TRANSPOWER

North Island 400 kV Upgrade Project

Investment Proposal

Part IV – Cost Benefit Analysis

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1 Summary

This Part IV sets out the cost benefit methodology used to assess the proposed investment. This methodology is consistent with the Electricity Commission's Grid Investment Test. The cost benefit analysis demonstrates the following conclusions.

A long run development plan for the transmission network at 400 kV is more economic than continuing with incremental augmentation at 220 kV. The expected net market benefit of a 400 kV development plan over a 220 kV development plan is estimated at $133 million. Therefore 400 kV is the most economic choice for the main backbone voltage of the National Grid.

There are substantial benefits in implementing transmission augmentation when compared to a "do nothing" alternative which allows only for that generation anticipated in either Transpower's or the Electricity Commission's generation scenarios to be established.

The proposed investment has a substantially higher expected net market benefit than the best case transmission alternative of a diesel fired peaking plant. The expected net market benefit (cost) of a diesel fired peaking plant ranges between -$75 and -$105 million for one year deferral of transmission.

In summary the proposed investment based on the construction of a 400 kV double circuit transmission line between Whakamaru and Otahuhu is the most economic alternative to provide long run security of supply into the upper North Island and satisfies the requirements of the Grid Investment Test.

2 Cost/benefit analysis approach

The cost/benefit approach used for this analysis is consistent with the Grid Investment Test as required for investment proposals submitted to the Electricity Commission under the Grid Upgrade Plan provisions of Part F of the Electricity Governance Rules.

2.1 Defining the base case

Transpower's current Grid Reliability Standards specify a deterministic criterion which is widely used by electricity transmission businesses in many parts of the world.

The Grid Reliability Standards require that Transpower maintain the core grid to an N-1 standard as discussed in Part II of this submission. Under this criterion, it is necessary only to compare developments which are technically feasible and will, at a minimum, satisfy the deterministic standard.

This contrasts with the purely economic approach which would require a value to be ascribed to unserved load. Using such an approach, the base case would include market development scenarios which include expected new generation and which reflect expected demand growth, but which do not include new transmission development (that is a “do nothing” base case). The economic justification for transmission development would then depend upon maximising the economic benefit of the proposed new transmission investment by reducing the extent of the unserved load in the particular region under consideration.

In developing its generation scenarios, Transpower assumes that new generating capacity will continue to be installed to meet electricity requirements throughout New Zealand. The generation scenarios are intended to provide Transpower with a basis for proposing grid augmentation for a range of plausible generation developments.

The base case for analysis of the transmission options implicitly assumes that sufficient generating capacity will be installed to meet the overall standard of a 1 in 60 year severity of a “dry year”.

Since 220 kV is the current core grid voltage, the base case used for this analysis includes expected demand growth, expected new generation, and continued development of the grid at 220 kV to satisfy the Grid Reliability Standards for each of the nominated generation scenarios.

2.2 Costs considered

All costs included in the cost/benefit analysis are estimates in 2005 New Zealand dollars i.e. they do not account for inflation and a “real” discount rate is used. However, special provision is made for the assumption that the costs of acquiring property rights and easements will escalate at 1% above the average inflation rate.

Since the cost/benefit analyses are all comparisons of technically feasible alternatives (including alternatives to transmission development such as distributed generation) only those costs which vary between the cases need to be included in any comparisons. The costs of maintaining the existing grid, for instance, are not included because they remain unchanged whichever case is being analysed.

The costs included in the analysis are summarised in this section. Part V of this submission provides further information about the estimated costs for the proposed 400 kV reliability investment.

2.2.1 Capital costs

The capital costs for the transmission options comprise estimates of the cost to design, purchase and construct new transmission assets (eg transmission towers, conductors, substation equipment). The approach used to determine these cost estimates and their estimated range over which the results are sensitised, is described in section 3.

For alternatives to transmission, publicly available cost information has been used and the source is referenced.

2.2.2 Operating and maintenance costs

Costs in this category are estimates of the costs of operating and maintaining either the transmission assets or alternatives to transmission relevant to each case.

2.2.3 Dismantling costs

Dismantling costs are the estimated costs of dismantling and removing assets that are no longer required. These costs are "net", being the cost of dismantling less any scrap value realised from the sale of recovered material.

2.2.4 Property and easement costs

These are the costs of securing the property rights needed for new or altered transmission assets, or alternatives to transmission. These costs include the costs of purchasing land and easement rights.

2.2.5 Approval process costs

These are the legal and administrative costs of obtaining approval for the proposed reliability investment. The costs include satisfying the requirements of the Resource Management Act 1991, the Electricity Act 1992, the Public Works Act 1981 and other relevant legislation.

2.2.6 Project management costs

These are the costs associated with project managing the build of new assets. A standard value of 8% has been used, which includes a mixture of Transpower's internal and external costs.

2.3 Benefits or costs evaluated

The following benefits or costs which are relevant to the comparison of alternatives have been considered in completing the cost/benefit analysis:

2.3.1 Avoidance of unserved energy

Differences in the level of unserved energy between the base case and each scenario have been quantified in MWh where relevant. The unserved energy has been calculated taking into account the generation available in each of the generation scenarios. Unserved energy has been valued at $20,000 MWh.

2.3.2 Energy loss differences

Any investment in transmission augmentation will generally reduce the extent of energy losses. The reduction in losses is a benefit which is quantified and valued.

Transpower has applied different values for such loss reduction recognising that transmission augmentation may serve to carry base load power flows or incremental power flows. Base-load loss differences are valued using the long run marginal cost which includes a capital cost for additional generating plant that would be required to make-up for the losses incurred. Incremental, or peak load loss differences are valued using the short run marginal cost of the marginal generation plant[1].

[1] Marginal plant is based upon the predominant mix of new thermal plant in the particular scenarios considered and is assumed to be gas fired in Scenario 1, coal fired in Scenario 2 and the average cost of gas and coal is used in the other scenarios .

The costs of generation required to make-up the transmission losses differ depending upon the Generation Scenario and (depending on the Scenario) range from the generation cost based on gas to the cost of coal or oil fired generation. The costs used are sourced from a publicly available report prepared for the Electricity Commission by Parsons Brinckerhoff Associates, “Thermal and Geothermal Generation Plant Capabilities,” dated December 2004.

2.3.3 Differences in energy costs

Some transmission options or alternatives to transmission will enable different generation dispatch patterns. For example, relieving a transmission constraint may enable expensive thermal generation to be displaced by cheaper hydro or wind generation. Where such differences are material, the dispatch differences are derived, the variable costs of generation are calculated in each case (primarily fuel costs) and the cost difference is calculated. The variable costs of generation used are also sourced from Parsons Brinckerhoff Associates report referenced above.

2.3.4 Differences in carbon costs

The relieving of a transmission constraint may enable expensive thermal generation to be displaced by hydro or wind generation with a consequential reduction in the CO_2 burden. Where such differences are material, the dispatch differences are derived, the tonnes of CO_2 generated in each case are estimated and the cost difference is calculated using a value of $15 per tonne CO_2.

2.3.5 Differences in ancillary service costs

Some transmission options or alternatives to transmission may enable different levels of ancillary services to be required. For example, voltage stability is the limiting design factor in the Auckland area and different investments will require the purchase of more or less dynamic voltage support from existing synchronous condensers or generators. These differing amounts of voltage support requirement are estimated and costed at the average voltage support cost in Auckland for 2004.

2.3.6 Generation reliability value difference

Transmission assets typically provide approximately 99.0% reliability, and a grid designed to an N-1 standard is available and provides continuity of supply 99.99% of the time. Unplanned outages occur only 0.3% of the time, but on account of redundancy, failure of supply occurs only 0.01% of the time.

In contrast, generation assets are typically 85-90% reliable, with planned outages occurring 5-10% of the time and unplanned outages about 5% of the time. Generation can only approach the same level of service to consumers if multiple generators are built, or individual generators have multiple redundancy in their generating units. Where relevant, estimates are made of the amount of unserved energy that will accrue, as a result of the unreliability of each configuration of transmission and generation considered.

2.4 Other Assumptions

2.4.1 Timeframe

Transpower has also applied the technique that uses residual values to extend the analysis to consider 40 years of costs and benefits This is particularly relevant to HVAC transmission augmentation which will have an expected technical and economic life in excess of 50 years and there are significant benefits accruing after the first 20 years.

2.4.2 Discount rate

A pre-tax real discount rate of 7% consistent with the Electricity Governance Rules is used to determine the present value of future cash flows.

2.4.3 Weightings applied to generation scenarios

The generation scenarios will be given equal weighting (ie 20% each) in calculation of the expected net market benefit, consistent with the Electricity Governance Rules.

