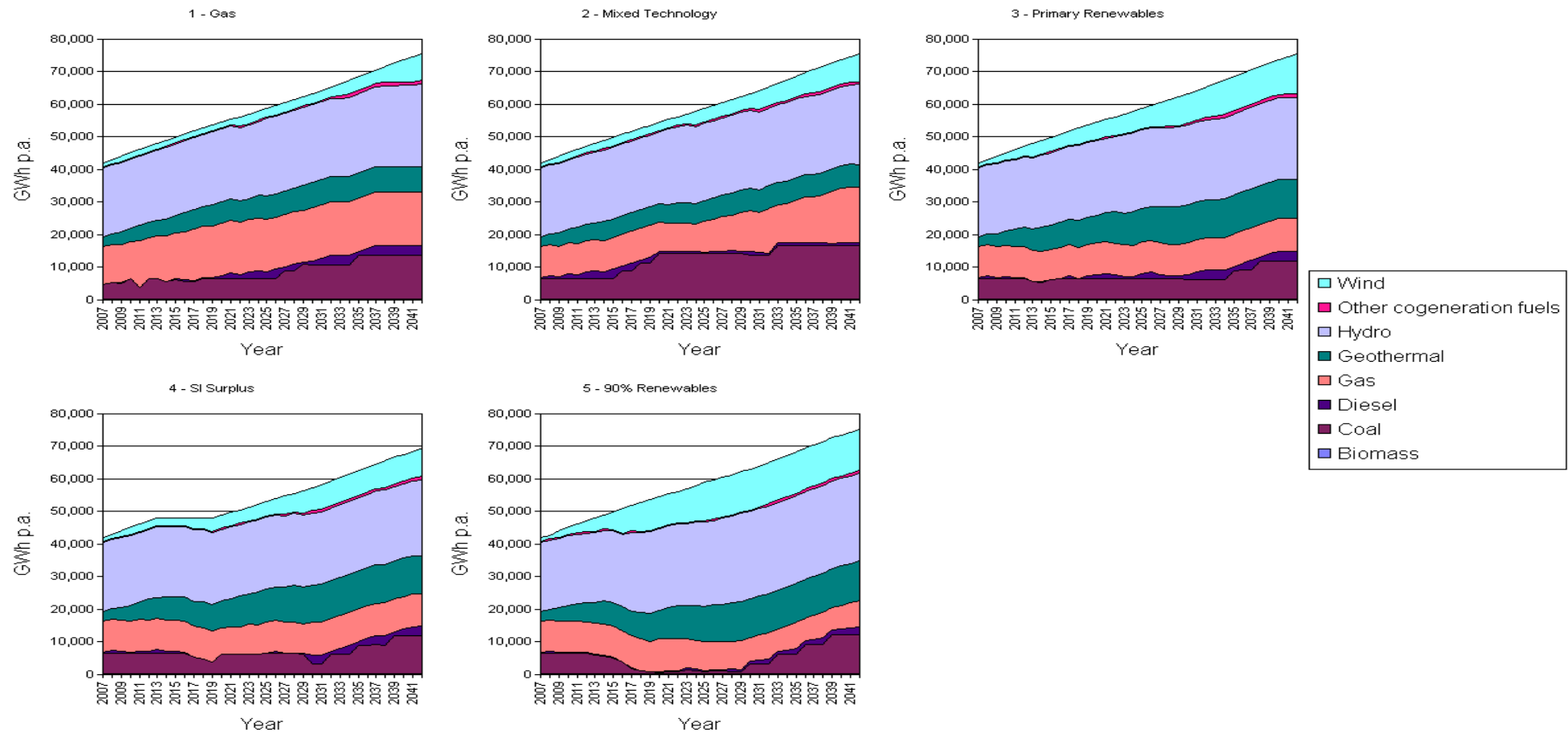




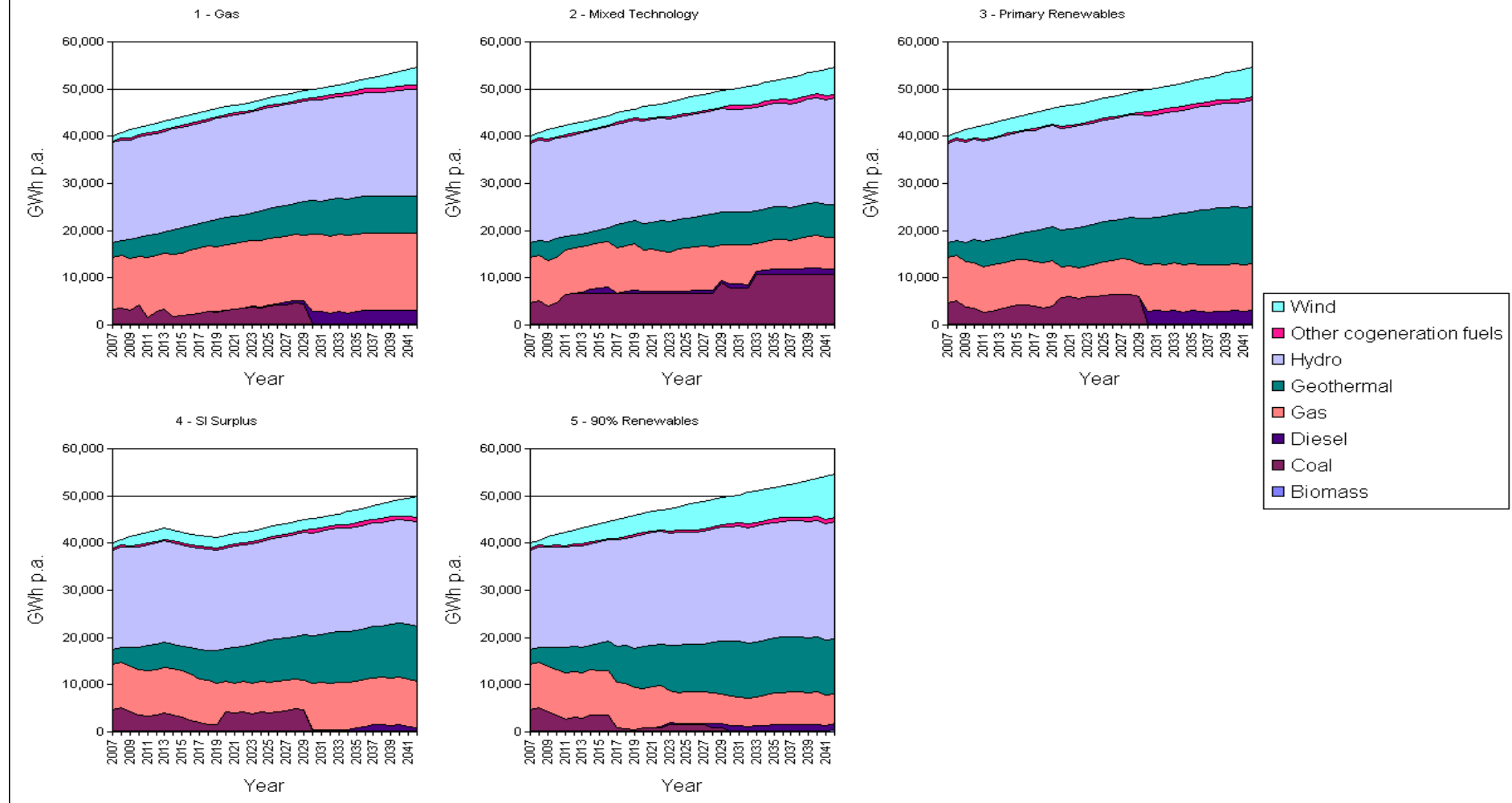


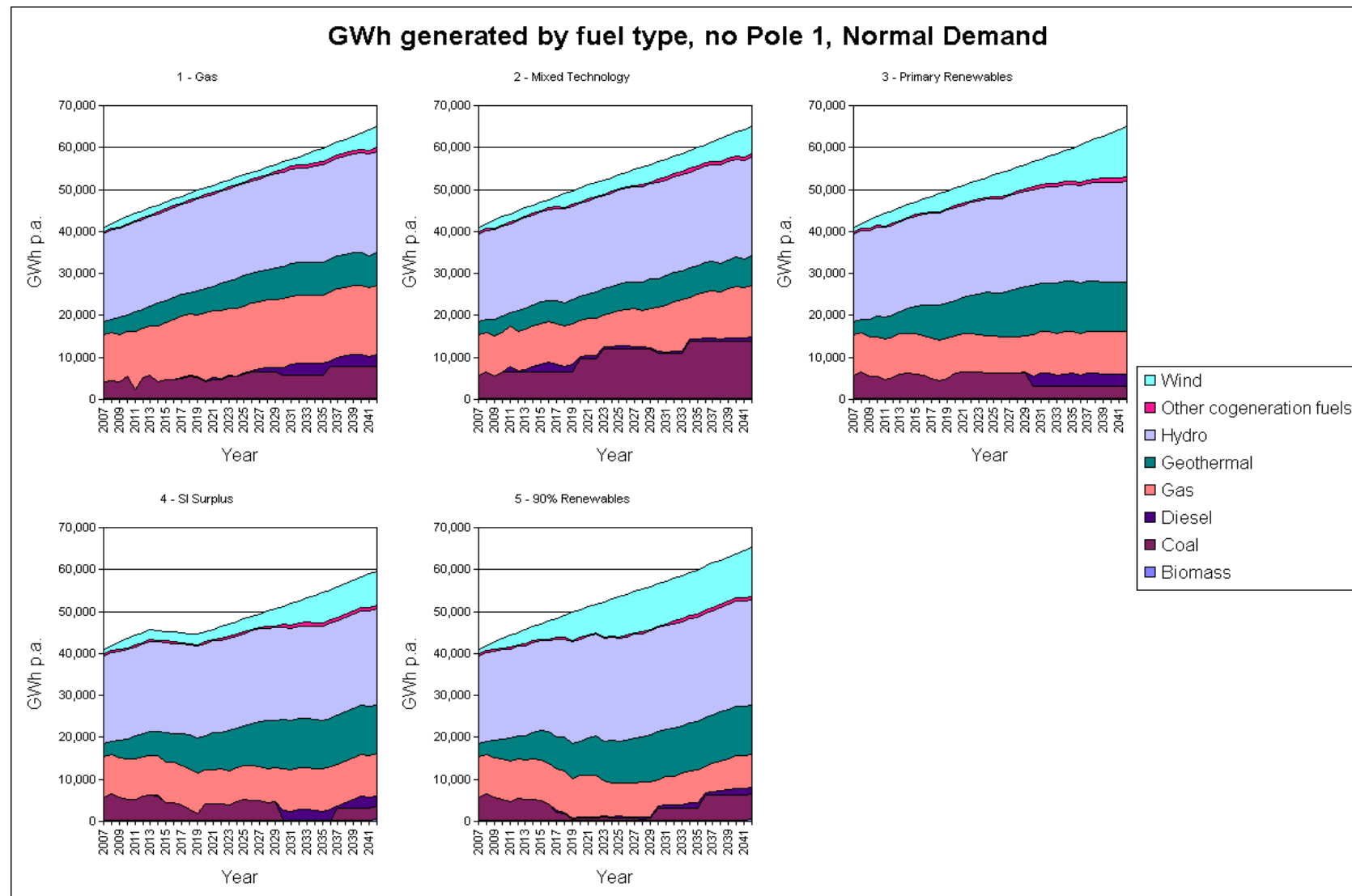
Appendix D National generation, GWh, for various demand paths, market development scenarios and HVDC options

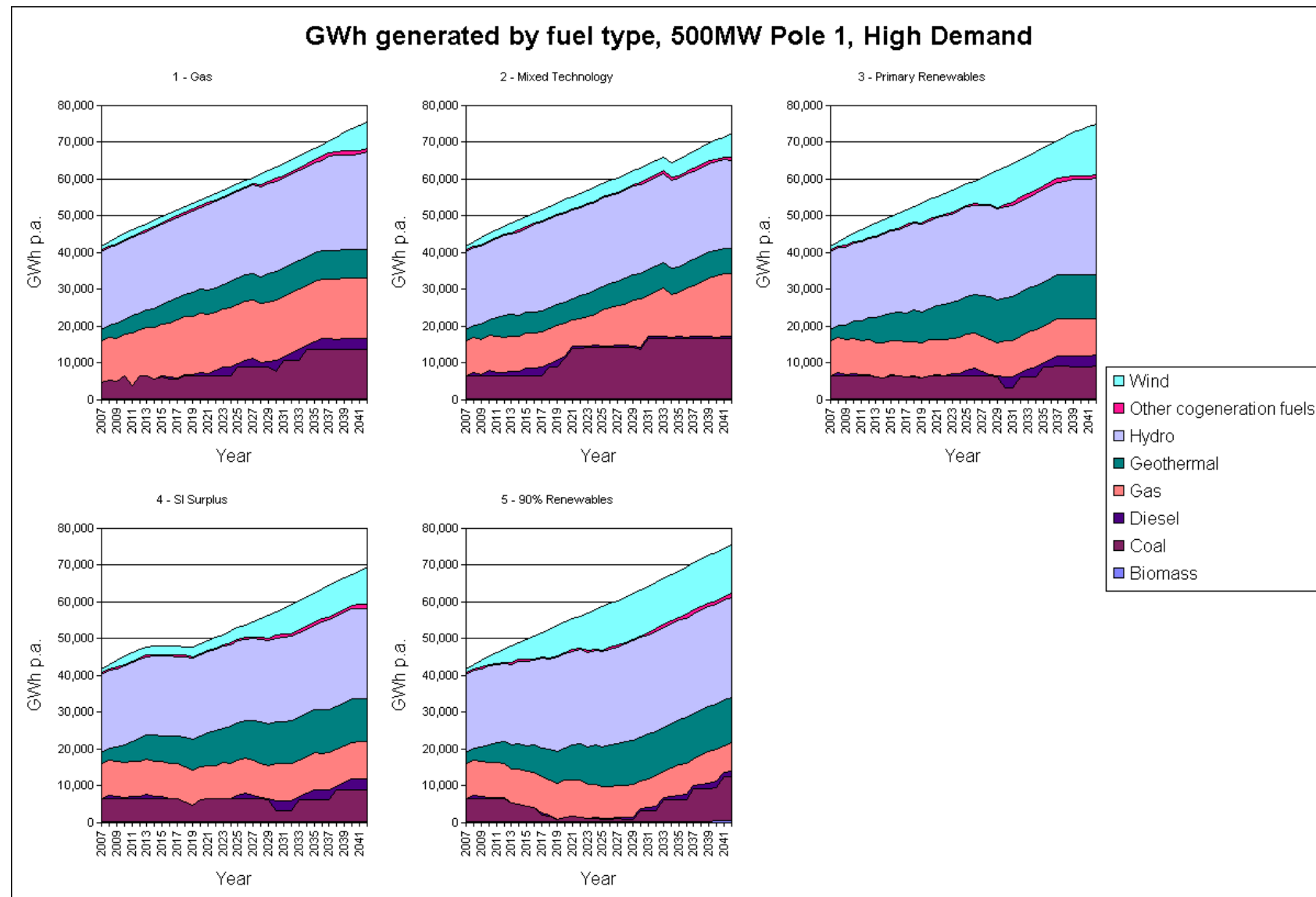
GWh generated by fuel type, no Pole 1, High Demand

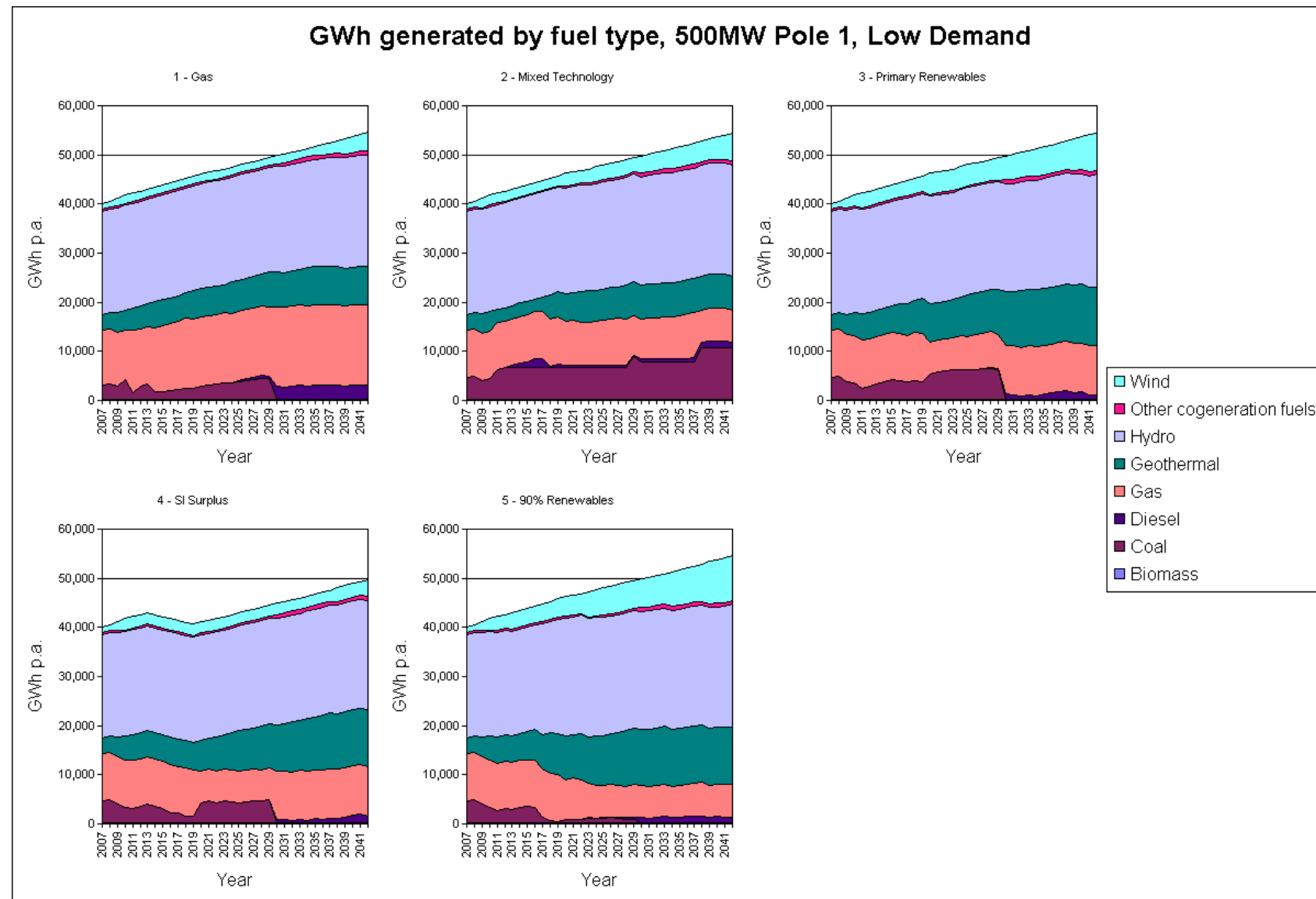


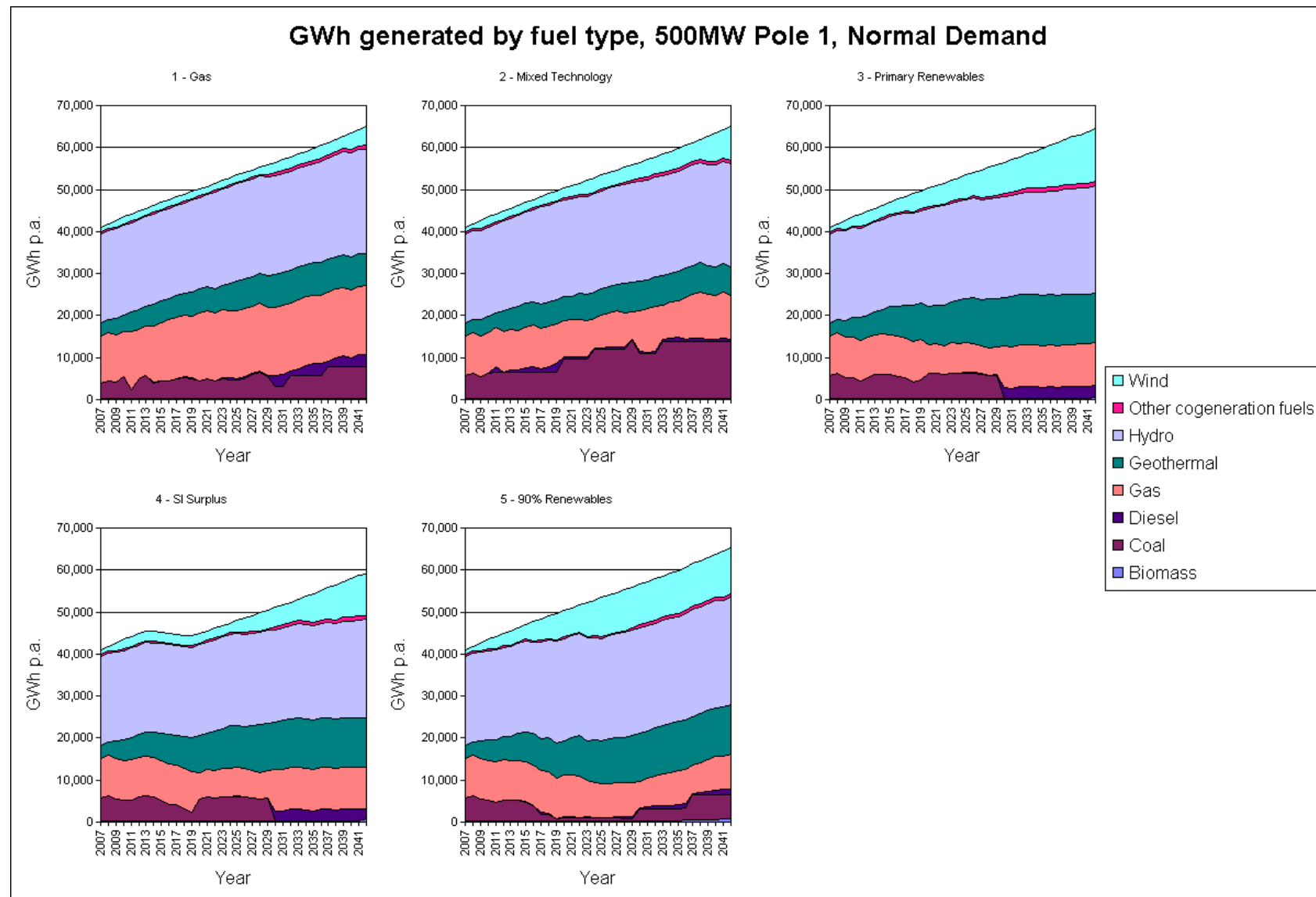
GWh generated by fuel type, no Pole 1, Low Demand

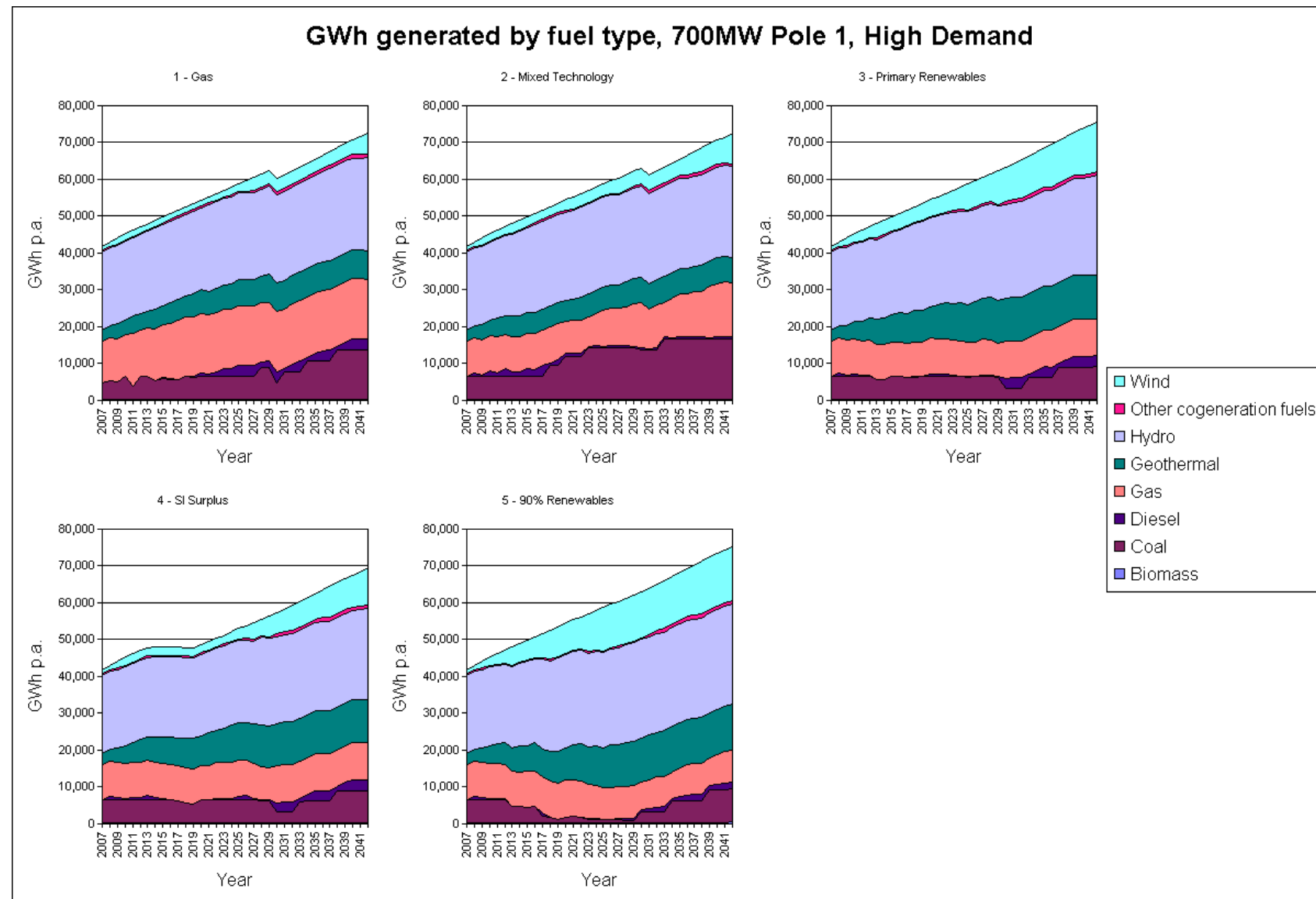


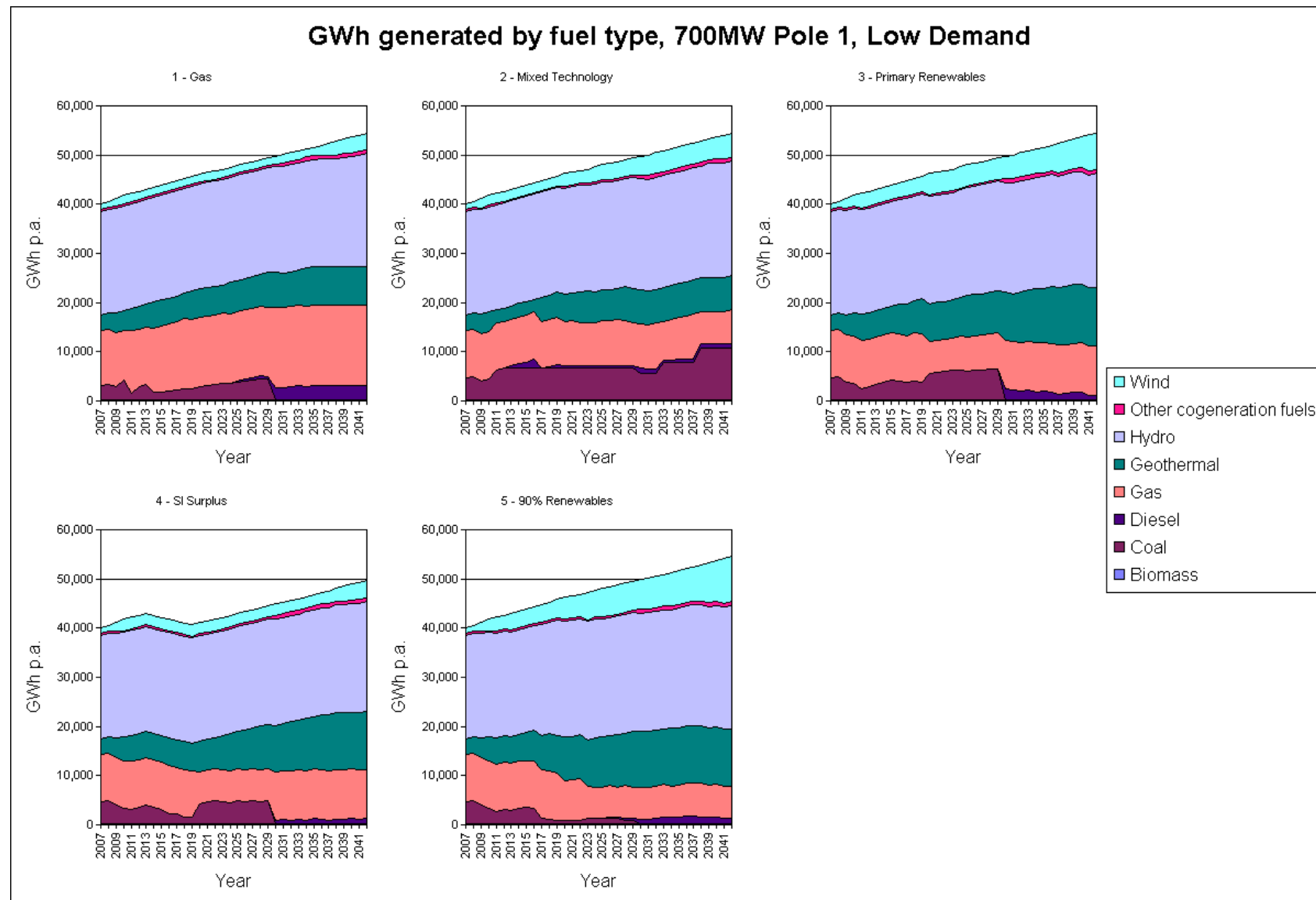


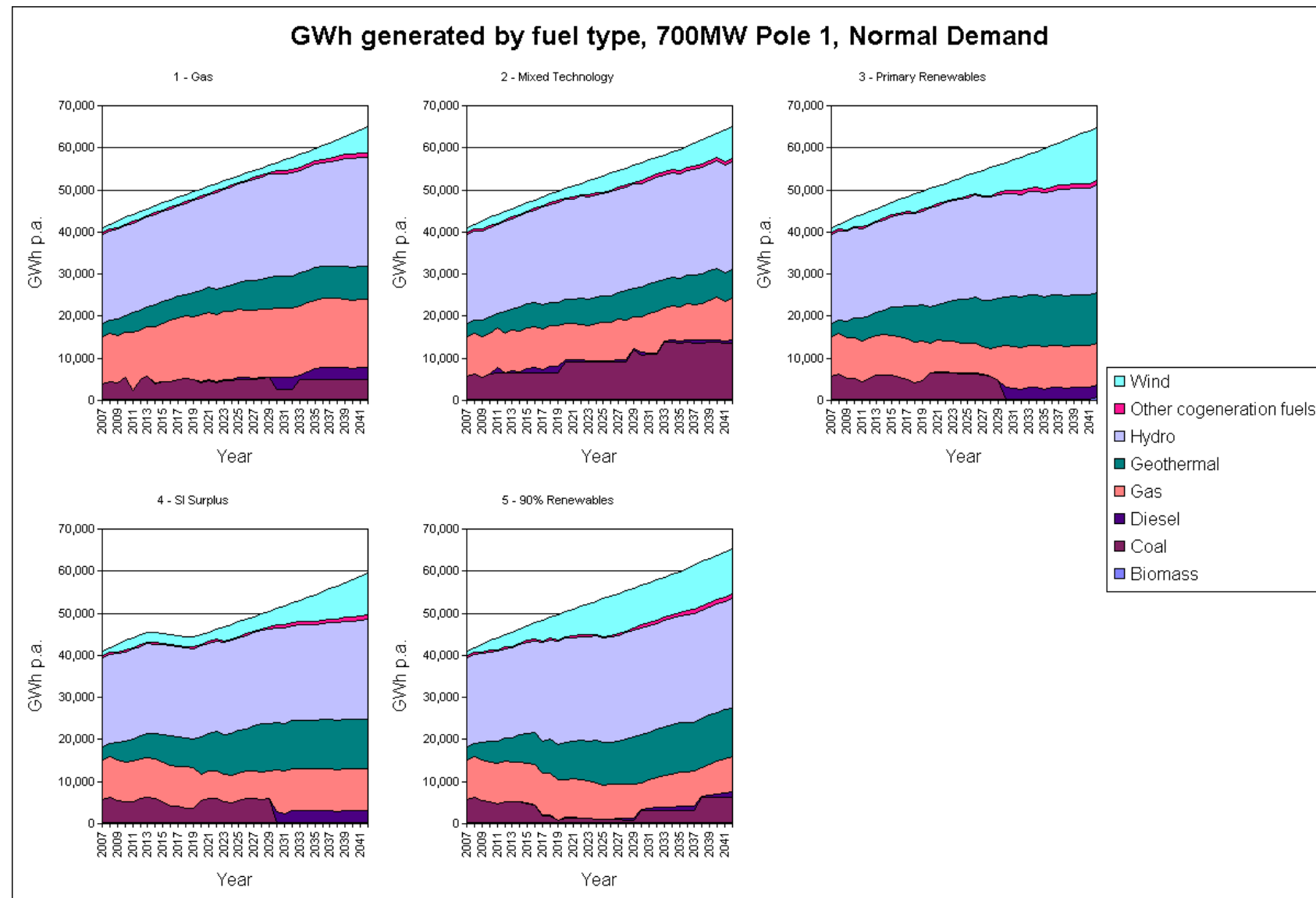


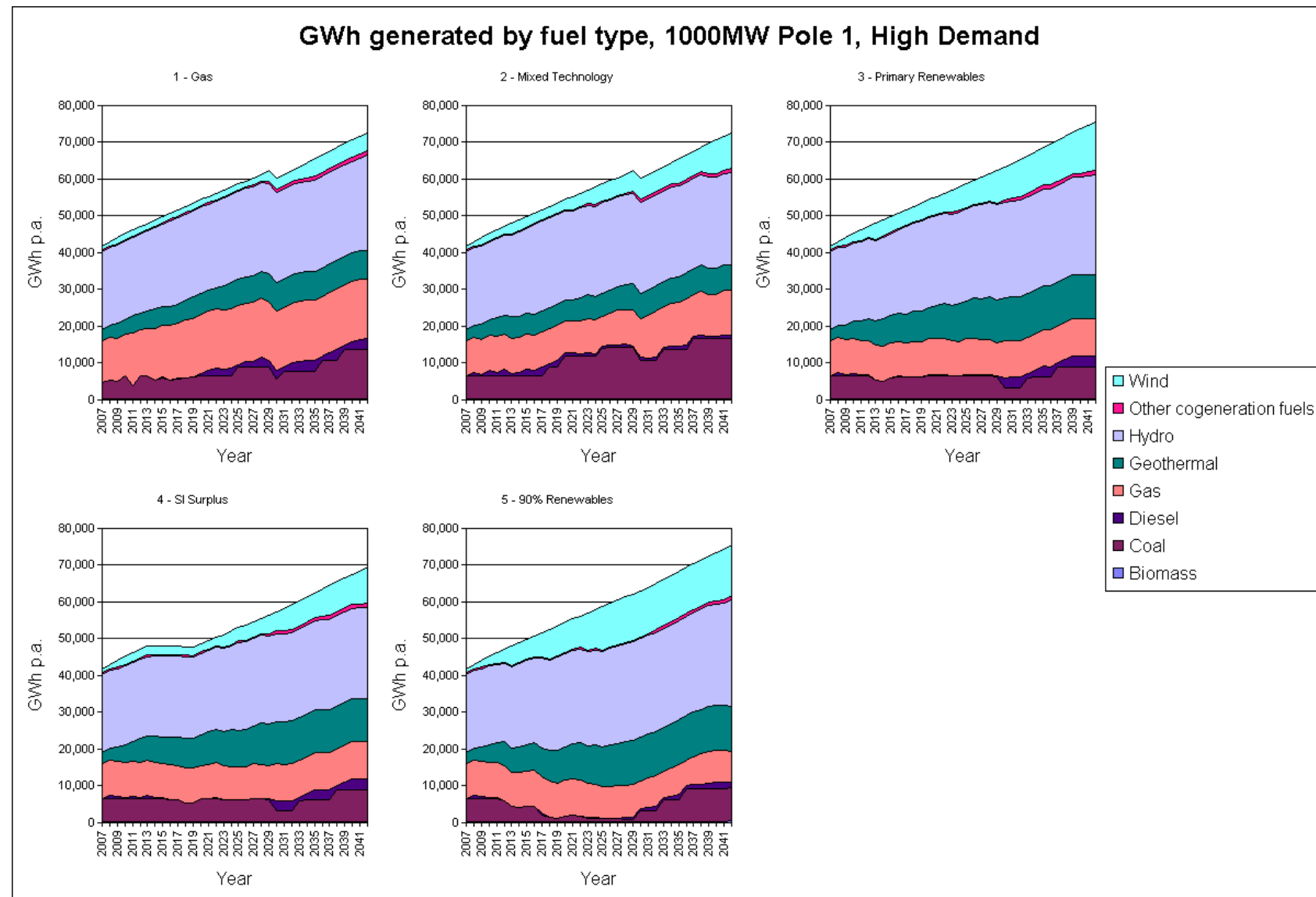


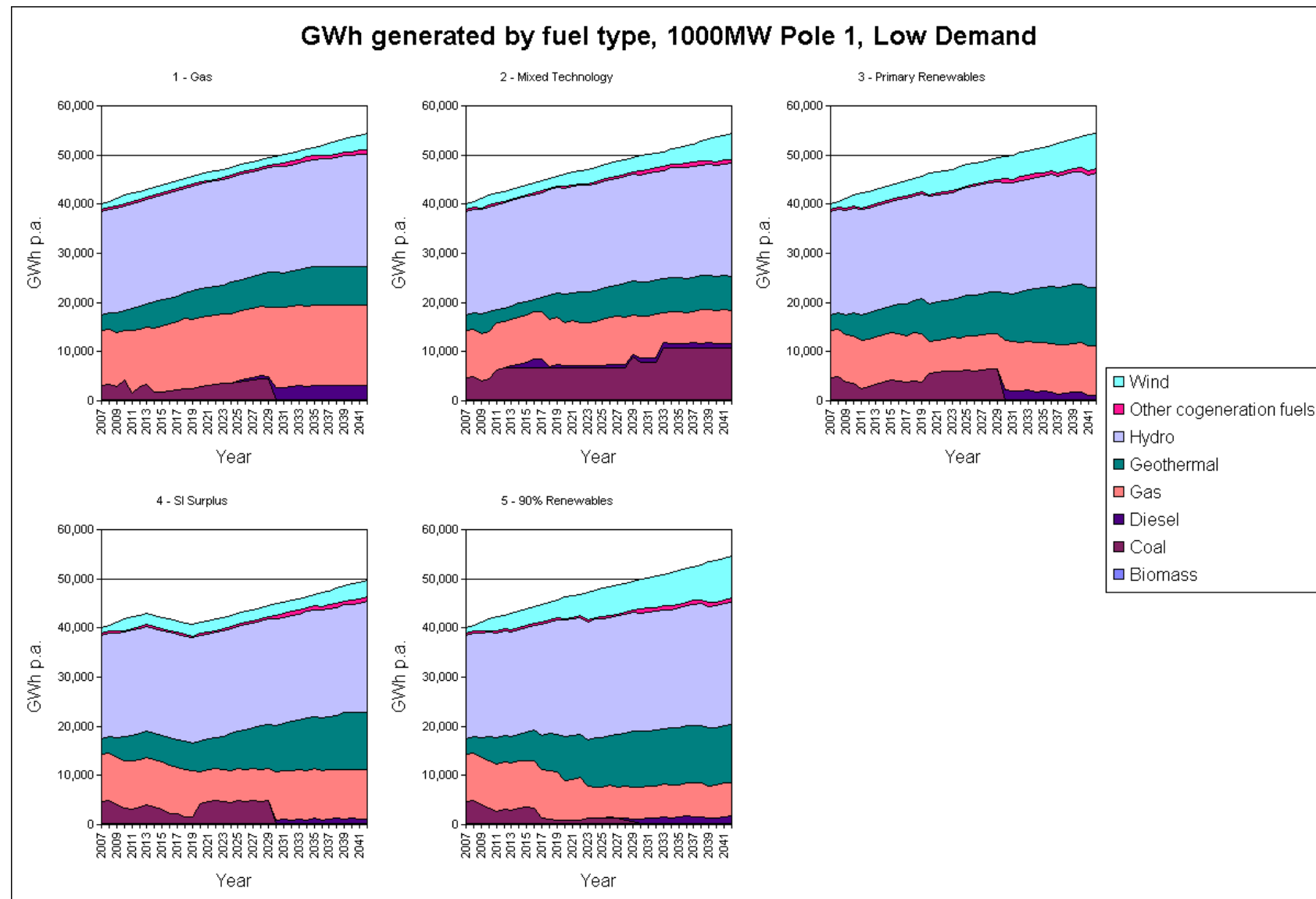


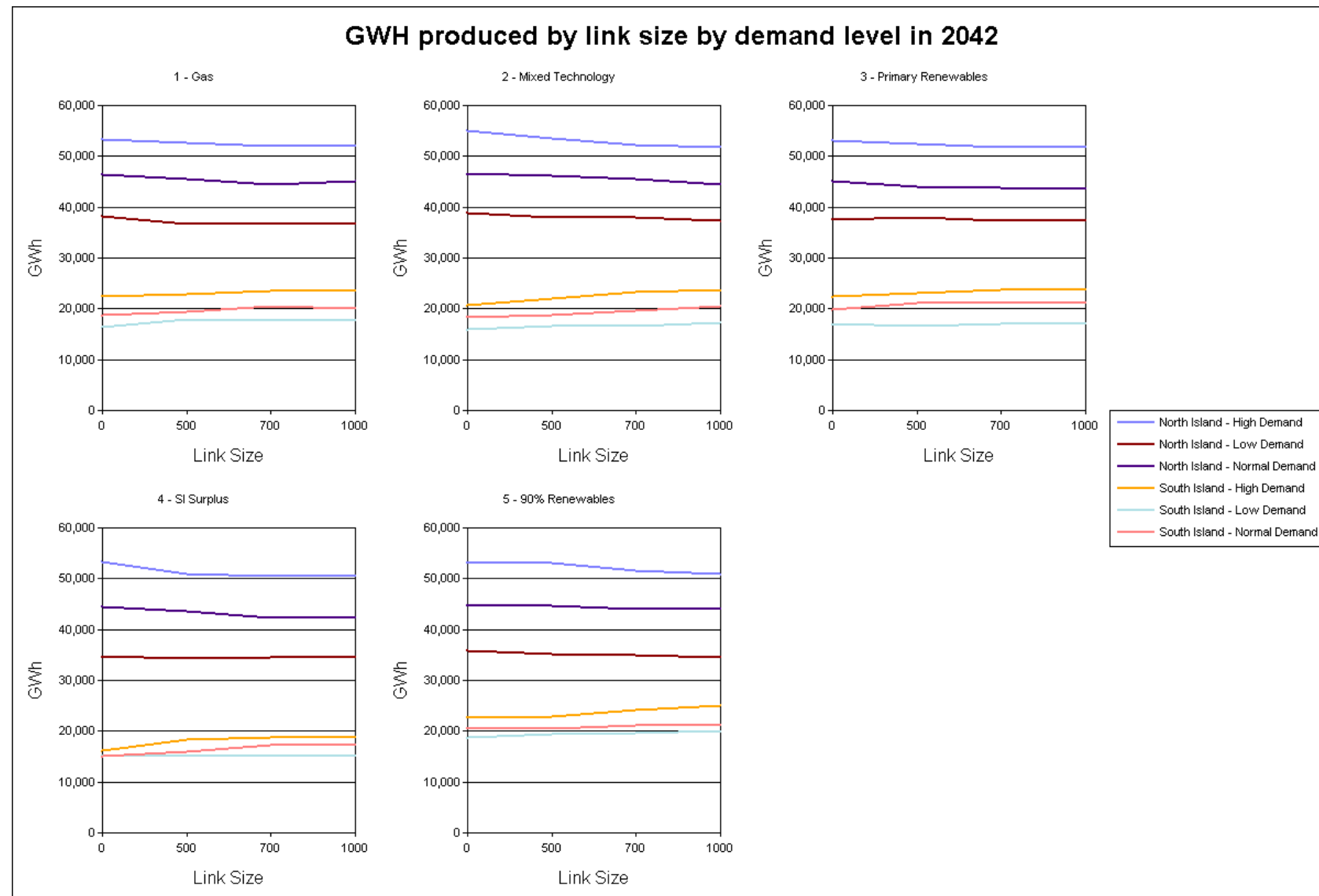




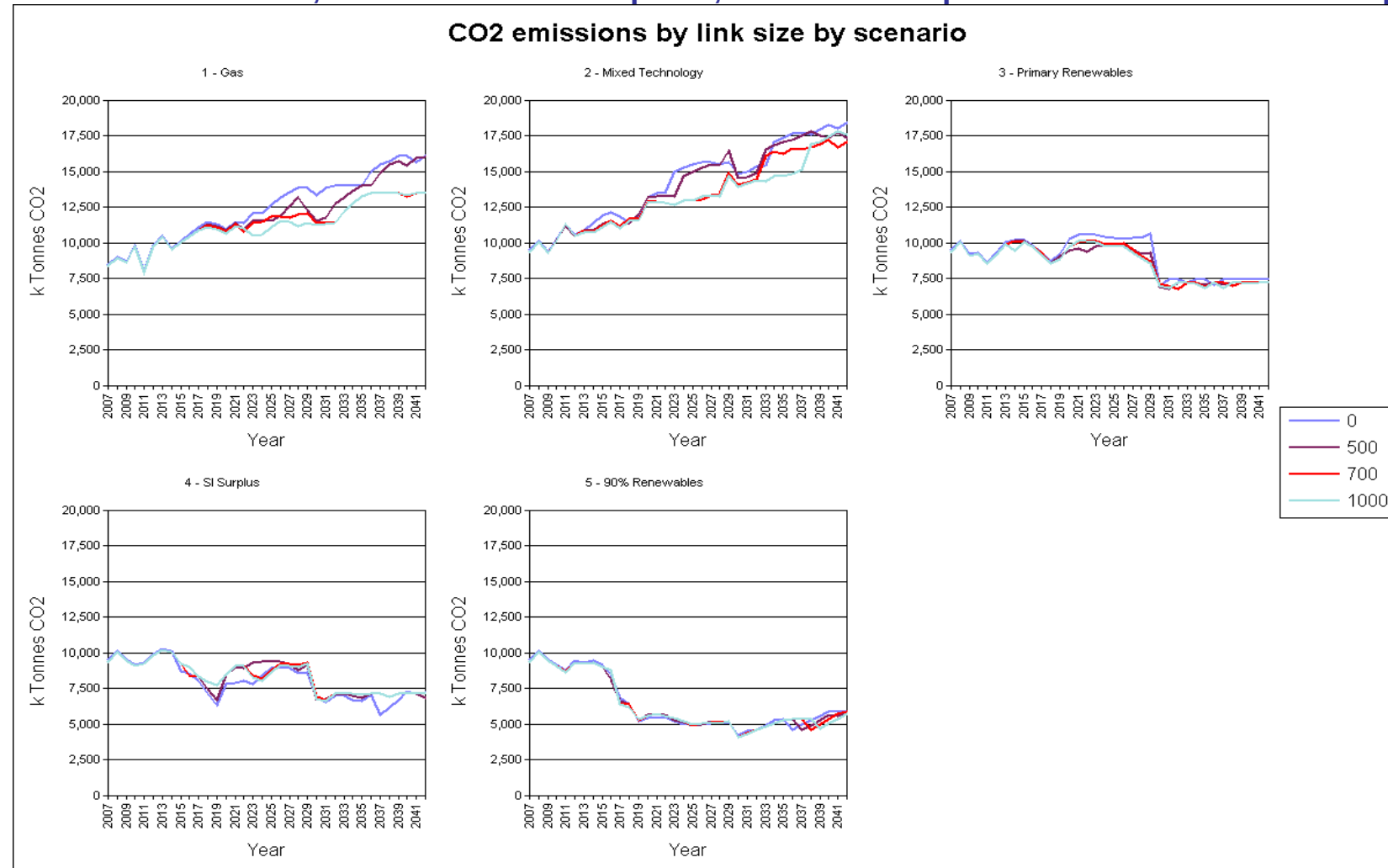




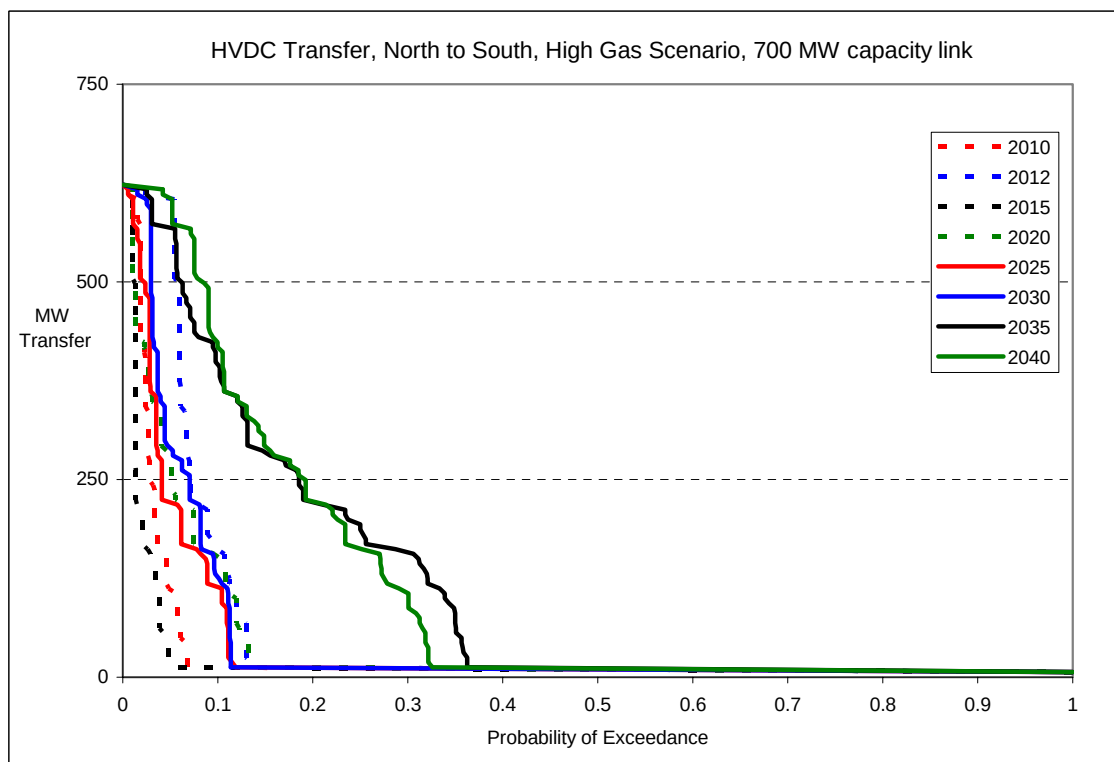
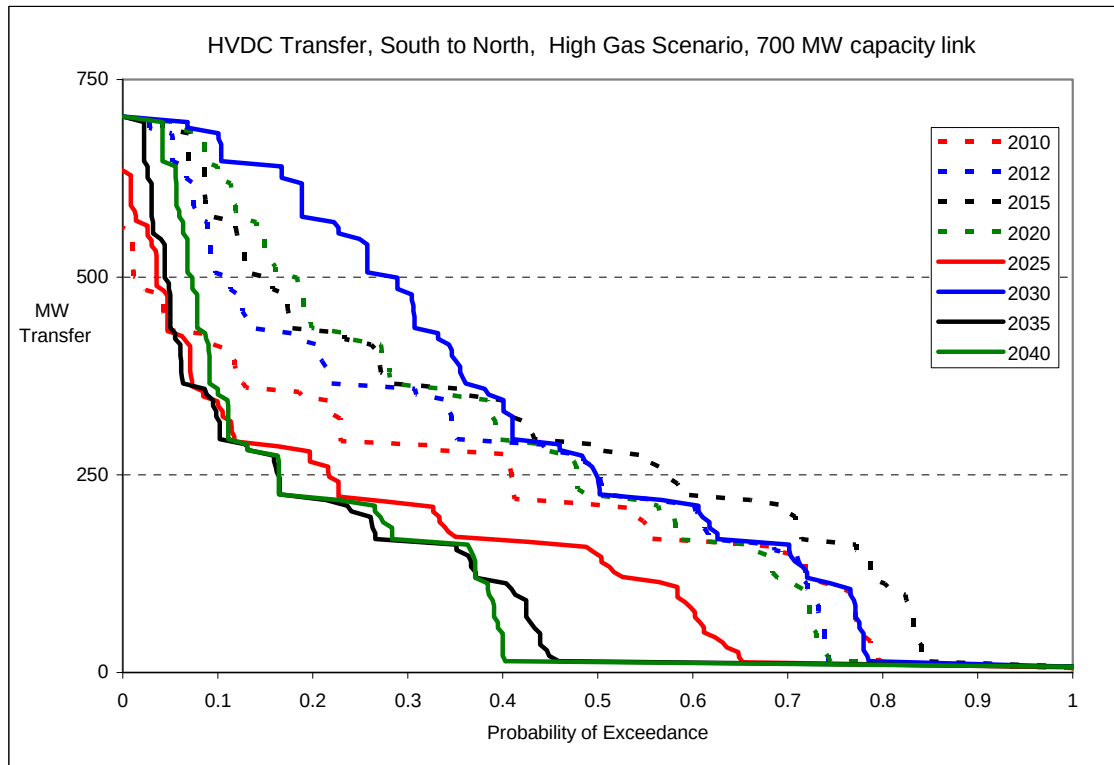