2.4.4 Competition Benefits

In situations where load can be supplied from either local generation or the grid, the level of competition in the energy market for that load is influenced by the level of transmission constraint. When the transmission to that load constrains, competition is reduced and local generators have a certain amount of market power which can be used to extract monopoly profits from consumers. Relieving the transmission constraint enhances competition and eliminates the ability of the generator to exert market power.

This benefits consumers in two ways. Firstly, enhanced competition actually lowers the cost of electricity, and secondly it also lowers the price of electricity. The price change consists of the cost change plus the extent to which generators can exercise market power.

Price changes due to the exercise of market power (decreases in consumer surplus at the expense of an increase in producer surplus, or the reverse), are collectively known as value transfers, and are not classified as competition benefits.

Competition benefits are that piece of the price change associated with cost changes. The competition benefits of a transmission investment are defined as the increase in size of the net consumer and producer surplus due to enhanced competition in the energy market[2] as a result of the investment.

This increase in surplus[3], resulting from generators offering closer to their short run marginal cost, theoretically leads to a decrease in the overall cost of dispatch as:

- operating costs of existing generation are reduced, leading to cheaper generation displacing expensive generation;
- capital expenditure on new generation is deferred or avoided;
- demand increases due to lower prices.

There is little consensus in the literature and amongst practitioners over a precise method for estimating competition benefits. However, a lower bound on their value can be determined by estimating the increase in consumer and producer surplus due to demand response to lower marginal electricity prices resulting from the investment.

Transpower has developed an approach for calculating such a lower bound on the competition benefits and this is described in the supporting document “A Methodology for Calculating the Lower Bound of Competition Benefits” (see Volume 2: Supporting

[2] Usually as a result of reducing generator market power
[3] Also known as a reduction in deadweight loss

Documents). At this time however, we do not have the price elasticity of demand information required to undertake the calculations.

The Part F rules allow competition benefits to be included in the cost-benefit analysis, provided such inclusion is appropriate, but do not require it. Transpower will continue to work on obtaining the necessary data to calculate a lower bound on competition benefits. The resulting competition benefits may be significant.

2.5 Calculation of expected net market benefit

The approach Transpower uses to calculate the expected net market benefit is a net present value analysis. Rather than being the outcome of a static spreadsheet calculation, the expected net market benefit is calculated by a Monte Carlo simulation in which demand is varied between the low and high bounds of the demand growth forecasts.

Figure 2-1 illustrates 1000 demand paths produced from a typical Monte Carlo simulation:

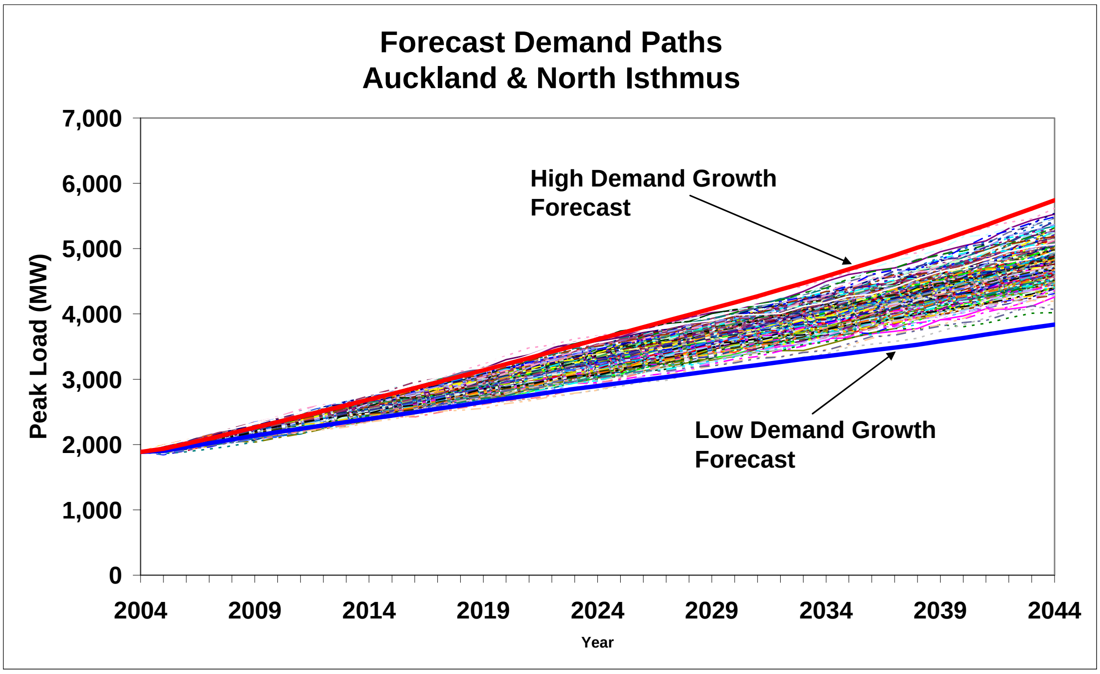


Figure 2-1 Illustration of demand paths from a Monte Carlo simulation

Transmission lines are large investments, with an economic life in excess of 50 years. There is considerable uncertainty when looking far into the future and in the particular case of transmission lines, uncertainty in:

- Future energy demands
- The location of new generation
- Technology changes that reduce the need for transmission.

Some transmission options and potentially alternatives to transmission include an inherent value, in that they include future investment flexibility to deal with uncertainty.

For example, projects which are built incrementally in line with growth in demand reduce the possibility of overbuild, because later investments can be deferred or cancelled should demand growth not be as high as expected.

Transpower's approach to calculating expected net market benefit does not capture all of this inherent value, in that a separate calculation is made for each generation scenario, but it does capture the value attributable to the uncertainty in demand growth.

2.6 Sensitivity Analysis

Transpower has sensitised the list of variables shown in Table 2-1, being those that may have a material impact on the cost/benefit analysis:

Variable	Range
Discount rate – transmission	4% to10%
Discount rate – alternatives	7% to 10%
Value of unserved energy	$10K to $30K
Value of losses	- 50%to +50%
Probability market development scenarios	0% to 40% ea
Capital Cost:	-10% to +50%
Operating and Maintenance Cost	-30% to +30%

Table 2-1: Table of variables which will be sensitised

Demand is not sensitised due to the effect of demand varying between the low and high bounds of the demand growth forecasts already being reflected in the Monte Carlo technique which calculates expected net market benefits.

3 Cost Summary

This section summarises all of the transmission costs used in the cost / benefit analysis.

3.1 Development Plan Costs

The 220 kV and the 400 kV grid development plans have been built up for each generation scenario, as described in Part III, section 5 of this submission. The costs presented here relate only to those developments which are unique to each transmission option[4].

Table 3-1 below shows the total costs (expressed in 2005 dollars) as they would be incurred for the base case 220 kV development plan out to the year 2040. It should be noted that the Operation and Maintenance Costs (O&M) have been included in this table for the purpose of comparing one transmission option against another. Other overhead costs associated with grid augmentation such as statutory approvals, property acquisition and project management have been included for the same reason. The treatment of capitalised cost of Interest During Construction (IDC) is taken account of in the projected incidence of investment costs.

[4] If a grid augmentation is required at the same time in both the 220 kV and the 400 kV development plans, the costs have been excluded on the basis that they are not necessary to compare development plans. this is a widely used approach in carrying out economic comparisons.

220 kV Development Costs Scenario Numbered ➡	$ million (2005)					
	No.1	No.2	No.3	No.4	No.5	Av.
Line + Cable capital costs	611	474	1,054	376	662	635
Substation capital costs	102	82	160	29	36	82
Property	451	363	732	194	402	428
O&M	83	56	97	21	15	54
Dismantling costs	4	4	4	4	4	4
Project Management Costs	99	80	162	49	88	96
Approval Costs	20	10	22	10	9	14
Total	**1,369**	**1,067**	**2,232**	**683**	**1,216**	**1,313**

Table 3-1: 220 kV Augmentation Plan Costs $million (2005)

Table 3-2 below shows the total costs (expressed in 2005 dollars) as they would be incurred for the proposed 400 kV development plan out to the year 2040. Similar qualifications apply to the cost estimates in this table as for Table 3-1 above so that they may be directly compared.

400 kV Development Costs Scenario Numbered ➡	$ million (2005)					
	No.1	No.2	No.3	No.4	No.5	Av.
Line + Cable capital costs	508	362	569	205	216	372
Substation capital costs	227	185	338	99	151	200
Property	248	199	320	97	105	194
O&M	106	84	126	46	54	83
Dismantling costs	4	4	4	4	4	4
Project Management Costs	79	60	99	33	38	62
Approval Costs	32	20	31	11	11	21
Total	**1,203**	**913**	**1,485**	**494**	**579**	**935**

Table 3-2– 400 kV Augmentation Plan Costs $million (2005)

Table 3-3 shows the present value of the total costs which are unique to the base case (220 kV) development plan, in 2005 dollars.

220 kV Development Costs Scenario numbered➡	Present value $ million (2005)					
	No.1	No.2	No.3	No.4	No.5	Av.
Line + Cable capital costs	354	234	427	176	277	294
Substation capital costs	43	39	54	9	10	31
Property	265	186	326	98	195	214
O&M	17	12	18	4	2	11
Dismantling costs	2	2	1	2	2	2
Project Management Costs	60	44	72	30	41	49
Approval Costs	14	8	13	3	3	8
Total	**757**	**525**	**910**	**322**	**532**	**609**

Table 3-3 - 220 kV Development Plan Costs $million (discounted)

Table 3-4 below shows the present value of the total costs which are unique to the proposed (400 kV) development plan, in 2005 dollars.

400 kV Development Costs Scenario numbered ➡	Present value $ million (2005)					
	No.1	**No.2**	**No.3**	**No.4**	**No.5**	**Av.**
Line + Cable capital costs	302	231	308	153	159	231
Substation capital costs	122	105	154	73	98	110
Property	167	142	194	85	89	136
O&M	24	19	26	12	14	19
Dismantling costs	2	2	2	2	2	2
Project Management Costs	48	39	53	25	28	39
Approval Costs	21	15	19	10	10	15
Total	**686**	**553**	**757**	**361**	**401**	**552**

Table 3-4 – 400 kV Development Plan Costs $million (discounted)

As can be seen from Table 3-3 and Table 3-4 above, the 220 kV development plan is $378 million (on the average) more expensive than the 400 kV development plan on a straight dollar comparison, but on a present value basis, this reduces to $57 million (on the average).

3.2 Proposed 400 kV Investment Costs

The costs associated with the proposed 400 kV investment, ie the 400 kV double circuit line and underground cable from Whakamaru to Otahuhu, that are used for the purposes of the cost/benefit analysis, are shown in Table 3-5.

Item	$million (2005)
Line capital costs	205
Substation capital costs	99
Property	97
O&M	46
Dismantling costs	4
Project Management Costs	33
Approval Costs	11
Preliminary Design & Investigation	12
Total	**507**

Table 3-5 – 400 kV first investment costs

A further set of costs are calculated, which include an estimate of costs associated with facilitating transmission across Auckland to North Isthmus. These costs also need to be incurred to ensure the energy flowing through the proposed new 400 kV line can reach load in Auckland and the North Isthmus.

Item	$million (2005)
Line capital costs	407
Substation capital costs	99
Property	97
O&M	57
Dismantling costs	4
Project Management Costs	49
Approval Costs	11
Preliminary Design & Investigation	12
Total	**737**

Table 3-6 – 400 kV First Investment Costs Including Across Auckland Costs

4 “Do Nothing” analysis – Is large scale base-loaded generation an economic alternative to transmission?

Transpower has undertaken analysis has been undertaken to determine whether the new generation that is forecast to emerge in the Auckland/North Isthmus region according to the generation scenarios, substitutes for transmission, and whether building transmission as well has a positive expected net market benefit.

4.1 Costs

The costs included in the analysis are the base case costs ie the costs of the 220 kV development plan. A sensitivity is included using the costs of the 400 kV development plan.

4.2 Benefits

The avoidance of unserved energy at $20,000 per MWh dominates the benefits included in the economic analysis. While there are a number of other benefits attributable to the proposed investment these have not been quantified or included in the analysis because they are relatively insignificant as compared to the avoidance of unserved energy. For completeness these other benefits include:

- Energy loss differences
- Differences in energy costs
- Differences in carbon costs
- Differences in ancillary service costs
- Generation reliability value difference

Energy loss differences, differences in energy costs and differences in carbon costs, would together represent the cost of meeting the otherwise unserved energy and as such would be a negative benefit if transmission was built. However, even if an average generation cost were used for thermal plant, of 7.5 cents per kWh, this only equates to $75 per MWh.

Ancillary service costs may increase in view of the higher demand being served but even if they were as high as the average cost of transmission, which is highly unlikely, that would only equate to $75 per MWh.

Generation reliability value is not a significant factor either. The previously unserved energy will be served through transmission, with an estimated reliability of 99.99%. The generation reliability cost will be 0.001% of $20,000 per MWh, or $2 per MWh.

Therefore, even if all of these were summed together, the likely maximum they could add is $152 per MWh, hence it is considered unnecessary to reflect them in the analysis. Rather, sensitivity analysis is undertaken on the unserved energy cost, using a low cost of $10,000 per MWh.

4.2.1 Expected net market benefit

The expected net market benefit of building transmission, as a result of applying the above assumptions, is:

$ million (discounted) Scenario number ➡	No. 1	No. 2	No 3	No. 4	No. 5	Average
Line capital costs	354	234	427	176	277	294
Substation capital costs	43	39	54	9	10	31
Property	265	186	326	98	195	214
O&M	17	12	18	4	2	11
Dismantling costs	2	2	1	2	2	2
Project Management Costs	60	44	72	30	41	49
Approval Costs	14	8	13	3	3	8
TOTAL COSTS	**757**	**525**	**910**	**322**	**532**	**609**
Avoidance of unserved energy	4,625	10,491	74,281	90,976	56,293	47,333
Total Benefits	**4,625**	**10,491**	**74,281**	**90,976**	**56,293**	**47,333**
Net Market Benefit	**3,868**	**9,967**	**73,371**	**90,654**	**55,761**	
Expected Net Market Benefit						**46,724**

Table 4-1 Expected Net Market Benefit Per Scenario

4.2.2 Sensitivities

The expected net market benefit has been sensitised for uncertainty in the cost estimates and the unserved energy cost, with the following results:

$ million (discounted)	Sensitised value	Expected Net Market Benefit
Base case without sensitivity applied		**46,724**
Total Costs	-10%	46,785
Total Costs	+50%	46,420
Unserved energy cost	$10,000	23,058
Unserved energy cost	$20,000	46,724
Unserved energy cost	$30,000	70,391

Table 4-2: Expected Net Market Benefit Sensitised for Uncertainty

As a separate sensitivity, the 220 kV development costs have been replaced by the 400 kV development costs, with the following result:

$ million (discounted)	Sensitised value	Expected Net Market Benefit
Base case without sensitivity applied		**46,724**
Total costs reflecting 400 kV development plan		46,782

Table 4-3: Replacement of 220 kV Development Costs with 400 kV Development Costs

4.2.3 Conclusion

From this analysis it is clear that both the base case (220 kV HVAC) and 400 kV HVAC have a highly positive expected net market benefit in all generation scenarios. Therefore, it can be concluded that:

- there is not enough large scale base-loaded generation forecast to appear to the North of Auckland in any of the generation scenarios to avoid significant amounts of unserved energy and thus large scale base-loaded generation does not substitute for transmission, and

- it is economic to augment existing transmission into the area to avoid the forecast unserved energy, and

- there is no certainty that the generation included in the generation scenarios will go ahead early enough to have any material effect on the timing of grid augmentation.

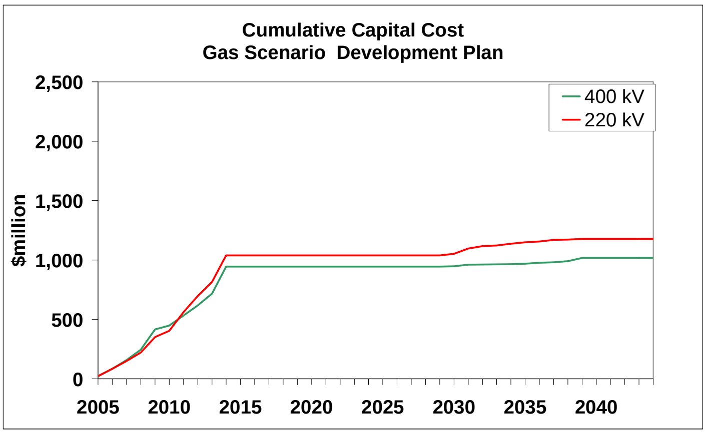
5 Cost benefit of 400 kV HVAC versus 220 kV HVAC

Previous studies have shown 400 kV HVAC to be the preferred technology from a wide range of alternative technologies including HVDC, for long-term development of New Zealand's national transmission grid. In this Section, Transpower compares a possible long-term grid augmentation plan using a 400 kV HVAC against a base case representing a "business as usual" case whereby the core grid elements continue to be designed and built to 220 kV HVAC.