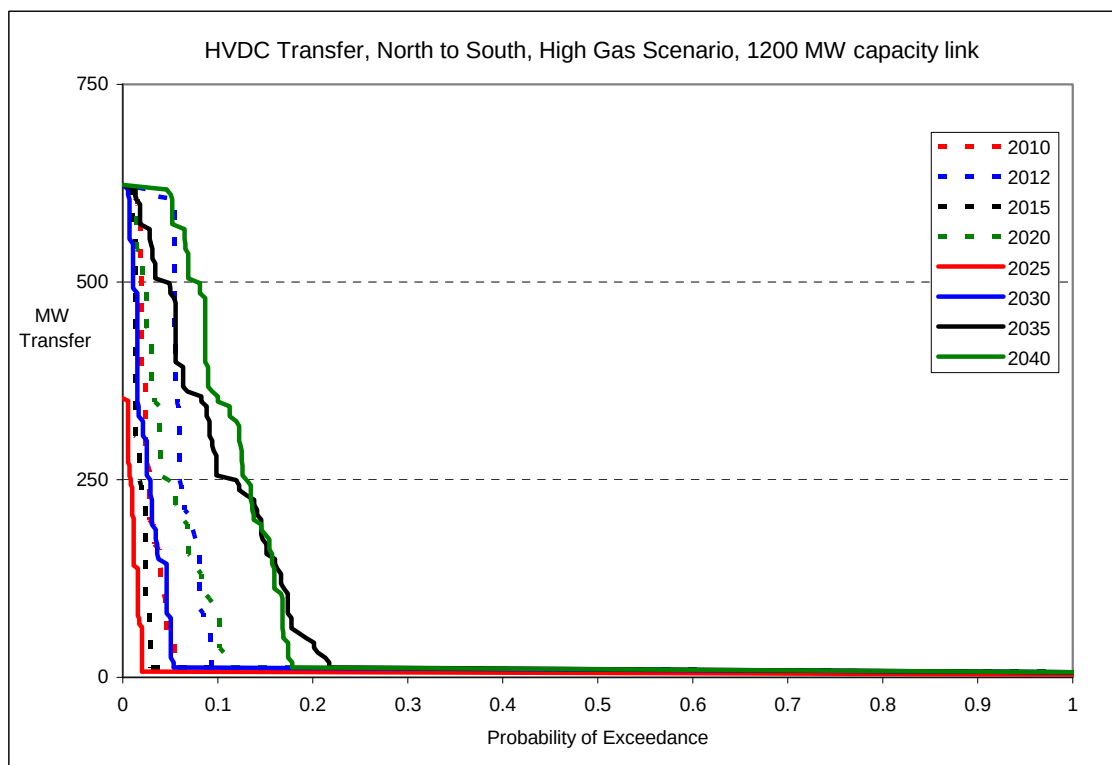
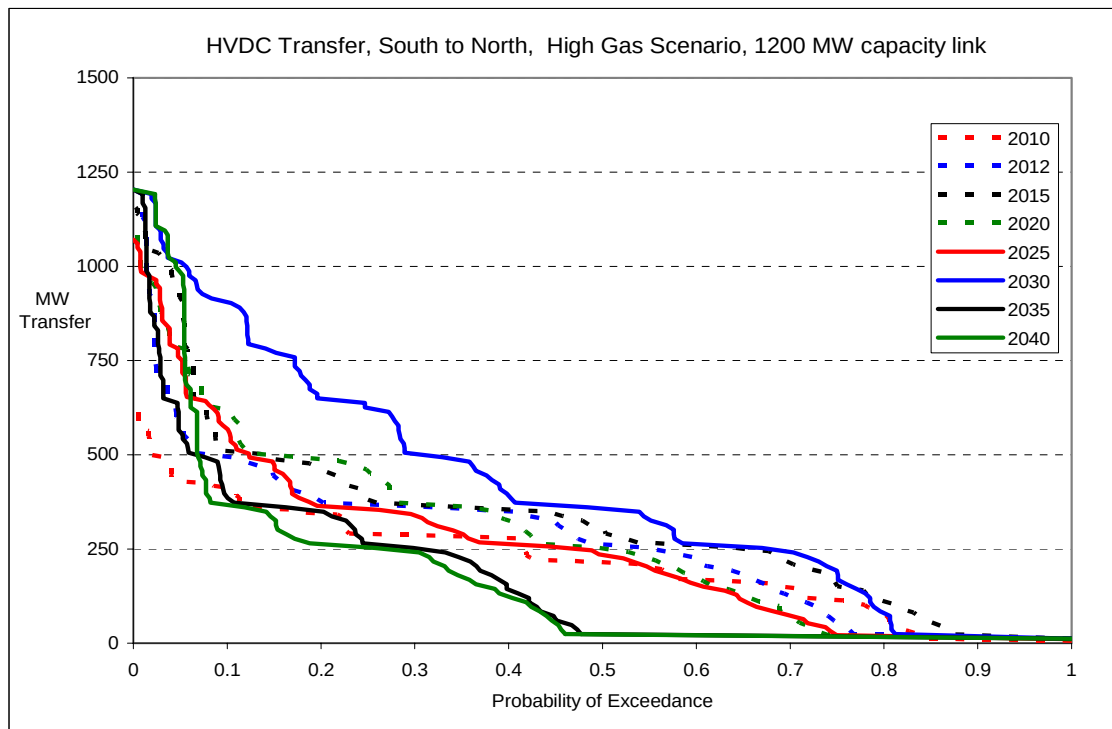


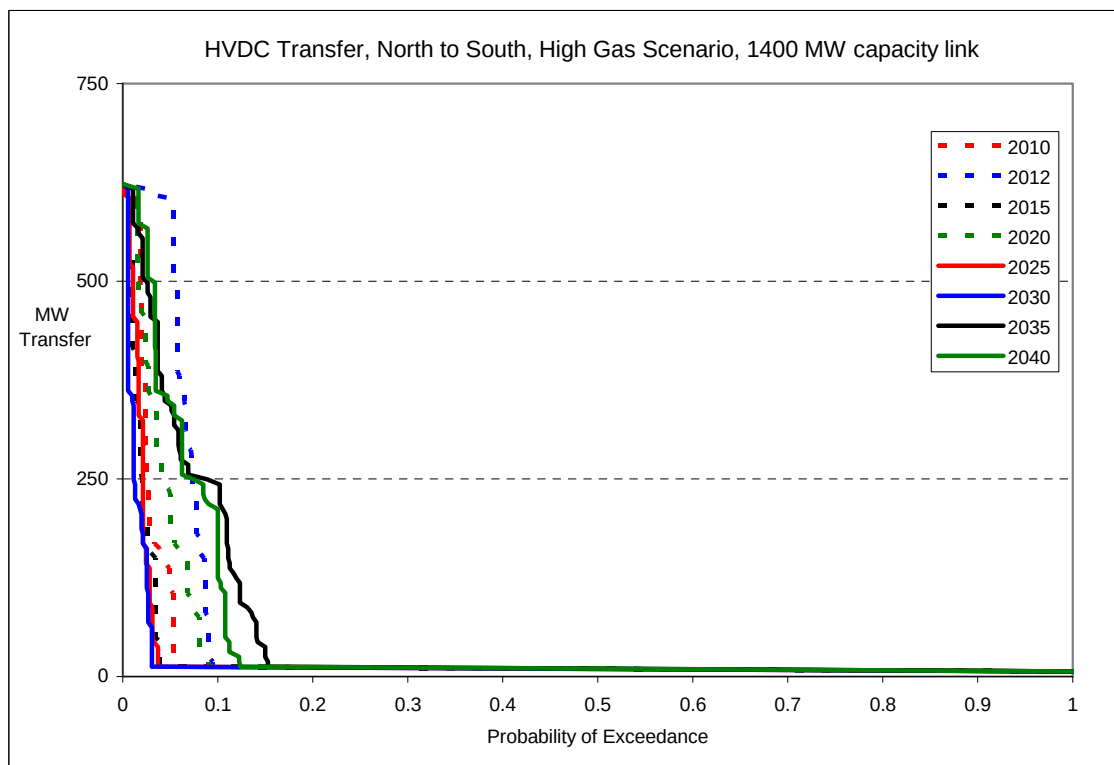
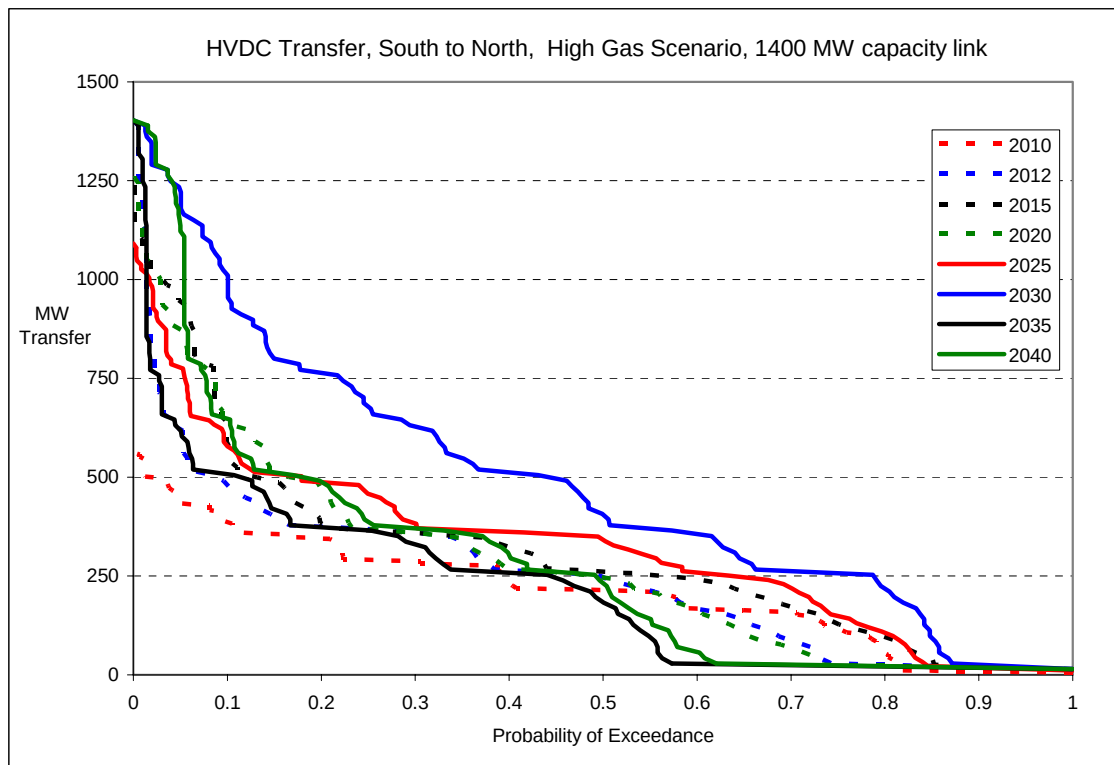
Appendix E CO₂ emissions, for various demand paths, market development scenarios and HVDC options

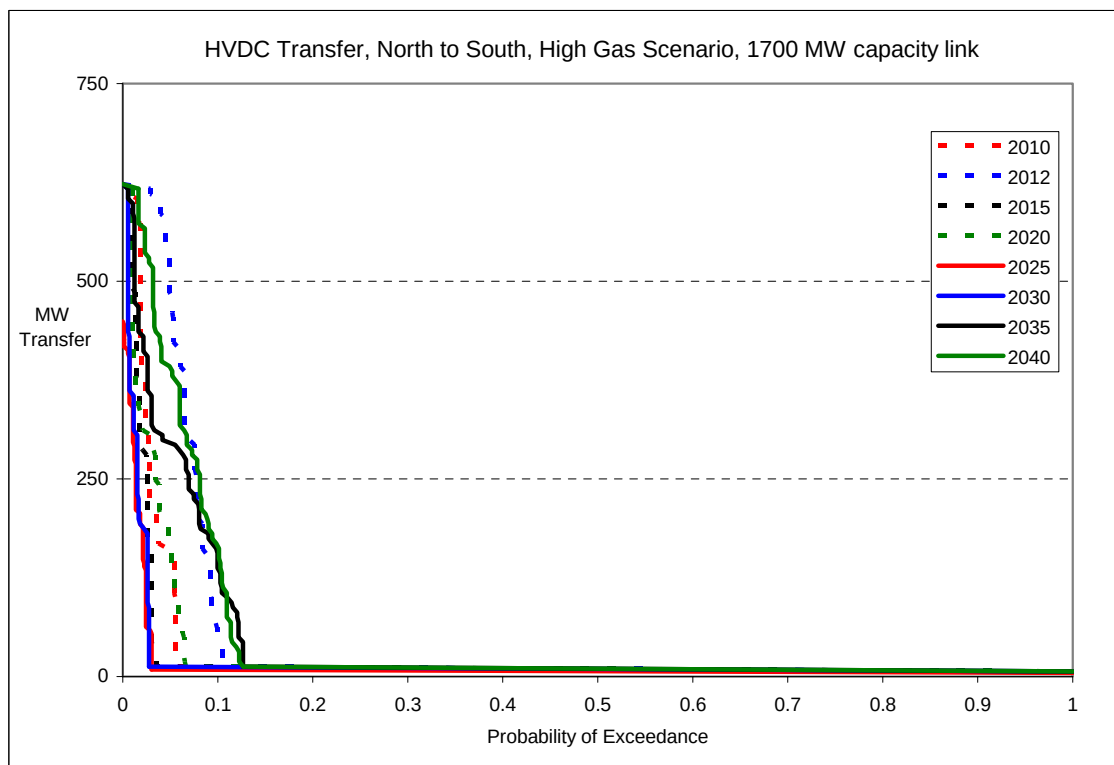
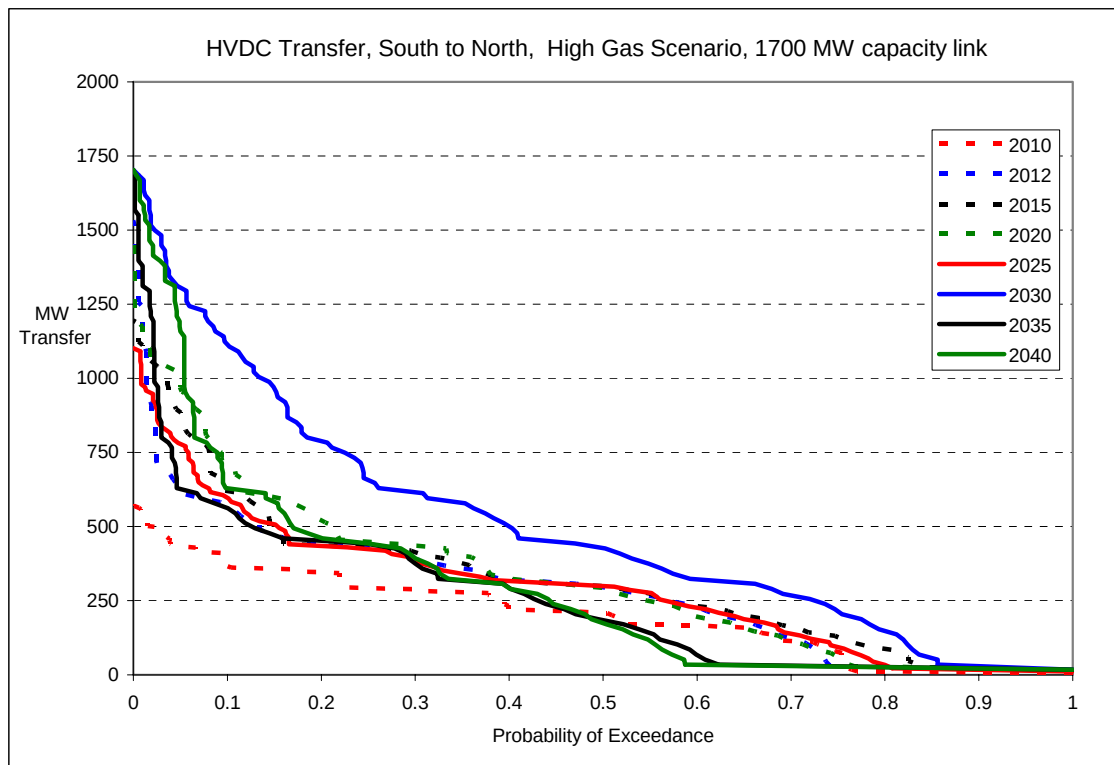


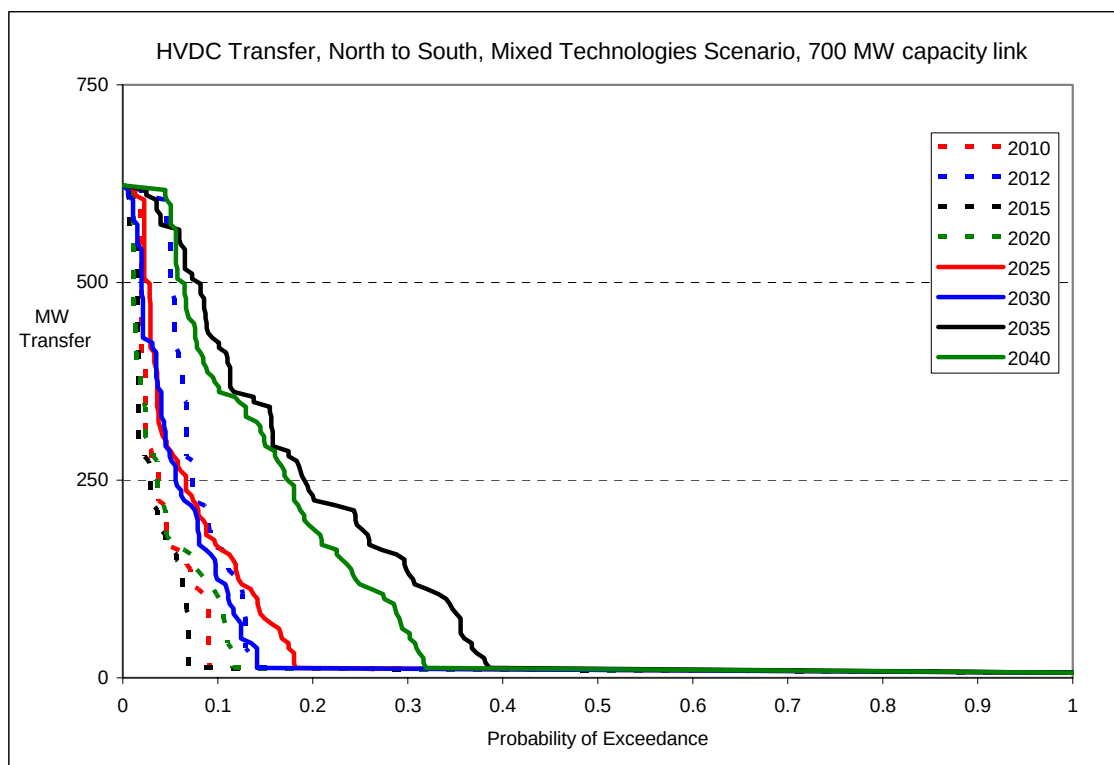
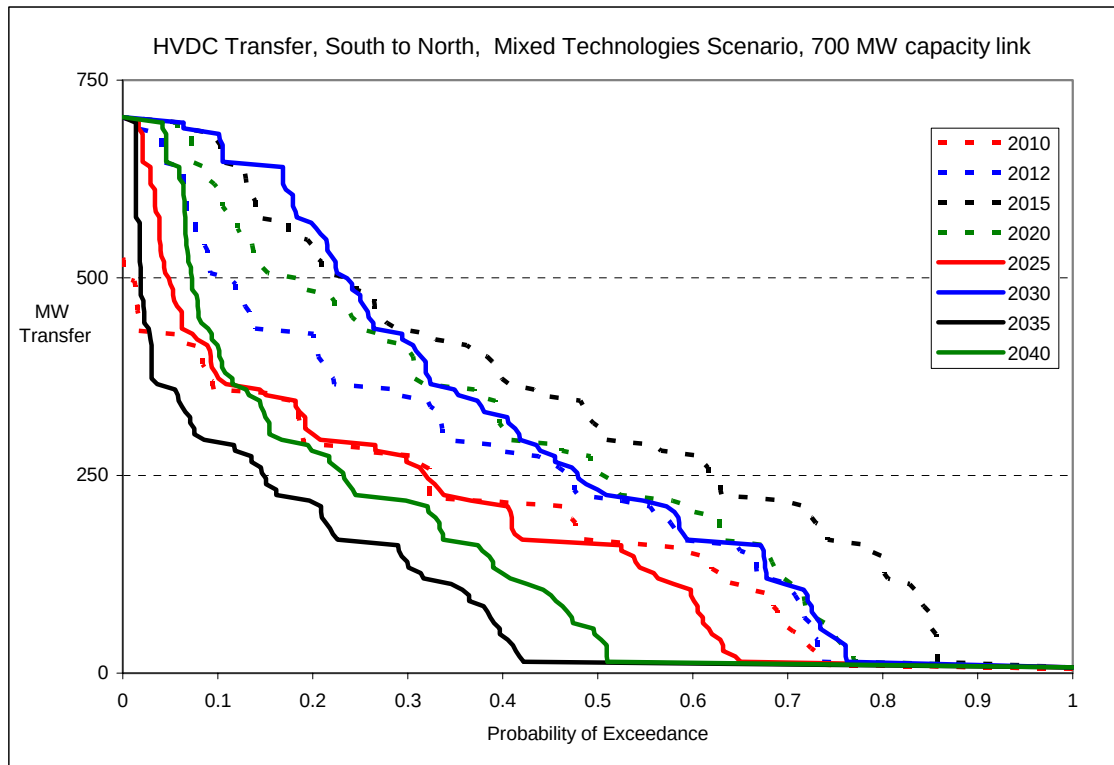
Appendix F HVDC utilisation graphs

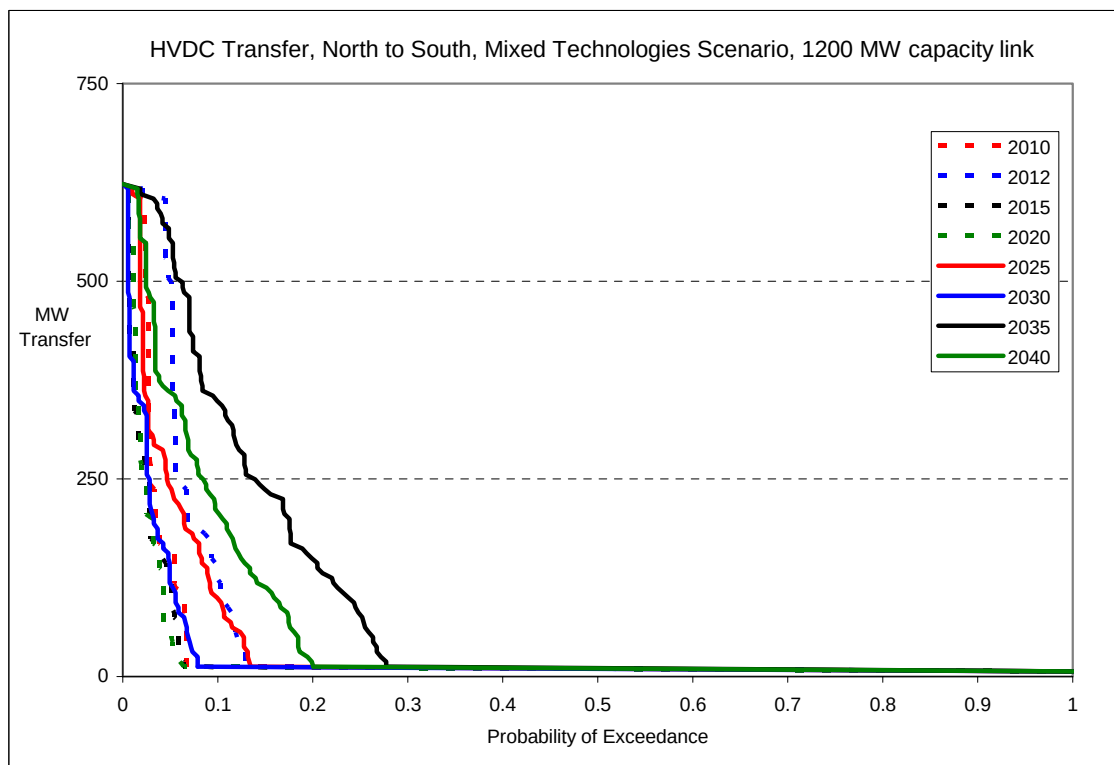
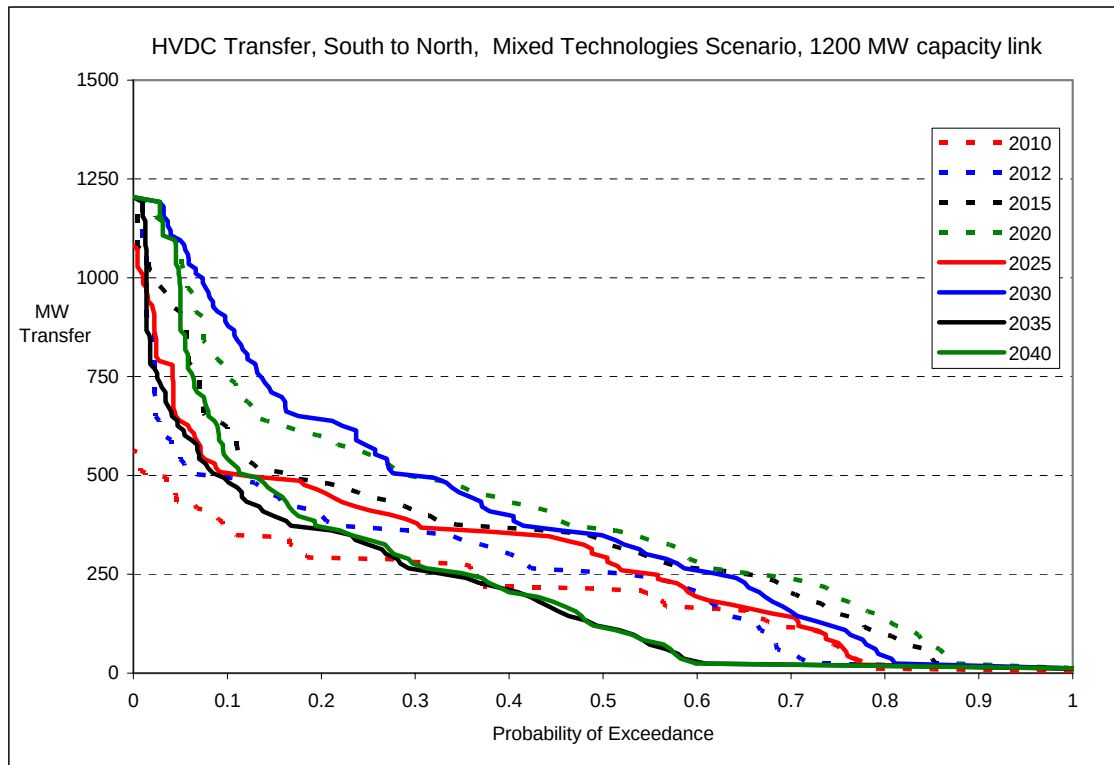


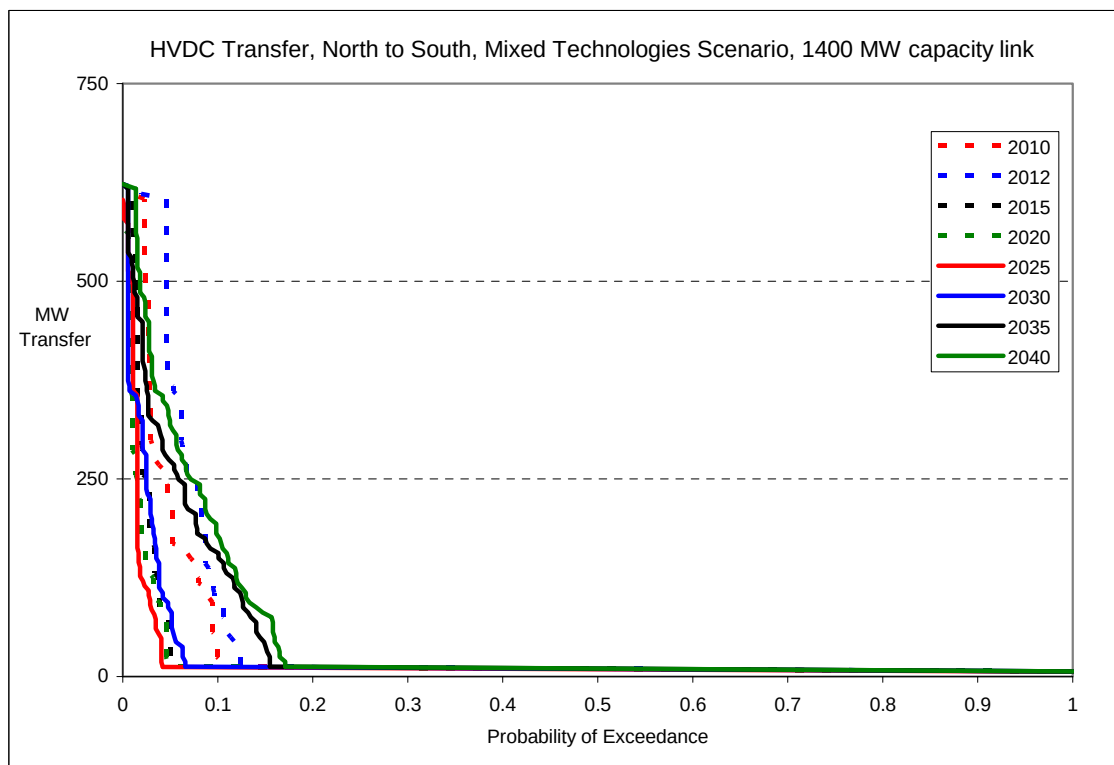
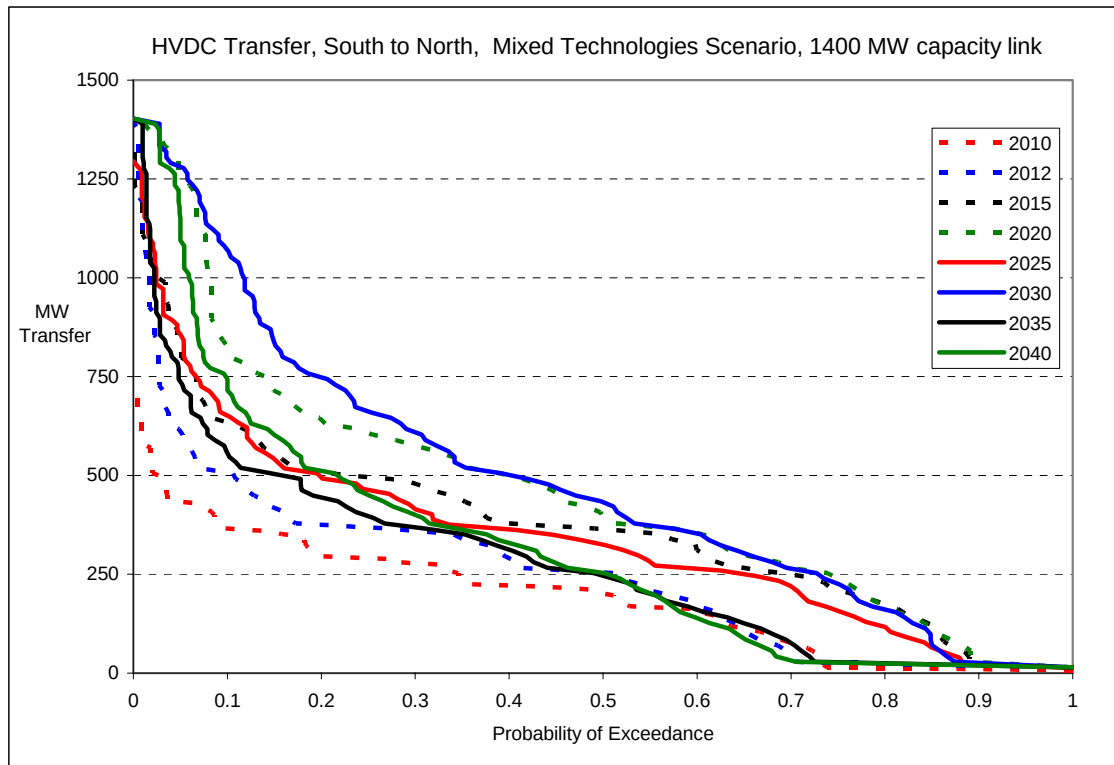


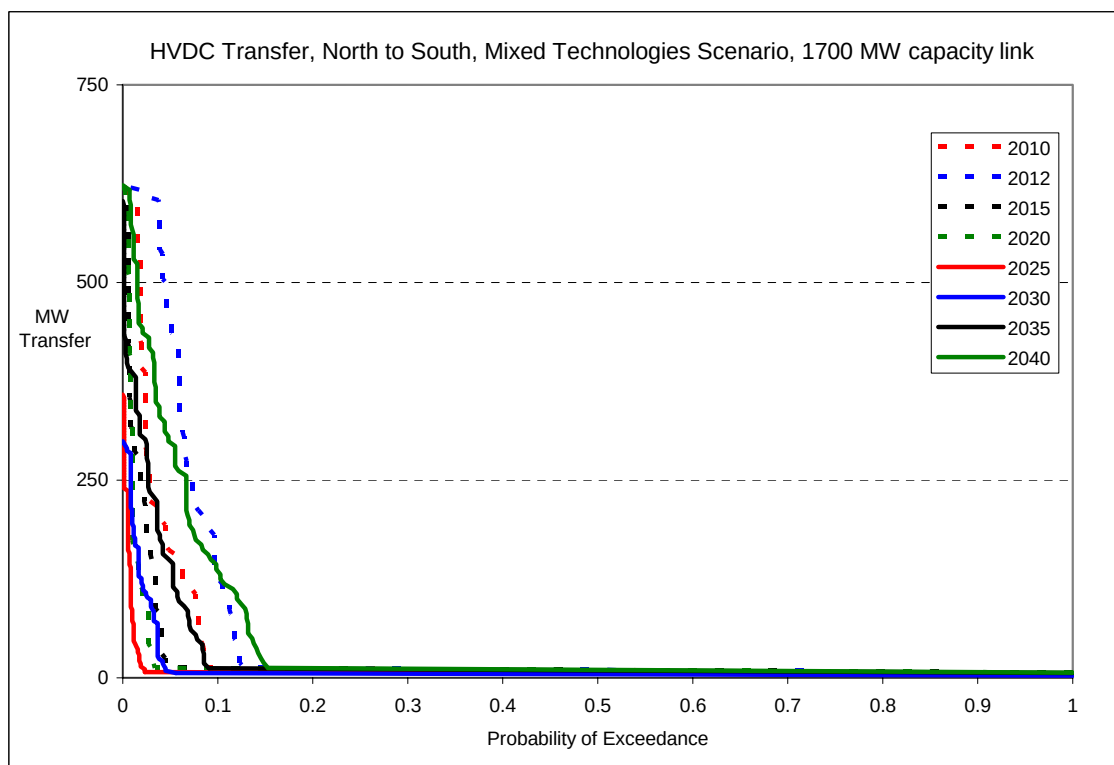
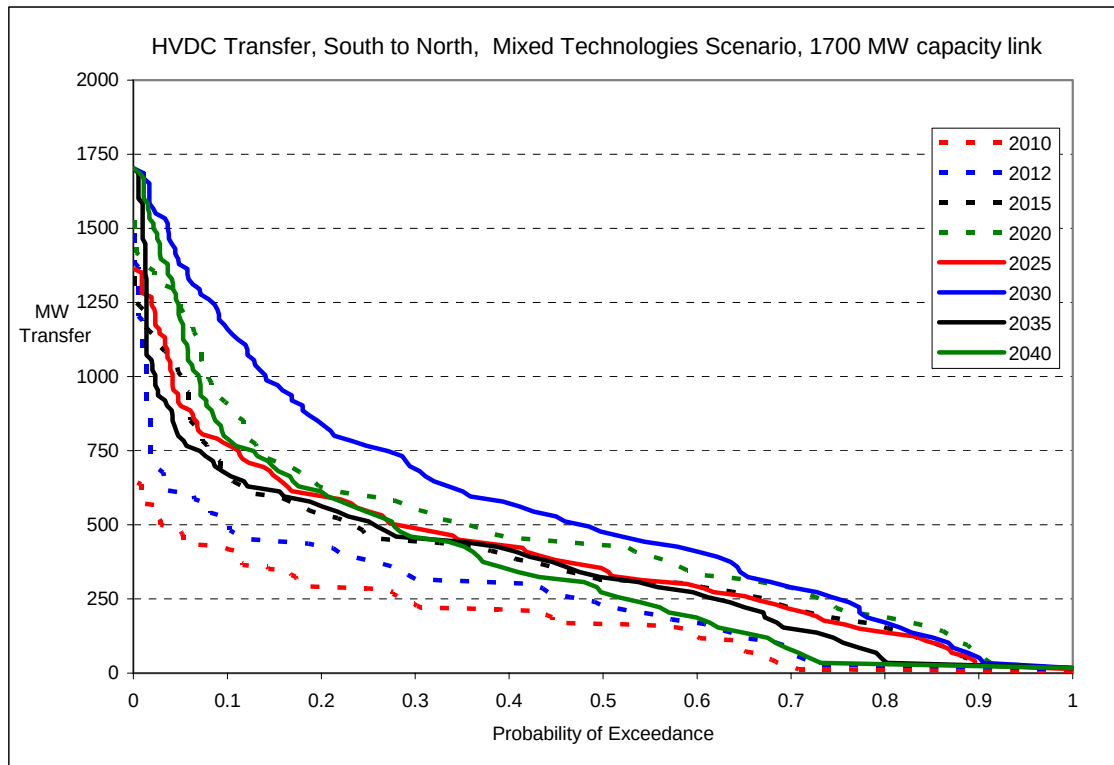


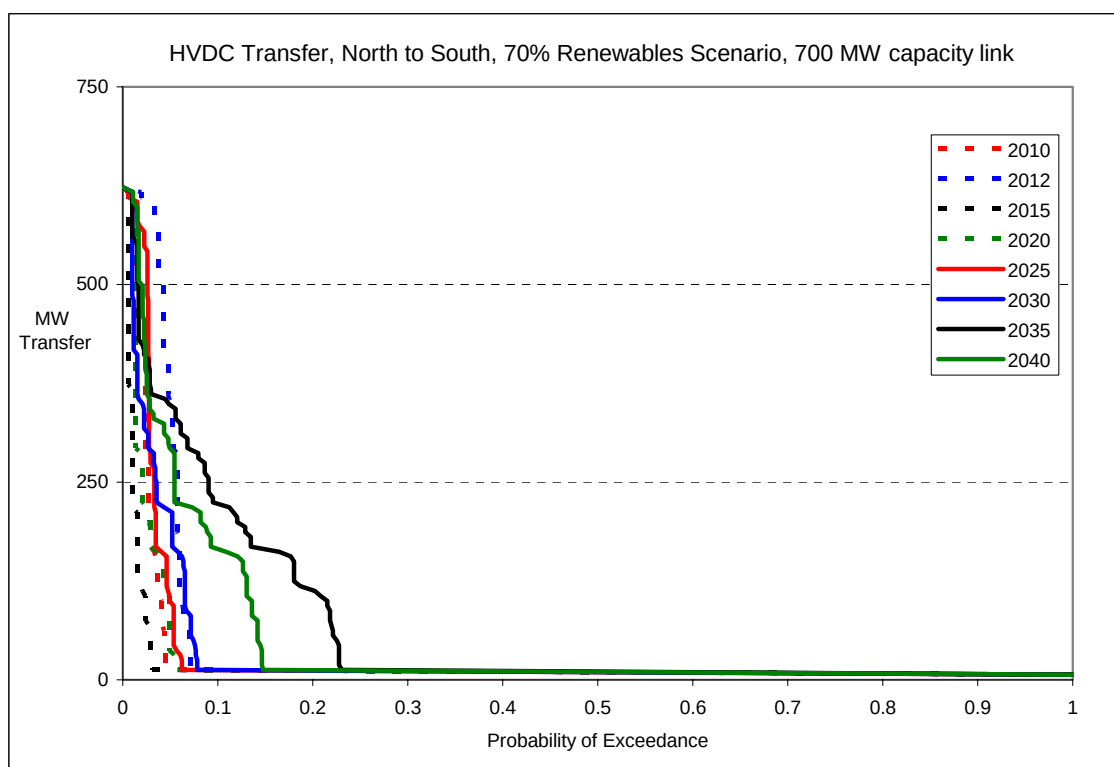
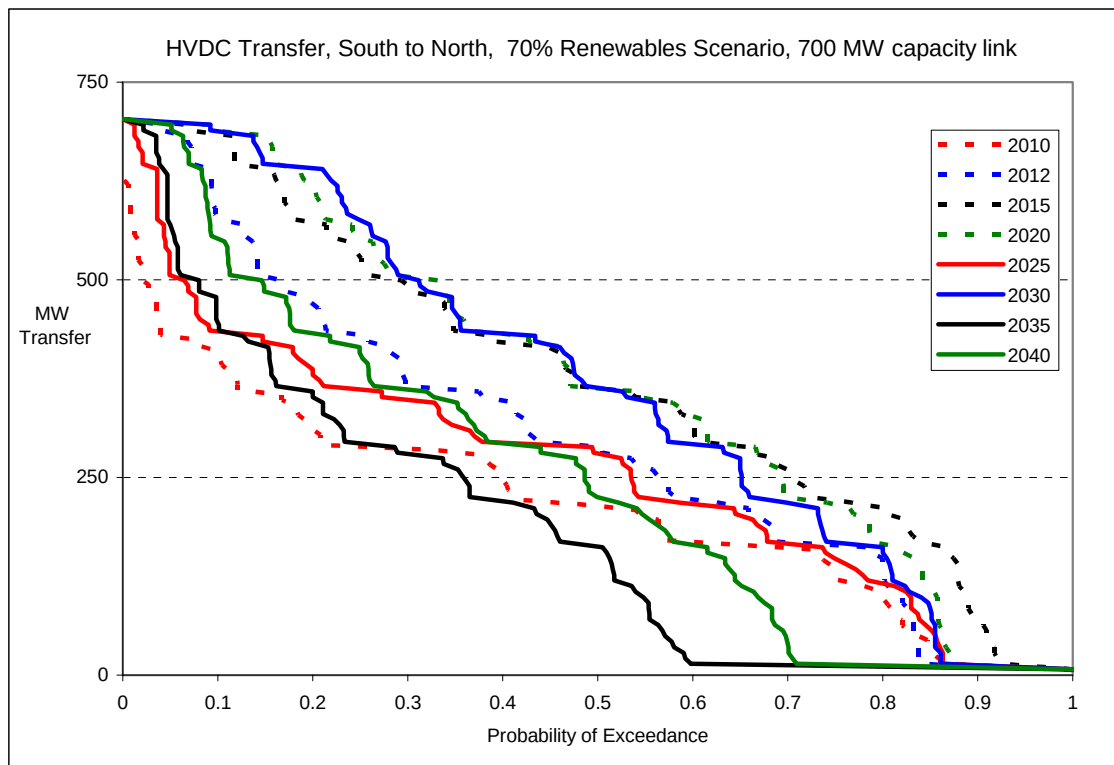


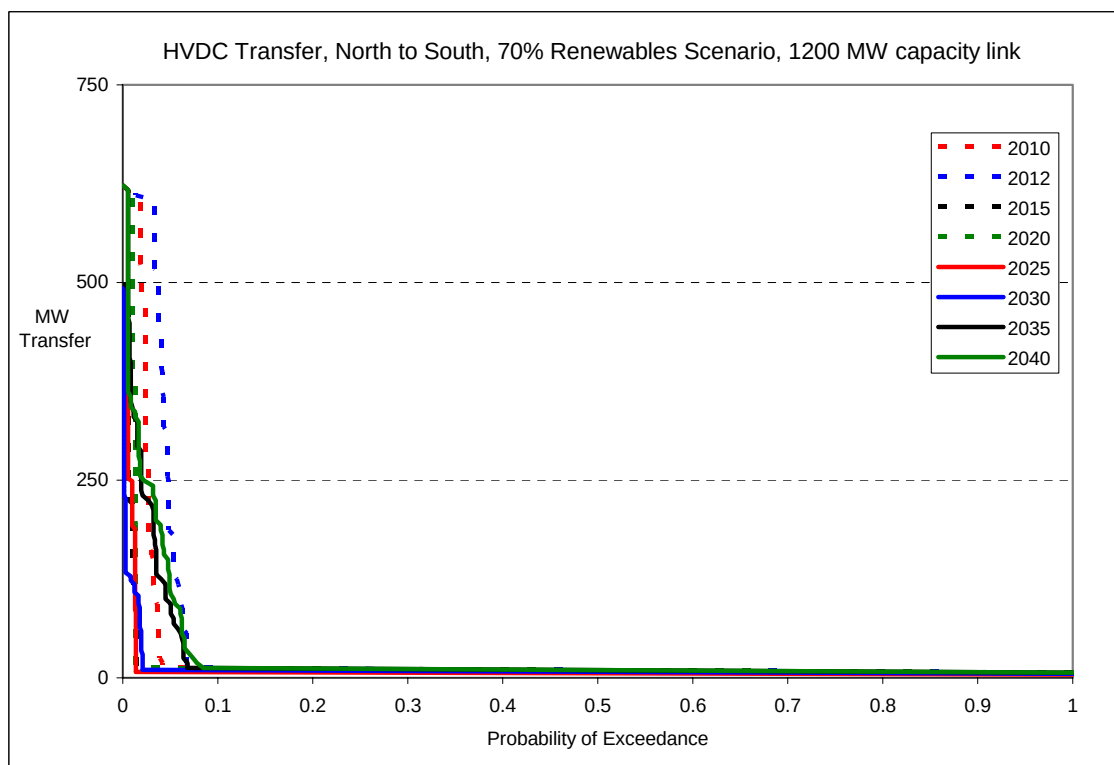
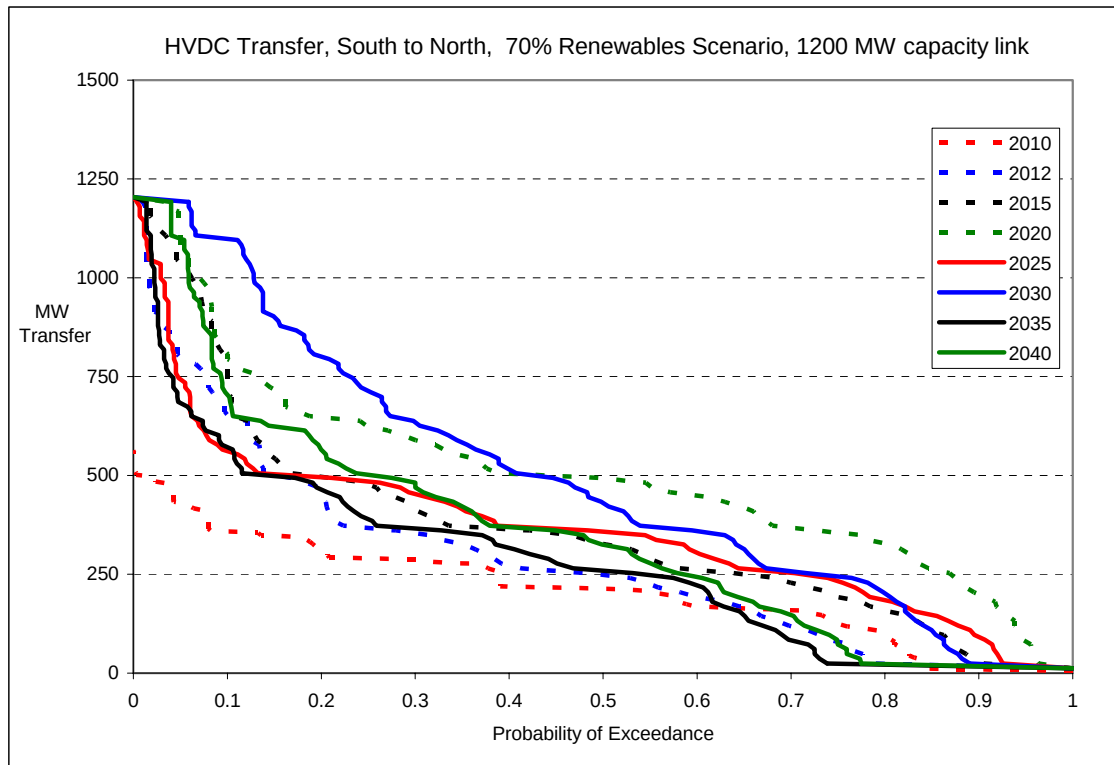


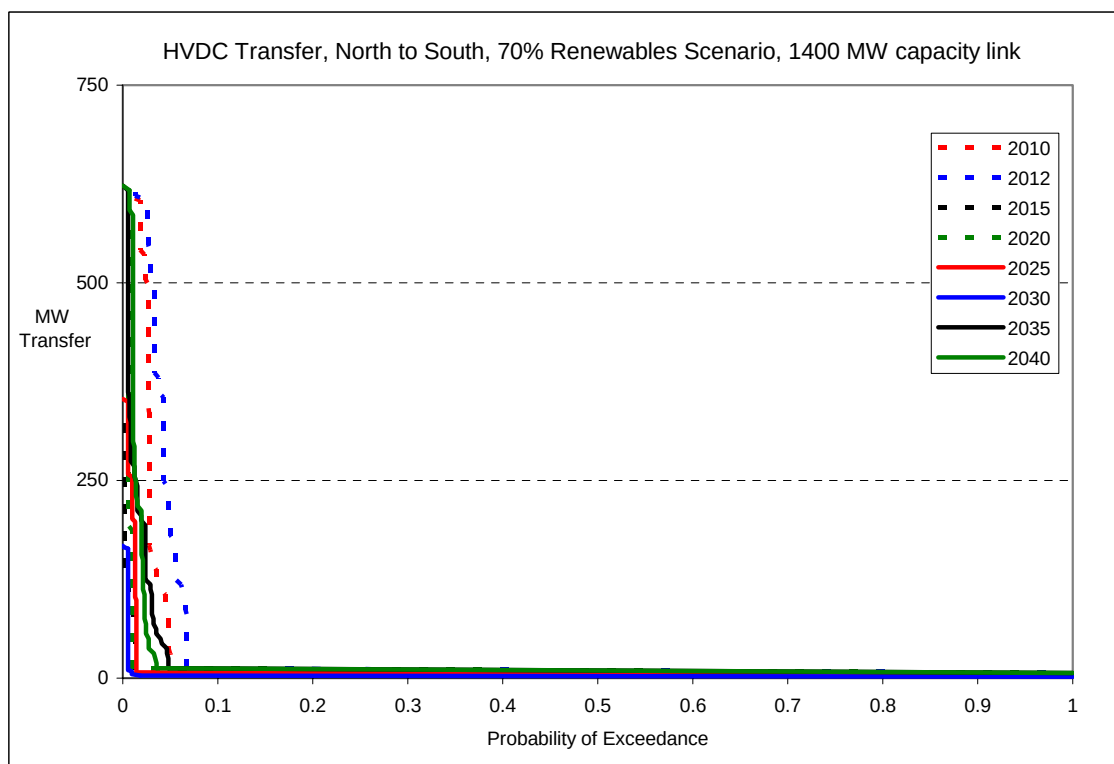
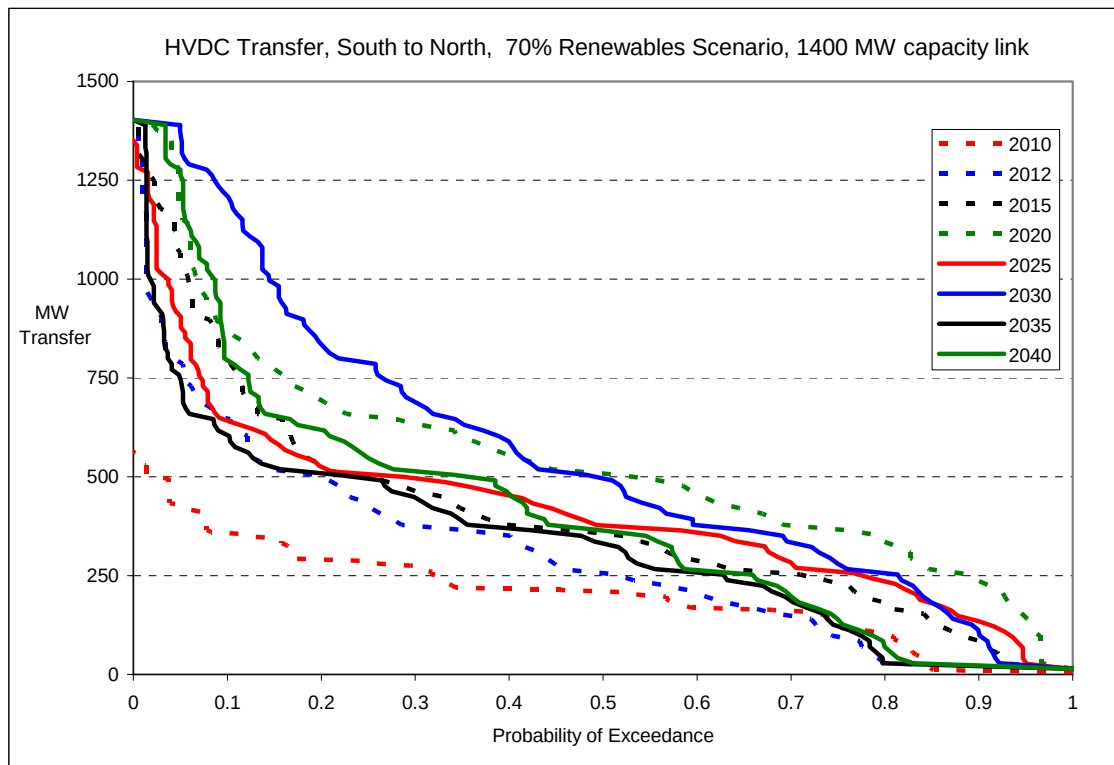


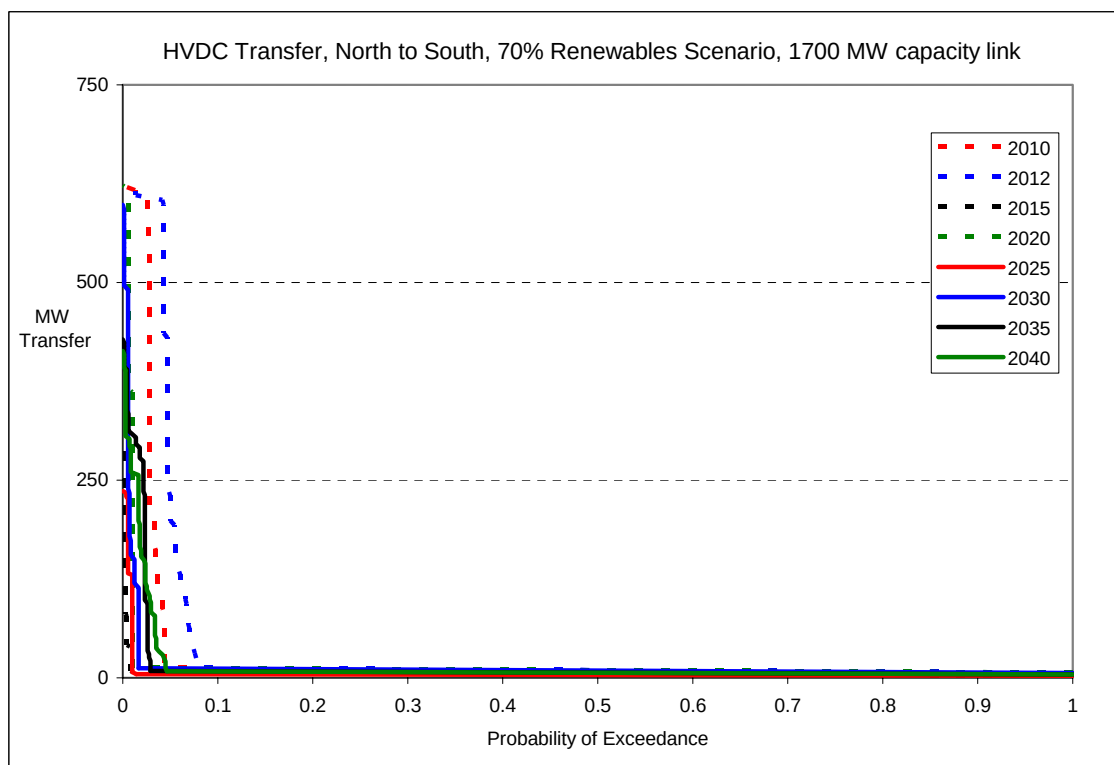
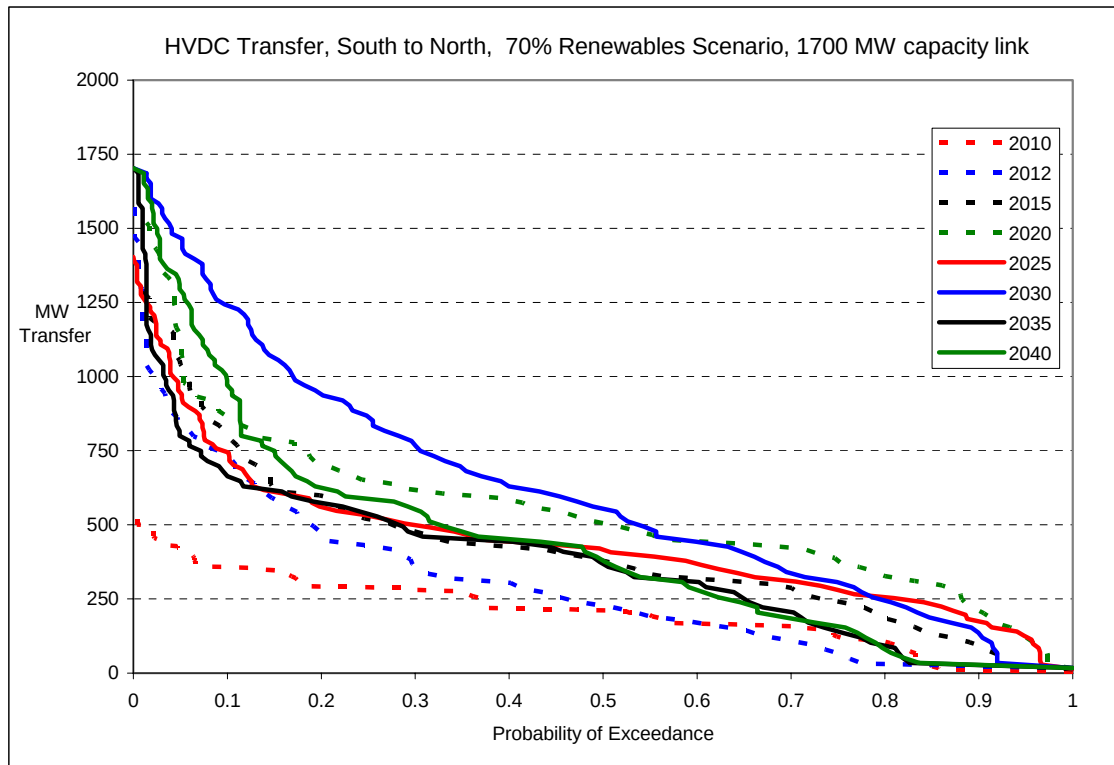


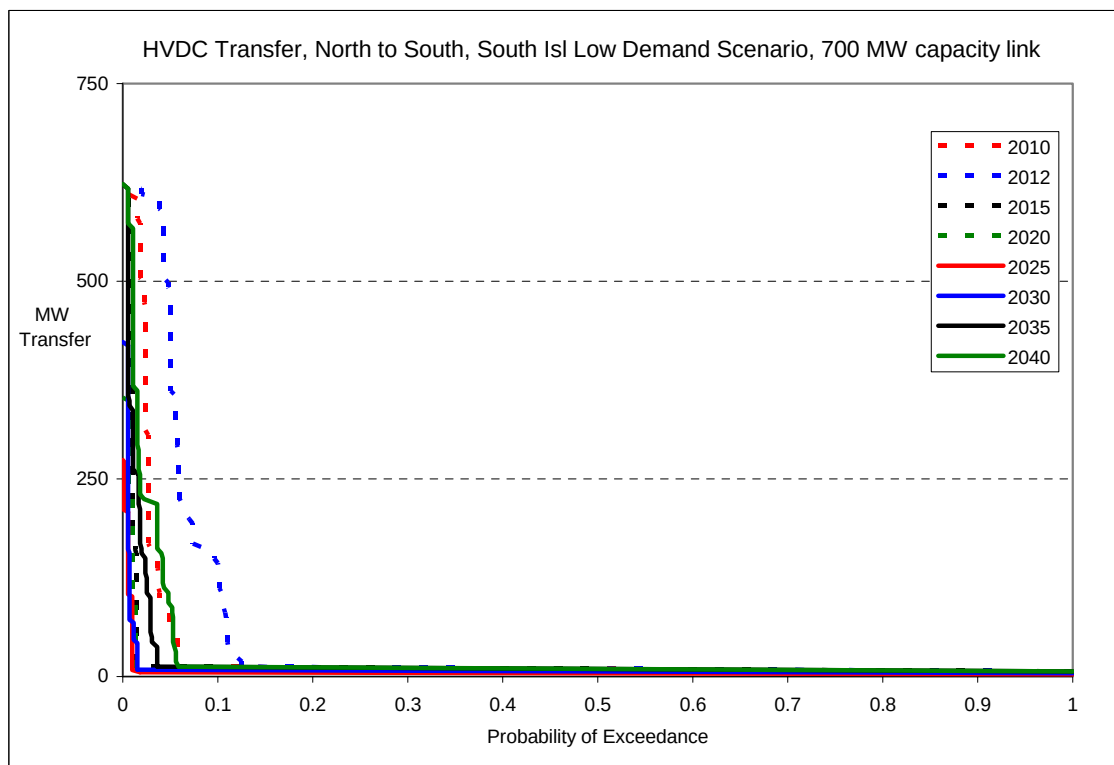
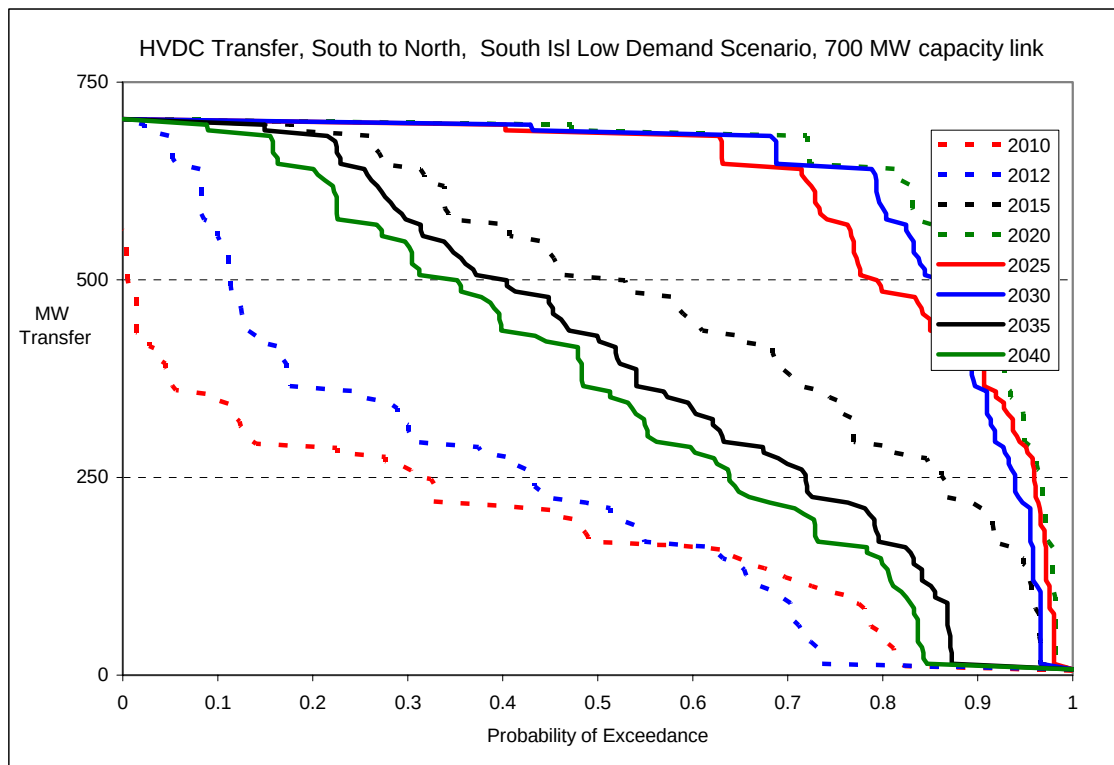


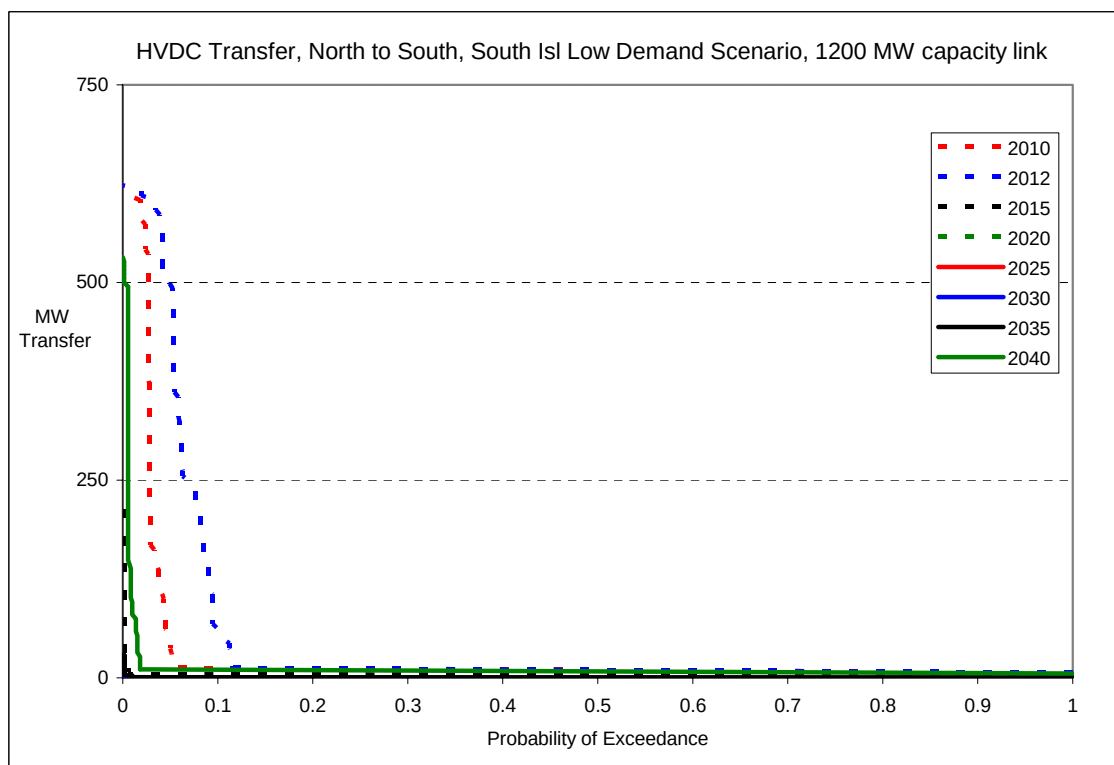
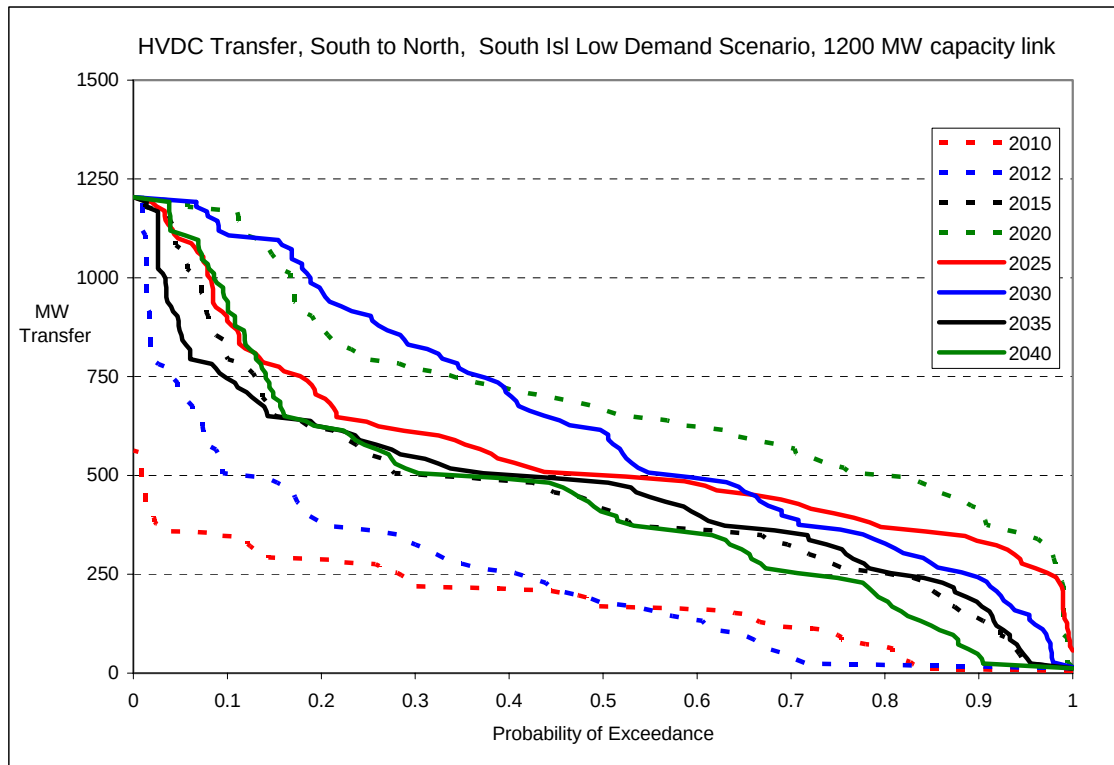


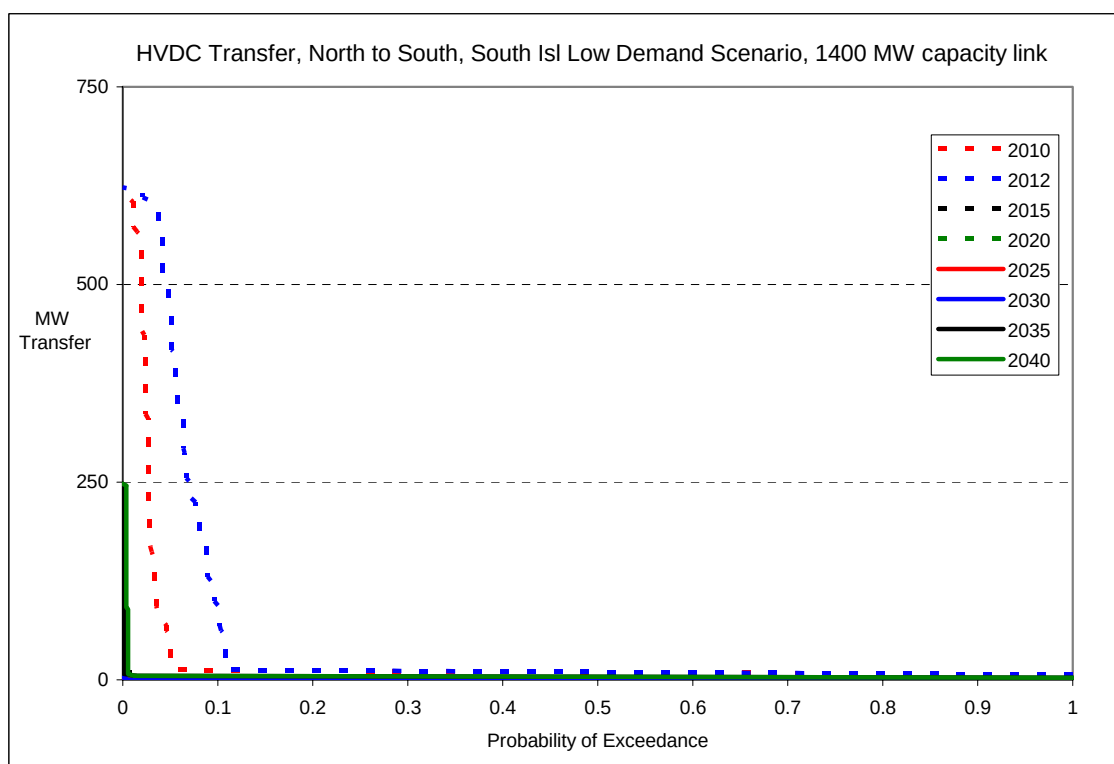
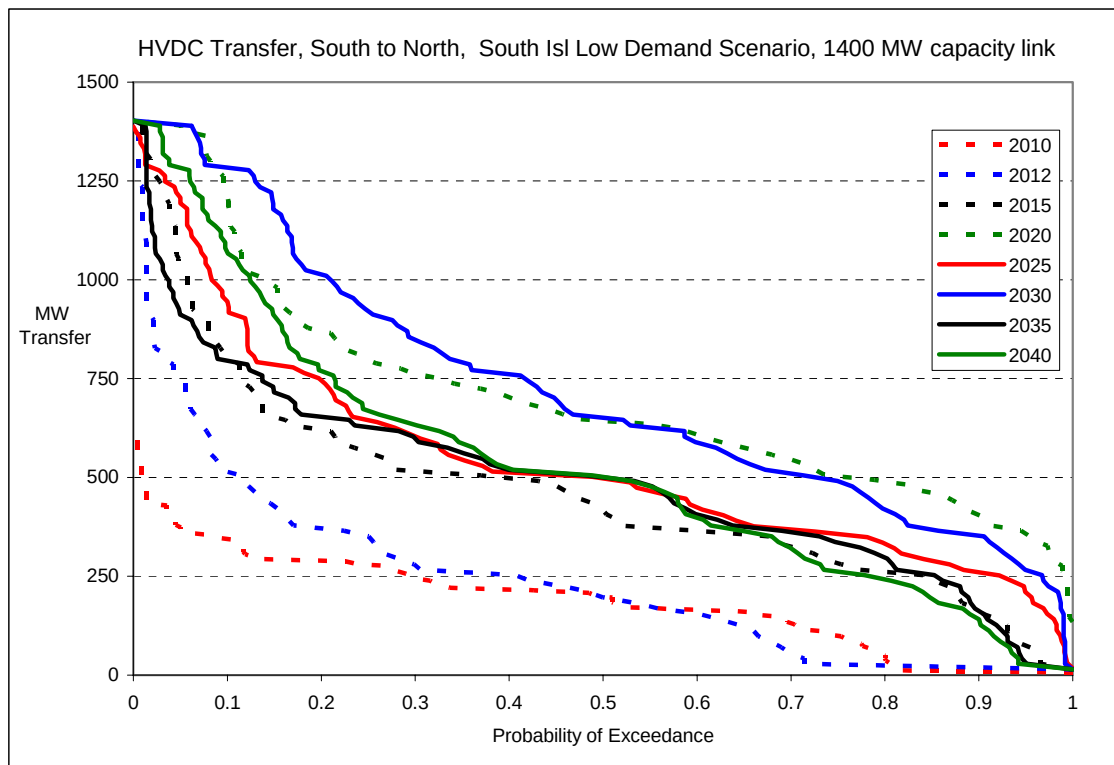


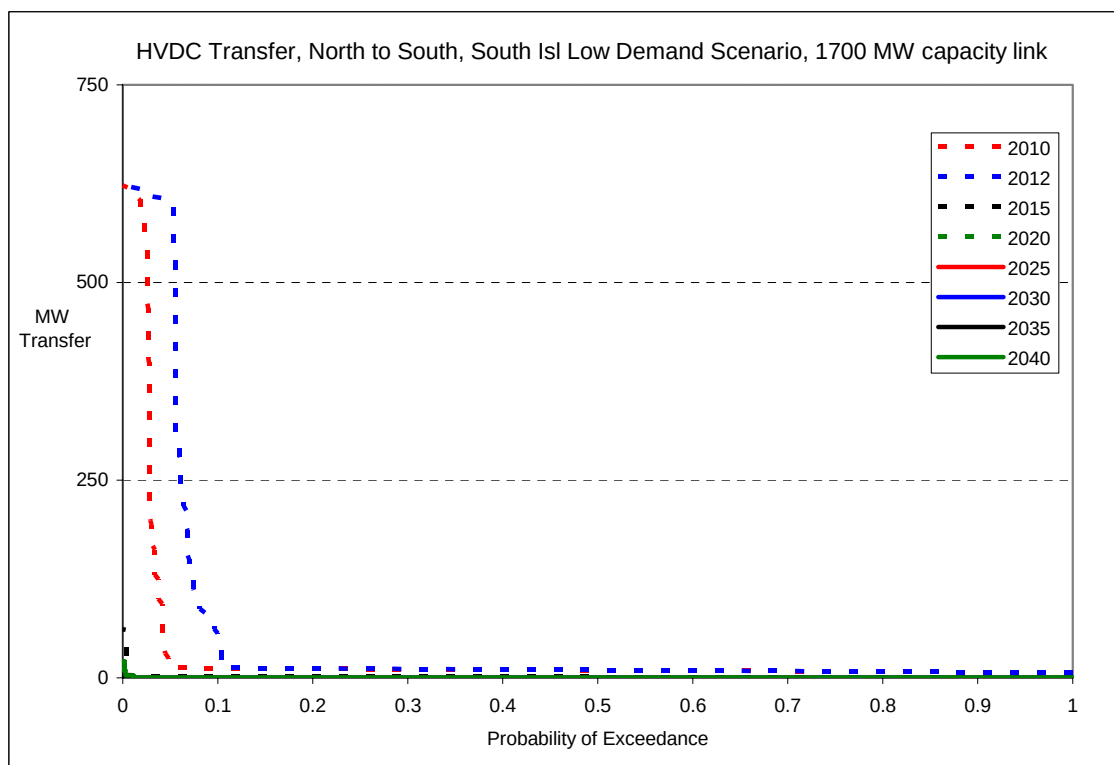
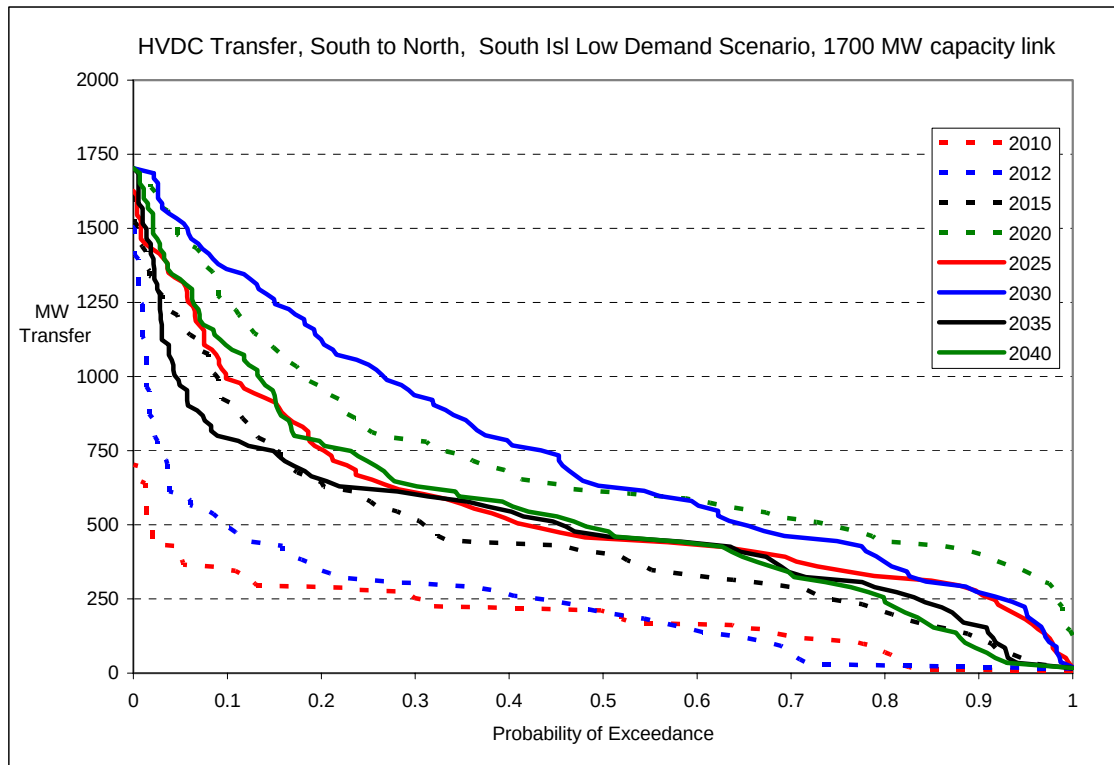


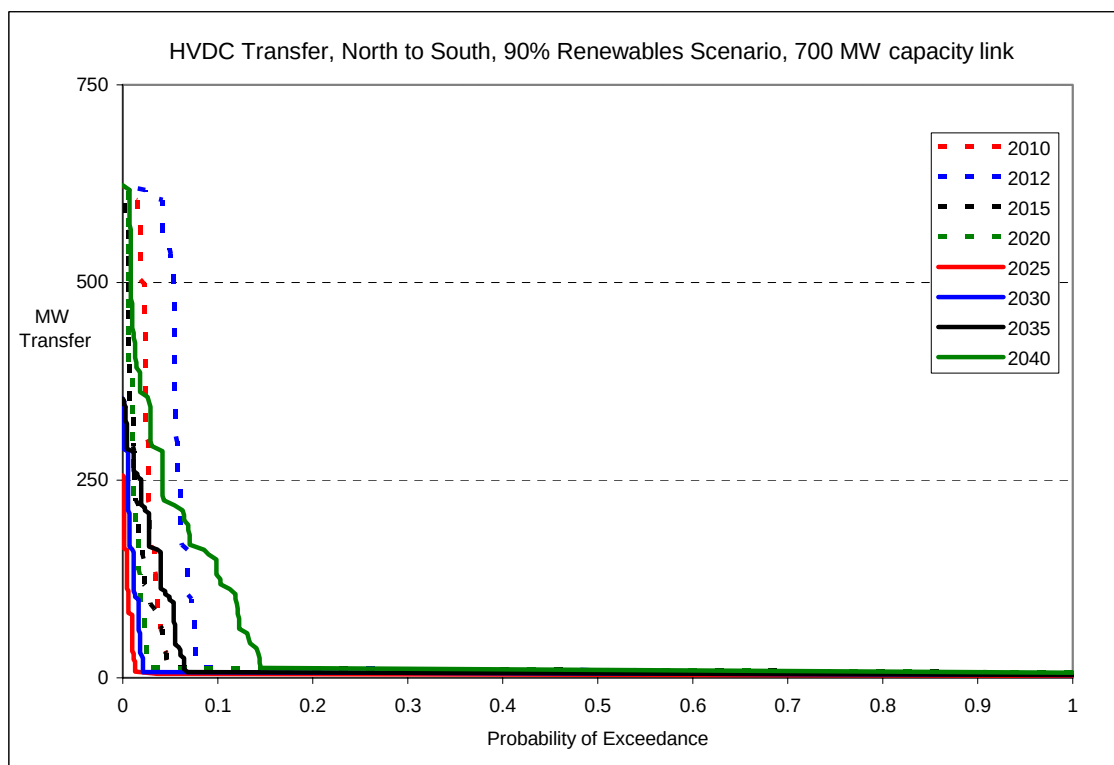
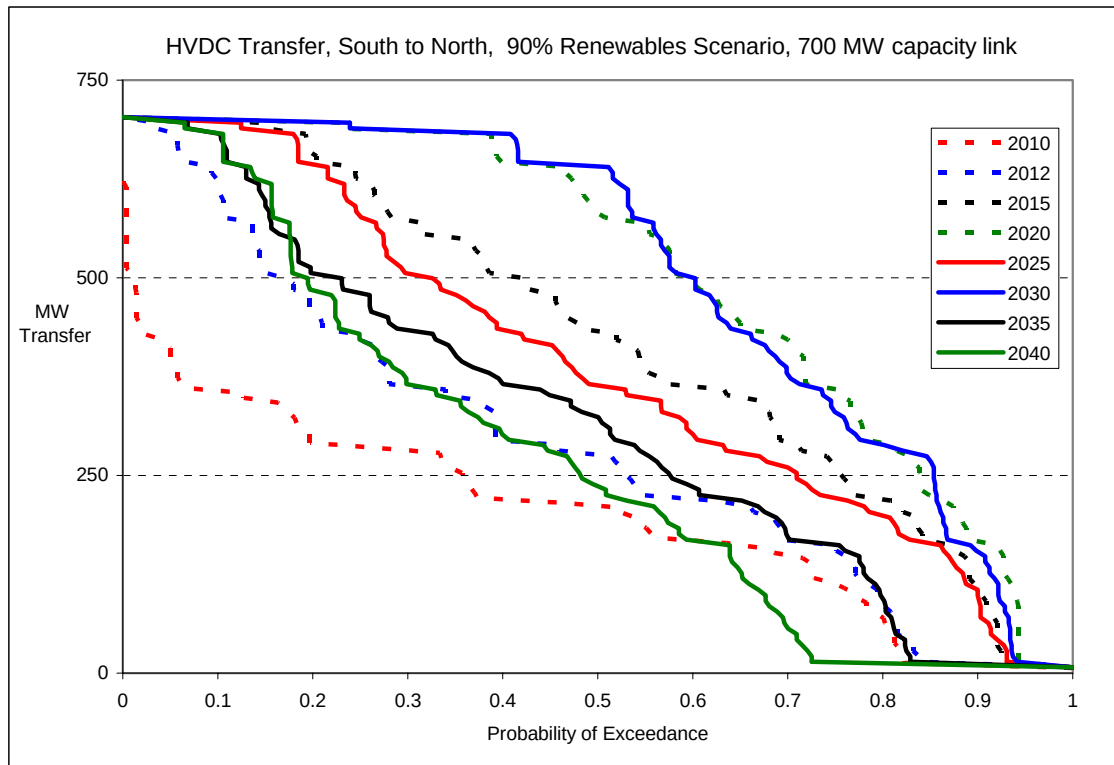