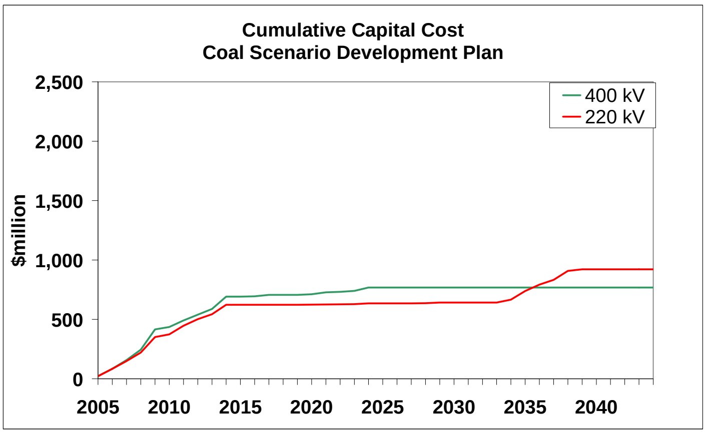
5.1 Capital Cost Summary

The following charts compare the cumulative capital costs associated with grid augmentation plans for the upper North Island development using 220 kV and 400 kV technology for each of Transpower's generation scenarios.

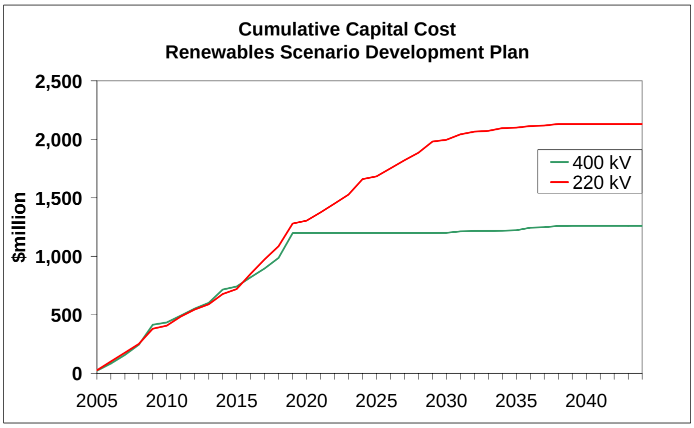
The costs shown in the charts below include line, substation, dismantling, property and approval costs only. They do not include operations and maintenance costs, transmission losses or project management costs.



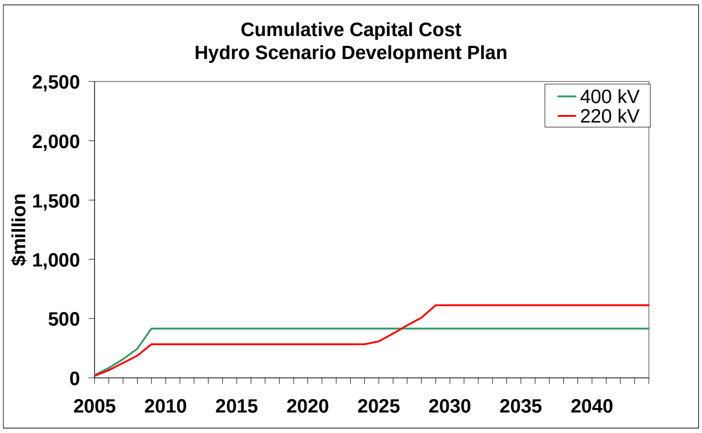
Scenario 1



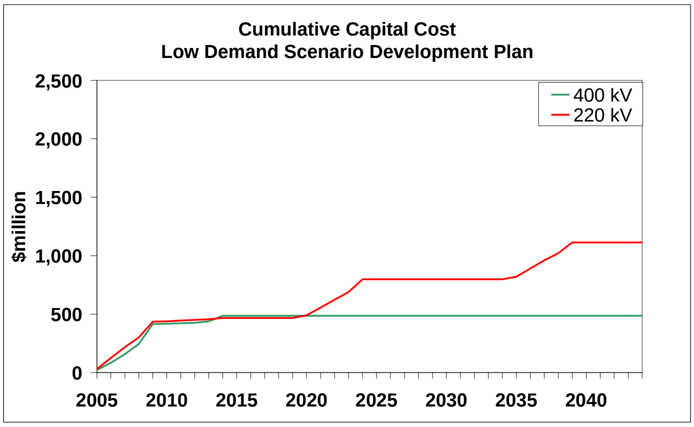
Scenario 2



Scenario 3



Scenario 4



Scenario 5

Figure 5-1: Cumulative Capital Cost Summary

As the charts in Figure 5-1 above show, the cumulative capital cost for 220 kV is higher in all scenarios, although grid augmentation at 400 kV costs incurs higher initial costs which pay off in the medium term.

5.2 Cost/benefit analysis results

The results of the cost/benefit analysis are shown in Table 5-1.

400 kV Advantage over Base Case $million (discounted)						
Scenario numbered ➡	**No. 1**	**No. 2**	**No. 3**	**No. 4**	**No. 5**	**Average**
Line capital costs	52	3	120	23	117	63
Substation capital costs	-79	-66	-101	-64	-88	-79
Property	98	43	132	13	106	78
O&M	-6	-7	-8	-8	-11	-8
Dismantling costs	0	0	-2	0	0	0
Project Management Costs	12	5	19	5	13	11
Approval Costs	-6	-7	-6	-7	-7	-7
Total Costs	**71**	**-29**	**153**	**-39**	**130**	**57**
Avoidance of unserved energy	0	0	0	0	0	0
Energy loss differences	95	75	105	18	85	76
Differences in energy costs	0	0	0	0	0	0
Differences in carbon costs	0	0	0	0	0	0
Differences in ancillary service costs	0	0	0	0	0	0
Generation reliability value difference	0	0	0	0	0	0
Total Benefits	**95**	**75**	**105**	**18**	**85**	**76**
Net Market Benefit 400 kV	**166**	**47**	**258**	**-21**	**215**	
Expected Net Market Benefit 400 kV						**133**

Table 5-1: Expected Net Benefit of 400 kV HVAC Augmentation of Supply to Auckland/North Isthmus Compared With 220 kV HVAC

The only material benefit that is applicable to the comparison of alternative transmission technologies dealt with in this section is the value of the lower transmission losses offered by the choice of a higher voltage level.

The value of transmission losses has been evaluated at the long run marginal cost (LRMC) of the most likely generation in each scenario, for example, gas fired in Scenario

1, coal fired in Scenario 2. Taken on average for all scenarios, the average value of losses is around $77/ MWh in 2020.

The analysis demonstrates that (on average) the 400 kV HVAC development option has an expected net market benefit of $133 million compared with the 220 kV HVAC base case development option.

Table 5-1 above, also shows that the 400 kV grid augmentation between Whakamaru and the Auckland/North Isthmus region is economically least attractive for Scenario 4. This scenario is based upon the assumption of extensive generation in the South Island in the short to medium term which would essentially be developed to supply loads in the North Island. This generation development in the South Island is assumed to be based upon new hydro resources being developed (Project Aqua plus other new hydro) but could equally be thermal generation based on the use of indigenous coal. It is also assumed that this development would take place within a reasonable period after the 400 kV augmentation of the grid supplying Auckland is completed.

If such large scale generation should develop, it is assumed that a new high capacity HVDC link would be established to deliver the new generation to a site near Auckland. If the HVDC terminal station is either in or near Auckland, the 400 kV development would have a low ongoing value for supply to Auckland and the North Isthmus which is reflected in the evaluation.

Equally well, the existence of the proposed 400 kV HVAC augmentation between Whakamaru and Auckland could be taken into account at the relevant future time and the HVDC terminated near Whakamaru where the availability of land and access is less likely to be and an issue than close to Auckland. If a terminal site to the south of Auckland is the preferred development in the future, the proposed 400 kV HVAC augmentation between Whakamaru and Auckland would have a substantial ongoing value which is not reflected in this scenario.

In reality, the possibility of a large scale generation in the South Island within a reasonable time-span which would warrant the construction of a major new HVDC link (rather than simply upgrading the existing link) seems to be of a low probability compared with the other generation scenarios that have been considered.

This points to the issues that may be introduced by taking a simple arithmetic average across all the generation scenarios. This approach assumes:

(i) that all scenarios have a similar likelihood of occurring with the result that a “unlikely” scenario could unduly bias the result, and

(ii) more importantly, it assumes that the outcome for any one particular scenario is equally acceptable in the context of future development of the national grid as it is for any other scenario.

This latter point is not considered in the Grid Investment Test. To put this point in the current context, the result of giving undue weight to scenario 4 was considered which would lead one to choose an extension of the 220 kV and the potential pitfalls of having to provide a further 220 kV line (or even migrate to 400 kV) some 10 years or so later if scenario 4 did not eventuate.

On the other hand, if this scenario was discounted as being the least likely, a decision in favour of 400 kV HVAC would leave the door open to the widest range of possible options including (as mentioned above) the possibility of siting a HVDC terminal station for a future HVDC link south of Auckland or even further south nearer Whakamaru. This has a very definite option value as suggested earlier in this Part IV but the possibility of putting a dollar value on such a future option has not been done in this instance as it is a difficult concept to give practical effect to.

If, for the reasons set out above, if scenario 4 is excluded from the calculation of the average of the expected net market benefit for the alternative scenarios, this increase the advantage of the 400 kV HVAC option over the "business as usual" 220 kV option from $ 133 million to $ 172 million.

5.3 Development Plan Sensitivity Analysis Results

Table 5-2 shows the results of the various sensitivities applied to the cost benefit analysis set out in the previous section. The expected net market benefit is the weighted average of the 400 kV development plan over and above the base case across all five generation scenarios[5].

Expected Net Market Benefit $million (discounted)	
Sensitivity Factor	**Benefit**
Base case without sensitivity applied	133
4% discount rate	275
10% discount rate	66
Loss value + 50%	172
Loss value – 50%	95
0% weighting on Scenario 4	172
40% weighting on Scenario 4	95
Capital costs + 50%	169
Capital costs -10%	128
O & M costs + 30%	133
O & M costs – 30%	133

Table 5-2 – Sensitivity Results for Expected Net Market Benefit of 400 kV

There is an economic advantage of the 400 kV investment over and above the base case in all of the sensitivity analysis.

Figure 5-2 shows that as the discount rate increases, the advantage of the 400 kV over the base case diminishes. However, even at the worst case of 10%, the advantage is still $66 million.

[5] The sensitivity results are the weighted average over all scenarios assuming that each scenario carries an equal weighting of 20%.

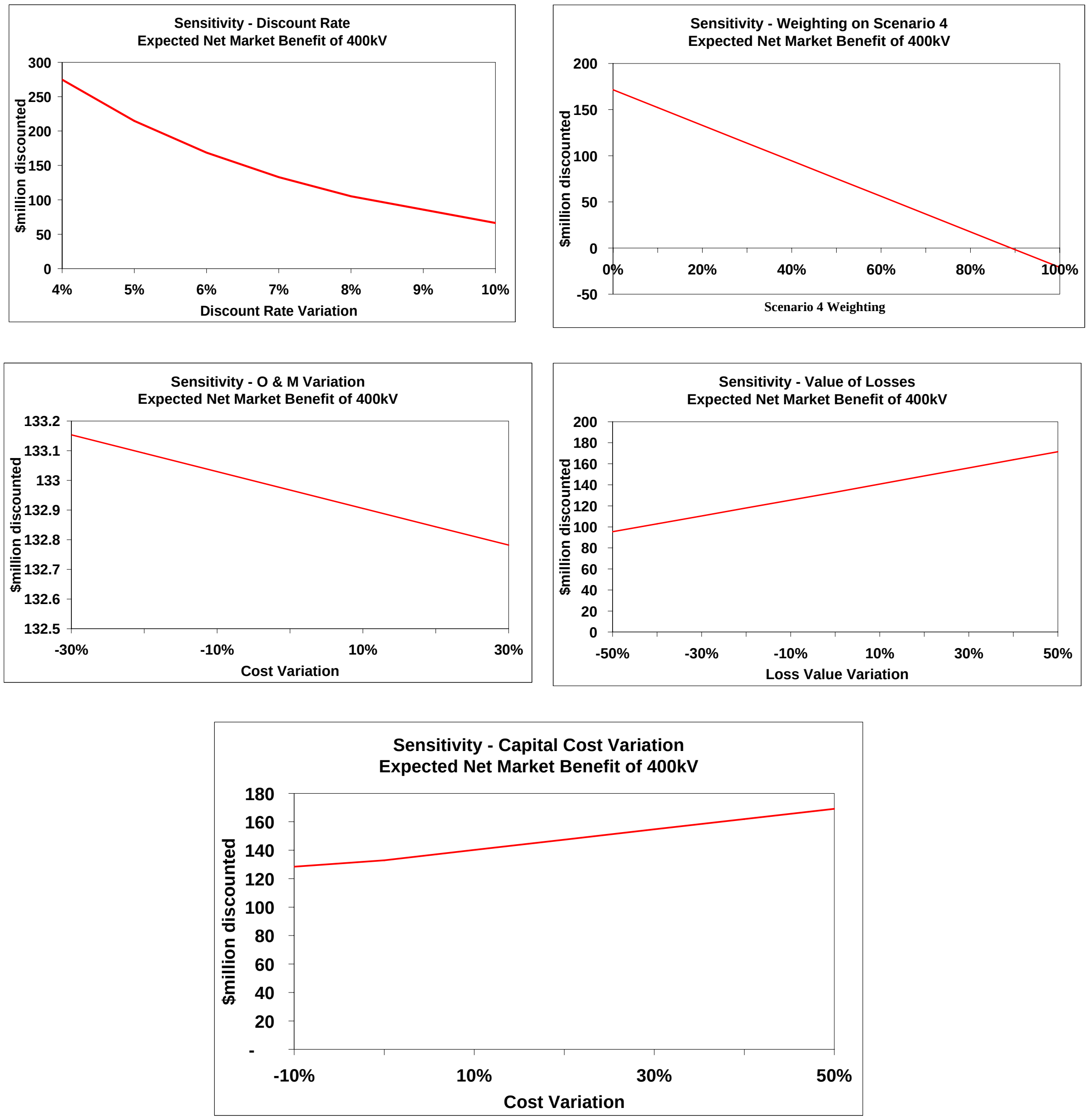


Figure 5-2: - Sensitivity Chart of Expected Net Market Benefit of 400 kV over Base Case

The analysis is fairly sensitive to the value of losses and this is to be expected given that this is a key point of difference in assessing the relative benefits of the project. However, it should be noted again, that even if the value of losses is decreased by 50% this would equate to an average marginal cost of generation of around $43/ MWh in 2025. This is less than the SRMC of a coal fired plant excluding any carbon tax. Transpower therefore considers that the loss figures used represent a reasonable view of their future value.

The weighting for Scenario 4 was also sensitised given that this is the scenario which favours the base case to the greatest degree. All other scenarios had an equal weighting applied. The significance of Scenario 4 and this sensitivity was discussed previously.

It was not considered necessary to sensitise the other scenarios as this would only provide different variations of positive expected net market benefit.

The cost sensitivities were applied to both the 400 kV and the 220 kV[6] total costs and since the 220 kV total costs are higher than the 400 kV total costs, the benefit of the 400 kV increases as the capital costs increase.

6 Expected Net Market Benefit of the proposed 400 kV HVAC grid augmentation

The Electricity Governance Rules provide that the *grid investment test*[7] is to be applied by the *Board* (the Electricity Commission) to review and approve *reliability investments* and *economic investments*.

Furthermore, *the grid investment test* (see Schedule F4 to Schedule II of Part F of the Electricity Governance Rules) states that:

4. "A *proposed investment* satisfies the grid investment test if the *Board* (now the Electricity Commission) is reasonably satisfied that :

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

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

    4.3. if sensitivity analysis is conducted, a conclusion that a *proposed investment* satisfies clauses 4.1 and 4.2 is sufficiently robust having regard to the results of that sensitivity analysis."

Transpower considers that its economic analysis and methodology is consistent with that required under the Grid Investment Test.

This estimation of the expected net market benefit has been carried out and included in this submission for the sole purpose of assisting the Electricity Commission considering its position.

In seeking to establish the *net market benefit* for a particular grid augmentation, Transpower has to rely on an assumption that the generation scenarios included in the particular *market development scenarios* used to determine the *net market benefit* contain sufficient generating capacity to meet the electricity requirements of New Zealand as a whole. Otherwise, there will be a concern that the results will contain an artefact arising from insufficient generation in the scenarios used. In developing its own generation scenarios, Transpower has been particularly careful to ensure that provision has been made for sufficient generation throughout New Zealand.

The expected net market benefit has been calculated by undertaking the same analysis as used for the "do nothing" analysis in section 4, but with the proposed 400 kV double circuit line from Whakamaru to Otahuhu only in service. In the "do nothing" base case, no transmission is built and there is a cost associated with unserved energy in the Auckland and North Isthmus regions.

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[6] It is considered unlikely that there would be a significant variation in the 400 kV costs which would not also be reflected in the base case costs, hence, the sensitivity was applied equally to both cases.