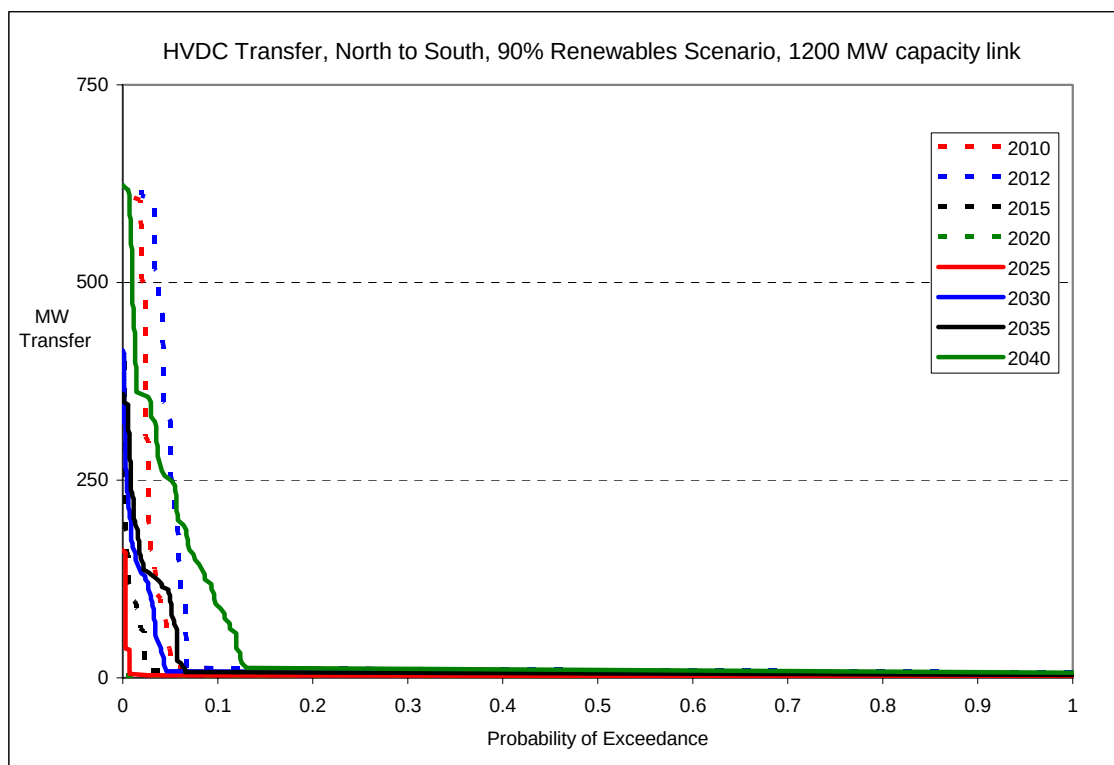
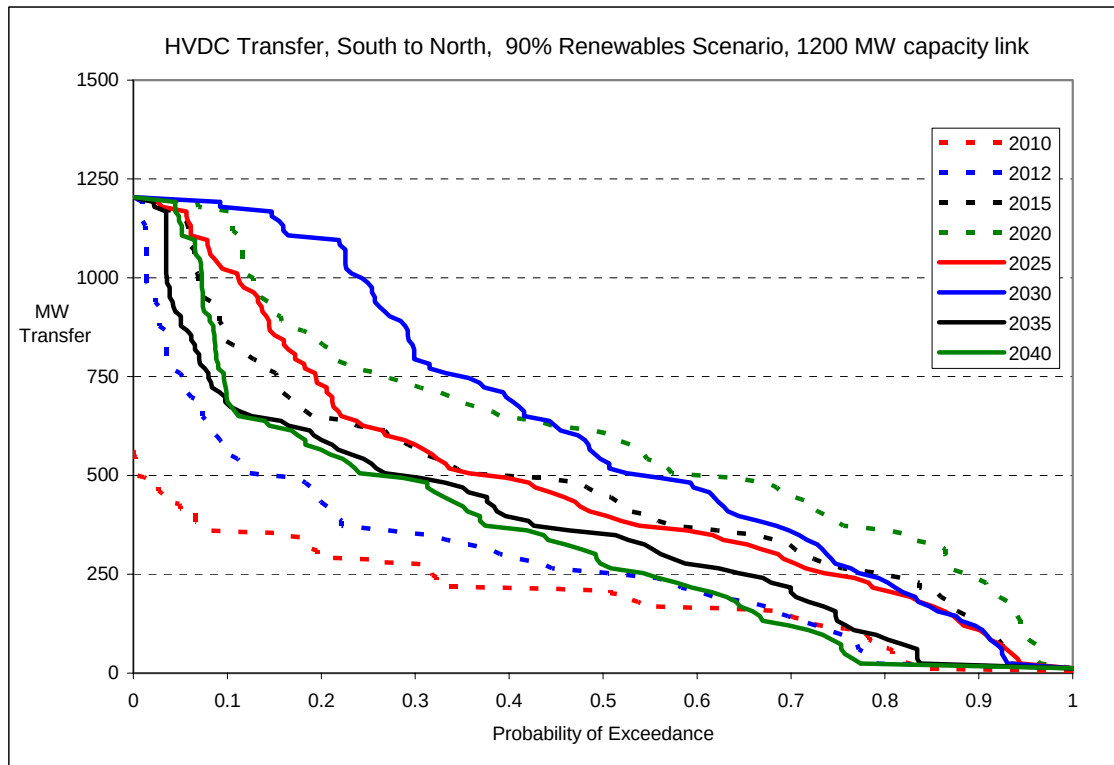


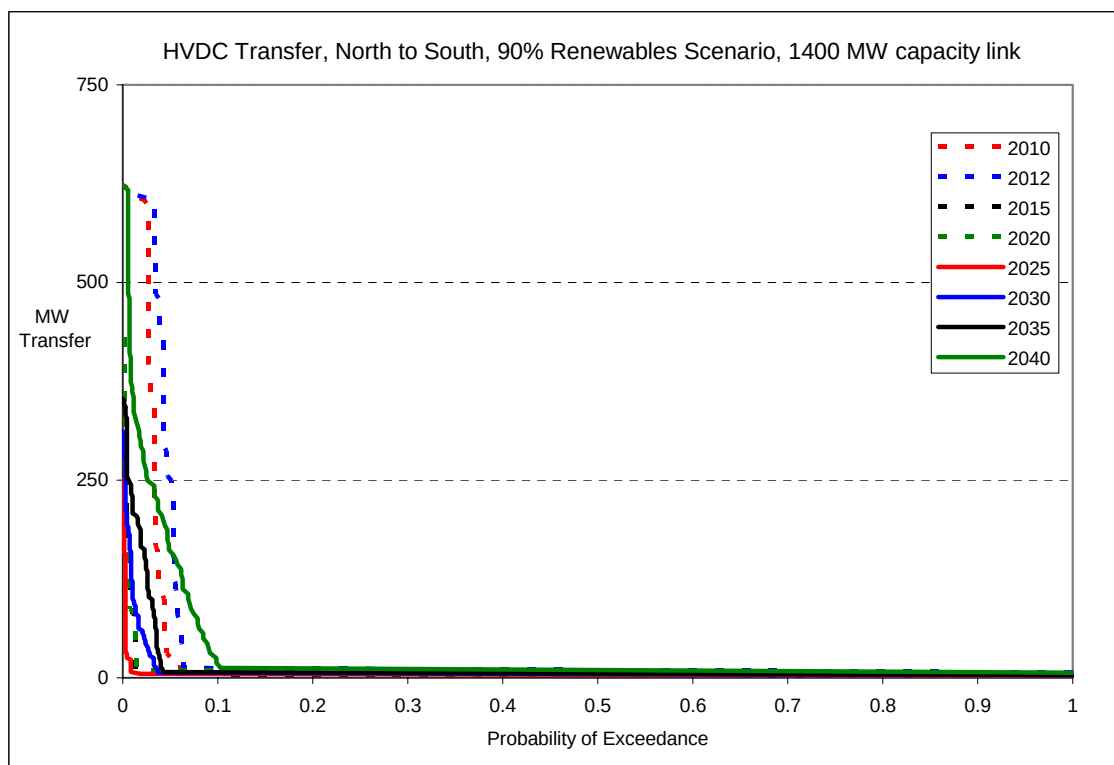
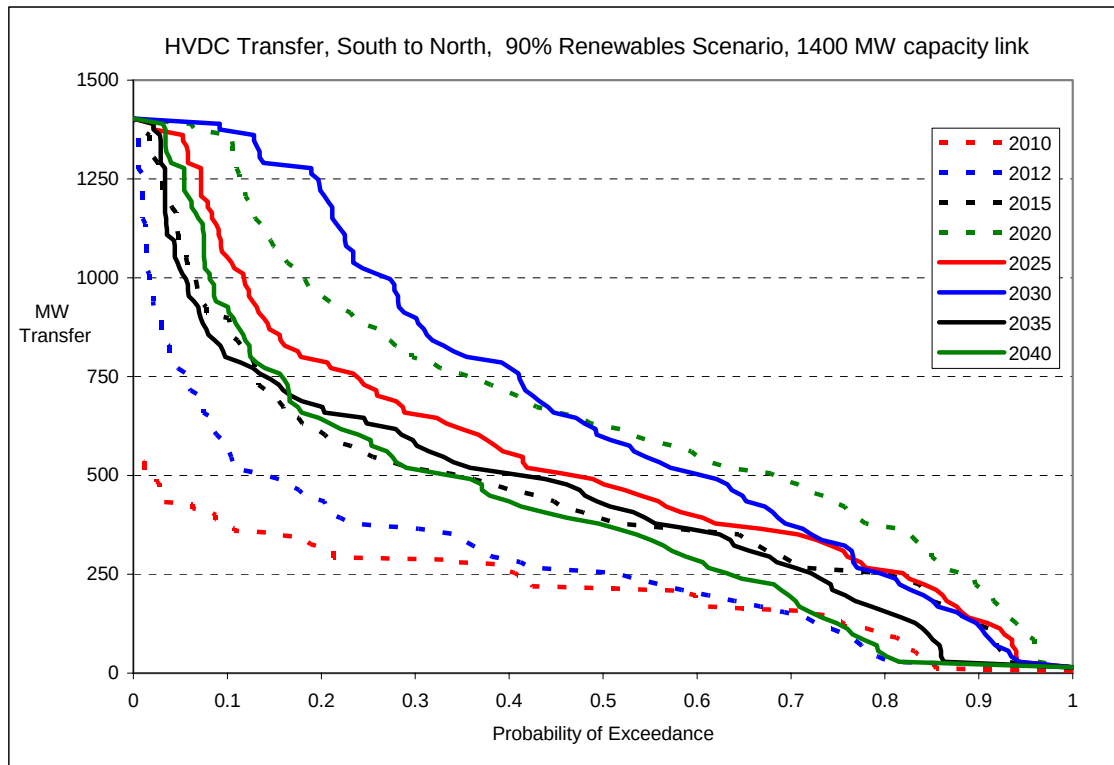


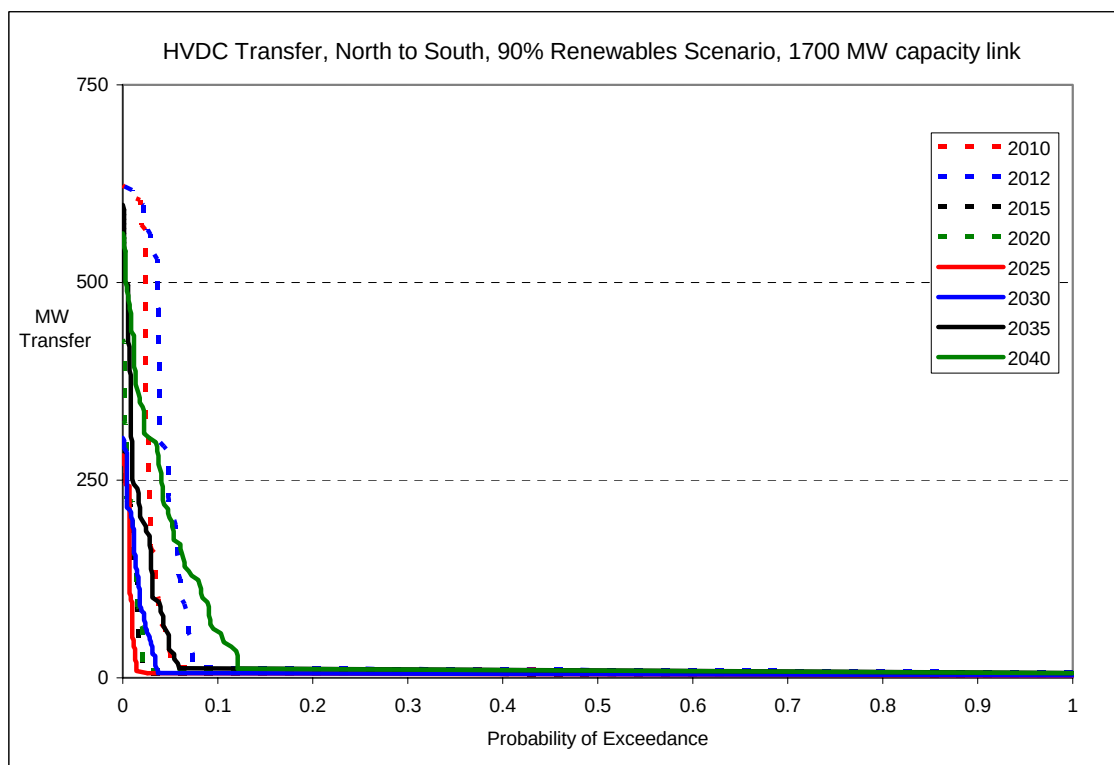
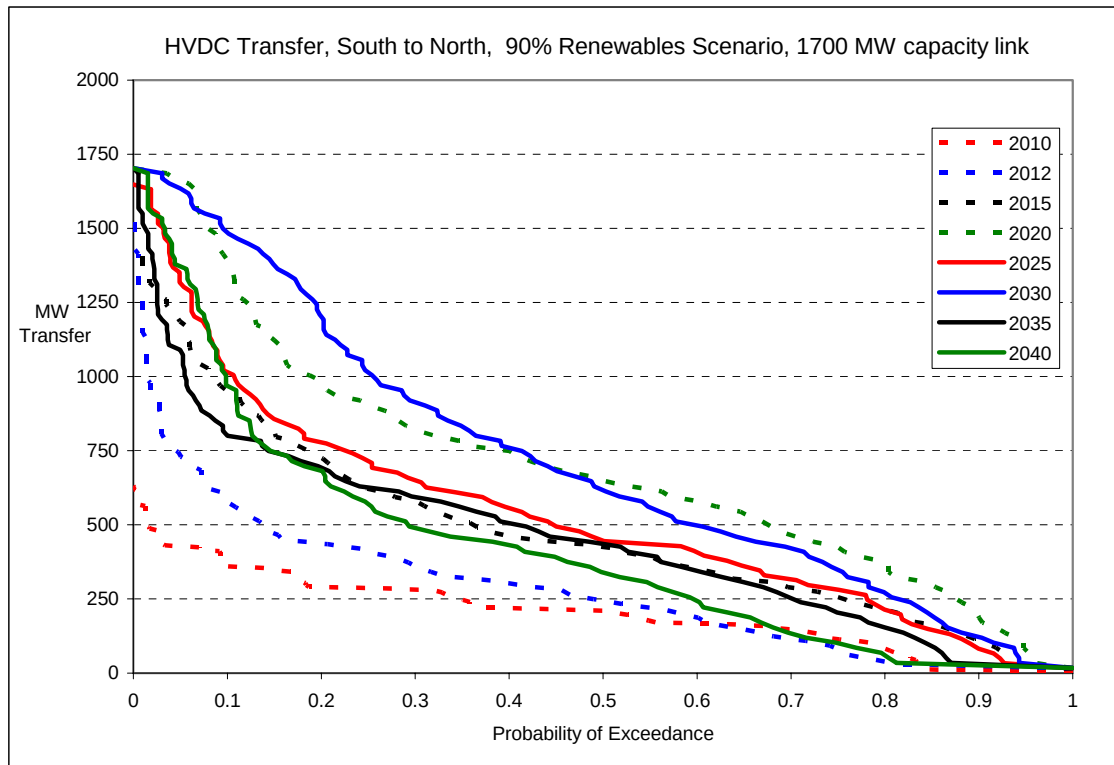














T R A N S P O W E R

HVDC Grid Upgrade Project

Proposal

Attachment B

Revised MAV Pole 1 - Economic Analysis

Doc reference: Inter-island HVDC Pole 1 Replacement Investigation/DC/Consult/Pole 1
Recommissioning Analysis/001/Rev C

May 2008

Document Revision Control

Document Number/Version	Description	Date
001/Rev A	Initial document	2008-02-01
001/Rev B	Terminology change - 'Base Case' changed to 'Reference Case' to differentiate it from the 'Base Case' used within the GIT. Minor editorial changes.	2008-02-07
001/Rev C	Updated with new analysis to assess the impact of New Plymouth being out and the intermittent operation of Pole 1 now in place.	2008-05-02

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Executive summary

Following a request from the Electricity Commission on 7 January 2008, Transpower has carried out a high level economic analysis for a hypothetical situation where full service operation of the existing Pole 1 of the HVDC link (Pole 1), or half of Pole 1, is possible beyond the earliest likely commissioning date of a new Pole 1 (i.e. 2012). This represents a period of future operation which would be more than twice as long as the one to two years recommended by an environmental report commissioned by Transpower by Resource and Environmental Management Limited (the Environmental Report)¹.

The purpose of the economic analysis is to determine whether this hypothetical situation could reasonably provide benefit by hypothetically deferring the preferred HVDC Pole 1 replacement option as determined by the GIT. As such, the analysis attempts to identify whether there would be any significant net market cost in complying with the Environmental Report's recommendations, without comprehensive regard to all of the practicalities that arise from not carrying out the report's recommendations.

Following feedback from the Electricity Commission on the earlier versions of the document, Transpower has extended the analysis and discussion around it to clarify issues around the impacts from pre-2012 benefits and to update it with the latest developments in the market. The revised analysis replaces most of its previous analysis in this updated document.

¹ Environmental Risk Analysis of Pole 1, Resource and Environmental Management Limited, 18 December 2007

1 Background and purpose

Transpower has been concerned for some time about the continued deterioration in the HVDC Pole 1 assets given the age of the plant and the risks identified in the 2005 GUP².

As part of the HVDC Pole 1 Replacement Investigation Project, Transpower needed to quantify the economics of continued Pole 1 operation. To that end, Transpower commissioned an assessment from its insurance advisers in mid-2007 on the costs of insuring Pole 1. It was intended that these costs would then form part of the necessary GIT analysis for the replacement project.

Advice from Transpower's insurers was that the Pole 1 assets were uninsurable in their current state because of the potential consequences of failure, and the age and condition of the assets³. Transpower subsequently commissioned further reports on mitigation costs and timings^{4,5}.

After considering all the reports, Transpower decided on balance that it could not prudently continue to operate the Pole 1 assets other than in a limited mode of operation for a limited time, without risking a high impact event. Transpower consequently announced that it intended to decommission one half-pole and look to make the other half-pole available for limited northbound operation during peak demand periods only.

Pole 1 Assets Background

The existing Pole 1 was commissioned in 1965 and uses technology that is now obsolete. Spares are no longer available and Transpower has had to procure 'used' spares when other similar links overseas have been shut down. One other similar link remains in operation – but as a backup supply only.

The existing assets were built to different standards (inadequate by modern standards), and pose consequential environmental risks that are very costly to mitigate and, in the case of mercury, remain intrinsic to the technology and cannot be fully mitigated.

Although robustly constructed at the time, the ageing assets have uncertain future performance, and repairs and refurbishment are very expensive.

Even if some components are refurbished, many components are aged and expected to have increasing failure rates with failed components difficult to repair or replace. There is a risk that the refurbishment costs could be stranded if performance drops or a catastrophic failure occurs.

The above considerations have been key drivers in Transpower expediting the HVDC Pole 1 Replacement Investigation Project.

HVDC Pole 1 Replacement Investigation Project

At the commencement of the HVDC Pole 1 Replacement Investigation Project, the economics of the existing Pole 1 continuing in some form in the future were considered. To assist that analysis and determine whether it would be possible to continue operation of Pole 1 beyond 2010, Transpower engaged TransGrid Solutions to provide advice on the condition of the equipment and further engaged insurance advisers Marsh to advise on the cost of insuring against events relating to the aging Pole 1 assets. It was intended to use these costs in the GIT analysis for Pole 1 replacement.

² HVDC Grid Upgrade Plan, Sep 2005 submitted to the Electricity Commission

³ Risk Analysis Pole 1 HVDC Link, Marsh, 19 September 2007

⁴ Pole 1 Risk Mitigation Evaluation for Continuous Operation, Marsh, 18 December 2007

⁵ Environmental Risk Analysis of Pole 1, Resource and Environmental Management Limited, 18 December 2007

Professional Advice Received

In its initial report⁶, Marsh advised that the Pole 1 assets, because of age and condition, had potential modes of failure with severe consequences. It was Marsh's opinion that these assets were uninsurable in current operating condition.

The Marsh report was additional to the condition assessments of Pole 1^{7,8} which highlighted the risks of continuing with 40+ year technology that was no longer supported by any manufacturer. Those assessments resulted in Transpower limiting Pole 1 to northward flow only, to limit the stress to transformer windings from 'arc backs' during southward flow.

The initial Marsh report showed that Transpower could not prudently continue to operate the Pole 1 assets with the risks as reported and so Transpower initiated further work to quantify these risks and potential mitigation measures.

The second Marsh report⁹ identified the mitigation works required to make the assets insurable. These works are significant and would take two or more years to complete.

Transpower also commissioned the Environmental Report¹⁰ to address issues related to oil and mercury contamination. One of the conclusions of this report was that the assets should only be operated for 'one to two' more years (i.e. less than the period required for mitigation), and only in a limited mode of operation. Given these timeframes, the mitigation works described by Marsh¹¹ are not reasonably expected to enable the deferment of an investment of a new replacement Pole 1 for a period of 12 months or more. In addition, the probability of any significant benefit arising from the mitigation works is expected to be low.

On the basis of the identified risks, the costs of mitigation and the uncertain operating future of the aging assets and obsolete technology, Transpower has closed one half of Pole 1¹². This physically removes half the risk.

In order to mitigate potential supply security risks, Transpower is seeking to make the remaining half pole available until a new pole is operational. Operation would be restricted to periods of shortage and would avoid southward flow.

High Impact Low Probability (HILP) events

Both Transpower and its advisors consider that there is a risk of a catastrophic failure if the existing assets are operated in an unrestricted manner for an indefinite period. This is due to the complexity of the assets, their age (and hence reliability) and technology.

Post-event analysis of a severe failure event would raise questions of prudence in operating aged and obsolete assets with known high impact failure modes.

While it may not be possible to determine whether an HILP event will occur, it is neither prudent nor good electricity industry practice (GEIP) to continue operation when it is known that an HILP event of the identified severity could occur.

Conclusions

To some commentators, Marsh's treatment of individual risks may appear overstated and, conversely, some risks may not appear to be addressed at all. Nevertheless, Transpower has concluded that on balance there are material risks that will be difficult and costly to mitigate and that some risks cannot be mitigated because of the technology used.

The consequences of a catastrophic failure cannot be ignored. Transpower cannot prudently continue to operate the Pole 1 assets other than in a safe mode of operation for a limited time without risking a high impact event.

⁶ Risk Analysis Pole 1 HVDC Link, Marsh, 19 September 2007

⁷ HVDC Grid Upgrade Plan, Sep 2005 submitted to the Electricity Commission

⁸ Pole 1 Condition and Risk Assessment Reports, TransGrid Solutions, 3 October 2007

⁹ Pole 1 Risk Mitigation Evaluation for Continuous Operation, Marsh, 18 December 2007

¹⁰ Environmental Risk Analysis of Pole 1, Resource and Environmental Management Limited, 18 December 2007

¹¹ Pole 1 Risk Mitigation Evaluation for Continuous Operation, Marsh, 18 December 2007

¹² <http://www.gridnewzealand.co.nz/n960.html>

Should Transpower continue to operate the existing Pole 1 assets and if a high impact were to occur, the knowledge of the risks enumerated in the Marsh and environmental reports would place Transpower in a position where it has not acted prudently and exercised an appropriate level of duty and care.

Operation of a half pole under limited conditions for short periods of time to meet system emergencies may be achievable because of the measures in place to limit the risk, such as the closure of (the other) half pole, the short exposure period and the removal of high risk modes of operation. This represents a balance between the consequences of not having a half pole available and risk of a high impact event.

The proposed restricted operation of the existing assets has the potential to deliver capacity benefits to the North Island for no additional investment. There is a risk that if the assets are run in an unrestricted mode, a failure could lead to the full shut down of Pole 1, potentially foregoing any further benefits of operating in a restricted manner.

Summary

Given the timeframes required to complete mitigation work on Pole 1 (i.e. two or more years) and the limited future remaining life of Pole 1 (i.e. one or two more years) mitigation works are not reasonably expected to enable deferment of a new replacement Pole 1 investment for a period of 12 months or more. In addition, the probability of any significant benefit arising from the mitigation works is reasonably expected to be low.

Based on the above, implementation of mitigation works required to extend the life of the existing Pole 1 is:

- not reasonably practicable; and
- not considered reasonably likely to proceed.

In addition, Transpower does not consider it prudent nor GEIP to continue Pole 1 operation in full service when it is known that an HILP event of the identified severity could occur.

The purpose of the analysis is to identify whether complying with the environmental recommendations will impose any significant costs on New Zealand as a whole.

2 A quantitative, model based analysis

Transpower has updated its previous analysis into the economics of Pole 1 recommissioning to reflect market developments and other changes to its GIT analysis. Its previous analysis is set out at Attachment F to the Consultation Document (see Volume 2).

One major change is that Transpower is already decommissioning one half pole. The remaining half pole has been made ready for emergency operation during winter periods. Any analysis therefore focuses on the recommissioning of a half pole.

Transpower considers that 2012 is the optimal timing of Stage 1 of the Proposal, as set out in Section 5.7 of the Proposal. Transpower's quantitative analysis, therefore, focuses on the costs of complying with the recommendations of the Environmental Report. That is comparing the net benefits of carrying out Stage 1 of the Proposal in 2012 to a full reinstatement of the half pole for a longer time horizon, so no replacement takes place till 2014, 2016 or 2018.

Transpower's other main updates to this analysis are:

- The base case reflects Pole 1 being available for emergency operation (winter quarter, 200 MW max, north transfers only) in 2008-2009. From 2010, Pole 1 is available all year with 270 MW capacity.
- New Plymouth power plant has been removed from service. Instead, Transpower has included 200 MW of open cycle gas turbine (OCGT) capacity at Stratford in 2009 as recently committed by Contact Energy. The model furthermore added an extra OCGT plant (150 MW) to meet the capacity constraint for the North Island.
- The analysis has been undertaken with the GEM model only.

2.1 Costs

2.1.1 Generation system costs

The GEM analysis resulted in the following scenario-weighted generation system costs, i.e. generation CAPEX as well as fixed and variable O&M costs:

Table 2-1: Scenario-weighted generation system costs by scenario (NPV, \$2007 million)

	Halfpole 2012	Halfpole 2014	Halfpole 2016	Halfpole 2018
GEM results	23515	23556	23529	23604
Difference from 2012	0	42	14	89
Linear trend	0	24	48	73

2.1.2 Costs of mitigation options

Transpower used the mitigation costs identified in the Marsh reports as the costs of migration in this analysis. The Marsh reports estimates are set out below:

Mitigation options that could return Pole 1 to an insurable condition have been considered in the body of the report and are summarised as follows:

Mitigation options	Pole configuration	Cost estimate (\$NZ millions)	Estimated lead time (Years)
Replace converter transformers and wall bushings	Full pole	200	4.5
	Half pole	115	3.5
Fully refurbish converter transformers and replace wall bushings	Full pole	150	3.5
	Half pole	87	2.5

These costs do not include any contingency and do not allow for significant relocation of, or civil works for, converter transformers. If new foundation pads had to be provided, for example, this would increase the costs. These costs also do not include those that are not readily quantified both due to natural fluctuations in market pricing and also simple uncertainty in the scale of additional work (protection, civil works, infrastructure, etc.) involved in replacing or refurbishing the converter transformers.

Accordingly, the costs identified in the Marsh reports are conservative and will fall in the lower end of the expected range. For the purpose of this analysis, the lowest cost option has been selected for the half Pole 1 option, i.e. \$87 million.

Assuming a \$3 million cost per year¹³ of operating the half Pole 1 in either full (2010+) or limited operation (2008-2009), the total NPV costs of mitigation work and operating Pole 1 is set out below. Operating costs after the replacement of a half Pole 1 are included in the HVDC costs in the following section.

Table 2-2: Mitigation cost by case

Case	\$2007 mill. NPV	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018
Halfpole 2012	83	87+3	3	3	0	0	0	0	0	0	0
Halfpole 2014	87	87+3	3	3	3	3	0	0	0	0	0
Halfpole 2016	91	87+3	3	3	3	3	3	3	0	0	0
Halfpole 2018	94	87+3	3	3	3	3	3	3	3	3	0

¹³ This is less than the budgeted Pole 1 operating costs for 2007, which was ~\$3.5 million for the full pole. It is expected that the cost of having a half pole is not going to be much less and it could increase over time, as equipment gets older.

2.1.3 Reserve costs

A recent report by MMA (see Attachment D to the Proposal) assesses the likely impact on the results of reserve costs. Figure 2.1 from that report is shown below.

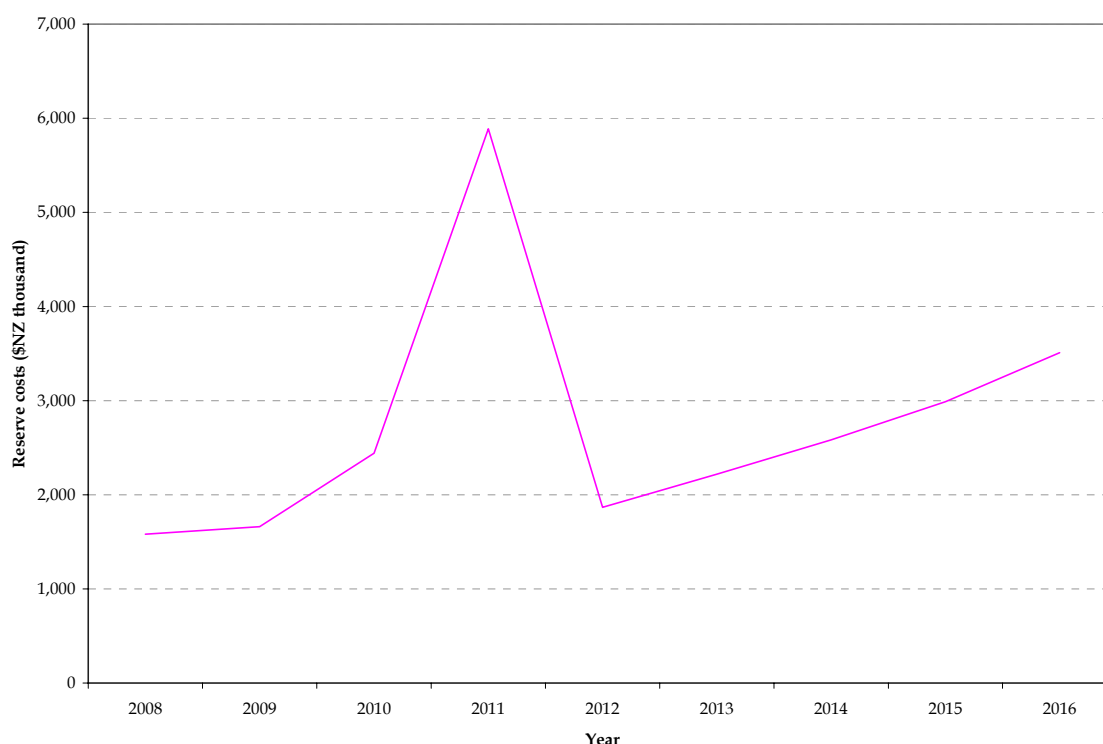


Figure 1: Reserve costs per year

It shows how reserve costs increase rapidly up until 2012 when the link is assumed replaced in the model – in the last year, from 2010 to 2011, the increase in costs is more than \$3 million alone. The sharp increase is due to the fact that the North Island starts to become capacity constrained. Reserve capacity has therefore to come from new investments, which makes it significantly more expensive than merely adjusting the dispatch of existing capacity.

For the recommissioning analysis, Transpower has conservatively assumed that operation with a 270 MW pole 1 and 700 MW Pole 2 will result in additional reserve costs around \$2 million in comparison with a balanced 500/500 MW operation that Stage 1 of the Proposal will result in. The table below summarizes the reserve costs associated with the reserves.

Table 2-3: Reserve cost by case

Impact from reserves	Halfpole 2012	Halfpole 2014	Halfpole 2016	Halfpole 2018
2008	0	0	0	0
2009	0	0	0	0
2010	0	0	0	0
2011	0	0	0	0
2012	0	2	2	2
2013	0	2	2	2
2014	0	0	2	2
2015	0	0	2	2
2016	0	0	0	2
2017	0	0	0	2
2018	0	0	0	0
NPV (\$2007 million)	0	3	5	7

2.2 Deferral benefits

By delaying the investment in replacing a half Pole 1 there will be a benefit equal to the expected expenditure times the discount rate per year of deferral. However, not all elements can be deferred by the same amount. For all cases, it has been assumed that an additional Cook Strait cable is added in 2018. Furthermore, due to lack of spares, the replacement of the control system of HVDC Pole 2 operation and HVDC bipole operation is assumed to occur at 2014 at latest. Finally, seismic strengthening is assumed to take place in 2012 at latest.

Transpower has used a 7% discount rate in this analysis which is consistent with the approach taken for the discount rate used in applying the GIT to the HVDC Pole 1 Replacement Investigation Project. The deferral benefits for a 7% discount rate for a half Pole 1 are shown below. This corresponds to the discount rate used in the GIT Base Case.

Table 2-4: Deferral benefit by case in \$2007 million NPV

	Reference Case	Deferred case	Difference
Halfpole 2012	440	440	0
Halfpole 2014	440	401	38
Halfpole 2016	440	366	73
Halfpole 2018	440	336	104

The last column shows the difference between the Reference Case and the deferred investment. These amounts are in \$2007 million NPV.

2.3 Comparing costs and benefits

Combining the modelled costs and benefits shows the overall implications from full reinstatement of the remaining half Pole until replacement in 2012, 2014, 2016 or 2018 compared to the Proposal:

Table 2-5: Overall impact of each case compared to the Proposal (in \$2007 million NPV)

	Halfpole 2012	Halfpole 2014	Halfpole 2016	Halfpole 2018
Deferral benefit	0	-38	-73	-104
Mitigation cost	83	87	91	94
Generation costs	0	24	48	73
Reserves costs	0	3	5	7
Total cost compared to the 2012 case	83	76	71	70
Total cost compared to the 2012 case if no mitigation costs	0	-7	-12	-13

Each reinstatement scenario produces a fairly overall similar net cost compared to the Proposal. The magnitude must be interpreted cautiously as the model is unable to capture the benefits pre-2012 from having a fully available half Pole instead of the limited operation, which is the current base case. In fact, there might be a zero cost or negative cost if the pre-2012 benefits are higher than the costs.

The *important* results from the figure are the cost changes between the four cases. These are more clear in the last row, which has the mitigation cost and Pole 1 O&M costs prior to 2012 reset to zero (removing the \$83 million). The benefit of keeping a fully operational half Pole is \$13 million at most for deferring the replacement the 6 years till 2018. This benefit of ~\$2 million a year will only eventuate around \$83 million of pre-2012 benefits can be found.

This should be compared with the environmental risks. Furthermore, the timing analysis (see GIT Results – Attachment A to the Proposal) identified that lower capacity can lead to significantly a significantly more costly dry year event.

The graph below shows the expected utilisation of a 1400 MW link (i.e. the Reference Case, a 700 MW pole 1 replacement) for the 90% renewables scenario based on a SDDP model simulation.

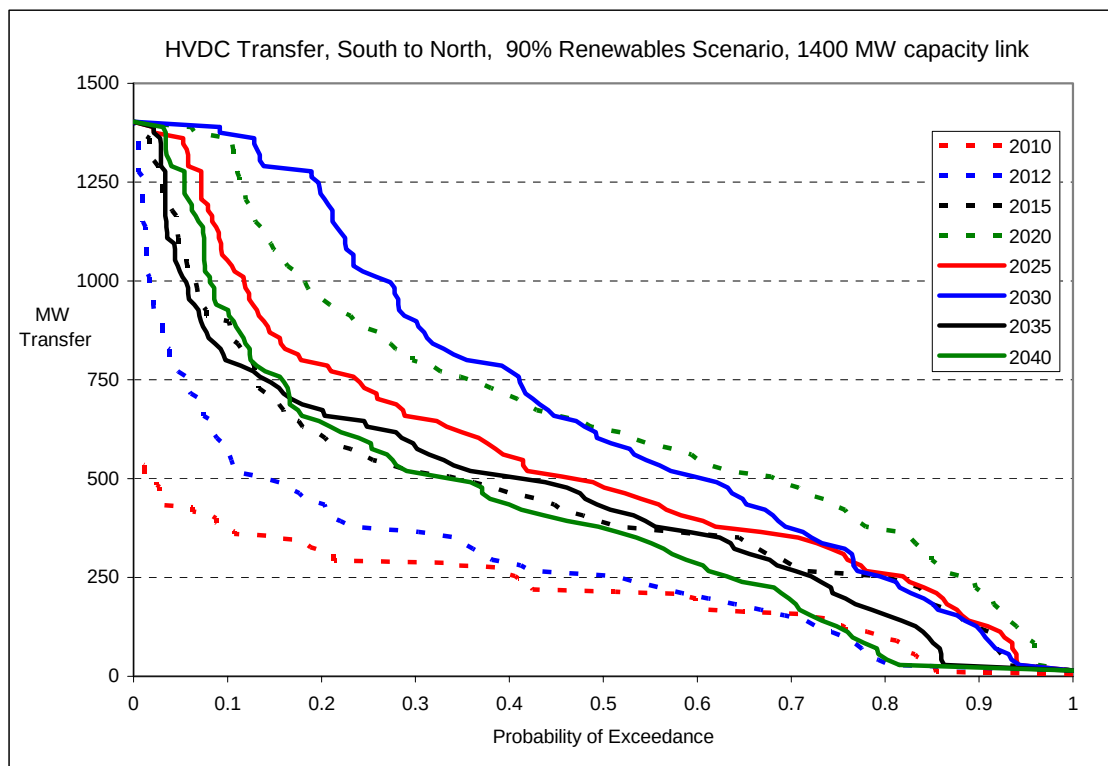


Figure 2: Expected utilisation of 1400 MW link for 90% renewables

It shows an expected increase in the utilisation of the link between 2015 and 2020 and further beyond. The optimal utilisation is expected to exceed 1000 MW in 20% of the time in 2020. Around that time, it must be assumed that having less capacity will become more and more costly.

3 Conclusions

The purpose of this analysis was to establish whether there would be any significant costs for New Zealand to comply with the recommendations in the Environmental report. It can be seen that *even if* benefits pre-2012 exceed the cost of fully reinstating Pole 1, the benefits per year of keeping it beyond 2012 are around \$2 million at best. This benefit needs to be compared to the identified risks and benefits a replacement Pole 1 may provide such as increased competition and potentially enabling a national reserve market sharing (see Section 5.9 of the Proposal).

Therefore, in Transpower's view this analysis demonstrates that complying with the environmental recommendations will not impose any significant costs on New Zealand as a whole. Furthermore, given this, any considerations regarding full reinstatement of the remaining half pole will not impact on the optimal timing of the proposal.



T R A N S P O W E R

HVDC Grid Upgrade Project

Proposal

Attachment C

Covec Report on South Island Demand

Doc reference: Inter-island HVDC Pole 1 Replacement
Investigation/DC/Consult/Covec Report

May 2008

South Island Electricity Load Growth

John Small
24 April 2008

Introduction

As part of an evaluation process for upgrades to the HVDC link, Transpower needs to understand how fast demand in the South Island is likely to grow. This is an important input into the analysis because load on the link depends on the supply/demand balance in the South Island relative to the North Island.

Selecting Variables to Drive the Forecast

A debate has occurred over the appropriate way to model and forecast demand, with the relevance of population as the driver of forecasts being questioned. In this report, we investigate the performance of a wider range of variables in models that *explain* historic demand in the South Island. However it needs to be understood that while the ability to explain history is important, it is not the sole criterion for designing a forecasting model. One additionally needs to consider the ability of the model to actually generate reliable forecasts.

To explain this point more clearly, consider a simple model of the following form

$$D_t = \alpha + \beta X_{t-1} + \varepsilon_t$$

where D_t is demand in period t , X_{t-1} is a variable observed in the previous time period ($t-1$) and thought to influence demand, α and β are parameters to be estimate and ε_t is a random error term.

If this model explains the history of demand well, future demand can be predicted one period ahead with relative ease. If a and b represent the estimates of α and β , the predicted demand in period $t+1$ is simply

$$D_{t+1} = a + bX_t$$

The key point is that we already know X_t , which drives the forecast of D_{t+1} . If we want to forecast demand any further ahead, we also need to forecast the driving variable X . Errors in the forecasts of X are a potentially important source of errors in forecasts of demand. Thus, when selecting a variable to drive a forecasting model, confidence in *forecasts* of that variable are a relevant consideration.

Our Empirical Analysis

We investigated the empirical relevance of three potential drivers for forecasts of South Island demand:¹

- Population;
- Economic activity measures; and
- Dairy sector indicators.

Population is obviously a factor contributing to residential demand, though household numbers and electricity usage per household are also likely to matter. In the absence of reliable time-series information that would address these composition issues, we used aggregate population. Statistics New Zealand publishes sub-national population forecasts, which are not error-free but are at least widely understood.

The best known measure of economic activity is real GDP. This is potentially a useful explanatory variable, though again there are compositional factors that could be relevant (eg shifts away from manufacturing and towards commercial services). A further difficulty is that sub-national GDP estimates are not available over an adequate time-span. Statistics New Zealand has only published sub-national estimates of nominal GDP for the years 2000-03 inclusive,² but this is too short a time-series to be useful.

We therefore considered two options as indicators of economic activity in the South Island: national real GDP, and the economic activity index published by the National Bank (which we annualized by averaging across quarters).³ Figure 1 shows that these variables are highly correlated; their linear correlation is 99.5%.⁴

There are several dairy industry indicators available for the South Island including:

- Cow numbers
- Litres of milk
- Kilograms of milk solids.

All potential measures have in excess of a 99% correlation with cow numbers, which is the variable we used.

Finally, we need a measure of demand for electricity. The two options are total withdrawals from the grid, and peak withdrawals from the grid. We used the variables contained in Meridian's letter to Transpower dated 25 February 2008. Both variables are available for the period 1997-2007 inclusive. They have a linear correlation of 96% over this time period.

¹ We only considered publicly available data for inclusion in the models.

² This was an experimental project. While the experiment was successful we understand that continuation of the series was not resourced. Further information is available at <http://www.stats.govt.nz/analytical-reports/regional-gross-domestic-product.htm>.

³ <http://www.nationalbank.co.nz/economics/regional/default.aspx>

⁴ Over the short period for which sub-national *nominal* GDP is available, it is highly correlated with both these measures: 99% with the NBNZ series, and 98% with national real GDP.

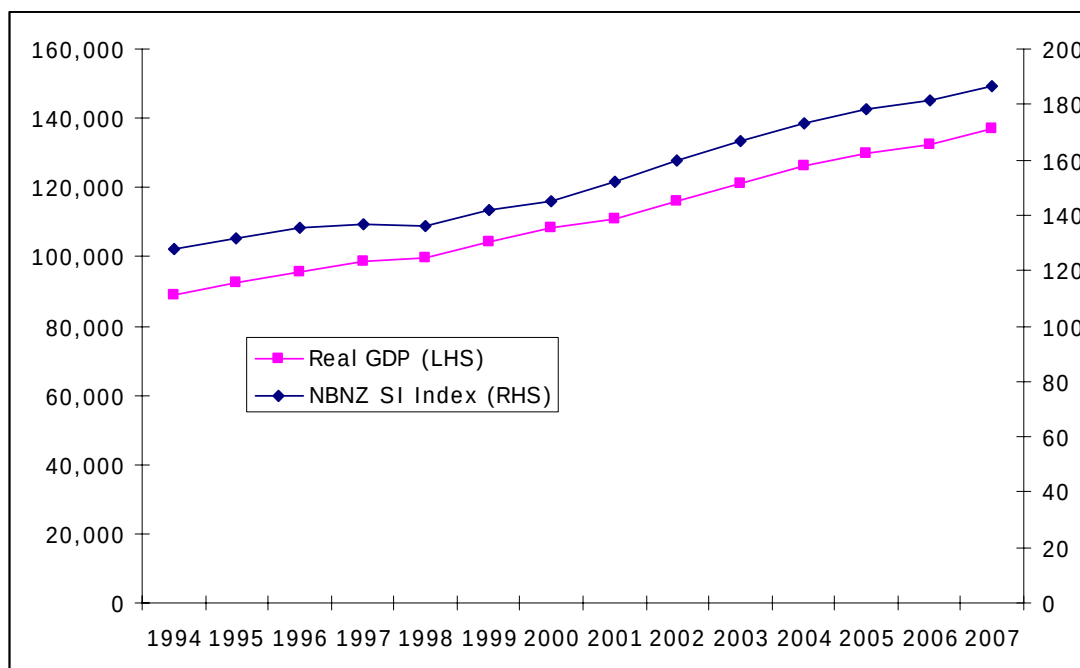


Figure 1 Nationwide Real GDP and South Island Economic Activity

Before modelling, it is useful to inspect the data, most of which are plotted in Figure 2. This shows steady and reasonably smooth growth in all variables except cow numbers which experienced something of a surge beginning in 2001.

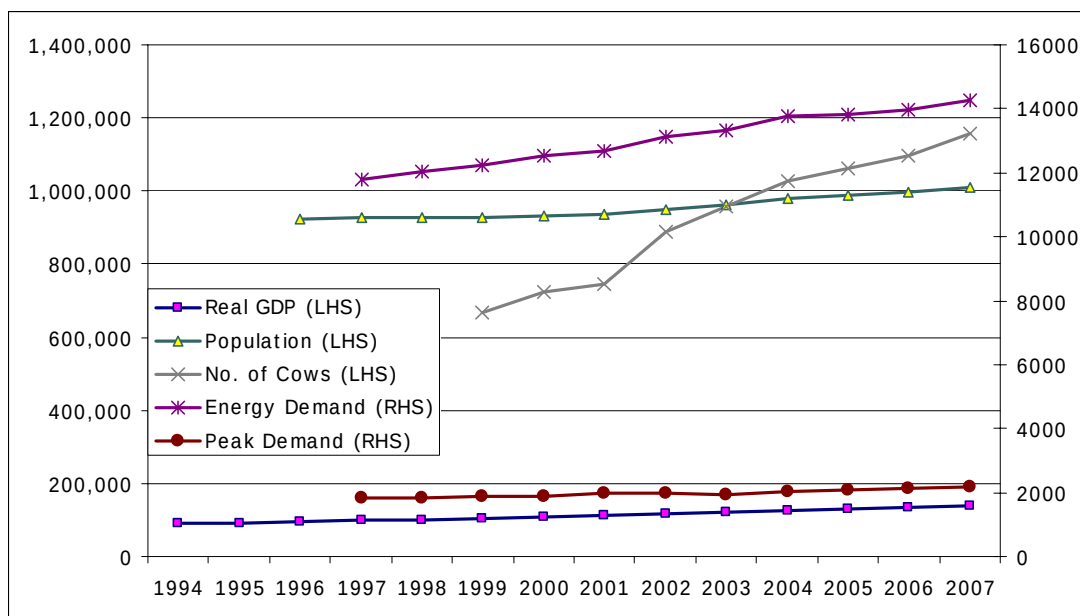


Figure 2 SI Electricity Demand and Potential Explanatory Variables

Dairy Growth

We investigated the growth of dairy-related electricity demand in the South Island. There is relatively little information on the medium- and longer-term outlook for this industry. However it is clear that most of the industry's growth over recent years has occurred in the South Island.