[7] The italicised terms defined in the Electricity Governance Rules

The "present value" of unserved energy that would be avoided by the proposed *reliability investment* comprising a 400 kV double circuit line from Whakamaru to Otahuhu is calculated, and this is compared to the "present value" cost of the proposal.

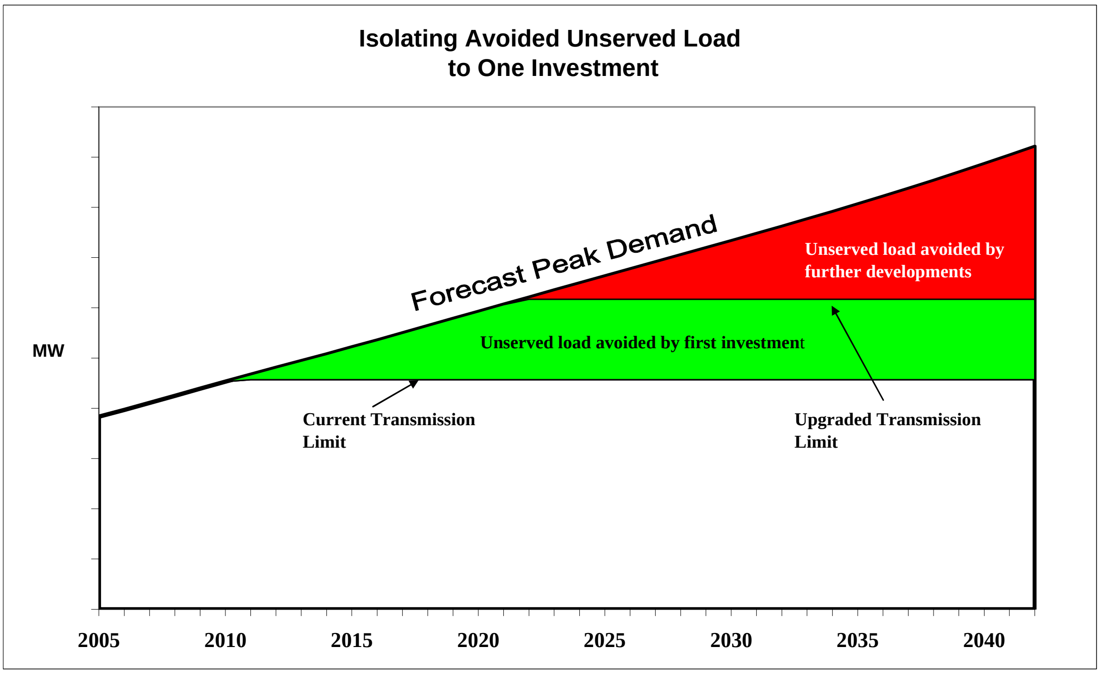

Figure 6-1: Illustration of Unserved Load Avoided by Initial 400 kV Investment

Figure 6-1 is an illustration of how unserved load can be isolated to one transmission investment. The avoided unserved load (MW) figure is the area shown in green which is the difference between the existing load capacity in Auckland and North Isthmus area and the future load capacity once the proposed investment has been built. The area in red is the unserved load that would be avoided by subsequent investments such as further grid augmentation or development of major generation in the Auckland area or north of Auckland.

The unserved energy associated with the proposed *reliability investment* is calculated separately for each market development scenario. In this analysis, the unserved energy figure used in the analysis is the average result over 1,000 demand paths lying between the maximum and minimum load forecast so that the results are robust for a range of load developments (effectively the "expected" unserved energy that will be avoided by building the first 400 kV investment).

In this analysis, the transmission option under consideration is the proposed 400 kV augmentation of the North Island grid between Whakamaru and Otahuhu and the expected net market benefit of this proposal is to be evaluated. Because it is common to all generation scenarios, the estimated present value cost of implementing the proposed investment as well as reinforcing the the 220 kV network across the Auckland Isthmus[8] is set separately in Table 6-1 below. Care should be taken in comparing this table with the capital cost estimates shown elsewhere in this submission as the costs are "present

[8] The investment costs to reinforce the Auckland isthmus are included because without this reinforcement, demand will not be able to be supplied at peak times to the North Isthmus and Northland. Therefore the in order for the proposed investment to be credited with serving the North Isthmus and Northland demand the cross Auckland reinforcement must be included.

valued" and also contain a 40 year estimate of the operation and maintenance costs of the proposal.

Present Value Costs of Building, Operating and Maintaining the Proposed 400 kV Reliability Investment	
	$million
Line + Cable capital costs	309
Substation capital costs	73
Property	85
Dismantling costs	2
Project Management Costs	38
Approval Costs	10
Operation & Maintenance	15
Preliminary Design & Investigatio	10
Total Costs	**542**

Table 6-1 - Present Value Cost of the Proposed Investment

Table 6-2 below shows the results of the cost benefit analysis over all scenarios for the proposed investment including the necessary cross Auckland Isthmus 220 kV reinforcements. The average column shows the weighted average assuming each scenario carries an equal weighting of 20% each.

Expected Net Market Benefit of Proposed 400 kV Reliability Investment for Transpower's Generation Scenarios $million discounted						
Scenario Number ➡	**No.1**	**No. 2**	**No. 3**	**No. 4**	**No. 5**	**Average**
Avoidance of unserved energy	3,830	7,118	42,911	49,115	36,073	27,809
Less total cost of proposed 400 kV reliability investment	542	542	542	542	542	542
Net Market Benefit Proposed 400 kV Investment	**3,288**	**6,575**	**42,369**	**48,573**	**35,530**	
Expected Net Market Benefit Proposed 400 kV Investment						**27,267**

Table 6-2 – Expected Net Market Benefit of First 400 kV Investment

The average expected net market benefit assuming it is relevant to give all generation scenarios the same weight is $ 27,267 million.

Three conclusions may be drawn immediately from this Table 6-2 as follows:

(i) the numbers obtained from such an analysis are extremely large being many billions of dollars,

(ii) the range of the net market benefits is extremely large being from $3.3 billion to $48.6 billion,

The reason the numbers are extremely large is that the *net market benefit* is evaluated over a period of 40 years on the basis that the proposed *reliability investment* will not be built. Quite clearly, if the proposed *reliability investment* is not built and the national welfare suffers losses of the order of magnitude indicated in the above table, then some form of alternative development would likely take place to remedy the situation.

Transpower concludes the following from the numbers in Table 6-2:

(i) that Scenario 1 appears to be the least robust for the proposed reliability investment. This is because Scenario 1 includes a substantial amount of base load generation near Auckland or in the North Isthmus using gas as a fuel but this is dependent upon further discoveries of gas in commercial quantities and new gas transmission infrastructure. The postulated development does not provide for new generation in a time-frame that adversely affects the economic value of proceeding now with a 400 kV development but the availability of local generation reduces the quantum of unserved energy in the longer term.

(ii) that Scenario 4 is the most robust for the proposed reliability investment. This raises questions as it has been shown in Section 5 of this Part IV that for Scenario 4, the proposed 400 kV grid augmentation is the least attractive when compared with continued development of the 220 kV grid. The reason for this is that Scenario 4 has the least amount of generation in the immediate Auckland area and there is greater reliance in the longer term on the transmission grid south of Auckland to provide security of supply and minimise the unserved energy.

(iii) While the assumed termination of a new HVDC link from the South Island in or near Auckland diminishes the long term value of the proposed 400 kV grid augmentation, in the longer term with the new HVDC link in service, it is necessary to have the augmented transmission between Whakamaru and Otahuhu in service to continue to supply some 2000 MW into Auckland. It has been indicated earlier in this section that the 400 kV HVAC option would reduce transmission losses and minimise the use of easements to achieve this end.

6.1 400 kV Line Sensitivity Analysis Results

Table 6-3 and Figure 6-2 below shows the results of the various sensitivities applied to the cost/ benefit analysis. Table 6.3 shows the expected net market benefit of the 400 kV development plan over and above base case[9].

Expected Net Market Benefit - $million discounted	
Sensitivity	**Benefit**
Base Case without Sensitivity applied	27,267
4% discount rate	55,793
10% discount rate	15,893
Unserved load value - $10,000/ MWh	13,364
Unserved load value - $30,000/ MWh	41,173
0% weighting on Scenario 1	33,263
40% weighting on Scenario 1	21,274
Capital costs + 50%	27,009
Capital costs -10%	27,320
O & M costs + 30%	27,265
O & M costs -30%	27,272

Table 6-3: Expected Net Market Benefit Against Various Sensitivities

[9] Apart from the 'weighting" sensitivity, the sensitivity results show the weighted average ENMB over all scenarios assuming that each scenario carries an equal weighting of 20%.