The vast majority of New Zealand's milk production is exported; it is supplied to factories on a seasonal basis, with the winter months being the off-season. This is likely to explain the relatively modest growth in peak demand relative to South Island cow numbers over the last decade apparent in Figure 2.

There are no official forecasts of South Island dairy industry growth. However data are available on dairy cow numbers by region back to the 1998/99 season. Selected years for South Island regions are shown in Table 1 with compound average annual growth rates over the whole period and the most recent three years.

Table 1 Cow Numbers by South Island Region 1999-2007 (Source: Livestock Improvement⁵)

Region	1999	2004	2007	CAGR (99-04)	CAGR (04-07)
Nelson/Marlborough	78571	85505	81309	1.7%	-1.7%
West Coast	80787	115548	127581	7.4%	3.4%
Canterbury	226494	376697	467061	10.7%	7.4%
Otago	112577	146768	160884	5.4%	3.1%
Southland	170323	300821	318482	12.0%	1.9%
South Island	668752	1025339	1155317	8.9%	4.1%

It is clear from these data that dairy growth has slowed markedly in the South Island. Two factors are mostly likely to be contributing to this slow-down:

- Bidding up of prices for land suitable for conversion to dairy due to greater awareness on both sides of the relevant markets; and
- Constraints on the availability of water for irrigation.

Competition for water has become intense in Canterbury, where recent (2004-07) dairy growth has been strongest. There is evidence that water is now a serious constraint on dairy industry growth in the eastern parts of the South Island. Two reports are relevant.

The Business Council for Sustainable Development has recently circulated maps⁶ showing that large parts of Canterbury and Otago have allocated more water than is available. Figure 3 shows the NZBCSD estimates for surface water. Red indicates that more than 100% of the available surface water has been allocated; grey areas are ones for which no data are available. For groundwater, NZBCSD estimates that Canterbury has more than five aquifers that are in excess of 75% allocated.⁷

⁵ http://www.lic.co.nz/lic_19981999_New_Zealand_Dairy_Statistics.cfm

⁶ <http://www.nzbcscd.org.nz/story.asp?StoryID=891>

⁷ Note that because demand for water varies over time, it is possible to survive with more than 100% allocated provided that savings made from lower off-peak demand more than compensate for excess draw-offs during peak periods. There are also a range of difficult measurement issues involved. Nevertheless, these data do indicate severe stress on the water resource.

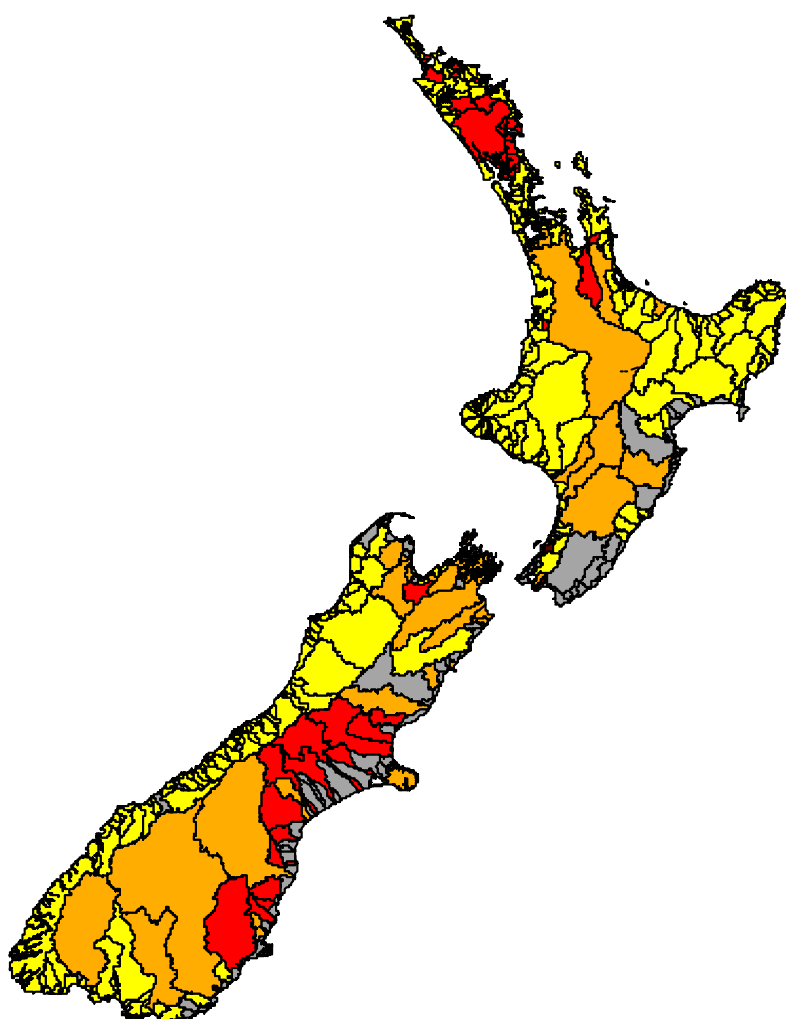


Figure 3 Surface Water Allocation Shares (Source NZBCSD)

It is clear that irrigation is the primary reason for this situation. The Ministry for the Environment commissioned a survey of water resources in 2006. It reported that 77% of all water use in New Zealand is for irrigation, and that two thirds of that is used in Canterbury.⁸

In summary, there is clear evidence that the growth rate of the dairy industry in the South Island has slowed markedly. While we cannot be certain what has caused this slowdown, it is very clear that competition for scarce water resources has intensified, and that it will only become more difficult in the future to obtain additional water for irrigation. We therefore consider that it would be unwise to expect a continuation of historic rates of growth in the South Island dairy industry.

⁸ Snapshot of Water Allocation in New Zealand, Ministry for the Environment, November 2006.
<http://www.mfe.govt.nz/publications/water/water-allocation-snapshot-nov06/index.html>

A second relevant issue is the dairy industry's demand for electricity. There appears to be a trend towards increased use of bio-energy, which is likely to constrain the dairy industry's demand for electricity, whatever the scale of the industry. However it is also likely to serve non-dairy demand. Bio-energy plants on quite large scales are under development around Timaru (municipal waste) and Balclutha (meat processing waste).⁹

Similar systems are being installed on dairy farms. For example, Natural Systems Ltd (rated the most exciting environmental technology company in New Zealand by the National Business Review, March 2008) recently installed a digester on a LandCorp dairy farm in North Canterbury recently, saving 35% of the energy previously purchased to run the milking shed.¹⁰ Electricity prices are only one of the drivers for this type of substitution: it also helps farmers manage environmental contamination. As a result, this activity is expected to grow over time.

Population Growth

Statistics New Zealand data show that over the recent past (2001-07), the population of the South Island has been growing at a rate of 1.3% per annum. Statistics New Zealand is projecting this growth to slow markedly, to an annual rate of one half of one percent over the period out to 2031.¹¹ We note in passing that the North Island population growth rate is also expected to decline, but from a higher base (1.6%) and by a lesser amount (the medium forecast is growth of 0.9%).

Regression Models

When these variables are used in regression modelling, a large set of regression models can be estimated. Four such models are reported in Table 2, all of which explain energy demand. To illustrate the impact of different variables, we have erred on the side of over-fitting these models, which is why some of the P-values exceed 10%. All variables are specified in levels and the models were estimated by Ordinary Least Squares.

Table 2 Regression Models Explaining Energy (MWh) Demand

	Model 1		Model 2		Model 3		Model 4	
	Coef	P-value	Coef	P-value	Coef	P-value	Coef	P-value
Population	0.026	0.000			-0.006	0.177		
GDP			0.062	0.000	0.075	0.000	0.029	0.114
Cows							0.002	0.090
Constant	-11871	0.001	5816	0.000	9739	0.006	7910	0.000
R Squared	0.929		0.991		0.993		0.994	
DW P-value	0.000		0.249		0.549		0.759	

⁹ <http://tinyurl.com/6hwsnm>

¹⁰ <http://www.naturalsystems.co.nz/BioGenCool.html>

¹¹ These figures were obtained from the latest information available at <http://www.stats.govt.nz/people/population/default.htm>

In all cases, the National Bank's indicator of economic activity in the South Island was eliminated due to being insignificant; models in which this replaced GDP were inferior to models using GDP alone. Note also that South Island cow numbers are only available from 1999, so model 4 was estimated with two fewer observations than Models 1 to 3.

Of this set, we would prefer model 2 because it has no coefficients that are negative or insignificant and it has an acceptable Durbin Watson statistic (DW).¹²

Table 3 Regression Models Explaining Peak Demand (MW)

	Model 1		Model 2		Model 3		Model 4	
	Coef	P-value	Coef	P-value	Coef	P-value	Coef	P-value
Population	0.003	0.000			-8E-04	0.651		
GDP			0.008	0.000	0.009	0.029	0.022	0.027
Cows							-9E-04	0.106
Constant	-1346	0.011	1010	0.000	1539	0.211	186.3	0.709
R Squared	0.871		0.93		0.932		0.926	
DW P-value	0.025		0.137		0.055		0.604	

Table 3 shows models explaining peak demand. The patterns are very similar to the energy demand models. Population alone results in a negative constant and strong positive autocorrelation. Models 3 and 4 have negative and insignificant coefficients. So again, GDP alone appears to offer the best explanation of history.

We conducted a few experiments using the first difference of energy and peak demand and other variables, but the resulting models had very poor fits.

In the limited time available it was not possible to explore this line of work further; further experimentation may yield better results.

Conclusions

Based on the above relatively limited research, we have reached several conclusions.

First, South Island population and national GDP are both correlated with demand for electricity in the South Island. There are also strong theoretical/logical rationales for believing that they influence demand. However they are also correlated with each other, so it is relatively difficult to construct a regression model in which both are significant.

Expansion of the dairy industry in the South Island is also a driver of electricity demand. Cow numbers are strongly correlated with electricity demand. However for similar reasons, it is difficult to construct a model in which cow numbers and either of the other variables are both significant.

¹² The DW P-values are based on tests for positive autocorrelation. Values less than 5% or 10% imply autocorrelation is present (which is undesirable).

In our view, these variables (or others designed to better measure the same effects) are the main factors that influence South Island load. Since they are so highly correlated with each other, it follows that for practical purposes one needs to choose one of them. This need not be a once-and-for-all choice however: cross-checks will be useful as a sanity check on forecasts.

Of the three variables available, population is the only one for which predictions are published. It is highly attractive for that reason. Based on this position, we expect the recent strong load growth in the South Island to moderate over the medium to long-term. Some corroborating evidence is available from constraints on the growth of dairying due to competition for water resources, and substitution towards alternative energy sources by dairy farmers, agricultural processors and others. The latter substitution is likely to be driven by a combination of price and environmental sensitivity.

Overall, we consider that the most likely scenario is that recent strong growth in electricity demand in the South Island demand will not continue.



T R A N S P O W E R

HVDC Grid Upgrade Project

Proposal

Attachment D

MMA Report on Reserves Risk

Doc reference: Inter-island HVDC Pole 1 Replacement
Investigation/DC/Consult/MMA Reserves Report

May 2008

Report to
Transpower

**Impact of reserves modelling in market benefit
analysis of short-listed HVDC options**

18th April 2008



Ref: J1503 Reserves Report

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1 INTRODUCTION

Transpower engaged McLennan Magasanik Associates (MMA) to conduct a market benefit analysis of a number of possible HVDC Pole 1 replacement alternatives for the 540 MW link that has been retired between the North Island (NI) and the South Island (SI). MMA analyses, reported in “Market benefit analysis of short-listed HVDC options”, showed that the replacement of Pole 1 with a 700 MW link (700-700 case) was the augmentation alternative with the higher expected net market benefits for the set of market development and load growth scenarios provided by Transpower.

In particular, for the 700-700 augmentation alternative, the expected net market benefits obtained from MMA’s PLEXOS simulations are \$399 million. Transpower undertook its own market benefit analysis to identify the preferred augmentation option under the Grid Investment Test (GIT). The higher net market benefits obtained from MMA’s PLEXOS results, compared with Transpower’s \$187 million, are partially explained by the fact that PLEXOS model reserves, while GEM/SDDP used in Transpower’s analyses does not. This report shows the impact of modelling reserves in MMA’s results.

1.1 Methodology

First, capacity expansion plans for the 0-700 and the 700-700 augmentation cases (medium demand growth only) were obtained using PLEXOS LT-Plan with and without having the reserve modelling activated. The capacity expansion plans showed only minimal variations with and without modelling reserves, which indicates that reserves do not have a big impact on building decisions.

Then, for each market development scenario, detailed market simulations using the chosen capacity expansion plan were conducted using PLEXOS MT-Schedule. Net market benefits from the market simulations are presented in the next section.

2 ADDITIONAL BENEFITS FROM MODELLING RESERVES

Table 2-1 presents net market benefits of the 700-700 augmentation for medium demand obtained from PLEXOS with and without activating the reserve modelling. The net market benefit is calculated as the difference between the NPV of the total cost in the non-augmentation case (0-700 case) and the NPV of the total cost in the 700-700 case. A positive value indicates the total savings in the system (in terms of capital and operating costs) as a result of building the 700-700 augmentation.

Table 2-1 Net market benefits of the 700-700 augmentation with and without reserve modelling, medium demand case

Market development scenario	Net market benefits with reserve modelling (\$M)	Net market benefits without reserve modelling (\$M)
MDS1	-\$57	-\$83
MDS2	\$307	\$264
MDS3	\$85	\$21
MDS4	\$797	\$746
MDS5	\$605	\$560
Weighted average	\$374	\$330

As expected from solving a less constrained optimization, the total costs of the simulations without reserves were lower than the total costs of the simulations with reserves. Also, higher net market benefits arising from the 700-700 augmentation were observed when modelling reserves for all market development scenarios.

Thus, modelling reserve increases the benefits of the 700-700 augmentation relative to the base case (0-700), as shown in Table 2-2. The magnitude of the additional benefit is in the order of \$44 million NPV.

Therefore, Transpower results are likely to under-estimate the benefits of augmentation as reserve modelling was not included in its analysis.

Table 2-2. Additional benefits as a result of modelling reserves, 700-700 augmentation, medium demand case

Market development scenario	Additional benefits as a result of modelling reserves (\$M)
MDS1	\$26
MDS2	\$43
MDS3	\$64
MDS4	\$51
MDS5	\$46
Weighted average	\$44

PLEXOS MT-Schedule runs were also undertaken with and without modelling reserves using the expansion plan obtained by GEM for MDS5. Our results show that without modelling reserves there was a reduction in the net benefits of augmentation of \$34 million, which is consistent with our results.

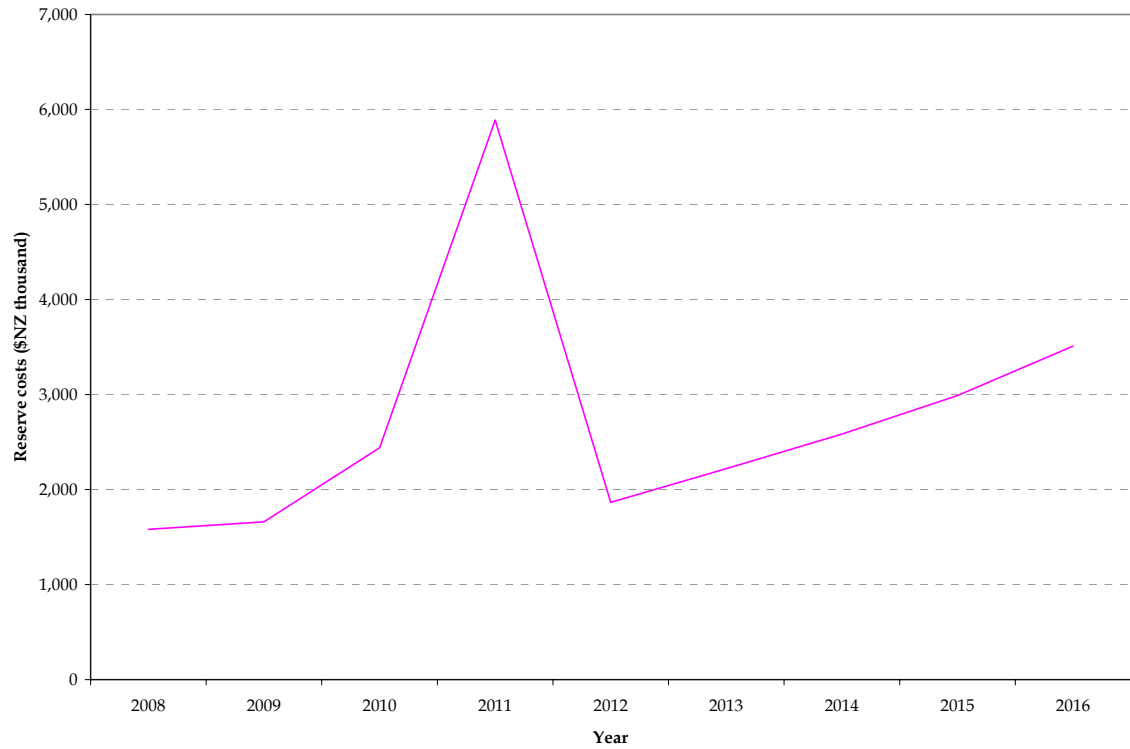
2.1 Optimal timing analysis

This analysis has demonstrated that HVDC augmentation reduces the cost of reserves. Therefore, had reserve modelling been included in Transpower's analysis, the benefits of augmentation would have been higher under all market development scenarios.

It also follows that the benefits of advancing the timing of the augmentation from 2014 to 2012 would also have been underestimated in Transpower's analysis.

In our analysis, reserve costs show an increasing trend prior to 2012, followed by a dip in 2012 when the augmentation is assumed to occur, as demonstrated for MDS4 in Figure 2-1. This reduction in reserve costs could be observed for all hydrological years employed in our simulations, except for the hydrological year of 1933. Post 2012, reserve costs begin to increase again but total costs are lower than without the augmentation.

Figure 2-1 Reserve cost weighted average, 700-700 augmentation, MDS4 medium demand scenario





T R A N S P O W E R

HVDC Grid Upgrade Project

Proposal

Attachment E

Summary of consultation submissions and response to issues raised

Doc reference: Inter-island HVDC Pole 1 Replacement
Investigation/DC/Consult/Summary and Response/Rev A

May 2008

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1 Introduction

This document summarises:

- the written submissions received to Transpower's consultation on its proposed application of the Grid Investment Test; and
- provides Transpower's response to those submissions either directly, or where appropriate, by reference to the amended section of Transpower's application of the GIT.

Transpower would like to thank those parties who participated in the consultation. All comments are valuable and will help ensure a robust analysis of the options and case for replacing Pole 1 of the HVDC.

2 Transpower summary of GIT consultation submissions received and reply to issues raised

Submitter	Ref	Written submission	Transpower response
Process			
Meridian Energy (letter of 18 March 2008)	1	Transpower has predetermined the upgrade process.	Transpower values the role of consultation and the contributions made by interested parties. It has considered all issues with an open mind and has not pre-determined the outcome of this process. Transpower also responded to this point in its letter to Meridian Energy on 28 March 2008.
Genesis Energy	2	Genesis Energy welcomes Transpower's thorough and transparent approach to analysing the economics of Pole 1 replacement options and hopes that this up-front effort will be rewarded by a relatively smooth regulatory approval process. Given the challenges imposed by the strictures of the GIT, Genesis Energy believes that Transpower has done a good job of putting together a well-structured consultation package that leads readers very neatly through Transpower's analysis.	Transpower notes Genesis Energy's support for its process.
Contact	3	Contact notes that the consultation has spanned many months since the initial consultation workshop in June 2007. Parties like Contact will provide updates to databook inputs as they become available. During this time the Electricity Commission has...made good progress on its Grid Planning Assumptions, which now may be more relevant to test the HVDC replacement project with. Transpower's evaluation process needs to be accommodating of ongoing inputs such as these.	Transpower understands that additional information will arise naturally over time and will come to Transpower's attention as provisional analysis and consultation develops. Transpower will seek to take into account all relevant information as it becomes available. It does, however, strongly encourage all participants to engage at an early stage in the process to maximise the efficiency of the process. With respect to the recently published draft 2008 Grid Planning Assumptions (GPAs), Transpower notes that these have recently been published and consulted on by the Electricity Commission. The Commission has, however, yet to publish a revised Statement of Opportunities reflecting the final GPAs and the results of that consultation. Transpower has relied on the draft 2007 GPAs as a starting point on which it has consulted extensively. It therefore considers it would be inappropriate to reflect these assumptions in the core GIT analysis at this stage until the results of the Commission's consultation become clear. However, we have evaluated qualitatively that the likely effects of using the draft 2008 demand forecast are not material to the GIT analysis .

			This discussion can be found in section 5.6.6 of Attachment A to the Proposal – Revised GIT Results.
MEUG	4	Transpower are to be congratulated on the extent of consultation in the preparation of the GIT and willingness to answer questions on what is a very complex analysis.	Transpower notes MEUG's support for its process.
Options			
MEUG	5	Concern that the screening criteria of "facilitating renewables" used in deciding the short list of options means promoting renewables irrespective of costs.	MEUG's concern with the possible interpretation of this criterion is noted. Transpower agrees, consistent with MEUG's comment later in their submission, that the short-listed options would not be any different without this criterion.
MEUG	6	As excluding the "facilitating renewables" criteria would not result in any change to the short list, short list appears reasonable.	Noted. Transpower agrees with this position.
Meridian Energy	7	Meridian Energy considers that Transpower has avoided prudent life extension options for Pole 1 and have applied unique insurance criteria to the HVDC link assets to limit the scope of life extension options.	Transpower has carefully investigated the possibility of future operation of the existing HVDC Pole 1 as part of a separate investigation (see http://www.gridnewzealand.co.nz/n960.html for further details). Transpower's reasoning is based on a number of factors including an environment report, insurance reports and GEIP (see section 6.3.2 of Attachment E to the Consultation Paper). The expert reviews undertaken resulted in a recommendation that continued operation of the existing Pole 1 should only be considered for a further 1-2 years. Transpower will continue to review this situation. However, it is possible that the existing Pole 1 may not be capable of being operated (in its limited operation mode) prudently for more than another 1-2 years.
Genesis Energy	8	Overall, the short list of options is reasonable.	Noted.
Genesis Energy	9	Given comments on reserve market impacts (see below), Genesis Energy queries whether overload capacities should be a factor in evaluating the short list.	Transpower acknowledges that overload capability on the HVDC converters could add value, particularly if a national reserves market is introduced. Transpower will include overload capacity as a desirable characteristic of the new converter and will value overload capacity when assessing tenders. However, it is difficult to assess the economics of overload capability at this point in time, because the cost, if any, is unknown. If there is a cost, then the economics will be evaluated at that time. Although overload capability may add further benefit to replacing Pole 1 of the HVDC,

without knowing the costs, it is difficult to consider whether this could contribute to a significant cost difference between the short list options. Transpower will only understand the GIT implications of overload capability sufficiently robustly once the tendering process is complete.

MMA did consider reserve market impacts in their GIT analysis with the PLEXOS model. They concluded:

With larger link sizes (700-700 or 1000-700) there may be value in switching to a national instantaneous reserve market. To estimate this value, we ran each market development scenario under medium growth conditions with a single national reserve market, limiting the SI contribution to the spare capacity on the HVDC link in any given period.

It was found that switching to a national instantaneous reserve market produced additional benefits, compared with two single reserve markets, ranging from an NPV of \$3 million to \$28 million across the market development scenarios.

However, it should be noted that the implementation of ancillary service modelling for this analysis was rather rudimentary, as detailed unit commitment and minimum stable levels were not modelled.

Assuming that MMA's analysis is producing overload capability benefits of the correct order, then it seems unlikely that such differences would be a significant factor in distinguishing between options.

Genesis Energy	10 Genesis Energy queries whether operating Pole 2 in permanent earth return mode is a realistic assumption for the base case. In particular, Genesis Energy questions whether this would incur significant maintenance expenditure. If not realistic, then greater losses would be applicable for metallic return operation.	Transpower considers that using two pole conductors in parallel in permanent earth return mode, rather than metallic return operation, of Pole 1 is a realistic assumption in the base case. Operating only Pole 2 conductor in earth return mode with no paralleling, however, halves the line losses for the same amount of power transferred compared to using two pole conductors in metallic return mode. Operating Pole 2 in earth return mode provides the opportunity to parallel both Poles 1 and 2 conductors, halving the resistance of the line and line losses for the same amount of power transferred compared with no paralleling of pole conductors. Overall, using two paralleled conductors in earth return mode will result in four times lower line losses than would be the case using metallic return operation. As Genesis Energy has pointed out there is, however, an increased maintenance cost associated with the electrode operation in using conductors in permanent earth return mode.

		Transpower expects inspections, minor repairs, electrode cleaning and replacement of electrode arms would result in additional costs of around \$400,000 to \$500,000 per annum, as well as one-off costs of around \$50,000 to clean electrodes. The net loss saving benefit outlined above is very likely to be considerably higher than the increased maintenance expenditure. Recent work indicated these loss savings would exceed \$1 million per annum. Transpower, therefore, considers that permanent earth return mode, rather than metallic return operation, of Pole 1 is a realistic assumption in the base case. For purposes of the GIT assessment, this assumption also represents the most cost effective base case. In the event Transpower reverts to use of a metallic return, the benefits of the proposal (and 500 and 1000 MW alternatives) would increase relative to the base case.											
Genesis Energy	11	Comparing ranking results for BEN-HAY options versus BEN-BPE options, the North Island AC costs are higher for the BPE options, as are the variable generation O&M costs. These seem to be counter-intuitive results. If BEN-BPE options and ROX-HAY options do not stack up, then ROX-BPE does not need to be analysed in detail. If on the other hand these options did stack up, then Genesis Energy would not be convinced at this stage that the difficulties of undertaking two significant transmission projects at once would render a ROX-BPE completely impractical. On the face of it, there would seem to be some diversity benefit to such an option as well as the benefit of bringing demand and supply electrically closer together.	The North Island AC augmentations are very similar whether a replacement Pole 1 is installed at Bunnythorpe or Haywards. However, if installed at Bunnythorpe, one of the existing BPE-HAY single circuit tower lines is converted from AC to DC to supply the connection between the two sites. This creates a problem when the HVDC is shutdown for the Bunnythorpe Pole 1 option, as there is one AC circuit less for security of supply to Wellington. This was addressed by duplexing the other single circuit line between Bunnythorpe and Haywards for the Bunnythorpe pole option. It is this cost that is the main difference between the two site options. Transpower does not consider that the Bunnythorpe terminal option gives a higher variable generation O&M costs. The generation system variable O&M costs calculated using the SDDP dispatch model, per market development scenario (MDS), in \$2007 million, are as follows: Bunnythorpe terminal, 700 MW link, for MDS 1 to 5: <table><tr><td>\$12,337</td><td>\$12,520</td><td>\$11,389</td><td>\$11,173</td><td>\$10,064</td></tr></table> Haywards terminal, 700 MW link, for MDS 1 to 5: <table><tr><td>\$12,331</td><td>\$12,552</td><td>\$11,431</td><td>\$11,225</td><td>\$10,107</td></tr></table> The Bunnythorpe terminal option gives lower variable generation O&M in 4 out of 5 cases, as might be expected, because of the lower losses overall from moving the HVDC termination point for Pole 1 further north.	\$12,337	\$12,520	\$11,389	\$11,173	\$10,064	\$12,331	\$12,552	\$11,431	\$11,225	\$10,107
\$12,337	\$12,520	\$11,389	\$11,173	\$10,064									
\$12,331	\$12,552	\$11,431	\$11,225	\$10,107									
Genesis Energy	12	Genesis Energy queries whether consideration has been given to potential reliability and loss-reduction benefits of developing the 700MW and 1000MW options with two new cables instead of one.	Not at this point in time. The optimal timing analysis indicates that a new cable will not be economically justified until 2018 at the earliest. A new cable will be part of Stage 3 of the proposed project, which will be submitted to the Electricity Commission closer to the need date.										

			In any event, for the purposes of the GIT analysis of the Proposal, the reliability benefits and loss reduction benefits of using two rather than one additional cable(s) are relatively second-order in comparison to the primary benefit and it is unlikely that these alone would justify a second new cable. Loss benefits are likely to be small considering that the losses are incurred mainly in the overhead line rather than in the relatively short cable. Transpower will consider the merits of two versus one new cable at a later date, once it appears that new cable capacity could be justified economically in the near term.
Contact	13	In the Transpower presentation on re-commissioning of the half pole it states that the “proposed emergency mode (limited operation) would capture most of these benefits”. Should the continuation of the proposed emergency mode then be considered as an alternative to replacement?	As noted above, Transpower has carefully investigated the possibility of future operation of the existing HVDC Pole 1 as part of a separate investigation (see http://www.gridnewzealand.co.nz/n960.html for further details). Transpower’s reasoning is based on a number of factors including an environment report, insurance reports and GEIP (see section 6.3.2 of Attachment E to the Consultation Paper). The expert reviews undertaken resulted in a recommendation that continued operation of the existing Pole 1 should only be considered for a further 1-2 years. Transpower will continue to review this situation. However, it is possible that the existing Pole 1 may not be capable of being operated (in its limited operation mode) prudently for more than another 1-2 years.
Demand assumptions			
Genesis Energy	14	Genesis Energy is comfortable with Transpower’s demand growth assumptions. However, Genesis Energy also recognises that the differential between North Island and South Island demand growth is a reasonably significant driving factor for the outcome of the GIT. As such, Genesis Energy suggests that it could be of value to run a sensitivity analysis where North and South Island growth paths are decoupled (for example, using medium North Island growth and high South Island growth). This would be a fairly extreme sensitivity test, but would be useful for understanding where the bounds of the NPV-positive domain may lie.	Transpower has considered further the need to carry out a sensitivity with different demand growth paths for each of the North and South Islands. Transpower commissioned Covec to consider whether the recent (relatively) high demand growth in the South Island was likely to be sustained. Their report is included as Attachment C to the Proposal. They concluded that the recent growth was primarily due to a high growth in dairy farming and that the growth in demand from this sector was unlikely to be sustained. However, two demand growth sensitivities have been undertaken which should provide Genesis Energy with an insight as to the effect of their proposed sensitivity. One where South Island demand is assumed to continue growing throughout the analysis period at the same high rate as in the last ten years, and one where South Island demand is assumed to continue growing for the next ten years, at the same high rate as in the last ten years and then reduce to Transpower forecast levels. These sensitivities and their outcomes are fully described in section 5.6.1 of Attachment A to the Proposal – Revised GIT Results. The results indicate that a 700MW Pole 1 replacement still maximises expected net market benefit and that the expected net market benefit is still positive.

Meridian Energy (letters of 21 and 22 February 2008)	15	Meridian Energy requested a sensitivity in which demand growth for each of North and South Island was extrapolated rather than relying on the Electricity Commission's 2007 using the 90% renewables scenario.	Transpower carried out the analysis requested, as set out in section 5.6.1 of Attachment A to the Proposal – Revised GIT Results. Those results indicate that a 700MW Pole 1 replacement still maximises expected net market benefit and that the expected net market benefit is positive.
Meridian Energy	16	Transpower's low South Island demand growth forecasts which are present in all scenarios create higher than reasonable HVDC transfers from the South to the North Island in stark contrast to what has occurred historically. Transpower's demand forecast assumptions systematically over value the HVDC link. Meridian Energy therefore recommends that when the HVDC upgrade is submitted by Transpower as a Grid Upgrade Plan the following changes are made: 1. The South and North Island demand forecasts are revised to be based on an extrapolation of historical demand growth and not allocated on the basis of population growth alone; 2. The starting point for North Island demand growth should be reset at 2007 actual levels to remove the 1000 GWh North Island starting point bias; 3. The starting point for the South Island demand-generation balance should be reset to be consistent with 2007 actual transfer levels (adjusting for hydrology) to remove the 600-800 GWh South Island starting point bias; On Meridian Energy's analysis, revising demand growth assumptions in line with extrapolation of historic demand results in the 700MW option only delivering a net market benefit in the 90% renewables scenario. Transpower has undertaken no historical analysis to support the proposition that population growth is the primary driver to allocate demand growth between the North and South Islands. Meridian Energy suggests own analysis of North and South Island demand growth and population growth shows an absence of correlation.	Responding to each of Meridian Energy's points individually: The demand forecasts are not produced based on an allocation of population growth only, but rather several factors including population growth and GDP. Transpower has thoroughly reviewed whether the demand forecast methodology and the forecasts themselves used in the GIT analysis are reasonable and has concluded they are. Transpower's full response to this point is set out in section 5.6.1 of Attachment A to the Proposal – Revised GIT Results As set out in response 14 above, Transpower also engaged Covec to review the forecasts of South Island demand. 1. Transpower is of the view that this request is likely based on a misinterpretation of the demand forecast used in Transpower's analysis. Typically historical data is collated from metering data based on GXP level loads. That is to say the load is net of embedded generation and AC losses. This is the case for the EM6 data which is stated as the source of the historical GWh data displayed in the table on page 4 of Meridian Energy's submission [of 4 April]. Meridian Energy's assertion that the "<i>starting point of Transpower's demand forecast for the North Island is some 1,050 GWh higher than actual demand</i>" appears to be based on comparing the forecast demand inclusive of some embedded generation and losses against the actual demand which is net of both embedded generation and losses.

Comparison of Calendar Year 2007 Demands GWh		
	NI Demand	SI Demand
GEM Demand Forecast	24,997	14,246
Losses, Embedded Gen	1922	882
Net Demand Forecast	23,074	13,364
Actual Net Demand	23,949	14,243
Difference	-875	-879
Net Demand Forecast Ratio	63%	37%
Actual Net Demand Ratio	63%	37%

The above table compares the 2007 actual demand with the net modelled demand. It illustrates that the net demand forecast understated the actual 2007 demand in both the North and South Islands. Rather than being 1,050 GWh higher than actual demand in 2007, the Commission's North Island demand forecast was 875 GWh lower than actually occurred.

If Transpower reset the demand forecast starting point to 2007 actual demand levels for its GIT analysis, as suggested by Meridian Energy, the North Island demand forecast would increase by the same amount as the South Island demand. This is in direct contradiction of Meridian Energy's assertion that North Island demand would fall and South Island demand would rise.

Given that the proportion of North Island forecast demand to South Island forecast demand in 2007 is the same as the current proportion, at 63:37, it is Transpower's view that such a reset would not materially change the GIT results since both forecasts would increase.

It should also be noted that 2007 actual demand growth was relatively higher in the South Island when compared to previous years, with growth of 2.5% on 2006 levels. This is one third higher than the average growth in the island

demand over the last ten years of 1.8% per annum. In particular, given the anomalous nature of this increase, Transpower does not believe it would be useful to reset the starting point of its demand forecasts to 2007 levels. It considers the use of forecast 2007 demand is reasonable in this analysis.

2. From Figure 2 in Meridian Energy's submission dated 4 April, the net transfer adjusted for hydro inflows is shown at just over 2,000 GWh and the starting point for the 2007 forecast is around 2,800 GWh.

Transpower has examined the actual 2007 South Island generation data against the actual 2007 HVDC net transfer data and is of the view that when adjusted to mean inflows, the 2007 net transfer is in line with the forecast transfer limit from its GIT analysis.

The table below shows the actual 2007 South Island generation to be around 17,084 GWh. South Island inflows in 2007 were 90% of the long term mean. Adjusting the generation data to 100% mean inflow level would give an additional 10% of available South Island generation which could be transferred over the HVDC link. This would give a net transfer of 3,587 GWh which is around 30% higher than the forecast net transfer limit, as opposed to 43% lower as implied by Meridian Energy's analysis.

	SI Generation	Net HVDC Transfers
2007 Actuals	17,084	1,879
Adjusted to 100% mean inflows		3,587
Adjusted to 95% mean inflows		2,733

Whilst the adjustment to mean inflows may overestimate the additional generation that would be available under mean inflow conditions, in as much as it assumes all inflows could be used for generation, it is fair to assume at least half of the additional inflows could be used for additional South Island generation. This would bring the 2007 net HVDC transfer figure to 2,733 GWh which is in line with the resulting net HVDC transfer figure (2007) from Transpower's modelling.

Transpower is, therefore, of the view that the demand forecasts in the draft 2007 GPAs are reasonable for use in this GIT analysis.

MEUG	17	The demand assumptions used may need updating following feedback to the Electricity Commission on the recent Grid Planning Assumptions (GPA) consultation paper. MEUG expects any changes to be within the sensitivity range considered by Transpower. A materiality check against the final GPA demand forecasts may be prudent.	As noted above (response 3), Transpower does not consider appropriate to rely on the draft 2008 GPAs in the same way as the draft 2007 GPAs, as Transpower has consulted extensively on the latter, while the results of the Commission's consideration of the consultation is ongoing. Transpower has evaluated qualitatively the likely effects of using the draft 2008 demand forecast are not material to the GIT analysis (see section 5.6.6 of Attachment A to the Proposal – Revised GIT Results).
Contact Energy	18	Transpower needs to adequately address and explain the divergence between historic HVDC transfers and transfers forecast in its GIT analysis. It also needs to explain the significant differences between historic South Island load growth and the assumptions used in the GIT. Contact Energy does not consider that Transpower's letter to Meridian Energy of 20 March 2008 satisfactorily canvasses these points.	The divergence between the historic HVDC transfers and transfers forecast in the GIT analysis are a function of the generation expansion plans which emerged from the generation expansion modelling. That modelling is indicating that more new generation is likely to be built in the South Island than is required to meet South Island demand growth and that HVDC transfers from the South Island to the North Island will increase, compared to recent historical levels as a result. This is discussed in more detail in section 4.4 of Attachment A to the Proposal – Revised GIT Results. The issue of historic South Island load growth and the assumptions used in the GIT is considered in the reply to Genesis Energy and Meridian Energy's questions above (see responses 14 and 16 above). In short, Transpower commissioned Covec to consider whether the recent high demand growth in the South Island was likely to continue. Their report is included as Attachment D to the Proposal. They concluded that the recent growth was primarily due to a high growth in dairy farming and that this growth was unlikely to be sustained. Transpower has concluded, after reconsidering whether the methodology used for producing the demand forecasts is appropriate, that the long-term forecasts used in the GIT analysis are reasonable.
Demand forecast weightings			
Meridian Energy	19	Meridian Energy considers that Transpower should revisit its scenario weightings and in particular divide MDS 5 into two separate scenarios for achieving a 90% renewable future. The weightings between low, medium and high demand scenarios are second order to these issues with the key inputs and MDS 5.	This issue is further discussed in Transpower's response to Meridian Energy's specific suggestion to split the 90% renewables by 2025 scenario into two, see response 23 below.
MEUG	20	Weighting appears to be reasonable.	Noted.
Genesis Energy	21	Genesis Energy is comfortable with the weightings of Transpower's demand growth assumptions.	Noted.
Generation scenarios			
Meridian	22	Meridian Energy considers use of a capacity constraint with	Transpower understands that Meridian Energy is concerned the peak capacity constraint

Energy

generation expansion model will bring on generation earlier than current market will deliver. Projects therefore likely to not be revenue adequate, and therefore are unlikely to occur in reality. This is likely to overvalue the replacement of Pole 1 of the HVDC link.

If Transpower can demonstrate the level of VOLL implied by the peak capacity constraint, this would go some distance towards providing Meridian Energy with some comfort on this point. Meridian Energy therefore recommends that when the HVDC upgrade is submitted by Transpower as a Grid Upgrade Plan the following change is made:

The impact of the capacity constraint on all scenarios is identified by removing the constraint in GEM and re-running each scenario. (In an earlier letter Meridian Energy asked Transpower to run a particular scenario with an "N" peak capacity constraint and a VOLL of \$3,000/MWh.) This will identify the incremental expected net market benefits that are solely associated with managing peak capacity related security of supply concerns.

Meridian Energy

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Meridian Energy considers that the 90% renewables scenario is too dominant and not adequately sensitised to changes in technology costs. This scenario contains a critical input assumption that approximately 2500 GWh of new generation will be constructed in the South Island in 2015/16 (including North Bank Tunnel for which Meridian Energy is the proponent). At the same time two Huntly units and P40 will be decommissioned for what appears to be non-economic reasons. Meridian Energy is concerned that the likelihood of this series of events (North Island thermal retirement and large scale South Island hydro build by 2015) is not likely enough for it to have such a significant impact on the HVDC valuation.

Meridian Energy therefore recommends that when the HVDC upgrade is submitted by Transpower as a Grid Upgrade Plan the following change is made:

Sensitivity analysis is performed on MDS5 to show the impact of Huntly units 3, 4 and P40 being replaced with North Island

in GEM may not result in generation expansion outcomes similar to those a market might deliver and so has requested that Transpower carry out further analysis, ie to run a particular scenario with no peak capacity constraint. Transpower considers that it is more important to assess whether the outcomes from GEM are realistic or not. Transpower's conclusions in this respect are presented in section 4 of Attachment A to the Proposal – Revised GIT Results. Transpower explains that the GEM results created on the basis of an N-1 capacity constraint are consistent with current "generation margins", i.e. the amount of firm generation capacity over peak demand.

Nevertheless, Transpower has undertaken further work along the lines requested by Meridian. A full description is set out in section 4.6 of Attachment A to the Proposal – Revised GIT Results. in brief, the analysis shows that:

- using an N-1 capacity constraint results in outcomes with similar levels of reliability as currently exist; and
- using no constraint results in outcomes whereby there is a far less secure supply system than at present.

Transpower has considered this issue again, in light of the analysis undertaken for Meridian Energy, but has reached the same view as in the proposed GIT analysis: using GEM with an N-1 capacity constraint produces realistic generation expansion plans and using such a constraint is reasonable.

Transpower has undertaken further work to identify the impact of splitting the 90% renewables by 2025 into two, as suggested by Meridian.

A full description of this analysis is included in section 5.6.3 of Attachment A to the Proposal – Revised GIT Results.

In brief, Transpower found that splitting the existing market development scenario 5 (90% renewables), which has a weighting of 50% in the GIT, into two – each of 25% total weight (one being the existing and one being similar to the geothermal cost sensitivity study carried out above) will affect the GIT results in the following way:

- 500 MW (Option 1) will have its scenario weighted net market benefit reduced by \$13 million (or 25% of \$51 million); and
- 700 MW (Option 2) will have its scenario weighted net market benefit reduced by \$14 million (or 25% of \$56 million).

This results in the following impact on the GIT results:

geothermal and wind, instead of South Island hydro and wind. Meridian Energy recommends that this is achieved by splitting MDS 5 into two 90% scenarios in which capital costs between hydro, wind and geothermal generation are varied. Contact Energy's suggestion to reduce geothermal costs by 20% is a pragmatic solution to achieve this outcome.

Item	Base Case No Pole 1 replacement	Option 1 500 MW Pole 1	Option 2 700 MW Pole 1
Present Value 2007\$M			
Expected Net Market Benefit	-	125	177

Transpower does not consider these changes to be material and that its GIT results are therefore robust to these sensitivities.

MEUG	24	If possible, scenarios and weighting should be discussed with Electricity Commission and other parties taking into consideration comments on recent draft GPA generation scenarios consultation.	See response 17 above. Transpower has consulted on its approach extensively and openly.
MEUG	25	The 50% weighting on the "90% renewables by 2025" scenario because it ¹ <i>"should be considered likely, given it is government policy"</i> is a very flimsy reason. MEUG do not think the "90% renewables by 2025" target should be accepted without very good reason.	Transpower considers that assessing the weighting to be attributed to scenarios is a difficult task on which it must rely on its expert judgment considering the input of affected parties. Transpower has considered the issue further, and sets out its thinking at section 5.6.4 of Attachment A to the Proposal – Revised GIT Results. Transpower considers that while its reasoning is brief, it is reasonable. To test the sensitivity of the GIT result to the weightings however, Transpower has calculated the impact of using different weightings, for comparison. The table below shows how expected net market benefit changes for various weightings. The first column shows the expected net market benefit using Transpower's assumptions, as per the GIT analysis. In the second column, the high weighting for the 90% renewables by 2025 scenario is reduced and all scenarios are given an equal weighting. Option 2 is still preferred and still has a positive expected net market benefit. In the third column, the weighting for the SI surplus scenario is reduced to zero and the other four scenarios are given equal weightings. This equates to renewables scenarios

¹ Consultation Document, paragraph 5.1.5 (see Volume 2).

being given a weight of 50% and thermal scenarios a weight of 50%. As seen, Option 2 is still preferred and still has a positive expected net market benefit.

In the fourth column, the original weightings between thermal and renewables scenarios are reintroduced, but the high weighting is given to the primary renewables scenario, which includes 70-80% renewables. As seen, Option 2 is still preferred and still has a positive expected net market benefit.

In the fifth column, the weighting for the SI surplus scenario is again reduced to zero, the thermal scenarios are given a weighting of 50% and the renewables scenarios are given a weighting of 50%, but now the primary renewables scenario is given a high probability and the 90% renewables by 2025 scenario a low probability. As seen, Option 2 is still preferred and still has a positive expected net market benefit.

Scenario	Weighting				
High gas	20%	20%	25%	20%	25%
Mixed technologies	10%	20%	25%	10%	25%
Primary renewables	15%	20%	25%	50%	40%
SI surplus	5%	20%	0%	5%	0%
90% renewables by 2025	50%	20%	25%	15%	10%
Expected net market benefit (2007\$m)					
Option 1 - 500 MW	138	76	79	88	58
Option 2 - 700 MW	191	122	134	99	95
Option 3 - 1000 MW	106	26	43	1	-2

As can be seen, even if Transpower used different weighting to that it has used, and considers reasonable, the same option would be preferred.

Genesis Energy 26 The approach taken to generation scenarios and weightings in absence of an updated Statement of Opportunities appears reasonable.

Noted.

GIT modelling

Genesis Energy 27 Transpower's approach to generation expansion modelling is generally reasonable. The reality check provided by having a third party analyse generation expansion using an alternative model provides additional comfort that the approach and output

Noted.

		is reasonable.	
Genesis Energy	28	Genesis Energy has some concern around the treatment of reserve requirements in GEM. In particular, Genesis Energy queries whether the modelling schedules enough capacity to meet the reserve energy requirements created by unbalanced operation – particularly in the base case. As PLEXOS does model reserve requirements, it is of considerable comfort that the PLEXOS-based GIT analysis shows that Transpower's analysis is conservative. Genesis Energy is comfortable the 'reserves issue' is a reason <i>for</i> replacement rather than a reason not to invest.	In response to Genesis Energy's comment, Transpower has carried out further PLEXOS analysis, without reserves being modelled, in order to identify the probable impact of not modelling reserve requirements in GEM. The results of that analysis are reported in section 4.7 of Attachment A. This has shown that the GEM modelling is conservative and understates the expected net market benefit of the Proposal by around \$44m.
Meridian Energy	29	We consider the inputs contain systematic biases. We also consider that the weightings of the 90% renewables scenario creates a significant bias in the HVDC valuation.	Transpower's response is set out above. See responses 7, 15, 16, 19, and 23 above.
MEUG	30	The use of two models (GEM/SDDP and PLEXOS) with similar results is helpful. On balance, the generation modelling appears reasonable.	Noted.
GIT assumptions			
MEUG	31	Assumptions, parameters and sensitivities reasonable, subject to the following two comments.	Noted.
MEUG	32	Assumptions regarding New Plymouth power station and the continuation of the Rio Tinto contract need to be updated. MEUG notes the report does comment on these more recent events and provides a reasonable view that even if included in the analysis the overall result would not change.	Transpower notes that additional and new information will always become available as its provisional analysis and consultation develops. It does seek to take into account all relevant information as it becomes available. Transpower notes MEUG considered that the proposed GIT analysis was reasonable. Transpower has considered further the impact on the on analysis of various changes to the market assumptions on a qualitative basis. The discussion can be found in section 5.6.5 of Attachment A to the Proposal – Revised GIT Results. The conclusion is that: - no identified change in market assumptions is likely to lead to a significant change in the GIT results; and - most identified changes tend to favour the Proposal.
MEUG	33	Report assumes carbon prices and gas prices are correlated, ie	Although Transpower has not been party to the design behind the scenarios, it is our understanding that there has not been assumed any correlation between carbon prices

		if carbon prices are high then gas prices will also be high and vice versa. That may not be true. Rather than review the assumptions, this is more a matter of reviewing the generation scenarios assumed as commented on by MEUG in another comment (see comments 24 and 25 above).	and gas prices, though the presentation of the scenarios may suggest this. However, Transpower believes that a carbon constrained scenario (i.e. a scenario with high carbon prices) will tend to lead to a higher gas demand worldwide as fuel switch (coal to gas) is typically one of the most economic emission reduction means. It should be noted that the current government policy to place a moratorium on thermal base-load generation for the next 10 years may lead to a different result. Lower demand than expected by industry may result in a lower price increase than expected in the assumptions. However, as thermal plants cannot be built, there will be no impact on the generation scenarios as such. Rather, the additional "cheaper" gas is likely to be bought and consumed by other industries. Transpower has considered further the generation scenarios used. While it reached the same view as it proposed, it has carried out sensitivity analysis to test the robustness of the results to alternative assumptions (see response 25 above)
Contact Energy	34	There will be errors in analytical techniques used to calculate discount rate.	Transpower agrees with Contact Energy that discount rates can vary over time, but is not aware of any practical analytical technique to take account of such changes. It is also noted that this would introduce a new uncertainty – the forecast of discount rates – which may or may not make introducing such a change worthwhile. The expected net market benefit has been sensitised to the discount rate, as reported in sections 5.5.1 and 5.5.2 of Attachment A to the Proposal – Revised GIT Results. As expected, the discount rate is the most significant variable in the calculation of expected net market benefit, but the result remains the same over the sensitised range of 4% to 10%. Transpower notes that the New Zealand Energy Strategy incorporated a 5% discount rate for such analyses and the use of a discount rate of this order would align with Transpower's own opinion that the GIT discount rate should be closer to a social (rate of time preference) rather than the 7% stated in Schedule F4 of the Electricity Governance Rules (Rules).
Contact Energy	35	The cost difference between greenfield and brownfield developments in the current portfolio of actual projects is unlikely to be as great as has been used in the GEM analysis.	Transpower received no information about this aspect during its earlier consultation on the data assumptions. However, the issue is addressed by the sensitivity analysis (see reply to response 36 below) in which future geothermal generation was discounted by 20%, compared to the costs assumed in the GIT. The GIT outcomes were, in any event, relatively insensitive to assumed geothermal costs, as geothermal was economic

			irrespective of the capital cost variations included in this analysis. Transpower considers the geothermal costs applied were reasonable.
Contact Energy (letter of 11 March 2008)	36	Geothermal costs used by Transpower in the GIT analysis were too high by roughly 20%.	Transpower has received contrary submissions at the customer engagement consultation phase that the geothermal costs used were too low, and the basis of that industry feedback applied a sensitivity in which, amongst other things, geothermal costs were lowered by 20%. Transpower applied a sensitivity as requested in which costs were lowered by assuming -20% capital costs for all geothermal projects plus a lower growth in costs for the generic projects, giving them a higher discount than the 20% suggested by Contact Energy (see letter of 27 March 2008 and section 5.6.3 of Attachment A to the Proposal – Revised GIT Results). The results still favoured the Proposal over other options by some margin. Transpower also notes that the impact of lowering geothermal generation capital costs on build year is minor, if any.
Contact Energy (letter of 11 March 2008)	37	Planned capacity of 200MW for Tauhara, not 90MW as in the GIT analysis. Planned capacity of Te Mihi 225MW, not 240MW as in the GIT analysis.	Transpower considers that increasing the capacity of Tauhara in the model would simply delay investment in one or more of the generic geothermal plants in the model and so result in similar GIT results. The change to Te Mihi would offset this to some degree, and would have little effect on the results.
Genesis Energy	38	Assumptions, parameters and sensitivities reasonable.	Noted.
GIT results			
Meridian Energy	39	The outcomes are based on unreasonable input assumptions so by definition the outputs are unreasonable and unreliable.	Transpower has considered Meridian Energy's comments about the inputs (as set out above). Transpower has made the input data available for comment, we have reviewed aspects of the data (e.g. Covec review of future South Island demand growth) and cannot agree that the input data or assumptions are unreasonable.
Meridian Energy (letter of 21 February)	40	Meridian Energy requested Transpower provide information on how the level of historic HVDC transfers compares to those forecast by Transpower over the analysis to understand the impact Transpower is forecasting a new Pole 1 would have on HVDC transfers.	Transpower provided this information on 20 March 2008 (see section 4.4 of Attachment A to the Proposal – Revised GIT Results).
Contact Energy	41	Contact Energy has some reservations about interpretation of the results of the GIT analysis. Transpower's analysis has found 700MW replacement option for Pole 1 to be the option that maximizes the expected net market benefit at \$187 million. The balance of probabilities may produce an expected net market	Transpower has carefully considered Contact Energy's arguments. Transpower considers that its GIT analysis is reasonable and robust. Its sensitivity analysis has carefully identified the major factors for and against replacement, after consultation with affected parties and the Electricity Commission, and considered what

benefit of less than zero, although a number of plausible scenarios would lead it to be less than zero.

There is a good deal of uncertainty about generation options, economics and build scenarios and all sorts of outcomes are feasible given the nexus of economics and commercial drivers that lead to new generation build. Contact Energy does not believe that Transpower's sensitivity analysis has been robust enough to conclude that the replacement of Pole 1 should proceed immediately and be commissioned from 2012. We believe that there could be considerable value in the option of waiting and watching how demand, and generation consenting and build, track over the next 2 to 3 years before revisiting this investment decision.

Cost avoided by deferring investment should be given high commercial credibility. The savings from generation foregone are much more debatable.

There is also a risk of the project is more expensive, dry weather conditions are dry and the current half of Pole 1 remains functional.

impact that would have on the alternative projects considered.

Transpower accepts that there is an option value in delaying investment, but does not believe that it exists to the extent suggested by Contact Energy. Transpower considers that there is a more significant countervailing option value. This results from the earliest possible commissioning of the Proposal creating options for generators which would not be there otherwise. Transpower believes that it is widely accepted that, particularly as the lead times of transmission investment exceed that of generation investment, an efficient generation investment market requires transmission investment to lead generation investment. There are also a number of other reasons that favour investment that Transpower has not quantified (see sections 5.7 and 5.8 of the Proposal).

MEUG	42	The results appear reasonable on the basis of MEUG's participation in workshops, consideration of the detailed report, and lack of unexplained serious aberrations in the results.	Noted.
Genesis Energy	43	The results of the proposed GIT are reasonable. Ultimately it is important to focus on whether the analysis is reasonable and defensible, not whether it is "correct".	Noted.
Genesis Energy	44	Genesis Energy's inclination is that where there is a close call, over-investment in transmission would be preferable to under-investment.	Noted.
Transpower's proposed GIT approach			
Meridian Energy	45	Approach not reasonable.	Transpower has considered Meridian Energy's detailed comments above and below, and considers that it has responded to issues raised and conducted sensitivity studies to demonstrate that its approach is reasonable, consistent with the GIT requirements, the

			GPA's and the Rules. On balance, Transpower considers its approach is reasonable.
MEUG	46	The approach in applying the GIT appears reasonable.	Noted.
Genesis Energy	47	Transpower's approach is generally reasonable, in light of the requirements of the GIT and expectations of the Electricity Commission. Having third party results using an alternative model (PLEXOS) provides additional comfort that approach (and the output) is reasonable.	Noted.
Other			
Genesis Energy	48	Development plans for the short list of options appear reasonable.	Noted.
Meridian Energy	49	Meridian Energy considers that the additional (AC) transmission augmentation options are reasonable.	Noted.
Meridian Energy (letter of 21 February)	50	Meridian Energy requested information to assess further Transpower's proposed analysis of investment timing.	Transpower provided this information on 20 March 2008 (see section 7 of Attachment A to the Proposal – Revised GIT Results).
Meridian Energy	51	Investment timing. We are convinced that the option of highest expected net market benefit is to delay the HVDC upgrade project for at least three more years (i.e. 2014-2015 commissioning). For a project of this scale, the capital deferral benefits will be in the order of \$50-60 million per annum. The accumulated capital deferral benefits could be as high as \$150-180 million. Other critical information includes: • clearer understanding of likely development path for renewable generation, in particular relative costs of geothermal, wind and hydro development; • the impact of the ETS on the price of electricity and renewable project economics; and the future role for Huntly which is a key assumption in the analysis. Meridian Energy therefore recommends that when the HVDC upgrade is submitted by Transpower as a Grid Upgrade Plan the following change is made:	Transpower has carefully considered the optimal timing for commissioning the Proposal and this analysis is fully described in section 7 of Attachment A – Revised Grid Investment Test results – and section 5.7 of the Proposal document. The economic timing analysis found that the net benefits of the Proposal are similar between 2012 and 2014, decreasing after 2014. However, the economic timing analysis did not consider several important aspects related to the benefits a replacement Pole 1 would have for the electricity system. These are fully discussed in section 5.7 of the Proposal document and once these are considered, Transpower recommends that stage 1 of the Proposal should be built as soon as possible, being 2012. Those benefits include, amongst others: a) Generation option value - Transpower considers that the earliest possible commissioning of the Proposal creates options for generators which would not be there otherwise. Transpower believes that it is widely accepted that, particularly as the lead times of transmission investment exceed that of generation investment, an efficient generation investment market requires transmission investment to lead generation investment. b) Uncertainty over continued Pole 1 limited operation. c) Susceptibility to Pole 2 failure.

The impact of delaying HVDC investment timing is properly canvassed and the benefits quantified. Any deferral benefits should be calculated with the recommended revisions by Meridian Energy to the demand forecasts as set out in this submission.

- d) Increased resilience of the system to high impact low probability events.
- e) Enhanced ability for ancillary market development.

Contact Energy	52	Given the uncertainties surrounding demand and North Island versus South Island generation build clearly point to there being value in waiting until firmer information becomes available. This option is of value because the investment involves high costs, long life assets, large economies of scale, a high proportion of sunk/unrecoverable costs and considerable uncertainty. Two or three years more information would give much more certainty around the value of proceeding with the replacement of Pole 1.	See response 51 above.

Points raised outside scope of GIT consultation

Meridian Energy	53	Inconsistency between use of capacity constraint in proposed GIT analysis solely for the benefit of consumers and Electricity Commission's own determination that South Island generators are beneficiaries of the link.	Identification of the beneficiaries of the HVDC link is not a consideration in application of the GIT. This remark appears to be a commentary on the principles used to determine the Transmission Pricing Methodology and from that point of view it is outside the scope of this consultation.
Meridian Energy	54	Second key issue is to hold Transpower to account for any capital cost expenditure, or in other words, for South Island generators to be sheltered from any project cost over runs. Meridian Energy considers (as the party required to pay the majority of the costs) that Transpower's project costs should be capped to those used in GIT. This will provide right incentives on Transpower to plan and execute its project efficiently. Also creates appropriate disciplines on Transpower to not understate its costs in GIT and recover project costs over runs as extras after project commissioning.	Transpower does not consider that approval of actual costs up to a P90 amount is inappropriate. The approval of a P90cap allows for a reasonable number of contingencies to occur before Transpower is required to seek approval of additional expenditure from the Commission. Transpower, as set out in section 10, will continue to have appropriate project management techniques in place to manage project costs and risks, including: - o Undertaking independent periodic audits of its project management, procurement and commercial processes for the Transpower Board. These audits are aimed at demonstrating that project controls are in place and there is a process to identify areas where Transpower can improve its processes and performance. - o Tracking and reporting project progress on Transpower's website, and sending the Electricity Commission copies of those reports. - o Reporting periodically to the Transpower Board on progress against both expected costs and cost with contingencies, and reasons for any divergence (e.g. exchange rate fluctuations), allowing for indexed escalation or deflation of

linked costs.

- o Ensuring quality assurance is applied in planning, designing, and manufacturing, commissioning, testing and maintaining Transpower's assets in accordance with good electricity industry practice.



**Submission to Transpower NZ Limited
("Transpower") on the Inter-Island HVDC
Pole 1 Replacement Investigation, Grid
Investment Test ("GIT") Consultation:
February 2008**

From

Contact Energy Limited

4 April 2008

Introduction

Contact Energy Limited ("Contact") welcomes the opportunity to comment on Transpower's Grid Investment Test Consultation.

Contact's comments follow.

For any questions related to this submission, please contact:

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General Comments

Contact thanks Transpower for the considerable effort it has put into its Inter-Island HVDC Pole 1 Replacement Investigation. Evidently a significant number of people have worked long and hard on this project. This level of analysis is necessary on such a significant investment decision.

However, Contact has some major reservations about the approach and the interpretation of the results of the GIT analysis. The key reservations are:

- The psychology of the NPV approach tends to focus on a single number as the right answer. Transpower's analysis has found the 700MW replacement option for Pole 1 to be the option that maximizes the expected net market benefit at \$187 million. This is undoubtedly greater than zero as required by the Grid Investment Test (GIT). Transpower has sought to counter the focus on a single number with the traditional, one variable at a time, sensitivity analysis. This showed that the selected discount rate, assumed generation scenario and assumptions about demand growth were critical. Each of these value drivers could, when varied with reasonable bounds, drive the expected net market benefit from replacing Pole 1 of the HVDC to zero or negative.
- Transpower has concluded that this is all fine and that \$187 million is better than alternatives, is positive and is robust. Contact is less sure that the future is quite so mathematically precise.

We will now examine each of our concerns in more detail:

- **Discount Rate**

Looking first at the discount rate, the risk free rate is definitely subject to change, and market risk premiums and asset betas are attempts to use the past as predictors of the future. These are very useful analytical approaches to be sure, but it should be remembered that they are definitely subject to error and cannot pick up changes in risk profile that can materialize from significant technological changes. The undiversifiable risk of an industry is not immutable.

- **Generation Economics and Scenarios**

The generation scenario selected also has a big impact on the expected net market benefit. All generators will have their own views and expertise on the economics of generation options and Contact certainly does. We have written to Transpower expressing our view that the development costs included for geothermal generation in its modelling are too high. Transpower has run a sensitivity analysis on this for us by reducing geothermal generation costs by 20% and reducing the assumed growth of generic geothermal generation costs over time. This has reduced generation costs by \$40 million (averaging over Transpower's market development scenarios) despite what Transpower terms as the "minor" impact of new generation build. (Contact has since met with Transpower and in that meeting Transpower sought additional information on the cost differential between greenfield and brownfield geothermal developments. **We have included our views on this in the attached appendix).**

In Transpower's response letter it pointed out that in 2007 they were advised by some unspecified commentators that the geothermal costs in their modelling were too low and the wind costs too high. It is to be expected that different generators will have different views of the options and their economics, not to mention the chances of gaining the necessary consents. All this goes to show is that there is a good deal of uncertainty about generation options, economics and build scenarios and all sorts of outcomes are feasible given the nexus of economics and commercial drivers that lead to new generation build.

- **Demand**

In Contact's view Transpower needs to adequately address and explain the divergence between historic HVDC transfers and transfers forecast in its GIT analysis. It also needs to explain the significant differences between historic South Island load growth and the assumptions used in the GIT. Contact does not consider that Transpower's letter to Meridian of 20 March 2008 satisfactorily canvasses these points.

- **Optimal Timing**

Despite all the uncertainties inherent in an exercise such as the GIT analysis, it is possible that the expected net market value of replacing Pole 1 is positive. However, we believe that it is also quite possible that the expected net market benefit of the 700MW option is significantly less than the average of \$187 million. An entirely credible combination of different demand assumptions, generation build scenarios and discount rate and could result in a very different picture.

The uncertainties surrounding demand and NI verses SI generation build, clearly point to there being value in waiting until firmer information is available. This option is of value because the investment involves high costs, long life assets, large economies of scale, a high proportion of sunk/unrecoverable costs and considerable uncertainty. Two or three years more information on:

- How demand is tracking - for example are net south to north HVDC transfers following Transpower's forecast path or is it continuing to follow the historic trends; and
- Where new generation is focused and where consents are being given.

would give much more certainty around the value of proceeding with the replacement of Pole 1.

In Transpower's 20 March response to Meridian the PLEXOS model results that follow in Figure 6 give the cross-over point as 2015 for the additional system costs verses savings from deferring.

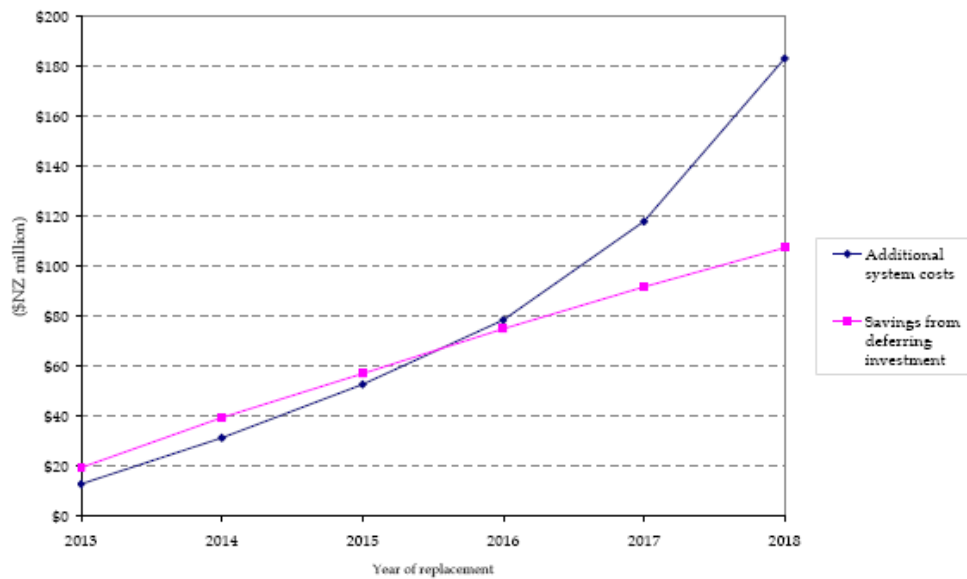


Figure 6 – Comparison of benefits from deferring investment in a replacement Pole 1, with system costs arising from deferral – MMA analysis

Transpower then provides in Figure 7 an updated version of that figure which apart from the costs associated with an average inflow year also shows the range of outcomes from the total of 10 hydro samples analysed.

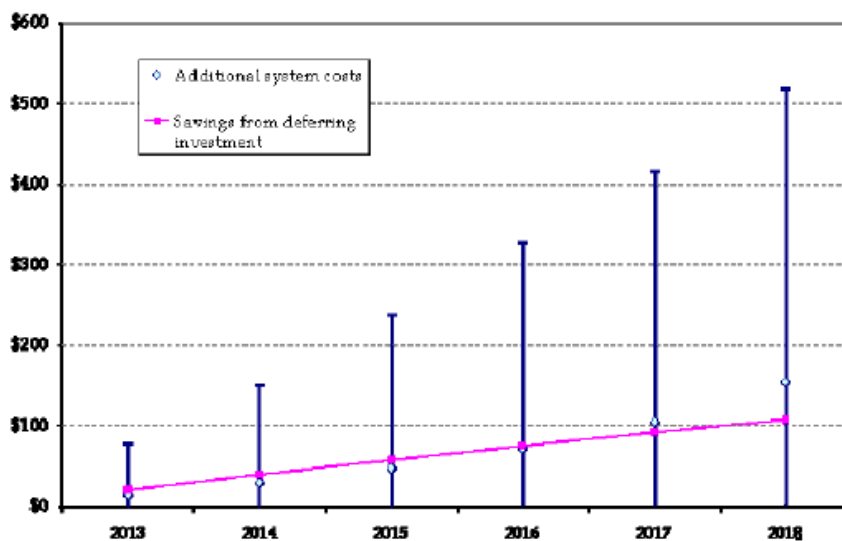


Figure 7 – Comparison of benefits from deferring investment in a replacement Pole 1, with system costs arising from deferral – MMA analysis, showing spread over various hydrological conditions

Figure 7 does show that there are significant variations in system costs depending on the hydro inflows; however the cross-over point is similar to Figure 6.

The significance that Contact takes from this information is that the cost avoided by deferring investment is a relatively fixed and material number and so accordingly should be given high commercial credibility. Meanwhile the savings from generation forgone are much more debatable and subject to much more variation and uncertainty.

In the latter part of the same response to Meridian, Transpower concludes that 2012 is the optimal time to commission a new Pole 1 despite its modelling showing indifference in timing out to 2015. Transpower argues that the project might be cheaper, wet conditions might increase the costs of that status quo and there is a risk that the existing half Pole could be lost. Equally, there is a risk that the project could be more expensive, that weather conditions are dry and that the current half Pole remains functional.

- **Pole 1**

In the Transpower presentation on the re-commissioning of the half pole it states that the “proposed emergency mode (limited operation) would capture most of these benefits”. Should the continuation of the proposed emergency mode then be considered as an alternative to replacement?

- **Procedural issues**

We note that the consultation has spanned many months since the initial consultation workshop in June 2007 due to the potential significance of the investment options being considered. Due to the amount of time that has elapsed Transpower needs to be cognisant that parties like Contact will provide updates to data book inputs as they become available. Contact’s generation projects have progressed during this period with, as you would expect, firmer details as project milestones are reached. During this time

the Electricity Commission has also made good progress on its Grid Planning Assumptions, which now may be more relevant to test the HVDC replacement project with. Transpower's evaluation process needs to be accommodating of ongoing inputs such as these.

Summary

To summarise, under the economic test in Part F of the Electricity Governance Rules 2003, Transpower's Inter-Island HVDC Pole 1 Replacement Investigation must:

- Maximise the expected net market benefit compared with a number of alternative projects;
- The expected net market benefit must be greater than zero; and
- The result must be sufficiently robust using sensitivity analysis.

In Contact's view Transpower's GIT analysis appears to point to a 700MW option being better than the other options. The balance of probabilities may produce an expected net market benefit greater than zero, although a number of plausible scenarios would lead it to be less than zero. However, Contact does not believe that Transpower's sensitivity analysis has been robust enough to conclude that the replacement of Pole 1 should proceed immediately and be commissioned from 2012. We believe that there could be considerable value in the option of waiting and watching how demand, and generation consenting and build, track over the next 2 to 3 years before revisiting this investment decision.

Appendix

Following a request from Transpower, Contact makes the following comments on the difference between Greenfield and Brownfield geothermal costs:

1. Ngatamariki is the only field geothermal field scheduled for development over the next five years that is a true greenfield site (i.e. that the field has no existing geothermal development infrastructure). All the rest have some production or civil assets in place.
2. Large incremental developments on existing sites will require virtually new steamfields, connection assets, and civil works to support them. For instance, the new plant currently underway at Kawerau (90 MW) has a new dedicated steam supply system; it cannot rely on the existing system because the steam pressures between the new power plant and the existing process steam are very different. It also requires a completely new switchyard and HV connection. Similarly, the new condensing-steam-turbine station at Rotokawa (130 MW) will have very different steam requirements compared to the existing binary plant (33 MW), so a separate steam system will need to be constructed for this project as well. While there may be scope for some economies of scale in the existing re-injection system, these are likely to be small as the current system will be sized to fit the existing plant.

In contrast, the Wairakei Binary plant genuinely represents an incremental capacity addition. However, the unit cost improvement is not as high as one might expect because there are very important economies of scale in building power developments and the Binary plant is a small plant.

Therefore, in Contact's view, the cost difference between greenfield and brownfield developments in the current portfolio of actual projects is unlikely to be as great as has been used in the GEM analysis.



4 April 2008

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Dear Peter

GIT Consultation – HVDC Pole 1 Replacement

Genesis Power Limited, trading as Genesis Energy, welcomes the opportunity to provide a submission to Transpower on its consultation paper “Inter-Island HVDC Pole 1 Replacement Investigation, HVDC-TRAN-DEV-01, Grid Investment Test Consultation” (Rev C) dated 17 March 2008 and supporting attachments.

Genesis Energy has prepared this submission from its perspective as a “substantially affected person”, being a generator and retailer with an interest in the market impacts of any HVDC replacement. Genesis Energy also approaches this submission from the following perspectives:

1. As an energy retailer, Genesis Energy believes strongly that reliable supply of electricity at least-cost is of benefit to New Zealand as a whole. Decisions on the future of HVDC Pole 1 could materially impact reliability and cost of delivered energy; and
2. Genesis Energy is interested in ensuring that the regulatory regime for transmission augmentation evolves in a way that will lead to timely and sensible decision making.

Genesis Energy welcomes Transpower’s thorough and transparent approach to analysing the economics of Pole 1 replacement options and hopes that this up-front effort will be rewarded by a relatively smooth regulatory approval process.

Genesis Energy has attached responses to the consultation questions as an appendix to this letter. In addition, we have included below a brief discussion on our approach to responding to Transpower's consultation. Following that, we comment on two issues that don't otherwise fit easily into the appendix.

Our Approach

Genesis Energy approaches this submission with some wariness towards the prospect of becoming buried in detail and losing sight of the 'big picture'.¹ Even though the Electricity Commission has been operating for some four and a half years now, the regulatory regime for approving major transmission investments remains largely its infancy. If Transpower proceeds with an application to the Electricity Commission for approval to invest in replacing Pole 1, then this will be an important test of the regulatory infrastructure. In this context, Genesis Energy is keen to see that precedents are established for a reasonably pragmatic process. Our approach to formulating this submission has therefore been guided by a range of high-level considerations, as discussed below.

1. The value of Genesis Energy's comments. In our view, the value of Genesis Energy providing a submission does not lie in lobbying for or against any positive or negative impacts on Genesis Energy's business. The focus of the grid investment test (GIT) is properly on net market benefit, not on questions of allocation.² The value Genesis Energy can bring to the consultation process is our understanding of our business (including the needs of the consumers we serve and the generation plant we operate) and our understanding of the electricity sector in general.
2. Coping with uncertainty. Uncertainty looms large over most aspects of the GIT analysis – including project costs, demand forecasts and supply forecasts. The GIT requires a range of analytical techniques to be employed for coping with this uncertainty,³ but these can only take the analysis so far. Ultimately it is important to focus on whether the analysis is reasonable and defensible, not whether it is "correct".
3. Where to err. Genesis Energy's inclination is that where there is a close call, over-investment in transmission would be preferable to under-investment. This inclination is based on the value that a

¹ With a consultation package extending to more than 400 pages, the risk of affected parties being 'lost along the way' and unable to formulate a meaningful submission is obvious. This risk is likely to be particularly acute for interested parties that are not well-resourced, but can also affect well-resourced parties that allow themselves to be overly consumed by the details. Given the challenges imposed by the strictures of the grid investment test, Genesis Energy believes that Transpower has done a good job of putting together a well-structured consultation package that leads readers very neatly through Transpower's analysis.

² Cost allocation undoubtedly sharpens the interest of some participants. This is both understandable and desirable, but does not mean that cost allocation is relevant to whether or not a transmission augmentation project should be approved, rejected, or deferred.

³ These include consultation, scenario analysis, sensitivity analysis and use of conservative assumptions.

robust transmission network provides to the country as a platform for competitive electricity generation and retail markets.

There is also an important question of regulatory overhead. It would be unrealistic for Genesis Energy to seek to duplicate Transpower's own analytical efforts, so we have focussed on sense-checking and fact-checking.⁴ Also, Genesis Energy is conscious that the purpose of this consultation round is essentially to help Transpower ensure that it can put forward a very robust grid upgrade proposal to the Electricity Commission.

Two Points

This section of the submission covers in more detail two points that do not otherwise fit easily with the specific consultation questions.

Instantaneous Reserves

Genesis Energy is somewhat disappointed that GEM does not account for the impact that the inter-island link configuration has on instantaneous reserves requirements, and that as a result this is not captured in the GIT.

The third-party modelling using Plexos, which does model reserves, suggests that omitting reserves understates the case for investing in a replacement Pole 1. In the context of this grid upgrade proposal, Genesis Energy is comfortable the 'reserves issue' is a reason *for* replacement rather than a reason not to invest. At its simplest, two balanced poles are better than one.

In terms of the Electricity Commission's ongoing work, Genesis Energy suggests that further work is required to understand the reserve market implications of the generation development scenarios that are so central to Part F of the rules – particularly given that wind power does not provide reserves, and it is difficult to see geothermal plant efficiently contributing to meeting reserves requirements.

Demand Growth

Genesis Energy is comfortable with Transpower's demand growth assumptions and believes that Transpower doesn't realistically have much choice other than to rely on the projections developed by the Electricity Commission. Similarly, Genesis Energy is comfortable with the approach to weighting high, medium and low growth scenarios.

However, Genesis Energy also recognises that the differential between North Island and South Island demand growth is a reasonably significant driving factor for the outcome of the GIT. As such, Genesis Energy

⁴ Genesis Energy is also concerned about the extent to which work is doubled-up between Transpower and the Electricity Commission. Some doubling-up is an essential feature of the regulatory regime, however there is a risk that this could be taken too far. Genesis Energy's concern mainly arises from the central role that complex generation expansion modelling seems to be taking in the regulatory regime for transmission augmentation. Genesis Energy understands the HVDC link to be somewhat of a special case in respect of Transpower needing to carry out detailed generation expansion modelling.

suggests that it would be useful for Transpower to perform a sensitivity analysis on decoupled growth scenarios. For example, a relatively extreme scenario with medium North Island growth and high South Island growth may provide a useful indication of the bounds of the NPV-positive domain.

If you would like to discuss any of these matters further, please contact me on 04 495 6357.

Yours sincerely

A handwritten signature in black ink, appearing to read 'J Carnegie'.

John A Carnegie
Regulatory Affairs Manager
Genesis Energy

Appendix One – Responses to Consultation Questions

QUESTION	COMMENT
Q1: Do you consider that the short list of options is reasonable?	Overall, yes. Given our comments on reserve market impacts (see cover letter), Genesis Energy queries whether overload capacities should be a factor in evaluating the options short list. Genesis Energy queries whether operating Pole 2 in permanent earth return mode is a realistic assumption for the base case. In particular, Genesis Energy questions whether this would incur significant maintenance expenditure. If permanent earth return operation is not realistic, then greater losses would be applicable for metallic return operation. Comparing the ranking results for BEN-HAY options versus BEN-BPE options (Attachment D, Appendix B), the North Island AC costs are higher for the BPE options, as are the variable generation O&M costs. These seem to be counter-intuitive results. Genesis Energy accepts that if BEN-BPE options and ROX-HAY options do not stack up, then ROX-BPE does not to be analysed in detail. If on the other hand these options did stack up, then Genesis Energy would not be convinced at this stage that the difficulties of undertaking two significant transmission projects at once would render a ROX-BPE completely impractical. On the face of it, there would seem to be some diversity benefit to such an option as well as the benefit of bringing demand and supply electrically closer together.
Q2: Do you consider that the development plans for the short list options is reasonable?	Yes. Genesis Energy queries whether consideration has been given to potential reliability and loss-reduction benefits of developing the 700MW and 1000MW options with two new cables instead of one.

QUESTION	COMMENT
Q3: Do you consider that Transpower's approach to generation expansion modelling is reasonable?	In large part, Transpower's approach to generation expansion modelling is constrained by the requirements of the GIT and the expectations of the Electricity Commission. In the context of these constraints, Genesis Energy considers that Transpower's approach is generally reasonable. The reality check provided by having a third-party analyse generation expansion using an alternative model provides additional comfort that the approach (and the output) is reasonable. This is particularly valuable given that this is the first time Transpower has used generation expansion modelling for a GIT analysis. Genesis Energy's has some concern around the treatment of reserve requirements in GEM. In particular, Genesis Energy queries whether the modelling schedules enough capacity to meet the reserve energy requirements created by unbalanced operation – particularly in the base case. As Plexos does model reserve requirements, it is of considerable comfort that the Plexos-based GIT analysis shows that Transpower's analysis is conservative. Genesis Energy also comments on reserves in the cover letter.
Q4: Do you consider that Transpower's demand growth assumptions are reasonable?	Yes. Genesis Energy suggests that it could be of value to run a sensitivity analysis where North and South Island growth paths are decoupled (for example, using medium North Island growth and high South Island growth). This would be a fairly extreme sensitivity test, but would be useful for understanding where the bounds of the NPV-positive domain may lie. Genesis Energy also comments on demand growth assumptions in the cover letter.
Q5: Do you consider that the weightings Transpower used for demand forecasts are reasonable?	Yes. As this is not a reliability investment, the weightings seem reasonable.

QUESTION	COMMENT
Q6: Do you consider that the generation scenarios and weightings Transpower used are reasonable?	Genesis Energy sympathises with the difficulties caused by the planned 2007 Statement of Opportunities (SoO) having been delayed in expectation of the NZ Energy Strategy. However, the approach taken in the absence of an updated SoO appears reasonable.
Q7: Do you consider that Transpower's overall approach in applying the GIT is reasonable?	Yes.
Q8: Do you agree that the input assumptions, parameters and sensitivities used in applying the GIT are reasonable?	Yes.
Q9: Do you consider that the results of applying the GIT are reasonable?	Yes.
Q10: Do you consider that there are other factors that Transpower should consider in selecting a preferred option?	No.



04 April 2008

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Transpower New Zealand Limited
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96 The Terrace
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Wellington

Dear Peter

Inter-Island HVDC Pole 1 Replacement Investigation

Meridian Energy ('Meridian') welcomes the opportunity to make submissions on Transpower New Zealand Limited's (Transpower's) Inter-Island HVDC Pole 1 Replacement Investigation ('the consultation').

1.0 Meridian's overall position

Meridian has undertaken a substantial review of Transpower's application of the grid investment test (GIT) to its proposal to upgrade Pole 1 of the HVDC link over the last month and has provided Transpower with early feedback of our views so that these could be considered early in the process.

The key issues we have found with Transpower's application of the GIT are that:

1. Transpower's demand forecasts, in particular the allocation of demand between the North and South Islands significantly inflate the results of the HVDC valuation. Amending the demand forecasts to be consistent with historical inter Island demand growth shows that the HVDC GIT is only positive in 1 of the 5 generation scenarios (MDS 5 – 90% renewables).
2. Transpower's inclusion of a capacity constraint in the generation expansion model does not reflect the current market drivers for investment in generation. This is likely to further over value replacement of Pole 1 of the HVDC link. To date Transpower has been unwilling to make the impact of this capacity constraint transparent despite multiple requests from Meridian. In this submission, we show that the presence of this constraint is likely to add a material increment to the HVDC valuation.
3. The MDS 5, 90% renewable scenario, with its 50% weighting, drives the majority of the HVDC valuation. This scenario contains a critical input assumption that approximately 2500 GWh of new generation will be constructed in the South Island in 2015/16 (including North Bank Tunnel for which Meridian is the proponent). At the same time

two Huntly units and P40 will be decommissioned for what appears to be non-economic reasons.

The result is a step change in South Island to North Island power transfers which again results in an increase the HVDC valuation. Meridian is concerned that the likelihood of this series of events (North Island thermal retirement and large scale South Island hydro build by 2015) is not likely enough for it to have such a significant impact on the HVDC valuation.

Meridian submits that the 90% renewables scenario should instead be split into two equally weighted scenarios in which the capital costs of the key technologies, geothermal, hydro and wind generation are varied to provide sensitivity to unit cost changes between technologies. This is similar to Contact Energy's request to include a scenario where geothermal project costs are reduced by 20%.

4. Transpower's analysis shows that the optimal timing for the HVDC link upgrade is 2014. Once the biases in the analysis (outlined in the previous points 1 to 3) are corrected, Meridian expects that the benefits of deferring Pole 1 replacement capital expenditure will be far greater and significant enough to place the project on hold until at least 2014.

On the basis of our analysis Meridian's expectation is that delaying the replacement of Pole 1 until 2014 at the earliest will have the highest expected net market benefit. For a project of this scale the capital deferral benefits will be in the order of \$50-60 million per annum.

We understand that Transpower is currently preparing preliminary design and procurement specifications for the HVDC upgrade. These could be completed and then put on hold for a decision by 2011 as to whether an upgrade should proceed. By this time there will be three more years of information on inter Island consumption trends, the likely development path for new renewable generation and the future of Huntly power station. The accumulated capital deferral benefits over this period could be as high as \$150-180 million.

The remainder of this submission expands on these points. The answers to Transpower's questions are contained Appendix One. Meridian has expressed a range of concerns over Transpower's application of the Grid Investment Test (GIT) in three separate letters dated 21 February, 22 February and 18 March 2008. These are contained in Appendix Two of this submission.

2.0 Introduction

After careful and detailed consideration of Transpower's application of the GIT and Transpower's responses to our letters, Meridian remains seriously concerned that Transpower's application of the GIT contains systematic biases that will over value the HVDC upgrade.

We use the term systematic bias because these biases are present in the demand forecast assumptions and in the generation assumptions across all of Transpower's scenarios which have been used to calculate the expected net market benefit from the HVDC upgrade.

As the party required to pay for approximately 80% of the upgrade costs, Meridian has approached the assessment of Transpower's HVDC GIT from the same perspective that we

would any internal investment proposal in generation or retail. In our view, the analysis completed by Transpower to date does not meet the standards we set ourselves for internal project approval. Meridian also considers that Transpower has not undertaken sufficient analysis to meet the requirements of the GIT. This includes not undertaking sufficient sensitivity analysis to ensure that the results of the GIT are robust.

In this submission we outline what these biases are and Meridian's view of how they can be remedied to meet the minimum level of analytical robustness that we would expect to see in such a significant investment decision and as implied under the rules.

3.0 Demand Forecasts

Meridian's letter of 18 March 2008 sets out in detail our concerns with Transpower's demand forecasts. In summary these concerns are that:

1. Transpower's demand forecasts fail to acknowledge that the drivers of demand growth are economic growth as well as population growth. Instead their allocation of national demand growth between the North and South Islands is based on population growth only;
2. Transpower has undertaken no historical analysis to support the proposition that population growth is the primary driver relevant to allocate demand growth between the North and South Islands; and
3. The outcome of Transpower's demand forecast modeling is a substantial reduction in South Island demand growth for the period of the HVDC analysis compared to what Meridian considers is reasonable. Transpower's demand forecasts create a significant amount of "surplus" energy in the South Island than, in our view, is likely to occur in the future. The presence of this excessive quantity of South Island surplus energy is present in all of Transpower's modeled scenarios and will (as demonstrated by Transpower's own analysis) over value the HVDC link upgrade.

3.1 Drivers of North and South Island Demand & Historical Performance

As Transpower has not undertaken an historical assessment of demand growth, Meridian has analysed North and South Island demand growth and its correlation (or lack of) with population growth.

Over the 11 years from 1997 to 2007 the South Island population grew at 70% of the rate of the North Island population. However, over the same period South Island GXP demand grew at 129% of the rate that was seen in the North Island.

This means that over a prolonged period of time while, the South Island population was growing more **slowly** than in the North Island, South Island demand for energy grew significantly **faster** than in the North Island. This makes intuitive sense when you consider the expansion of dairy in the South Island and the overall 'greening' of areas such as the Mackenzie basin through energy intensive irrigation. This outcome is in direct contrast to the regional allocation methodology used by Transpower in their GIT demand forecast.

These statistics – sourced from Statistics NZ, em6, and the HVDC GIT demand forecasts – are set out in the following table.

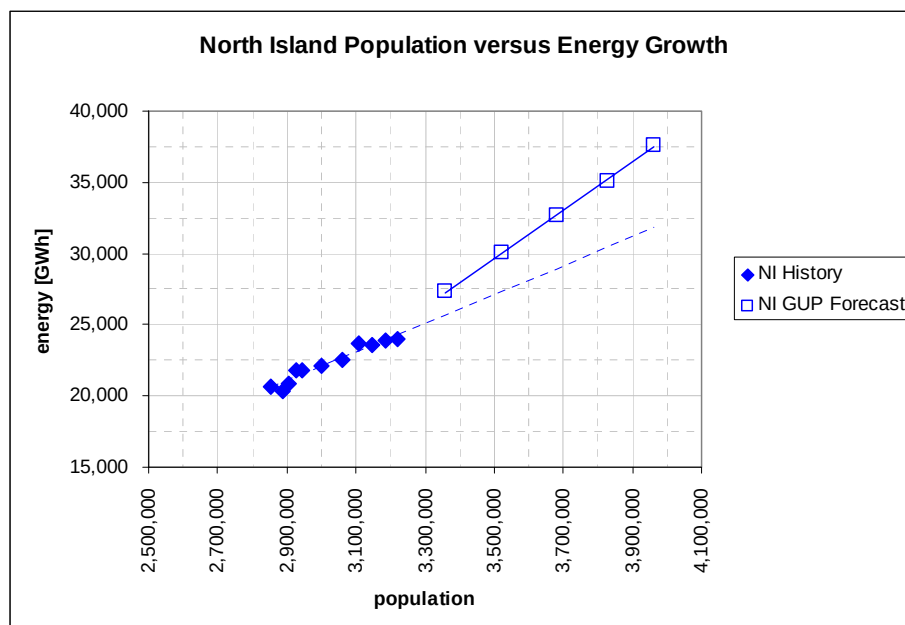
		NZ Population			Energy (GUP) Forecast		
		NI	SI	SI/NI ratio	NI	SI	SI/NI ratio
History	1997	2,854,700	925,700	32%	20,629	11,796	57%
	2007	3,219,000	1,008,300	31%	23,949	14,243	59%
	% Change	12.8%	8.9%	70%	16.1%	20.7%	129%
Forecast	2007	3,219,000	1,008,300	31%	24,997	14,246	57%
	2031	3,963,300	1,125,600	28%	37,585	17,222	46%
	% Change	23.1%	11.6%	50%	50.4%	20.9%	41%

Transpower's medium demand growth forecast out to 2031 has South Island energy growing at 41% of the North Island rate (compared to the 129% seen over the 1997 to 2007 period) with no analytically based rationale for introducing this significant step change.

A population only based demand forecast, i.e. one that ignores the economic growth, which has supported industrial and dairy growth related energy consumption in the South Island, would have grossly understated demand over the last 10 years and will continue to do so in a forecasting sense.

To illustrate this point another way, figure 1 shows some 5,800 GWh of additional North Island demand forecast in the HVDC GIT when compared to history, even allowing for population increases.

Figure 1

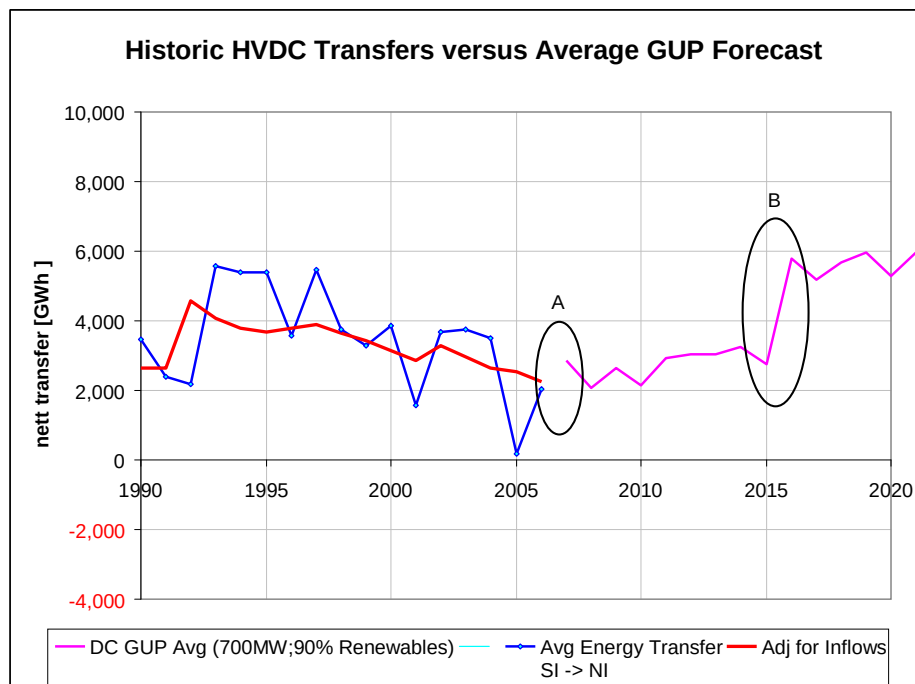


From another perspective, the impact of low South Island demand growth can be seen when comparing historical and future HVDC power transfers. Figure 2 sets out historical actual HVDC transfers, adjusted for inflows and a comparison with Transpower's forecasts.

The three key points from this analysis are:

1. The starting point of Transpower's demand forecast for the North Island is some 1,050 GWh higher than actual demand in 2007. This represents over 2 years of North Island demand growth which will materially affect the results. Meridian submits that the starting point for demand forecasts should be corrected in all scenarios.
2. Compounding this is an imbalance in the South Island demand-generation starting point identified by point A (see figure 2) where 600-800GWh of excess South Island generation is being assumed. This represents over 3-5 years worth of South Island demand growth which will also materially affect the results. Meridian submits that the starting point for demand forecasts should be corrected in all scenarios; and
3. In 2016 there are a suit of modeled South Island projects that reflect a significant upswing in HVDC transfers of about 2500 GWh. In MDS 5 these are Meridian's North Bank Tunnel project and Trustpower's Mahinerangi and Wairau projects, coinciding with Genesis retiring units 3, 4 and P40 at Huntly, identified in point B below. Meridian submits that a sensitivity study should be included to replace these South Island hydro and wind projects, with North Island wind and geothermal projects.

Figure 2



3.2 The Impact of Low South Island Demand Forecasts on HVDC Valuation

Attachment A of Transpower's GIT consultation documents includes the following table, showing the net benefit of HVDC upgrade alternatives under "medium demand growth" (p15, Appendix A, GIT Results).

Expected Net Market Benefit	Base Case No Pole 1 replacement	Option 1 500 MW Pole 1	Option 2 700 MW Pole 1	Option 3 1000 MW Pole 1
Present Value 2007\$M				
High Gas	-	-66	-92	-182
Mixed technologies	-	1	277	166
Medium demand Primary renewables	-	104	97	-35
SI Surplus	-	51	71	-83
90% renewables by 2025	-	275	379	296

Table 5-4: Results of application of the Grid Investment Test by demand growth scenario and generation scenario

Transpower's letter to Meridian of 12 March 2008 provides a further table illustrating how the allocation of demand between the North and South Islands using historical trends (rather than population growth) affects the system expansion cost solved by GEM. In all cases, the trend based solutions show a significant reduction of net expected market benefit from an HVDC upgrade.

Adjusting Table 5-4 for the decrease of benefits illustrated in Transpower's 12 March letter highlights the significance of the inter Island demand growth assumption.

Meridian's adjusted Table 5-4

Adjusted Net Market Benefit		0 MW	500 MW	700 MW	1,000 MW
Medium Demand	High Gas	0	-\$195m	-\$181m	-\$364m
	Mixed Technologies	0	-\$13m	\$6m	-\$17m
	Primary Renewables	0	-\$33m	-\$52m	-\$203m
	SI Surplus	0	-\$300m	-\$364m	-\$515m
	90% Renewables	0	\$264m	\$270m	\$182m

The adjusted table shows that if demand is allocated between the North and South Islands based on historical trends, then the HVDC upgrade **only** delivers a net expected market benefit in the "90% Renewables" market development scenario.