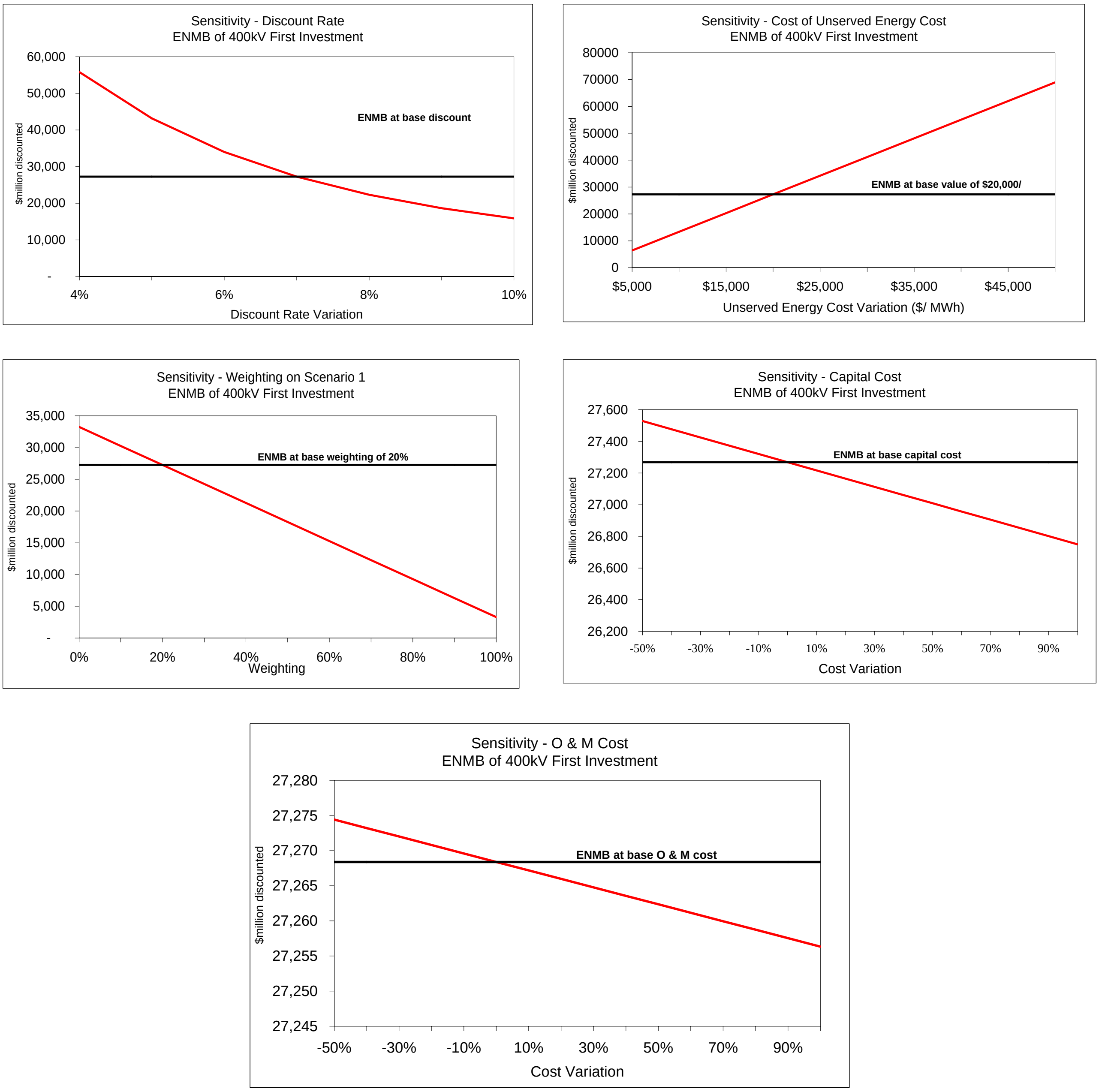

Figure 6-2: Sensitivities of the Initial 400 kV Investment

As expected when comparing the proposal to a base case of "no transmission", any reduction in the discount rate will reduce the expected net market benefit of the proposal, however even at a rate of 4%, the expected net market benefit of is still $27,200 million positive.

Variations in the cost of unserved energy affects the expected net market benefit of most significantly of all the sensitivities, but again, even at the low value of $5,000/ MWh, the expected net market benefit of is still positive at $6,411 million.

The sensitivity around the weighting of the scenarios was tested on Scenario 1, which returns the lowest expected net market benefit of due to the significant amount of modelled generation in the Auckland/ North Isthmus region in this scenario. The weighting on all other scenarios is assumed to be equal when varying Scenario 1's weighting. At the extreme of raising this Scenario's weighting to 100%, the expected net market benefit of is still $3,289 million positive.

The cost sensitivities demonstrate that the analysis is robust against significant cost variations with very little variation around the base value - even if costs were to double the expected net market benefit of the proposal would still be in excess of $26 billion.

6.2 400 kV Line using the Electricity Commission's Scenarios

A sensitivity analysis has been undertaken using the Electricity Commission's generation scenarios which form part of the Statement of Opportunities.

The Electricity Commission's scenarios all contain less generation in the upper North Island than Transpower's resulting in Transpower's scenarios providing a harder economic test for the proposed 400 kV line between Whakamaru and Otahuhu. This can be demonstrated by sensitising the economic analysis using the Electricity Commission's 2005 Generation Scenarios[10].

Given that there is substantially less assumed generation in the Auckland/ North Isthmus region under the Electricity Commission's scenarios than in the scenarios used in this analysis, the proposed investment will essentially avoid a larger proportion of the potential unserved energy. As a result the accrued benefits of the proposed investment will be higher.

Table 6-4 below shows the results of the economic analysis using the benefit of the avoided unserved energy under the Electricity Commission's generation scenarios. The average column shows the weighted average assuming each scenario carries an equal weighting of 20% each.

$million discounted						
Scenario Number ➡	**No. 1**	**No. 2**	**No. 3**	**No. 4**	**No. 5**	**Average**
Avoidance of unserved energy	13,086	32,207	97,375	101,838	58,263	60,554
Less total cost of proposed 400 kV reliability investment	542	542	542	542	542	542
Net Market Benefit 400 kV Investment	**12,544**	**31,665**	**96,833**	**101,295**	**57,720**	
Expected Net Market Benefit 400 kV Investment						**60,011**

Table 6-4: Expected Net Market Benefit of first 400 kV Investment under Electricity Commission Scenarios

As mentioned above, the benefit from avoidance of unserved energy is over twice that shown in the analysis using Transpower's generation scenarios. As a result, the Expected Net Market Benefit is over twice that from using Transpower's scenarios, at $60,011 million.

[10] For this exercise Transpower has used the generation scenarios published in the *"Initial Statement of Opportunities"* dated May 2005.

7 Alternatives to transmission which may economically defer transmission

Section 6 concluded that building the proposed 400 kV double circuit line from Whakamaru to Otahuhu, in 2010, has a positive expected net market benefit, under a range of reasonable scenarios. This section considers whether there are any alternatives to transmission which might economically defer the need for transmission in 2010.

7.1 Request for Information document

As discussed in Part III of this report, Transpower's approach to the question of an alternative to transmission deferring the need for the grid augmentation, was to issue a Request for Information document seeking information on potential "transmission alternatives" (the term used in the Electricity Governance Rules).

Part III also describes the analysis of the submissions received in response to the Request for Information and identifies the following alternatives to transmission as qualifying for further consideration.

- Load Shedding Bidding programme targeting peak demand reductions
- Peaking generation plant, diesel fired
- Base-loaded generation plant, gas fired

7.1.1 Load Shedding Bidding Programme

Although there is potential for a load shedding bidding programme to deliver peak MW load savings, no programmes are known to operate at present. Hence, there is considerable uncertainty about whether such a programme could deliver the quantity of load and certainty required in the Auckland area to defer transmission with the required degree of confidence.

The proposal did not provide adequate information on these matters. Particular questions that would need to be resolved relate to the total amount of sheddable load in the Auckland area and the extent to which a Load Shedding Bidding Programme would compete for sheddable load already available for other purposes. If sheddable load in the Auckland area is a scarce resource, then introducing a load shedding bidding programme may just serve to push up the prices being asked for instantaneous reserve. Because of these uncertainties, and the lack of data, this scheme is not considered as a viable alternative to transmission at this stage.

However Transpower has sponsored an independent investigation of such a programme to assess its potential benefits and to develop a design and implementation strategy.