In all other market development scenarios, the HVDC upgrade is neutral or a net expected market detriment.

Meridian considers that for the HVDC upgrade to only make economic sense in one market development scenario, should raise real concerns for Transpower (the proponent), the

ultimate decision maker (the Electricity Commission) and for all payers of the HVDC upgrade (that is, South Island generators). These concerns include:

- Ensuring that one specific market development scenario is split into a North Island and South Island scenario and not over weighted in a way that it undermines the negative value of all others;
- Ensuring that the inputs can stand up to scrutiny from both a common sense and hard analytical perspective particularly in terms of demand forecasting; and
- The need to complete a thorough assessment of the net expected market benefits from delaying an HVDC upgrade; and
- Whether the proposed investment has passed the fundamental question contained in the GIT, that is whether:
 - a. The expected net market benefit is greater than zero; and
 - b. The conclusion is sufficiently robust given the sensitivity analysis conducted.

In summary, Meridian strongly submits that Transpower has not demonstrated the reasonableness of its demand forecast assumptions. In our view, the current assumptions create a systematic and unjustified bias that results in over valuing the HVDC link upgrade.

Proposed Remedies

Given that over the last 10 years there has been very little correlation between South Island demand growth and population growth alone, Meridian considers there is no basis to assert that such a step change will occur in the drivers of energy consumption in the North and South Islands.

Meridian submits that a more appropriate basis for analysis would be to extrapolate historical demand patterns for at least the medium term (next 15 years) beyond which it may be arguable that some of the drivers for inter island demand growth may change.

To maintain that a sudden step change in demand growth across the country will occur means, in Meridian's view, that the analysis will contain a systematic and unjustified bias across all future scenarios.

It will be equally concerning if this position is taken forward into other grid upgrade plans as in some cases it will overstate (over value) the need for investment and in other cases understate (under value) the need for new transmission across the country.

Meridian therefore recommends that when the HVDC upgrade is submitted by Transpower as a Grid Upgrade Plan:

1. *The South and North Island demand forecasts are revised to be based on an extrapolation of historical demand growth and not allocated on the basis of population growth alone;*
2. *The starting point for North Island demand growth should be reset at 2007 actual levels to remove the 1000 GWh North Island starting point bias;*

3. *The starting point for the South Island demand-generation balance should be reset to be consistent with 2007 actual transfer levels (adjusting for hydrology) to remove the 600 GWh South Island starting point bias;*
4. *Sensitivity analysis is performed on MDS5 to show the impact of Huntly units 3, 4 and P40 being replaced with North Island geothermal and wind, instead of South Island hydro and wind. Meridian recommends that this is achieved by splitting MDS 5 into two 90% scenarios in which capital costs between hydro, wind and geothermal generation are varied. Contact's suggestion to reduce geothermal costs by 20% is a pragmatic solution to achieve this outcome.*

4.0 Generation Scenarios

To date, Transpower has dismissed Meridian's request to re-run GEM with the peak adequacy constraint turned off on the basis that this is "simply a modelling parameter in GEM".

Meridian submits that using a system reliability constraint within an economic expansion plan will result in inefficient and uneconomic system investment; largely because in economic terms the peak capacity constraint is arbitrary and uncosted. If Transpower can demonstrate the level of VoLL that is implied by the peak capacity constraint then this would go some distance towards providing Meridian with comfort on this point.

As currently configured GEM specifically precludes the model from choosing the outcome that at times may be better from a national cost-benefit perspective, specifically that small amounts of demand shortage may be preferable to investment in uneconomic generation plant. Allowing GEM to schedule VoLL (at reasonable price levels) tests the materiality of this thesis.

From the perspective of identifying the beneficiaries of the HVDC expansion, the presence of a capacity constraint confirms that one of the key drivers of the HVDC link valuation is to ensure that peak demand in either Island can be met adequately. The contribution to meeting peak demand or, viewed from a consumer's perspective, the avoidance of load shedding at times of peak demand is clearly a benefit for consumers who avoid the short run cost of non supply.

Therefore there is a clear inconsistency between the Electricity Commission's own determination that South Island generators are the beneficiaries of the link and Transpower's inclusion of a peak capacity constraint for the HVDC valuation which is included solely for the benefit of consumers.

Transpower's GEM results for MDS 5 demonstrate that this issue is more than simply a "modelling parameter" and in fact has a profound impact upon the HVDC. Figure 3 compares the growth in peak MW against the growth in 'firm' installed MW. It is clear that the model is scheduling new plant to meet the growth in peak MW – driven by the arbitrary capacity constraint modelled in GEM. The implications of this can be seen in figure 4 which compares the growth in annual demand energy against the assumed growth in new station annual output. Together these two pictures suggest that nearly 7,000 GWh of potential generation is being commissioned than that required to meet energy growth to provide 'sufficient' peak capacity.

Figure 3

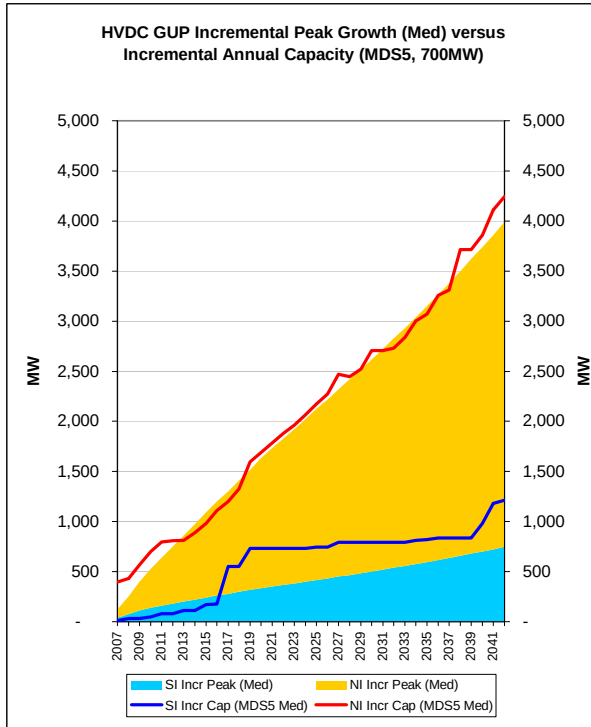
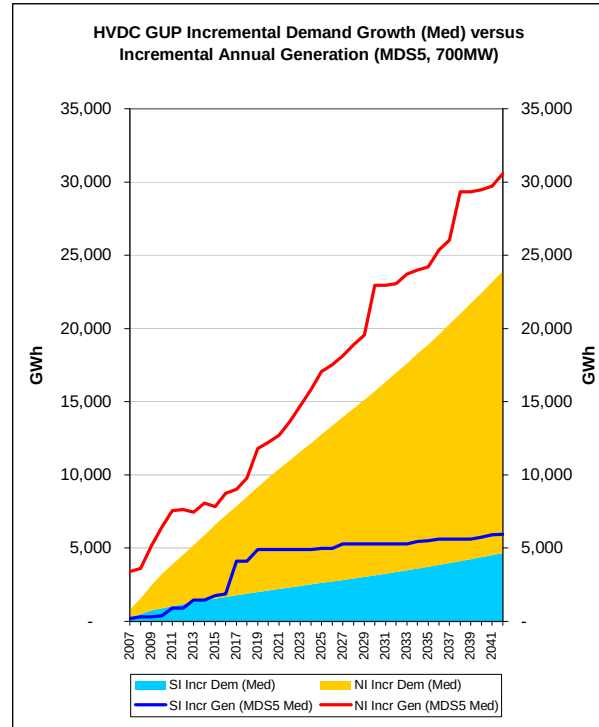


Figure 4



Proposed Remedy

Meridian considers that it is inconsistent for Transpower and the Electricity Commission on the one hand to say that South Island generators are the beneficiaries of the HVDC link while, on the other hand, include a capacity constraint which is specifically designed to include and value the avoidance of consumer load shedding at peak times.

Transpower's unwillingness to date to expose the difference in HVDC valuation with the capacity constraint removed does not provide the transparency that was communicated by the Electricity Commission as set out below.

*"3.4.7 The assessment of private benefit is complex and subject to a number of key uncertainties. Any results at this stage can only be considered to be preliminary, pending more detailed analysis. In particular, the private benefit analysis carried out by Meridian and reproduced by the Commission is static in nature (i.e. the effects of different HVDC link capacities on new generation are not internal to the model). More accurate results would be obtained from a dynamic analysis; the Commission will be in a better position to carry this out once its analysis under the grid investment test in relation to the HVDC Upgrade is complete."*¹

Meridian strongly submits that Transpower completes the analysis requested in our letters of 21 February and 18 March and clearly identifies the quantum of benefits that are being driven by the capacity constraint.

¹ Transmission pricing methodology - Final Decision Paper 7 June 2007

Meridian therefore recommends that when the HVDC upgrade is submitted by Transpower as a Grid Upgrade Plan:

5. *The impact of the capacity constraint on all scenarios is identified by removing the constraint in GEM and re-running each scenario. This will identify the incremental expected net market benefits that are solely associated with managing peak capacity related security of supply concerns.*

5.0 Investment Valuation and Investment Timing

Transpower's own analysis (see figures 5 and 6) shows that the optimal HVDC upgrade date should be between 2014 and 2015.

Figure 5

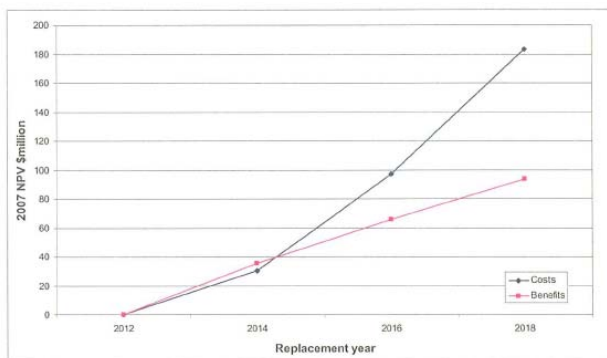
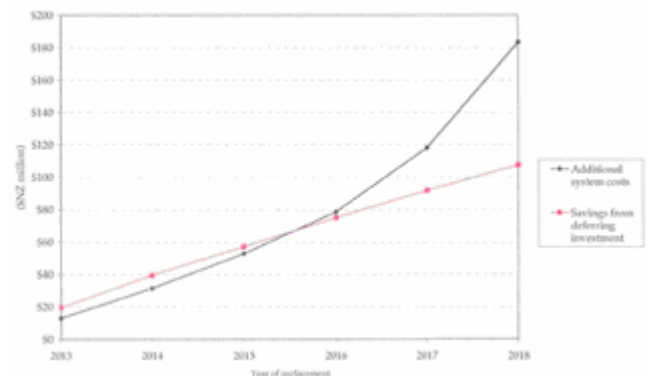


Figure 6



When this is considered in conjunction with Meridian's concerns regarding the demand forecast assumed are modelled then selecting the optimal timing date for any upgrade becomes even more of a substantive issue.

Proposed Remedy

Meridian therefore recommends that when the HVDC upgrade is submitted by Transpower as a Grid Upgrade Plan:

6. *The impact of delaying HVDC investment timing is properly canvassed and the benefits quantified. Any deferral benefits should be calculated with the recommended revisions by Meridian to the demand forecasts as set out in this submission.*

6.0 Summary and Conclusions

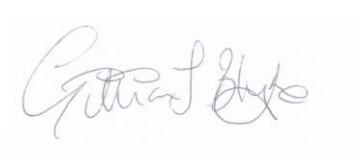
Meridian is seriously concerned that Transpower has put up a proposal that contains systematic biases across all the key assumptions that drive the valuation of the HVDC Upgrade.

Meridian therefore recommends that when the HVDC upgrade is submitted by Transpower as a Grid Upgrade Plan the following changes are made:

1. *The South and North Island demand forecasts are revised to be based on an extrapolation of historical demand growth and not allocated on the basis of population growth alone;*
2. *The starting point for North Island demand growth should be reset at 2007 actual levels to remove the 1000 GWh North Island starting point bias;*
3. *The starting point for the South Island demand-generation balance should be reset to be consistent with 2007 actual transfer levels (adjusting for hydrology) to remove the 600 GWh South Island starting point bias;*
4. *Sensitivity analysis is performed on MDS5 to show the impact of Huntly units 3, 4 and P40 being replaced with North Island geothermal and wind, instead of South Island hydro and wind. Meridian recommends that this is achieved by splitting MDS 5 into two 90% scenarios in which capital costs between hydro, wind and geothermal generation are varied. Contact's suggestion to reduce geothermal costs by 20% is a pragmatic solution to achieve this outcome.*
5. *The impact of the capacity constraint on all scenarios is identified by removing the constraint in GEM and re-running each scenario. This will identify the incremental expected net market benefits that are solely associated with managing peak capacity related security of supply concerns.*
6. *The impact of delaying HVDC investment timing is properly canvassed and the benefits quantified. Any deferral benefits should be calculated with the recommended revisions by Meridian to the demand forecasts as set out in this submission.*

Please call me or Guy Waipara if you wish to discuss this submission further.

Yours sincerely,



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Email guy.waipara@meridianenergy.co.nz

cc: John Gleadow and Bruce Smith, Electricity Commission
Gareth Wilson, Ministry of Economic Development

Attachments:

One: Meridian's answers to Transpower's questions.

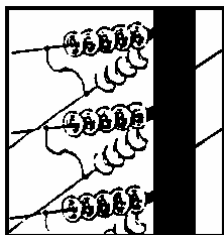
Two: Letters from Meridian to Transpower, dated 21 February, 22 February and 18 March 2008.

Appendix One: Reference to Meridian's Answers

Question	Response
1) Do you consider that the short list of options for the HVDC Pole 1 Replacement Investigation Project is reasonable?	No. We still consider that Transpower has avoided prudent life extension options for Pole 1 and have applied unique insurance criteria to the HVDC link assets to limit the scope of life extension options. Meridian finds it inconsistent that these same criteria have not been applied to the remainder of Transpower's HVAC assets where more traditional asset management criteria and approaches remain in place.
2) Do you consider that the development plans for the short list options for the HVDC Pole 1 Replacement Investigation Project are reasonable? If not, please explain.	Meridian considers that the additional transmission augmentation options are reasonable.
3) Do you consider that Transpower's demand growth assumptions used for the HVDC Pole 1 Replacement Investigation Project are reasonable? If not, please explain	No. In particular Transpower's low South Island demand growth forecasts which are present in all scenarios create higher than reasonable HVDC transfers from the South to the North Island in stark contrast to what has occurred historically. Transpower's demand forecast assumptions systematically over value the HVDC link.
4) Do you consider the weightings Transpower used for low medium and high forecasts, in calculating expected net market benefits for the HVDC Pole 1 Replacement Project are reasonable? If not, please explain	No. Meridian considers that Transpower should revisit its scenario weightings and in particular divide MDS 5 into two separate scenarios for achieving a 90% renewable future. The weightings between low medium and high scenarios are second order to these issues with the key inputs and MDS 5.
5) Do you consider that the generation scenarios and weightings Transpower used in calculating expected net market benefits for the HVDC Pole 1 Replacement Investigation Project are reasonable? If not, please explain	No. Firstly Meridian considers that the use of a capacity constraint with the generation expansion model will bring on generation earlier than the current market will deliver. Projects are therefore likely to not be revenue adequate, i.e. they will not receive sufficient revenues to cover their capital and operating costs and therefore are unlikely to occur in reality. Secondly Meridian considers that the 90% renewables scenario is too dominant and not adequately sensitised to changes in technology costs. Meridian considers that this scenario should be split into two and the capital costs of the key technologies varied to provide a real sensitivity analysis. Meridian concurs with Contact's approach whereby the costs of geothermal generation are reduced to test the interplay between the capital costs of wind, hydro and geothermal generation.

Question	Response
6) Do you consider that Transpower's approach in applying the GIT to the HVDC Pole 1 Replacement Investigation Project is reasonable? If not, please explain	No. We consider the inputs contain systematic biases. We also consider that the weightings of the 90% renewables scenario creates a significant bias in the HVDC valuation.
7) Do you consider that the input assumption, parameters and sensitivities used in applying the GIT to the HVDC Pole 1 Replacement Investigation Project are reasonable? If not, please explain.	No. The rationale is explained earlier and in the attached detailed submission.
8) Do you consider that the results of applying the GIT to the HVDC Pole 1 Replacement Investigation Project are reasonable? If not, please explain	No. The outcomes are based on unreasonable input assumptions so by definition the outputs are unreasonable and unreliable.
9) Do you consider that there are other factors that Transpower should consider when selecting a preferred option for the HVDC Pole 1 Replacement Investigation Project? If so, please explain	Meridian has two key issues. The first is one of investment timing. We are convinced that the option of highest expected net market benefit is to delay the HVDC upgrade project for at least three more years (i.e. 2014-2015 commissioning). Other critical information includes: • a clearer understanding of the likely development path for renewable generation, in particular the relative costs of geothermal, wind and hydro development; • the impact of the ETS on the price of electricity and renewable project economics; and • the future role for Huntly which is a key assumption in the analysis. The second key issue is to hold Transpower to account for any capital cost expenditure, or in other words, for South Island generators to be sheltered from any project cost over runs. Meridian considers (as the party required to pay the majority of the costs) that Transpower's project costs should be capped to those used in the Grid Investment Test. This will provide the right incentives on Transpower to plan and execute its project efficiently. It also creates appropriate disciplines on Transpower to not understate its costs in the GIT only to recover any project costs over runs as extras after project commissioning.

Appendix Two: Letters from Meridian to Transpower.



MAJOR ELECTRICITY USERS' GROUP

4 April 2008

Mr Peter Griffiths
Transpower New Zealand Limited

By email to peter.griffiths@transpower.co.nz

Dear Peter

Submissions on the HVDC Pole 1 replacement Grid Investment Test

1. This is a submission by the Major Electricity Users' Group (MEUG) on the Transpower report *Inter-Island HVDC Pole 1 Replacement Investigation: Grid Investment Test Consultation*, dated 7 February 2008.
2. MEUG represents parties that may be substantially affected if, for example, the application of the Grid Investment Test (GIT) for the HVDC Pole 1 Replacement Investigation project is not robust. MEUG is also interested in ensuring good precedents are established with this first ever economic investment project and thereby assist efficient consideration of other economic investment projects in the future.
3. Transpower are to be congratulated on the extent of consultation in the preparation of the GIT and willingness to answer questions on what is a very complex analysis.
4. Responses to each of the questions in the report follow:

No.	Question	Response
1	Do you consider that the short list of options for the HVDC Pole 1 Replacement Investigation project is reasonable?	MEUG has concern with the screening criteria of "facilitating renewables" in deciding the short list of options. The term "facilitating renewables" could mean ensuring removal of any unnecessary economic barriers to renewable generation. That would be acceptable. However it may also mean promoting renewables irrespective of the economic cost. That would not be acceptable to MEUG. Because there is some ambiguity as to what "facilitating renewables" means, MEUG consider it prudent to exclude that criteria. MEUG do not consider that excluding the "facilitating renewables" criteria would result in any change to the short list proposed by Transpower. Therefore the short list appears reasonable even though we disagree with the selection criteria.

2	Do you consider that the development plans for the short list of options for the HVDC Pole 1 Replacement Investigation project is reasonable?	MEUG has not undertaken a technical review of the development plans and therefore cannot make any comment.
3	Do you consider that Transpower's approach to generation modelling for the HVDC Pole 1 Replacement Investigation project is reasonable?	MEUG has not run GEM/SDDP nor undertaken a detailed evaluation of the material published on PLEXOS. WE have attended several briefing sessions by Transpower and the EC on the models to gain some overview of how they work. The use of two separate models for such an important decision is helpful. That both models had similar results is also helpful. On balance the generation modelling approach appears reasonable.
4	Do you consider that Transpower's demand growth assumptions for the HVDC Pole 1 Replacement Investigation project are reasonable?	These were reasonable at the date the EC advised such to Transpower. They may need updating following feedback to the EC on the recent Grid Planning Assumptions (GPA) consultation paper. MEUG expects any changes to be within the sensitivity range considered by Transpower. However a materiality check against the final GPA demand forecasts may be prudent.
5	Do you consider that the weightings Transpower used for low, medium and high demand forecasts, in calculating expected net market benefits for the HVDC Pole 1 Replacement Investigation project are reasonable?	Weighting the medium 70% and each of high and low at 15% appears reasonable.
6	Do you consider that the generation scenarios and weightings Transpower used in calculating net expected net market benefits for the HVDC Pole 1 Replacement Investigation project are reasonable?	If possible the scenarios and their weighting should be discussed with the EC and other parties taking into consideration comments to the EC on the recent draft GPA generation scenarios consultation. The 50% weighting on the "90% renewables by 2025" scenario because it ¹ <i>"should be considered likely, given it is government policy"</i> is a very flimsy reason. Government has not passed any legislation to support this target and we think the chance of the ban on new thermal generation being enacted is low. Government's makes various policy announcements over time but whether they actually result in a difference should be considered on a case by case basis. For example not long ago the government announced a policy of returning New Zealand to the top half of the OECD in terms of GPD per head. If Transpower believed that, then power demand forecasts would be much higher than that assumed in the GIT because the primary driver for demand would be very high rates of GDP growth. Just as Transpower (and the EC) do not assume government pronouncements on target GDP growth will eventuate, neither do we think the "90% renewables by 2025" target should be accepted without very good reason.

¹ Transpower HVDC GIT consultation report, paragraph 5.1.5, 7 February 2008

7	Do you consider that Transpower's approach in applying the GIT to the HVDC Pole 1 Replacement Investigation project is reasonable?	The approach in applying the GIT appears reasonable.
8	Do you consider that the input assumption, parameters and sensitivities used in applying the GIT to the HVDC Pole 1 Replacement Investigation project are reasonable?	Agree these have been reasonable subject to noting: - Some assumptions regarding New Plymouth power station and the continuation of the Rio Tinto contract need to be updated. MEUG notes the report does comment on these more recent events and provides a reasonable view that even if included in the analysis the overall result would not change. - The report assumes carbon prices and gas prices are correlated, ie if carbon prices are high then gas prices will also be high and vice versa. That may not be true. Rather than review the assumptions, this is more a matter of reviewing the generation scenarios assumed as commented on in question 6. - MEUG has no expertise to assess if the various capital, operating and maintenance and fuel cost assumptions have been reasonable.
9	Do you consider that the results of applying the GIT to the HVDC Pole 1 Replacement Investigation project are reasonable?	MEUG has not checked the detailed models used by Transpower or run separate models to validate the results. We have participated in workshops where the results have been considered and debated in detail. We have also considered the detailed report itself. There does not appear to be any unexplained serious aberrations in the results. On that basis the results appear reasonable. If as a result of this consultation round there are: - Materially different cost information and/or - Large changes to demand forecasts and/or; - Significant changes to the definitions and weightings of credible scenarios; Then the preferred option may change.
10	Do you consider that there are other factors that Transpower should consider when selecting a preferred option for the HVDC Pole 1 Replacement Investigation project are reasonable?	No comment.

5. This submission is not confidential.

Yours sincerely



Ralph Matthes
Executive Director

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28 March 2008

Mr Guy Waipara
Meridian Energy Limited
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Wellington 6143

Dear Guy

HVDC Grid Investment Test Consultation

Thank you for your letter of 18 March 2008. Transpower will consider Meridian's concerns carefully in deciding whether to submit a Grid Upgrade Plan (GUP) relating to the HVDC Pole 1 replacement investigation project (Project) to the Electricity Commission.

We re-iterate that Transpower has not pre-determined whether to submit a GUP and the content of the GUP in relation to the Project.

Transpower will consider its proposed Grid Investment Test (GIT) analysis with an open mind in light of submissions received as part of the consultation process. As you are aware, Transpower has engaged openly and extensively with market participants, including Meridian, for many months on the assumptions and methodology underlying its proposed application of the GIT. Transpower remains open to submissions. In response to Meridian's recent letters, Transpower has carried out considerable further analysis and set this out, with its provisional views regarding aspects of the usefulness of the work requested by Meridian, in order to engage constructively with Meridian. We will consider your comments further in deciding whether, in relation to this Project, to submit a GUP and the content of any GUP.

Yours sincerely



Peter Griffiths
Transpower New Zealand Limited

cc: John Gleadow, Electricity Commission

18 March 2008

Mr Peter Griffiths
Transpower New Zealand Limited
Level 7, Transpower House
96 The Terrace
PO Box 1021
WELLINGTON

Dear Peter

HVDC Grid Investment Test Consultation

Thank you for your letter in response to our questions regarding the HVDC GIT.

However, on the whole, we find your response disappointing and in particular the lack of willingness to explore valid sensitivity studies increases our concern that the analysis is constructed around systematic biases which will over value the HVDC link.

Transpower's reluctance to explore or consider these biases openly when considered alongside statements from the Transpower CEO Patrick Strange on 12-Mar-2008 such as:

"...Transpower still considers that a complete replacement option of Pole 1 is the best long-term solution and we are working as quickly as possible to progress this."

leaves Meridian with the clear impression that the outcome of this upgrade process has been predetermined and the analysis is being completed in a manner that supports this conclusion.

Major Drivers of Valuation

The two major drivers of the HVDC valuation are generation scenarios and demand forecasts. We address these two drivers as follows.

Generation Scenarios

Transpower has dismissed Meridian's request to re-run GEM with the peak adequacy constraint turned off on the basis that this is "simply a modelling parameter in GEM".. Putting to one side that the capacity constraint is far more than just a "modelling parameter" as it will in part drive the HVDC valuation, we would like to make two points:

1. Using a system reliability constraint within an economic expansion plan will result in inefficient and uneconomic system investment; largely because in economic terms the peak capacity constraint is arbitrary and uncoded. If Transpower can

demonstrate the level of VoLL that is implied by the peak capacity constraint then this would go some distance towards providing Meridian comfort on this point.

2. As currently configured, GEM specifically precludes the model from choosing the outcome that at times may be better from a national cost-benefit perspective, specifically that small amounts of demand shortage may be preferable to investment in uneconomic generation plant. Allowing GEM to schedule VoLL (at reasonable price levels) tests this materiality of this thesis.

As the sensitivity analysis that Meridian is requesting will provide a view consistent with how generation expansion in the current New Zealand electricity market is undertaken, we strongly submit that Transpower provides the analysis requested in point one of our letter of 21 February.

Demand Forecasts

Demand forecasts, in particular the balance of energy in the North and South Islands will have a substantial effect on the HVDC valuation. Meridian is therefore concerned that the demand forecasts are developed on the basis of as much actual historical insight as possible.

Meridian has asked Transpower to undertake sensitivity analysis using an extrapolation of historical North and South Island demand.

While we appreciate the analysis completed by Transpower, we are concerned that Transpower has dismissed the "realism" of this sensitivity largely on the basis that the GIT forecasts are similar to other recent forecasts used by Transpower and the Electricity Commission.

The national level econometric demand modelling methodology is a widely used approach to forecasting national demand and an approach that Meridian does not particularly disagree with. However, the ability of the method to meaningfully forecast regional and/or Island demand has yet to be demonstrated; certainly not by Transpower or by the Electricity Commission. The default position presented here by Transpower is that regional population growth is a valid basis on which to perform the allocation of national demand down to the regional or North and South Island level. Meridian restates, as it has stated in previous meetings with Transpower staff over the years, that this is almost certainly a poor approach.

In their letter of 12 March, Transpower has asserted that their econometric modelling is more realistic than extrapolation of historical trends, without taking the necessary steps to assess how these assertions have performed over recent history.

The efficacy of this assertion can be readily tested by the following assessment.

Over the 11 years from 1997 to 2007 the South Island population grew at 70% of the rate of the North Island population. However, over the same period South Island GXP demand grew at 129% of the rate that was seen in the North Island.

This means that over a prolonged period of time while the South Island population was growing more **slowly** than in the North Island, South Island demand for energy grew significantly **faster** than in the North Island. This outcome is in direct contrast to the regional allocation methodology used by Transpower in their GIT demand forecast.

These statistics – sourced from Statistics NZ, em6, and the HVDC GIT demand forecasts – are set out below.

		NZ Population			Energy (GUP) Forecast		
		NI	SI	SI/NI ratio	NI	SI	SI/NI ratio
History	1997	2,854,700	925,700	32%	20,629	11,796	57%
	2007	3,219,000	1,008,300	31%	23,949	14,243	59%
	% Change	12.8%	8.9%	70%	16.1%	20.7%	129%
Forecast	2007	3,219,000	1,008,300	31%	24,997	14,246	57%
	2031	3,963,300	1,125,600	28%	37,585	17,222	46%
	% Change	23.1%	11.6%	50%	50.4%	20.9%	41%

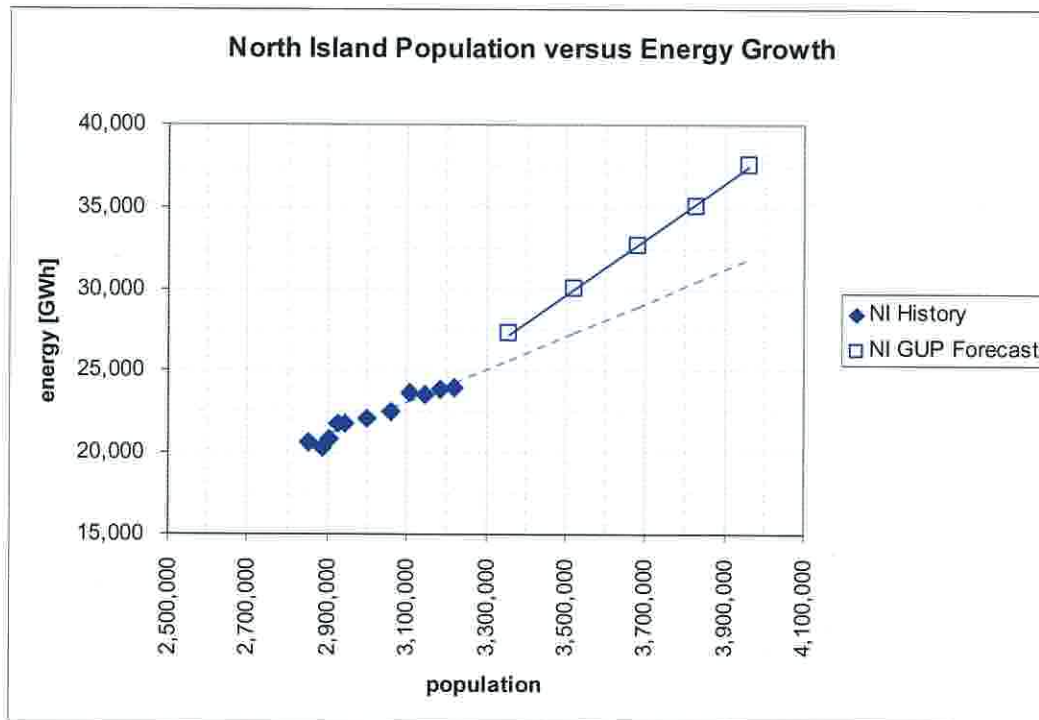
The medium GIT forecast out to 2031 has South Island energy growing at a mere 41% of the North Island rate (compared to the 129% seen over the 1997 to 2007 period) with no analytically based rationale for introducing this significant step change.

This is a major decision and one that in Meridian's view cannot be merely asserted away.

A population only based demand forecast, i.e. one that ignores the economic growth, which has supported industrial and dairy growth related energy consumption in the South Island would have grossly understated demand over the last 10 years and in Meridian's firm opinion, will continue to do so in a forecasting sense.

To illustrate this point another way, the following chart shows some 5,800GWh of additional NI demand forecast in the HVDC GIT when compared to history, even allowing for population increases.

We also note that the starting point of Transpower's demand forecast for the North Island is some 1,050 GWh higher than was observed in reality in 2007. This represents over 2 years worth of NI demand growth, yet another data assumption that will bias the HVDC GIT results towards positive benefits for a link replacement sooner than would otherwise be required.



In summary, Meridian submits that Transpower has not demonstrated the reasonableness of its demand forecast assumptions and in our view the current assumptions create a systematic and unjustified bias towards over valuing the HVDC link.

The sensitivity results requested by Meridian cannot be merely dismissed by Transpower as unrealistic and we strongly submit that they are taken forward into the GIT valuation process.

Comments on Transpower's Demand Forecast Sensitivity Analysis

Attachment A of the Transpower's GIT consultation documents includes the following table, showing the net benefit of HVDC upgrade alternatives under "medium demand growth".

	Expected Net Market Benefit	Base Case No Pole 1 replacement	Option 1	Option 2	Option 3
			500 MW Pole 1	700 MW Pole 1	1000 MW Pole 1
Present Value 2007\$M					
Medium demand	High Gas	-	-66	-92	-182
	Mixed technologies	-	-1	277	166
	Primary renewables	-	104	97	-35
	SI Surplus	-	51	71	-83
	90% renewables by 2025	-	275	379	256

Table 5-4: Results of application of the Grid Investment Test by demand growth scenario and generation scenario

Transpower's letter of 12 March provides a further table illustrating how the allocation of demand between the North and South Island using historical trends (rather than population growth) affects the system expansion cost solved by GEM. In all cases, the trend based solutions show a significant reduction of benefit from the HVDC upgrade.

Adjusting Table 5-4 above for the decrease of benefits illustrated in Transpower's letter of 12 March, highlights the significance of the inter Island demand growth assumption.

Adjusted Net Market Benefit		0 MW	500 MW	700 MW	1,000 MW
Medium Demand	High Gas	0	-\$195m	-\$181m	-\$364m
	Mixed Technologies	0	-\$13m	\$6m	-\$17m
	Primary Renewables	0	-\$33m	-\$52m	-\$203m
	SI Surplus	0	-\$300m	-\$364m	-\$515m
	90% Renewables	0	\$264m	\$270m	\$182m

The adjusted table shows that if demand is allocated between the North and South Islands based on an historical trend, then the HVDC upgrade **only** delivers a net national benefit in the "90% Renewables market development" scenario.

In all other market development scenarios, the HVDC upgrade is neutral or a net public detriment.

If the HVDC upgrade only makes economic sense in one market development scenario, then this creates real concerns for the decision making process to come.

These concerns include:

1. Ensuring that one specific market development scenario is not over weighted in a way that it trumps the negative value of all others;
2. Ensuring that the inputs have a much higher degree of analytical rigour applied to them than experienced to date, particularly with demand forecasting;
3. Ensuring that adequate and unbiased sensitivity analysis is completed; that is sensitivity analysis that tests the HVDC valuation in both positive and negative directions; and
4. Properly assessing the option to delay the HVDC investment as it is now becomes an option with material benefits associated with it.

Given the results are far less clear than earlier anticipated, Meridian is concerned that a decision to approve, reject or defer an HVDC upgrade is given thorough consideration from Transpower and the Commission. In particular, Meridian looks forward to your response on how Transpower intends to manage each of the significant issues raised in this letter that affect the HVDC valuation.

Yours faithfully

A handwritten signature in black ink, appearing to be 'Guy Waipara', with a long horizontal line extending to the right.

Guy Waipara
Strategy Integration Manager

Attachment: GEM System expansion costs from Transpower's 12 March letter.

DC Upgrade Size (MW)	Scenario Name	Scenario	PV System Costs with NI SI			Probability of Market Development Scenario			
			PV System Costs with NI SI demand split based on trend	demand split based on population growth rate					
0 MW	High Gas	MDS1	21216	21261	20%				
	Mixed Technologies	MDS2	22779	23148	10%				
	Primary Renewables	MDS3	23735	24060	15%				
	SI Surplus	MDS4	21013	21824	5%				
	90% Renewables	MDS5	24608	25090	50%				
500 MW	High Gas	MDS1	21285	21201	20%				
	Mixed Technologies	MDS2	22664	23019	10%				
	Primary Renewables	MDS3	23677	23865	15%				
	SI Surplus	MDS4	20842	21307	5%				
	90% Renewables	MDS5	24186	24657	50%				
700MW	High Gas	MDS1	21350	21306	20%				
	Mixed Technologies	MDS2	22667	22765	10%				
	Primary Renewables	MDS3	23721	23897	15%				
	SI Surplus	MDS4	20901	21277	5%				
	90% Renewables	MDS5	24097	24470	50%				
1,000 MW	High Gas	MDS1	21519	21382	20%				
	Mixed Technologies	MDS2	22720	22906	10%				
	Primary Renewables	MDS3	23880	24037	15%				
	SI Surplus	MDS4	21033	21412	5%				
	90% Renewables	MDS5	24207	24575	50%				
							Net Benefit of upgrade:		
							Trend split	Popn. Split	Fall in Benefit with NI/SI split based on trend rather than population
							-\$59m	\$60m	-\$129m
							\$115m	\$129m	-\$14m
							\$58m	\$195m	-\$137m
							\$166m	\$517m	-\$351m
							\$422m	\$433m	-\$11m
							-\$134m	-\$45m	-\$89m
							\$112m	\$383m	-\$271m
							\$14m	\$163m	-\$149m
							\$112m	\$547m	-\$435m
							\$511m	\$620m	-\$109m
							-\$303m	-\$121m	-\$182m
							\$59m	\$242m	-\$183m
							-\$145m	\$23m	-\$168m
							-\$20m	\$412m	-\$432m
							\$401m	\$515m	-\$114m



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27 March 2008

Mr Mark Trigg
General Manager – Generation
Contact Energy Limited
PO Box 10742
Wellington 6143

Dear Mark

HVDC Grid Investment Test Consultation – reply to your letter of 11 March 2008

Thank you for your letter of 11 March 2008. Transpower has the following comments, which are of course its current view and which will be reviewed fully without pre-conceptions in light of any further representations received as part of the consultation process.

Geothermal capital costs

Transpower has no direct information itself on the level of geothermal capital costs – as it is not an electricity generator – and therefore relies on external and expert evidence to assess these costs. Transpower's provisional view has been that drawing upon the Electricity Commission's published generation costs assembled for the draft 2007 and 2008 Statement of Opportunities¹ was appropriate. These figures were developed by independent experts and were then consulted on by the Electricity Commission, so are a solid foundation for investigations such as the HVDC Pole 1 replacement investigation project, absent convincing evidence to the contrary. Assessing new information always raises the obvious questions of on what basis the information was prepared (i.e. are the capital costs for the new plant only, for a fully installed new plant, or for something in-between) and the robustness of the information.

It is disappointing that Contact Energy has not provided its views on geothermal costs and detailed information on upcoming geothermal projects (Te Mihi and Tauhara for Contact Energy and Rotokawa 2 for Mighty River Power), prior to this point in the HVDC Pole 1 replacement investigation project. Transpower engaged with Contact Energy specifically, in June 2007, on the draft generation costs it was proposing to use and since then has consulted widely on the Databook, which includes these assumptions, but no feedback was provided at that time that geothermal costs were too high.

On the contrary, during the consultations Transpower held in 2007, the feedback from generators we did receive was that the geothermal costs were too low. We also received feedback that some of the wind generation costs were too high, hence the sensitivity undertaken in the GIT analysis in which geothermal costs were raised 20% and wind costs were lowered 10%.

¹ Transpower provisionally believes that using the figures of the latter as at the 1 February 2008 would be reasonable.

Contact's recent comments are contrary to that earlier feedback. In light of the submissions on this point, Transpower's preliminary view is that the geothermal costs used in the base case of the GIT analysis are reasonable. Nevertheless, Transpower has undertaken some further sensitivity analysis for Contact's benefit, in which geothermal costs are lowered, and will consider this issue with an open mind in light of any further submissions received.

Further analysis

Using the capital costs applied for the GIT analysis, geothermal projects are among the most economic projects to invest in. Hence, they in general appear almost as soon as they are allowed in the generation expansion plans produced by GEM, apart from some of the later generic geothermal plants, which are sometimes delayed 1-3 years from their first possible built date². Transpower's intuition is that there will be little impact from lowering geothermal generation capital costs as it only will affect the latter geothermal projects and only by a few years. Hence, we would expect the NPV impact should be limited.

Transpower undertook a sensitivity analysis assuming -20% capital costs for all geothermal projects plus a lower growth in costs for the generic projects, giving them a higher discount than the 20% suggested by Contact Energy. The focus in the sensitivity analysis was to look at the differences between the total generation costs (CAPEX + OPEX) only, i.e. costs of the HVDC options 1-3 and the AC development plans required to enable the generation scenarios are assumed unchanged.³ Hence, the total generation cost impact is assumed to equal the impact on the overall GIT result. As the 1000 MW option (option 3) was significantly more uneconomic compared with options 1-2, the sensitivity analysis was not undertaken for this option.

The table below shows the results based on a 7% discount rate. It can be seen that the impact on generation costs difference between base case (no replacement) and options 1 and 2 are between \$0 and \$100 million with a weighted average around \$40 million for both options. These changes would not affect the GIT result or conclusion and hence Transpower preliminarily considers that even if the geothermal costs were lowered in line with Contact Energy's suggestion, that a 700 MW Pole 1 replacement would still meet the requirements of the GIT.

Results per scenario	MDS1 - 0 MW			MDS2 - 0 MW			MDS3 - 0 MW			MDS4 - 0 MW			MDS5 - 0 MW		
Diff from base case (0 MW)	0 MW	500 MW	700 MW	0 MW	500 MW	700 MW	0 MW	500 MW	700 MW	0 MW	500 MW	700 MW	0 MW	500 MW	700 MW
GIT results	0	-330	-351	0	-414	-781	0	-475	-575	0	-796	-955	0	-698	-1000
-20% geo costs	0	-296	-352	0	-332	-682	0	-455	-565	0	-795	-948	0	-647	-944
Difference	0	34	-1	0	82	99	0	20	10	0	1	7	0	51	56

Weighted results	0 MW	500 MW	700 MW
Diff from base case (0 MW)			
GIT results	0	-567	-782
-20% geo costs	0	-524	-743
Difference	0	44	40

² The later projects have higher costs due to expected lower temperature and/or deeper geothermal fields.

³ Transpower expects that HVDC costs would be unaffected, and that any effect on AC augmentation costs would not impact materially on the HVDC GIT analysis.

The table below shows an example on the impacts on the new generation build schedules - in this case for using market development scenario 5 (90% renewables by 2025), for the 700 MW replacement Pole 1 (option 2).

Both the build years from the GIT analysis on which we are consulting and the build years with the geothermal costs proposed by Contact are shown, as well as the difference.

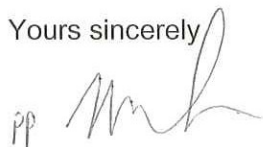
Plant	GIT	New	Diff
Ngawha 2	2009	2009	0
Kawerau	2009	2009	0
Mokai 3	2008	2008	0
Rotokawa Exp.	2010	2010	0
Tukairangi Road	2013	2010	3
Te Mihi	2011	2011	0
Generic Geo 1	2014	2012	2
Generic Geo 2	2015	2014	1
Generic Geo 3	2016	2016	0
Generic Geo 4	2018	2018	0
Generic Geo 5	2020	2020	0
Generic Geo 7	2022	2022	0
Generic Geo 8	2024	2024	0
Generic Geo 9	2029	2026	3
Generic Geo 10	2028	2028	0
Generic Geo 11	2032	2030	2

It can be seen that the impact of lowering geothermal generation capital costs on build year is minor, if any.

We will continue to consider Contact's more detailed comments about the capacity of Te Mihi and Tauhara. Our current provisional thinking is that increasing the capacity of these plants in the model would simply delay investment in one or more of the generic geothermal plants in the model and so result in similar GIT results.

We look forward to any further submission that Contact makes in relation to the HVDC Pole 1 replacement investigation project, which we will consider fully and without preconceptions in deciding whether to submit to a GUP and the content of any GUP.

Yours sincerely



Peter Griffiths
Transpower New Zealand Limited

cc: John Gleadow, Electricity Commission

11 March 2008

Mr Peter Griffiths
Transpower New Zealand Limited
Level 7, Transpower House
96 The Terrace
PO Box 1021
Wellington

By e-mail

Dear Peter

HVDC Grid Investment Test Consultation

Contact appreciated the opportunity to take part in the GIT consultation which Transpower held on 22 February 2008. We are keenly interested in the outcome of this consultation, due to the significant costs Contact will face, should HVDC Pole 1 be replaced.

We would like to provide you some early feedback on some key issues that we have identified in our early analysis of the GIT results.

The costs used in GEM to model geothermal development are too high. We are concerned that a systematic overstating of capital costs may distort decisions to invest in transmission upgrades. We have provided Transpower with indicative development costs for Te Mihi and Tauhara through its industry working group. Our estimated capital costs for both the Te Mihi and Tauhara developments are materially (20% to 24%) lower than the figures used in the GIT Consultation document.

There may a natural tendency to question any power development cost figures provided by generators. These figures are, after all, commercially sensitive and commonly privileged. However, the development cost figures used in the Consultation document seem overly conservative based on publicly available information. For instance, Mighty River Power has publicly stated that the cost of its current 90 MW project at Kawerau is \$275 million NZD or \$3,055 per kW. Even allowing for some extraneous costs, the figure is an order of magnitude less than the development costs of greater than \$5,000 per kW listed for generic developments, so clearly there must be issues with the underlying assumptions behind the geothermal estimates listed in the Consultation Document. Indeed, with development costs at the \$5,000 to \$6,000/kW level, geothermal would become uneconomic.

We suspect that the generic geothermal development projects in GEM (numbered 1 to 12) may simply escalate the unit costs of the particular development projects into the future. This seems a crude way of estimating

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development costs in a power system where costs are highly sensitive to economies of scale, exchange rates, and resource grade.

In addition, there are two items which may benefit from clarification. First, Contact's planned capacity development for Tauhara is in the order of 200 MW, not the 90 MW listed. The difference will be significant to the future HV transmission requirements in the Wairakei region. Similarly, our new project at Te Mihi is planned for 225 MW, not the 240 MW listed.

We note that Transpower's estimates of total geothermal capacity potential are consistent with the Electricity Commission's recent work on potential geothermal resources (which it did for the transmission to enable renewables project).

To summarise, we think that the assumed geothermal development costs in Transpower's model could impact on the analysis of the merits and the timing of replacing Pole 1.

Accordingly, we suggest that Transpower undertakes further sensitivity analysis on the impact of geothermal generation costs on the GIT result. Rerunning the model using 20% lower geothermal costs should allow Transpower to assess whether significantly different investment decisions would result.

Moreover, we would be very interested to see the results of any sensitivity analyses Transpower have on peak capacity constraints, actual vs. projected HVDC transfers, demand forecasts, and Meridian's proposed hydro/wind investment timing.

We would be happy to discuss our proposal and look forward to hearing back from you. In the first instance, please contact **James Collinson-Smith** [DDI: 04 462 1249, Email: james.collinson-smith@contact-energy.co.nz] if you have any questions.

Yours sincerely



Mark Trigg
General Manager - Generation

CC: Bruce Smith, Electricity Commission



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20 March 2008

Guy Waipara
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Dear Guy

HVDC Grid Investment Test Consultation – further to our letter of 12 March 2008

As indicated in our letter of 12 March 2008, we provide the following further comments regarding topics raised in your letters of 21 and 22 February 2008. The view of Transpower expressed in this letter are of course its current view, which will be reviewed fully without pre-conceptions in light of any further representations received as part of the consultation process. Transpower will publish this letter on its HVDC webpage within the next two working days.

Historical HVDC transfers

We understand Meridian would like to see how the level of historic HVDC transfers compare to those forecast by Transpower over the analysis period in order to understand the impact Transpower is forecasting a new Pole 1 to have on HVDC transfers.

Please find below figures showing HVDC transfers both south to north (Figure 1), north to south (Figure 2) and net (Figure 3) for the 90% renewables by 2025 scenario and for a 700 MW replacement Pole 1.

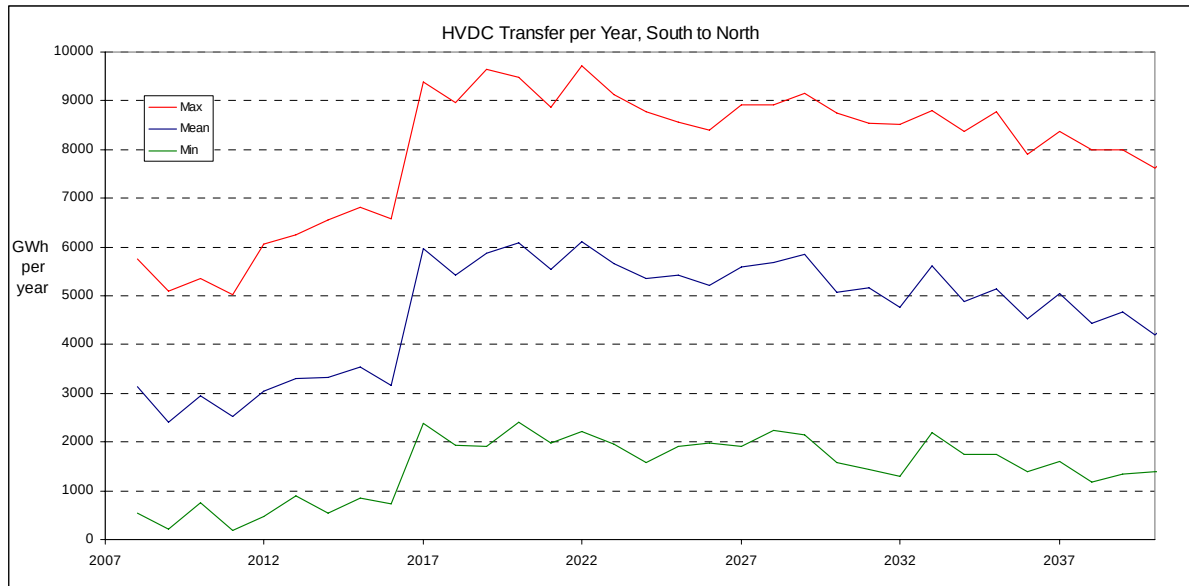


Figure 1 – HVDC transfers, GWh per annum, south to north, 700MW replacement Pole 1, 90% renewables by 2025 scenario

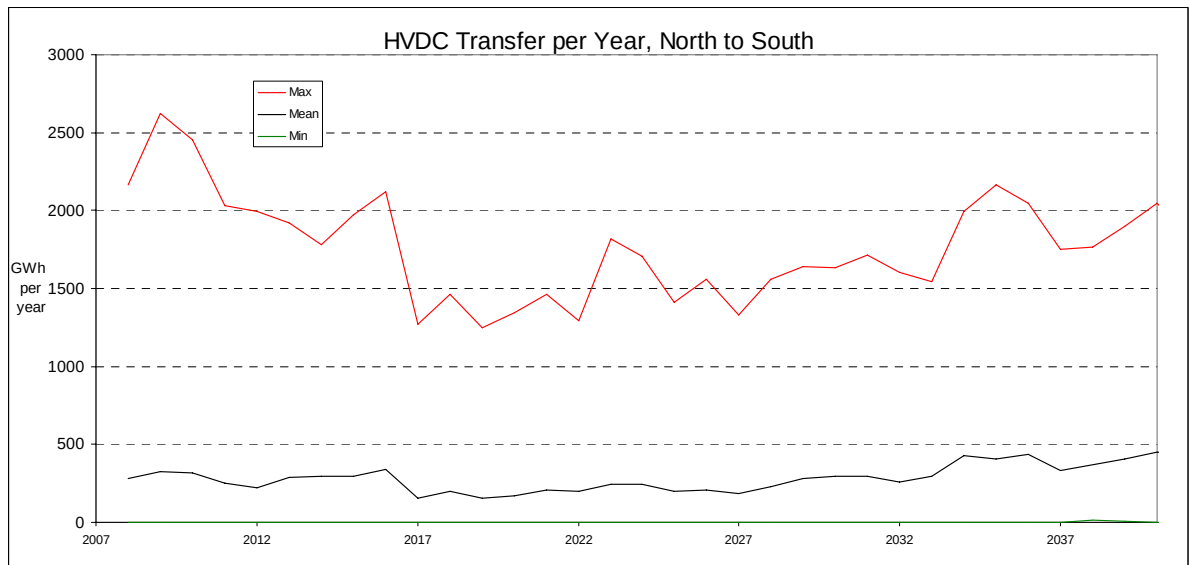


Figure 2 – HVDC transfers, GWh per annum, north to south, 700MW replacement Pole 1, 90% renewables by 2025 scenario

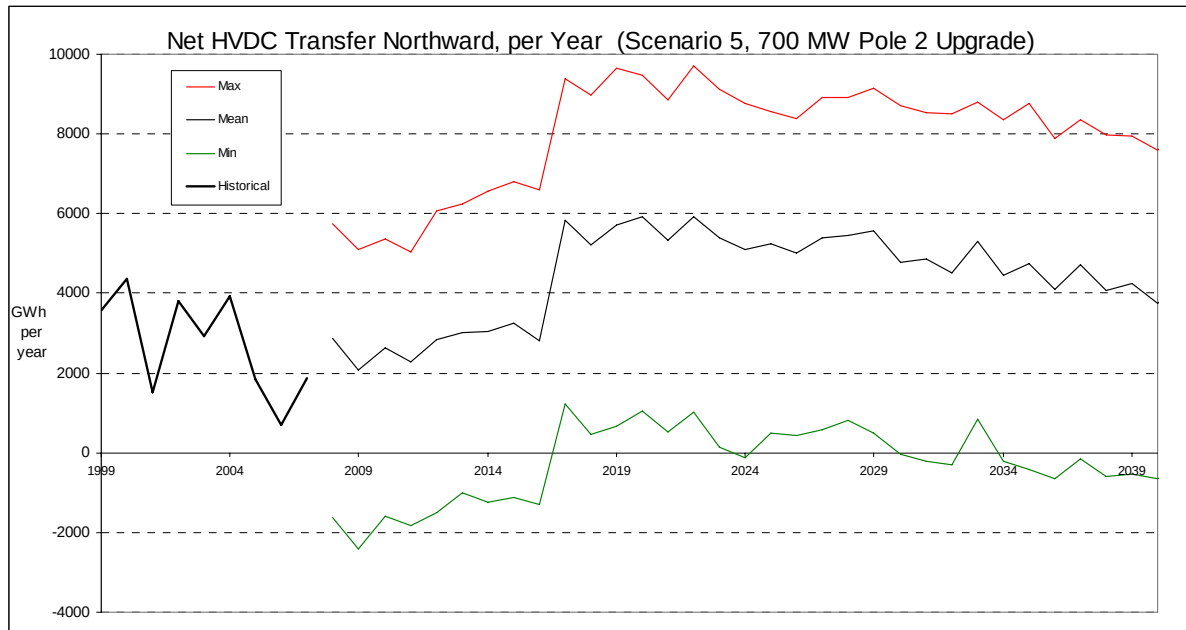


Figure 3 – Net HVDC transfers, GWh per annum, 700MW replacement Pole 1, 90% renewables by 2025 scenario

Figure 3 also shows historical net transfers, corresponding to the transfers shown in Meridian's letter of 22 February 2008. As can be seen the GIT analysis undertaken by Transpower, is forecasting a growth in net transfers through until about 2020 and then a gradual decline. There is a significant jump in transfers forecast in the period 2015 -2020, corresponding with significant new generation coming on-stream in the South Island.

To further illustrate the efficacy of these numbers, Figure 4 shows South Island generation over the same time period, being the black line. South Island demand is the burgundy area of the graph, with HVDC transfers south to north being the balance (less losses).

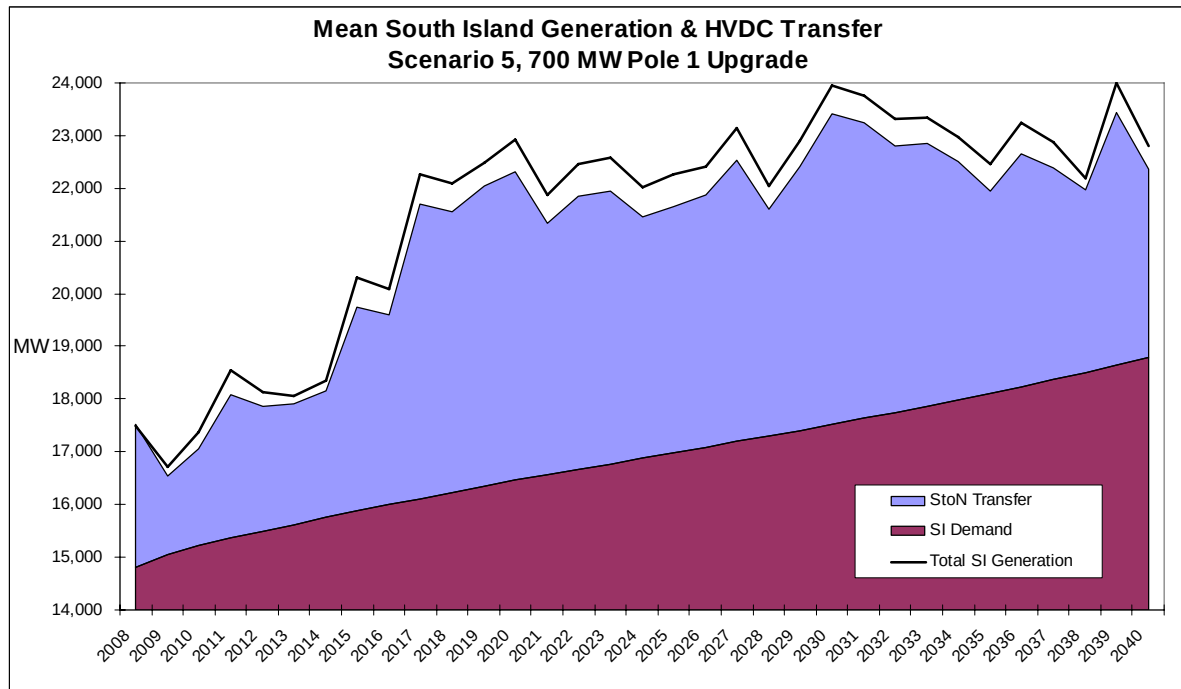


Figure 4 – Graph of SI generation, HVDC transfers south to north and SI demand, GWh per annum, 700MW replacement Pole 1, 90% renewables by 2025 scenario

We hope these illustrations assist Meridian with comparing historical transfers on the HVDC to forecast transfers.

Investment timing

Transpower understands Meridian is concerned that delaying investment in a replacement Pole 1 may be a more economic option than the option as analysed by Transpower in the consultation paper.

Transpower has analysed the economics of deferring investment in Stage 1 and 2 of a replacement Pole 1 beyond 2012 - 2014, 2016 and 2018.

The Pole 1 replacement is assumed to be 700 MW convertors at Haywards and Benmore, which is the option preliminarily identified in the GIT analysis as passing the requirements of the GIT.

The analysis is based on the methodology from Appendix F in the GIT consultation document, with the following changes:

- o The base case reflects Pole 1 being available for emergency operation (winter quarter, 200 MW max, north transfers only).
- o Contact's New Plymouth plant has been decommissioned but 200 MW Stratford OCGT capacity is added in 2009.

- o The PLEXOS GIT analysis showed higher expected net market benefits than Transpower's GIT analysis, at least partially because instantaneous reserves are modelled in PLEXOS. A bipole HVDC arrangement provides reserve capacity to cover loss of the biggest pole whenever the link is not fully utilized. To reflect this effect, the SDDP analysis has been undertaken limiting the north flow to 500 MW with monopole operation¹ in non-winter months and 700 MW in winter months.
- o The Appendix F analysis included some variability which partly turns out to arise from the fact that only 6 hydro sequences were analysed in SDDP. This analysis reflects detailed grid modelling being turned off in SDDP, allowing analysis of 74 hydro sequences. HVDC link and AC losses are calculated using historical percentages.

Results

The table below shows the impact on the generation system costs of deferring Stage 1 and Stage 2 of the Pole 1 replacement to either 2014, 2016 or 2018 for each of the scenarios.

	MDS 1	MDS 2	MDS 3	MDS 4	MDS 5	Weighted
Replacement in 2012	0	0	0	0	0	0
Replacement in 2014	-59	-7	-42	-25	-21	-31
Replacement in 2016	-72	-37	-77	-40	-131	-97
Replacement in 2018	-145	-361	-93	-117	-197	-183

These additional system costs should be compared with the benefits from deferring the investment arising from a capital deferral, which are shown below:

Case	Base	Deferred	Difference
Replacement in 2012	413.8	413.8	0.0
Replacement in 2014	413.8	375.3	38.6
Replacement in 2016	413.8	341.8	72.0
Replacement in 2018	413.8	311.1	102.7

The benefits above include a deferral of operating and maintenance costs for the replacement Pole 1, but do not reflect an increase in operating and maintenance costs for the existing Pole 1. This cost may be in the order of \$1.5 million per annum, although this number may rise the longer a replacement Pole 1 is deferred. Lowering the deferral benefit accordingly, the trade-off between savings and additional system costs is shown below.

¹ This is what currently is the transfer level of Pole 2 when running as monopole. It does occasionally go above 500 MW in a few trading periods, but as the peak load block in SDDP correspond to more than 7% of the time, 500 MW has been used as proxy for average flows.

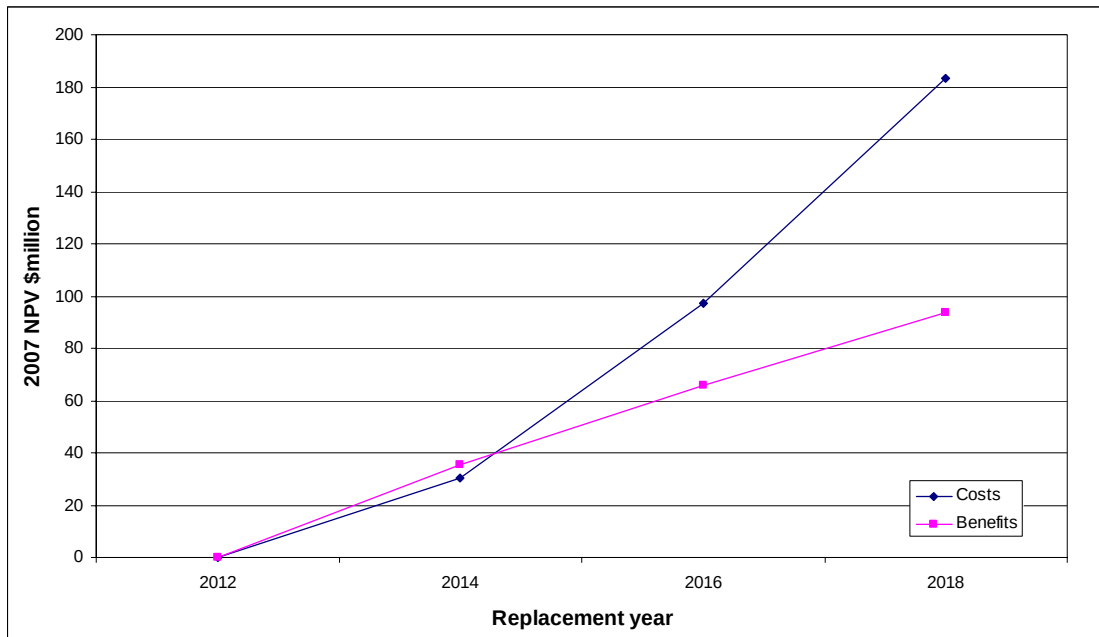


Figure 5 – Comparison of benefits from deferring investment in a replacement Pole 1, with system costs arising from deferral – Transpower analysis

Please note that these results reflect system costs averaged over 74 inflow sequences in SDDP.

A similar analysis was undertaken by MMA with the PLEXOS model and is shown in figure 3-8 in their “Market benefit analysis of short-listed HVDC options” report, available at:

http://www.gridnewzealand.co.nz/f282,124491/124491_attachment-g-plexos-results-_appendix-1.pdf

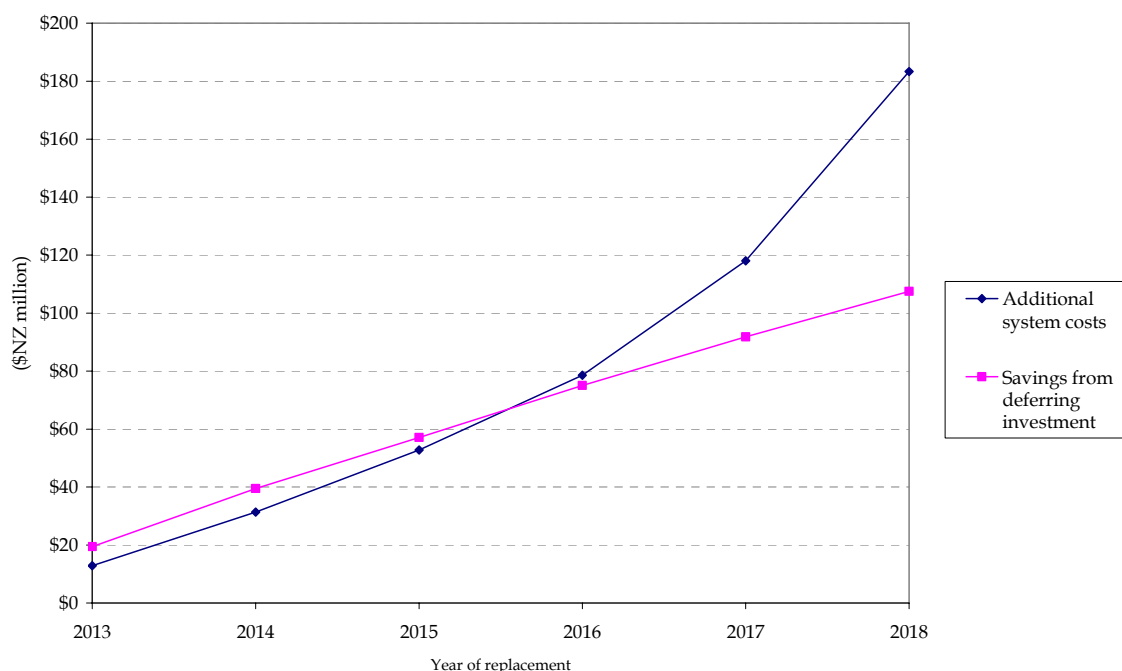


Figure 6 – Comparison of benefits from deferring investment in a replacement Pole 1, with system costs arising from deferral – MMA analysis

Below is an updated version of that figure which apart from the costs associated with an average inflow year also shows the range of outcomes from the total of 10 hydro samples analysed.

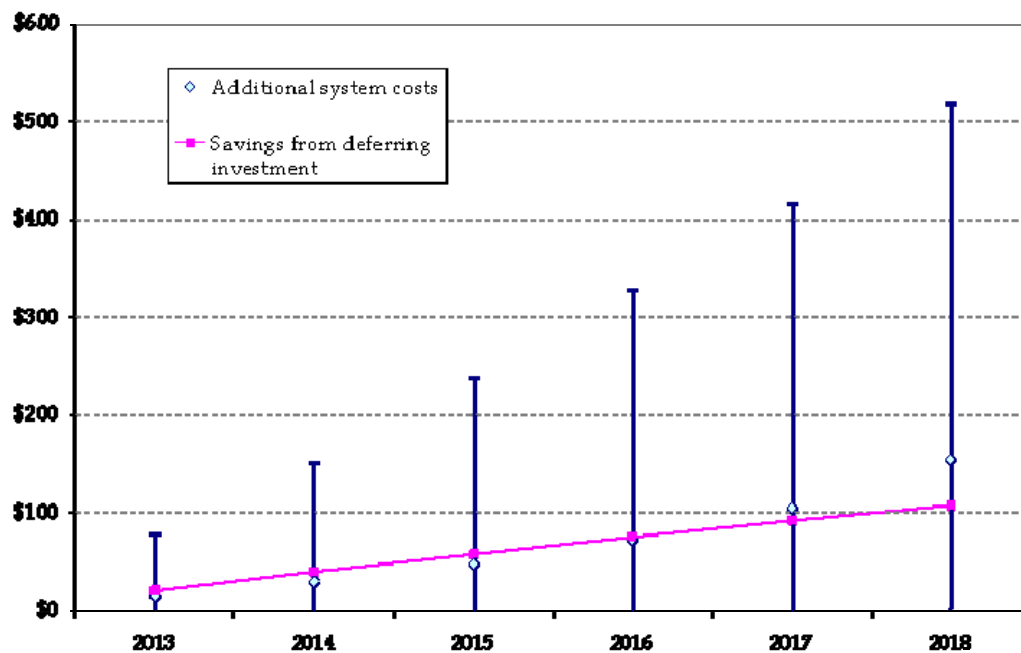


Figure 7 – Comparison of benefits from deferring investment in a replacement Pole 1, with system costs arising from deferral – MMA analysis, showing spread over various hydrological conditions

The average results (blue diamond marks) correspond well with the GEM/SDDP results from Transpower's analysis.

As this graph shows, there is a significant variation in additional system costs, depending on the hydro sample. For 2014, for instance, there is a risk of \$100 million additional costs. Given only 10 hydro samples have been analysed by MMA, this corresponds to approximately a 10% likelihood of these extra costs.

Conclusions

The GEM/SDDP results show that the optimal timing for investment in a replacement Pole 1 is close to break even during the period 2012 to 2014. The costs climb steeply after 2014.

Note that this analysis assumes Stage 1 and Stage 2 of the replacement Pole 1 are built together, initially.

Considering that:

- o further optimisation of the stages of the project may lower the deferral benefits further
- o there is a risk of additional costs under some hydro conditions
- o given the age of the existing half pole, there is a risk of losing it prior to 2012, in which case the additional system costs will increase for later replacement dates

Transpower provisionally considers that the optimal timing for Stage 1 of a replacement Pole 1 is 2012.

For the GUP, the analysis will determine the optimal timing for all stages of the project ie Stage 1, Stage 2 and Stage 3.

Transpower will consider this issue further in light of any further representations received.

Yours sincerely



Peter Griffiths
Transpower New Zealand Limited

cc: John Gleadow, Electricity Commission

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12 March 2008

Mr Guy Waipara
Meridian Energy Limited
Level 1, 33 Customhouse Quay
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Dear Guy

HVDC Grid Investment Test Consultation

Thank you for your letters of 21 and 22 February 2008. Transpower will publish your letters and this letter on its HVDC webpage in the next two days. The views of Transpower expressed in this letter are of course its current views, which will be reviewed fully without pre-conceptions in light of any further representations received as part of the consultation process.

Impact of peak capacity constraint

We understand that Meridian is concerned the peak capacity constraint in GEM may not result in generation expansion outcomes similar to those a market might deliver and so has requested that Transpower carry out further analysis, ie to run a particular scenario with an "N" peak capacity constraint and a VOLL of \$3,000/MWh. Transpower is not convinced that this analysis is reasonably necessary for the purposes of informing the consultation process or the GIT analysis. N or N-1 or N-2 is simply a modelling parameter in GEM and the more important issue is whether the outcomes from GEM are realistic or not.

In the GIT consultation documents, Transpower explains that the GEM results created on the basis of an N-1 capacity constraint are consistent with current "generation margins", ie the amount of firm generation capacity over peak demand (see Figure 4-5 and section 4.4 of Attachment A to the GIT consultation document). Transpower summarised this finding at the briefing of 22 February 2008 which you attended. Transpower's provisional view remains that its analysis in the GIT consultation document is reasonable and the outcomes realistic. We will, however, consider this further, in particular the reasonableness of the N-1 outcomes, in deciding whether to submit a GUP.

Transpower would welcome any further representations Meridian wishes to make on this matter.

Historical HVDC transfers

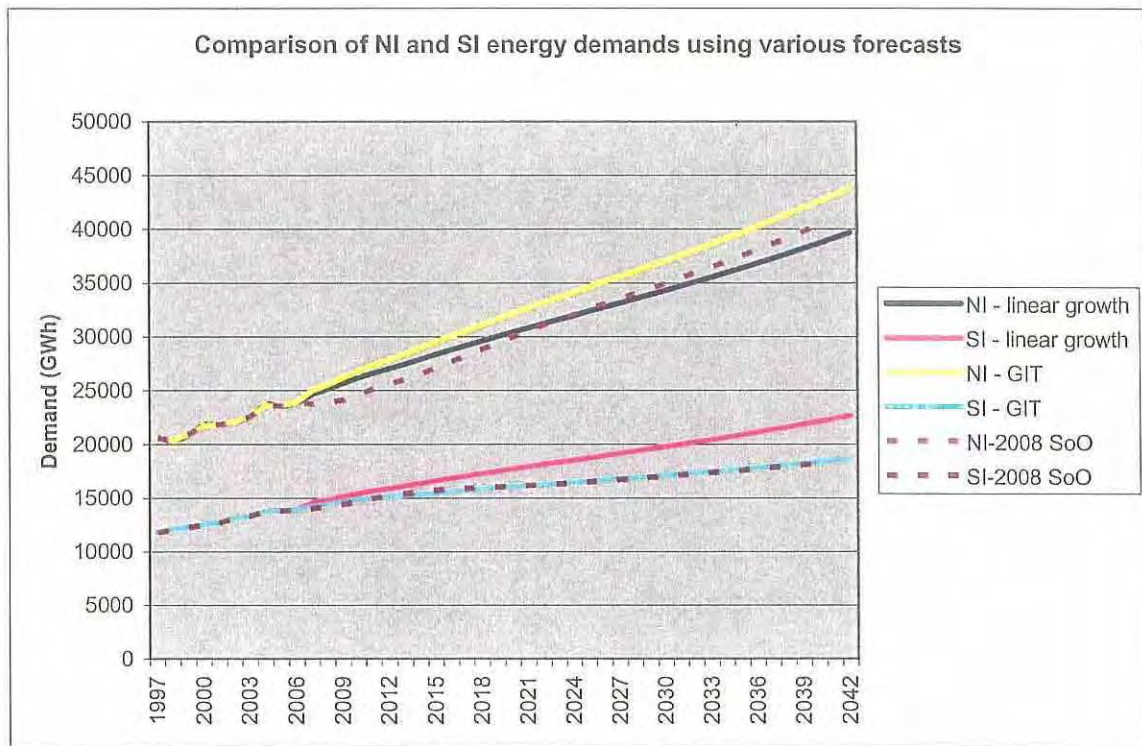
We understand from your letter of 21 February that Meridian would like to see how the level of historic HVDC transfers compare to those forecast by Transpower over the analysis period in order to understand the impact Transpower is forecasting a new Pole 1 would have on HVDC transfers.

Your letter of 22 February suggests that Meridian already has access to the historical information. However, Transpower will carry out this analysis and publish this information two weeks before the close of the expiry of the consultation period, ie 20 March 2008.

Demand forecasts

We understand Meridian's request in its letter of 21 February 2008 is largely superseded by its request in its letter of 22 February. Meridian requests a sensitivity in which North Island demand is reduced and South Island demand is increased.

Transpower is not convinced that the sensitivity requested by Meridian is realistic. The graph below shows linear extrapolations of North Island and South Island demands compared to the forecasts used in Transpower's GIT analysis and the Electricity Commission's draft 2008 Statement of Opportunities (SoO) forecasts. Both the GIT and draft 2008 SoO demand forecasts reflect a similar trend – a slowdown in South Island growth and an increase in North Island growth consistent with a gradual population drift north. Transpower considers that the econometric modelling used to produce these forecasts (which rely on NZIER forecasts of GDP and Department of Statistics forecasts of population growth) is more realistic than extrapolation from historical trends. Transpower is therefore not convinced that significant weight should be attached to results based on demand extrapolated from historic demand growth.



Nonetheless, Transpower has undertaken some analysis for Meridian's benefit. The results shown in the table below, show the total present value of costs and in brackets, the difference from the most economic option (both in 2007 \$million). These results are for medium demand only and are GEM outputs only, ie the dispatch costs are not from SDDP.

Base runs (7% discount rate)

Option	Scenario	Extrapolated growth		GIT growth	
0 MW option	MDS1	21216	(0)	21261	(60)
	MDS2	22779	(115)	23148	(383)
	MDS3	23735	(59)	24060	(196)
	MDS4	21013	(166)	21824	(547)
	MDS5	24608	(511)	25090	(620)
500 MW option	MDS1	21285	(68)	21201	(0)
	MDS2	22664	(0)	23019	(254)
	MDS3	23677	(0)	23865	(0)
	MDS4	20847	(0)	21307	(29)
	MDS5	24186	(89)	24657	(187)
700 MW option	MDS1	21350	(134)	21306	(105)
	MDS2	22667	(3)	22765	(0)
	MDS3	23721	(44)	23897	(32)
	MDS4	20901	(54)	21277	(0)
	MDS5	24097	(0)	24470	(0)
1000 MW option	MDS1	21519	(302)	21382	(181)
	MDS2	22720	(57)	22906	(141)
	MDS3	23880	(203)	24037	(172)
	MDS4	21033	(187)	21412	(135)
	MDS5	24207	(110)	24575	(104)

Option	Scenario	Extrapolated growth		GIT growth	
0 MW option	All	23436	(248)	23812	(391)
500 MW option	All	23210	(22)	23516	(94)
700 MW option	All	23188	(0)	23421	(0)
1000 MW option	All	23313	(125)	23530	(109)

The figures in the right hand column of the table show the GEM equivalent of the GIT results already published and the middle column shows the GEM results using the extrapolated demand forecast approach suggested by Meridian.

The expected net market benefit of replacing Pole 1 is less with the forecasts suggested by Meridian but is still positive and a 700 MW option still has the highest expected net market benefit. As already mentioned, Transpower is not convinced that any significant weight should be attached to these results, as it does not believe that they are based on realistic assumptions. However, if weight was attached to

these results, Transpower provisionally considers that they tend to support the GIT analysis. We will consider this issue further in light of any further representations received.

Investment timing

Transpower understands Meridian is concerned that delaying investment in a replacement Pole 1 may be a more economic option than the option which Transpower's GIT consultation paper preferred. While it was Transpower's intention to undertake such analysis for any Grid Upgrade Plan, it has considered your request and will carry out this analysis prior to submissions closing on 4 April 2008. Transpower intends to publish this information two weeks before the close of the expiry of the consultation period, ie 20 March 2008.

Yours sincerely

A handwritten signature in blue ink, appearing to read 'P. J. Griffiths', with a stylized flourish extending from the end.

Peter Griffiths
Manager, Power System Analysis

cc: John Gleadow, Electricity Commission

22 February 2008

Mr Peter Griffiths
Transpower New Zealand Limited
Level 7, Transpower House
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PO Box 1021
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New Zealand

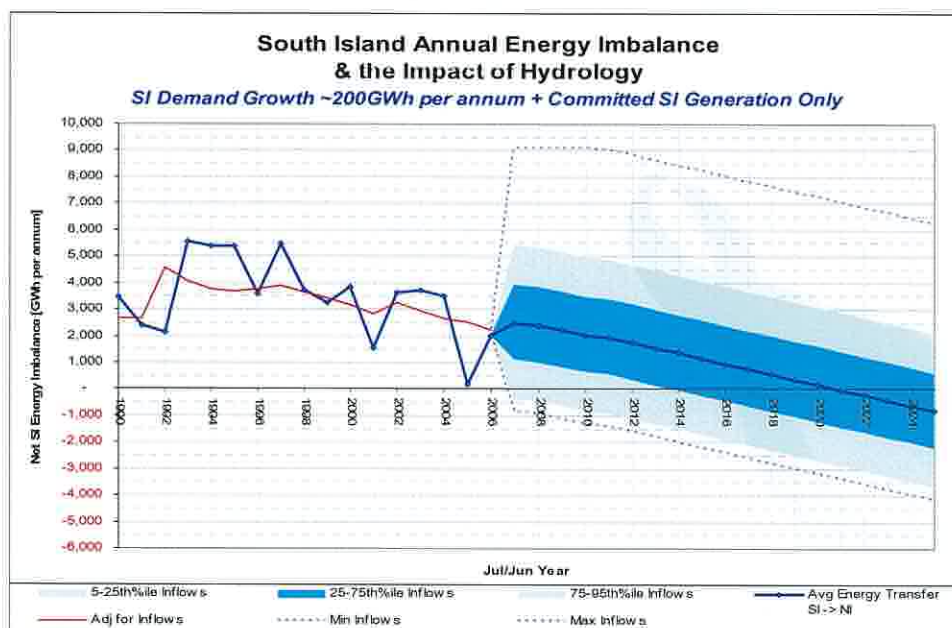
Dear Peter

HVDC Grid Investment Test Consultation

Further to our letter of 22 February and after attending the HVDC GIT consultation workshop, we are now acutely concerned that the HVDC GIT analysis contains a systematic bias across all generation scenarios. Furthermore the sensitivity analysis performed by Transpower (and highlighted in our previous letter) has not in our view uncovered the impact of this bias on the HVDC valuation.

Our concerns are chiefly around the extent to which all of Transpower's scenarios show a significant increase in HVDC energy transfers from the South Island to the North Island which is in stark contrast to what has occurred over the last 10 years. I raised this point at the workshop on Friday 22nd as a genuine question as to why all of Transpower's scenarios reflect a future set of market outcomes that are materially different from recent history.

By way of example, the graph below sets out the historical HVDC flows since 1990 (in aggregate) as well as a projection of future power flows across the HVDC link if only committed South Island generation is constructed. South Island demand growth is assumed to be a conservative 200 GWh per annum.



While the future assumptions are debatable, what is clear is that HVDC flows from the South to the North Island have continued to decline on average over the last 10-15 years. With no new South Island generation likely to be commissioned within the next three possibly four years due to consenting timeframes and transmission capacity issues, there is nothing committed in the market that will reverse this trend in the short term.

In contrast, all of Transpower's scenarios show significant and increasing energy transfers from the South Island to the North Island, opposite to what has been occurring in the market over the last 10-15 years.

We have since analysed Transpower's HVDC GIT and uncovered what we consider to be the primary source of this bias, which is in the demand forecasts.

Transpower's Demand Forecasts

The table below sets out historical demand across the North and South Islands¹. The average energy growth in the South Island over the last 5 and 10 years has been 226 GWh and 245 GWh per annum respectively.

Year	NI Demand		Growth		SI Demand		Growth	
	Energy (GWh)	Peak (MW)	Energy (%)	Peak (%)	Energy (GWh)	Peak (MW)	Energy (%)	Peak (%)
1997	20,629	3,743	-0.7%		11,796	1,810	4.4%	
1998	20,357	3,558	-1.3%	-4.9%	12,039	1,825	2.1%	0.8%
1999	20,904	3,666	2.7%	3.0%	12,260	1,888	1.8%	3.5%
2000	21,758	3,724	4.1%	1.6%	12,518	1,902	2.1%	0.7%
2001	21,843	3,918	0.4%	5.2%	12,694	1,967	1.4%	3.4%
2002	22,101	3,853	1.2%	-1.7%	13,112	1,995	3.3%	1.4%
2003	22,557	3,867	2.1%	0.4%	13,309	1,941	1.5%	-2.7%
2004	23,658	4,124	4.9%	6.6%	13,768	2,026	3.4%	4.3%
2005	23,571	4,103	-0.4%	-0.5%	13,819	2,070	0.4%	2.2%
2006	23,913	4,322	1.4%	5.4%	13,958	2,119	1.0%	2.3%
2007	23,949	4,351	0.2%	0.7%	14,243	2,167	2.0%	2.3%
10 Yr Avg	332	61	1.3%	1.6%	245	36	2.1%	1.8%
5 Yr Avg	370	100	1.6%	2.6%	226	34	1.8%	1.8%

In contrast, Transpower's South Island demand forecasts contained in the HVDC GIT for the medium demand growth scenario equate to 124 GWh per annum. This assumes that South Island demand growth will be a significant 100-120 GWh per annum lower than recent history. Even Transpower's "high" demand growth scenario contains less South Island demand growth than historical rates, at 184 GWh per annum.

HVDC GUP - Annual Growth to 2040

	NI		SI	
	Energy GWh	Peak MW	Energy GWh	Peak MW
High	742	125	184	29
Medium	532	90	124	20
Low	332	56	67	12
History	332	61	245	36

¹ These historical North and South Island demand figures are based on reconciled GXP data.

On a percentage basis, over the last 10 years, South Island growth has contributed 42% of national demand and the North Island 58% of national demand. In clear contrast to history, Transpower are forecasting that in the medium demand scenario that the South Island will only contribute 19% of national demand growth and the North Island 81%.

We cannot find any rationale for incorporating demand forecasts that represent such a substantive change from historical demand growth in all scenarios, given a review of the key drivers of demand, namely population and economic growth. Furthermore, we have seen no evidence of hind-casting being used to calibrate historical growth drivers with those incorporated in your future growth assumptions.

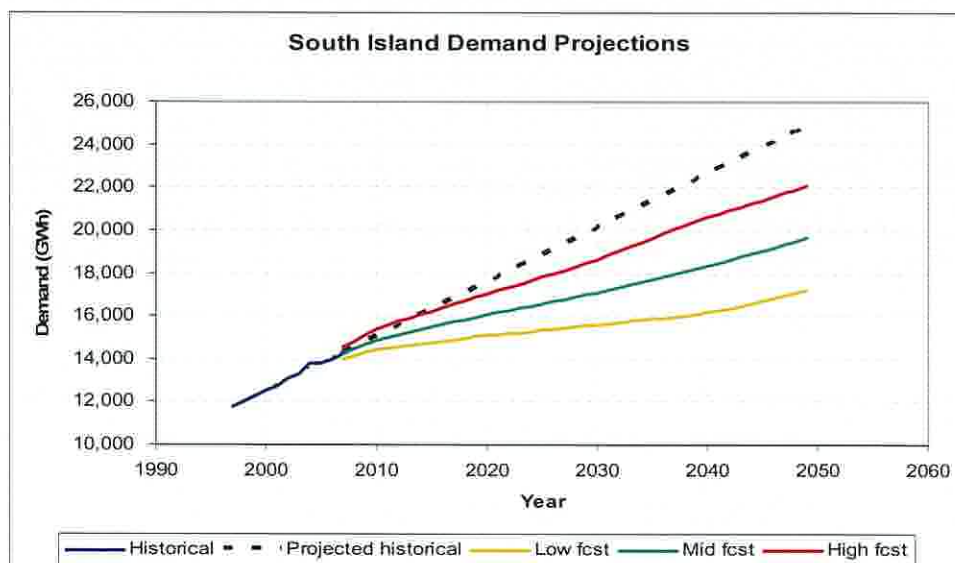
If the effect of this lower South Island demand growth is extrapolated across the period of the HVDC analysis then Transpower's results suggest that by 2040, a significant 4000 GWh of surplus South Island energy will be present compared to a counterfactual where demand growth continues at current rates.

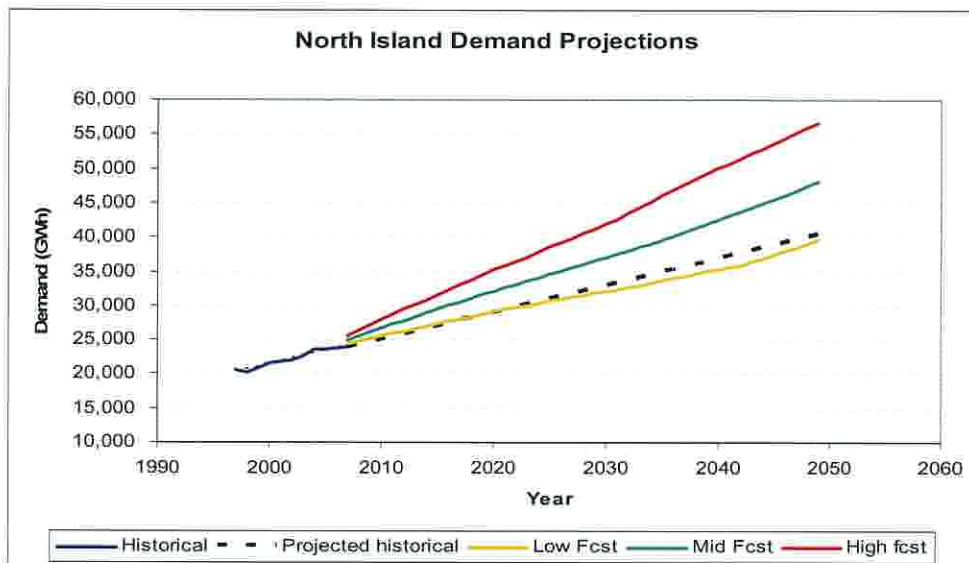
In a low growth scenario this South Island surplus could be as much as 6000 GWh. The consequences to the power system (in the medium and low demand scenarios) are equivalent to removing 80%-115% of the energy currently consumed by RTANZ at Tiwai point from the South Island and placing it in the North Island in every scenario. This will drive significant South to North energy transfers across the HVDC link as evidenced in your scenario analysis.

Demand Growth Difference by 2040 from Historical Growth

	NI		SI	
	Energy GWh	Peak MW	Energy GWh	Peak MW
High	13,515	2,110	-1,996	-225
Medium	6,599	948	-3,978	-518
Low	10	-160	-5,860	-796

Graphically the impact of the inter island demand growth assumptions are highlighted in the following two graphs, which show Transpower's low medium and high forecasts against a projection of historical (10 year average) demand growth.





Impact on HVDC Valuation

Meridian considers that it is likely that this systematic demand forecast bias across all generation scenarios will significantly affect the HVDC valuation. In our view, it is quite likely that Transpower's demand forecast assumptions will over inflate the HVDC GIT valuation.

In Transpower's own briefing you have stated that "The result (Grid Investment Test) must be robust with respect to sensitivity analysis".

We believe that Transpower has not met this test with respect to demand forecast sensitivity analysis.

Meridian therefore strongly recommends that Transpower performs a series of sensitivity studies to clearly identify the HVDC valuation impacts of the step change reduction in South Island demand forecasts contained within the HVDC GIT.

Specifically we recommend that Transpower conducts the following inter-island demand growth sensitivity analysis:

1. Use the 90% renewables and medium demand growth scenario as the basis for the inter-island sensitivity analysis. The rationale is that this scenario has the single highest weighting in the HVDC GIT analysis (at 50% for the generation scenario and 70% for the medium demand case) and is therefore responsible for the highest contribution to the HVDC valuation.
2. Change South Island demand growth to be consistent with historical demand growth rates (circa 220-240 GWh pa). North Island demand growth should be reduced accordingly to meet the overall national growth figures contained in the above scenario.
3. Run the mono pole base case and all pole 1 upgrade cases to assess the differential in HVDC upgrade valuations.

We have requested this sensitivity analysis early within the consultation period so that it can be completed with no impact to the overall timeframes of the HVDC GIT consultation.

We are happy to discuss any points of clarification if this request is unclear. Otherwise we look forward to your early response and expect that the results will be made public.

As with our previous information request, we may ask for further clarifications as our assessment of your proposal continues.

Yours faithfully



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Email Guy.Waipara@meridianenergy.co.nz

cc: John Gleadow
Electricity Commission



21 February 2008

Mr Peter Griffiths
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PO Box 1021
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New Zealand

Dear Peter

HVDC Grid Investment Test Consultation

Meridian has begun reviewing the HVDC GIT consultation documentation. Given that under the transmission pricing methodology Meridian is required to pay for the majority of the upgrade, we have taken the approach of assessing the HVDC GIT as if it were any other merchant investment that we may consider.

We have identified a number of sensitivity studies that are missing from what we would expect to see in any investment analysis of our internal projects. Meridian is unable to replicate the Transpower GIT analysis to develop our views on the key areas that the results are sensitive to. We therefore request that Transpower provides the following sensitivity information to Meridian and all other market participants to assist with a robust consideration of the proposal.

In order to not slow the investment decision making process, we have decided to request these sensitivity studies early rather than waiting until the closing date for submissions. This should provide Transpower sufficient time to complete this work within the consultation timeframes. Ideally this information should be presented before the submission closing date so that it may be taken into consideration by all potential submitters.

The specific questions we have are as follows:

1. Understanding the impact of the "Peak Capacity Constraint"

Can Transpower please provide sufficient information for Meridian to understand the impact that the peak capacity constraint in GEM has on the overall HVDC GIT results?

We request that Transpower reruns one specific GEM scenario (preferably the "90% renewables" scenario given that this accounts for 50% of the GIT valuation) with the capacity constraint removed. In doing this Transpower should allow GEM to explicitly schedule generation at a reasonably priced value of lost load (VoLL) where required. We request that a VoLL number of \$3,000/ MWh be used instead of a peak constraint as a reasonable proxy for the cost of non supply over an investment timeframe. This will clearly identify the difference in the HVDC valuation that is attributable to the GEM capacity constraint.

2. Comparing the projected HVDC transfers with historical transfers

Can Transpower please provide sufficient information to compare historical actual HVDC link flows with those assumed in the HVDC GIT?

We request that Transpower sets out the historical power flows (over say the last 15 years) across the HVDC link (in North flow and South flow directions and an aggregate net power flow position) and then adds to this data the projected HVDC link flows for the duration of the analysis. Again we suggest the 90% renewables scenario is used based on the previous rationale.

This information will enable us to compare the future assumptions to historical performance as a means to calibrate and test the robustness of the analysis.

3. Demand Forecasts

Can Transpower please provide sufficient information for Meridian to understand the sensitivity of the HVDC GIT to the relative South Island and North Island demand forecast assumptions?

We request that Transpower sets out historical demand growth in both peak demand and energy terms for both the North and South Islands (over say the last 15 years). The future demand growth assumptions in each Island for peak demand and energy growth should then be clearly set out so that we can compare and contrast historical demand growth with the future growth assumptions contained in the analysis.

We then request that Transpower runs a sensitivity scenario using demand assumptions (peak and energy) that are an extrapolation of historical demand growth. Again we suggest that the 90% renewables scenario is used.

This sensitivity study will identify how much the HVDC valuation is affected by differences in inter island demand growth assumptions.

4. Investment Timing

Can Transpower please provide sufficient information for Meridian to understand the sensitivity of the HVDC GIT to investment timing?

One key assumption that is held constant across the analysis is that the HVDC upgrade must occur in 2012 and no sensitivities have been completed to test the optimal timing for any upgrade.

We request that Transpower tests the sensitivity the HVDC GIT valuation to a delay in investment timing by running a scenario where the HVDC investment is delayed until 2014. Again we suggest that Transpower uses the 90% renewables scenario to test this sensitivity.

I am happy to discuss and clarify this request further if necessary and it is worth noting that we may request further points of clarification as our analysis progresses. Otherwise we look forward to your co-operation with these questions and the results of the sensitivity studies.

Yours faithfully

A handwritten signature in black ink, consisting of a large, stylized 'G' followed by a series of loops and a long horizontal stroke extending to the right.

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