7.1.2 Generation plant

Only the diesel fired peaking plant and gas fired base-loaded plant generation proposals are considered as potential contenders from an economic perspective at this stage.

Cost/benefit analysis has been undertaken to determine whether the use of such alternatives to transmission would have a positive expected net market benefit.

The analysis does not take a view on the form of the arrangements that would need to be in place to enable such alternatives, but does assume that the contractual arrangements would mean that the generation would be available to be dispatched, as and when required by Transpower. The practical use by Transpower of local generating plant, particularly for the base-loaded generation, has not been considered as such a generator would be a participant in the overall energy bidding market and Transpower has no place there.

7.2 Approach to evaluate alternatives to transmission to defer transmission

Rather than consider the particular generation plants offered in the RFI, a more generic approach was taken, whereby diesel generation equivalent to 1, 2, 3 and 4 years worth of demand growth (assuming medium demand growth) was considered. The applicability of these results to the economics base-loaded generation are discussed separately.

Costs

The capital and operating costs used, were sourced from various sources including Parson Brinckerhoff Associates "Thermal and Geothermal Generation Plant Capabilities" report, dated December 2004 and East Harbour Limited's "Cost of Fossil Fuel Generating Plant" dated September 2002.

Capital cost $m/MW	Fixed costs $m/MW/annum	Fuel costs $/MWh	Other variable costs $/MWh
1	0.019	164.86	8.00

Table 7-1: Diesel Peaking Plant Capital and Operating Costs

It is not clear what value should be assigned to the residual value of the diesel plant after 1, 2, 3 or 4 years use. The plant might either be scrapped entirely, or if constructed in such a way as to be moveable, it could be transported elsewhere for use. For the purposes of this analysis, the economics have been calculated assuming both no residual value and a 50% residual value.

Benefits

The primary benefit of deferring the 400 kV HVAC proposal past 2010 is that the capital cost of the 400 kV HVAC proposal is deferred. This equates to approximately a $24 million per annum saving on the capital cost of the whole project, or $17 million per annum saving if the property and easement costs are excluded.

Of the other benefits considered:

- Energy loss differences
- Differences in energy costs
- Differences in carbon costs
- Differences in ancillary service costs
- Generation reliability value difference

The first three were considered using SDDP[11] to determine an optimum national generation dispatch for each size of peaking generation. The model was optimised on a short run marginal cost basis for generation costs, rather than making assumptions about

[11] Stochastic Dual Dynamic Programme

market participant bidding behaviour. This approach ensures that the dispatch results are minimum cost from a national perspective, as required by the Grid Investment Test.

By calculating the cost of the national dispatch in this manner, the differences due to the first three benefits above, are all captured.

Ancillary service costs are calculated assuming:

– Reserve costs will not vary. Reserves are purchased based on the largest single generating unit in each island. Although transmission constraints can result in "islanded" demand, reserves are not purchased to cover regional risks caused by such islanding.

– Voltage support costs will vary. It is assumed for the purpose of this analysis that demand met using peaking generation will not require voltage support, but that if the same demand is met using transmission, then voltage support will be required. Actual 2004 voltage support costs for Zone 1 are used as the forecast cost for future voltage support.

Generation reliability differences are calculated using the methodology previously described. The estimated unserved energy in the Auckland/North Isthmus area for each transmission/generation configuration is calculated and valued at $20,000 per MWh.

Results

The results are summarised in Table 7-2 below for the case where all of the costs associated with the proposed 400 kV gird augmentation (including property and easement costs) are deferrable.

$ million (discounted)	Peaking plant 1 year deferral	Peaking plant 2 years deferral	Peaking plant 3 years deferral	Peaking plant 4 years deferral
Total 400 kV cost deferred, Zero residual value for generation				
Costs				
Capital cost generation[12]	54	104	152	196
Benefits				
Deferred transmission cost	24	46	67	87
National dispatch cost benefit	0	-1	-2	-7
Voltage support cost benefit	1	2	4	6
Generation reliability cost benefit	-70	-127	-170	-197
Residual value peaking plant	0	0	0	0
Total benefits	-45	-80	-102	-111
Expected net market benefit	**-98**	**-184**	**-253**	**-307**

Total 400 kV cost deferred, 50% residual value for generation				
Costs				
Capital cost generation	54	104	152	196
Benefits				
Deferred transmission cost	24	46	67	87
National dispatch cost benefit	0	-1	-2	-7
Voltage support cost benefit	1	2	4	6
Generation reliability cost benefit	-70	-127	-170	-197
Residual value peaking plant	23	43	60	74
Total benefits	**-22**	**-37**	**-42**	**-37**
Expected net market benefit	**-75**	**-141**	**-194**	**-233**

Table 7-2: Expected Net Market Benefit of Installing Diesel Fuelled Plant in the Auckland Area to Defer Transmission Augmentation Assuming Property & Easement Costs are Deferrable

Table 7-3 shows the corresponding result if the property costs are taken not to be deferrable.

[12] Note that these costs do not include land costs, installation costs, project management costs, etc, and so are not determined on the same basis as transmission . Neither do they include the cost of other infrastructure required e.g. noise abatement, diesel storage tanks, or a diesel pipeline.

$ million (discounted)	Peaking plant 1 year deferral	Peaking plant 2 years deferral	Peaking plant 3 years deferral	Peaking plant 4 years deferral
Partial 400 kV cost deferred, Zero residual value for generation				
Costs				
Capital cost generation	54	104	152	196
Benefits				
Deferred transmission cost	17	33	48	62
National dispatch cost benefit	0	-1	-2	-7
Voltage support cost benefit	1	2	4	6
Generation reliability cost benefit	-70	-127	-170	-197
Residual value peaking plant	0	0	0	0
Total benefits	**-52**	**-93**	**-121**	**-136**
Expected net market benefit	**-105**	**-197**	**-273**	**-332**
Partial 400 kV cost deferred, 50% residual value for generation				
Costs				
Capital cost generation	54	104	152	196
Benefits				
Deferred transmission cost	17	33	48	62
National dispatch cost benefit	0	-1	-2	-7
Voltage support cost benefit	1	2	4	6
Generation reliability cost benefit	-70	-127	-170	-197
Residual value peaking plant	23	43	60	74
Total benefits	**-29**	**-51**	**-61**	**-62**
Expected net market benefit	**-82**	**-154**	**-213**	**-258**

Table 7-3 - Expected Net Market Benefit of Installing Diesel Fuelled Plant in the Auckland Area to Defer Transmission Augmentation Assuming Property & Easement Costs are Not Deferrable

7.3 Sensitivities

The results for the most favourable case (ie the case with the highest expected net market benefits), where the total cost of the 400 kV AC proposal is deferred and the peaking plant has a 50% residual value, have been sensitised for uncertainty in the cost estimates and the benefit costs, with the following results:

$ million (discounted)	Sensitised value	Expected Net Market Benefit			
		Peaking plant 1 year deferral	Peaking plant 2 years deferral	Peaking plant 3 years deferral	Peaking plant 4 years deferral
Transmission cost	-10%	**-78**	**-146**	**-200**	**-242**
Transmission cost	0	**-75**	**-141**	**-194**	**-233**
Transmission cost	+50%	**-63**	**-118**	**-160**	**-190**
Generation cost	-30%	**-67**	**-123**	**-168**	**-199**
Generation cost	0	**-75**	**-141**	**-194**	**-233**
Generation cost	+30%	**-84**	**-159**	**-220**	**-268**

Table 7-4: Expect Net Market Benefit After Sensitivities Analysis of Peaking Plant

7.4 Conclusion

The expected net market benefit of installing diesel peaking generation and deferring the 400 kV HVAC proposal is negative under all conditions considered in the analysis. It is concluded that building the 400 kV AC proposal in 2010, rather than using alternatives to transmission to defer the proposal, is a robust investment.

8 Summary

The cost benefit analysis has demonstrated that, under a range of reasonable scenarios and sensitivities, building the proposed 400 kV double circuit line from Whakamaru to Otahuhu, in 2010, produces a positive expected net market benefit compared to “do nothing” and also that the 400 kV proposal has the highest expected net market benefit of the transmission options considered.

The analysis also demonstrates that the large scale base-loaded generation as set out in both Transpower’s and the Electricity Commission’s generation scenarios do not substitute for transmission. Furthermore the analysis shows that diesel fired peak generation plant is not an economic alternative to transmission.

Therefore, the cost/benefit analysis has demonstrated that the proposed augmentation of the grid between Whakamaru to Otahuhu at 400 kV and associated substation works in 2010, is economic and should be recommended.

This analysis is consistent with the Grid Investment Test required for such a Reliability Investment under the Electricity Governance Rules and demonstrates that the 400 kV proposal meets the requirements of that test.