

# **Review of Capital Cost Estimates for Transmission Augmentation into Auckland**

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## **Appendices**

Appendix A Excerpt from DOE G430.1-1 - Cost Estimating Guide

# Review of Capital Cost Estimates for Transmission Augmentation into Auckland

## 1. Introduction

This report presents the results of a review of the cost estimates for the final options prepared by the Electricity Commission (EC) and its consultants for the augmentation of transmission between Whakamaru and Auckland.

Specifically the following documents were reviewed:

- a) Costing of Power Electronic Equipment for Alternative Transmission Augmentation into Auckland –Prepared by Dr. B. R. Andersen, dated 29<sup>th</sup> December 2005[1]
- b) Transmission Augmentations Into Auckland Capital Cost Estimates For Short-Listed Alternatives To Transpower’s 400 kV Transmission Line Proposal – prepared by Parsons Brinckerhoff (PB) Associates, dated 26<sup>th</sup> March 2006[2]

The five short-listed transmission alternatives considered by the Electricity Commission are shown in Table 1:

<b>Title</b>	<b>Description</b>
400 kV in 2010	400 kV line OTA-WKM in 2010
400 kV in 2017	400 kV line OTA-WKM in 2017 preceded by intermediate investments in 2010
220 kV in 2017	220 kV line OTA-WKM in 2017 preceded by intermediate investments in 2010
HVDC in 2017	HVDC line OTA-WKM in 2017 preceded by intermediate investments in 2010
400 kV in 2021	400 kV line OTA-WKM in 2021 preceded by intermediate investments and duplexing of the OTA-WKM lines A&B in 2010

This report was prepared at the request of Transpower NZ Ltd.

## 2. Scope of Work

The scope of this work was to provide an independent review of the cost estimates, assumptions and methodology presented in the above documents, and identify any areas where different assumptions might be more appropriate or logical for an operating company such as Transpower.

### **3. Limitations**

This report was prepared within a very short time and without benefit of technical details of the alternatives, single line diagrams, construction schedules and cash flows assumed in the capital cost estimates. There was insufficient time to check any calculations within the EC estimates, to prepare independent cost estimates, or to compare costs in detail with recent cost information on other projects.

As such, the report primarily discusses areas where the cost estimates appear to be inconsistent with expected values based on considerations of reliability, constructability and operability.

### **4. Technical Factors that may Affect Cost Estimates**

This section discusses several areas where the capital cost estimates may not adequately account for costs due to assumptions or methodology that is not consistent with technical limitations that would be encountered in construction or operation.

#### **4.1 Level of Accuracy of the Estimates**

The level of accuracy of the estimates is stated on Page 6 of the PB Associates report as being considered to be within a  $\pm 10\%$  accuracy range. In our view this is inconsistent with the level of design that has been completed to date. Accuracy levels of  $\pm 10\%$  can only be achieved when designs are fully completed and actual bid prices have been obtained based on the designs.

A level of accuracy of  $\pm 30\%$  is considered more likely for the level of work that has been completed to date. This view is supported by the US DOE in their document "DOE G 430.1-1 - Cost Estimating Guide"[3]. Table 4-1 from this document is included in Appendix A for reference. In our view, the work presented in the PB Associates report represents a "Budget/Conceptual Design Estimate".

#### **4.2 Consideration of Losses and Cost of Losses**

None of the estimates appear to make any allowance for costs due to losses. In our experience, costs of losses are a significant consideration and can significantly affect comparisons between options to the extent that the rankings of alternatives based on cost would be affected if there were any appreciable difference in losses between the alternatives. Therefore we feel that cost of losses should have been included in this comparison.

It is noted that Dr. Anderson's report [2] states the expected no-load and full-load losses from each piece of equipment for which costs have been obtained. The stated values appear to be reasonable based on our experience with similar equipment.

However, in the PB Associates report [1], there is no discussion of losses or the cost of losses nor is cost of losses listed in any of the cost tables. We are not sure whether it was agreed to exclude consideration of losses or if this is an apparent oversight.

While there is no indication of the overall magnitude of no-load and load losses for each alternative in either of the two reports, it is expected that overall losses would be lowest in

the highest voltage alternatives (i.e. the 400 kV alternatives). Losses would tend to be increased in lower voltage options and in options where the natural power flow is modified using phase shifters or series capacitors.

### **4.3 SVC Costs**

The costs of the SVCs are based on relatively large module sizes. Module sizes of 100 Mvar have been assumed for the  $\pm 100$ Mvar alternatives and 150 Mvar TSC modules have been assumed for the 0/+300Mvar SVCs. While these large module sizes are favoured by suppliers because they tend to result in a simpler and very economical design, they are seldom suitable from a system point of view because the voltage change that occurs on module switching, especially in contingency situations, would be perceptible and annoying to utility customers.

The frequency of switching for TSC is much higher than is typical for a shunt capacitor bank and thus the permitted voltage change on module switching should be limited to a lower value than may be allowed for shunt capacitor switching. The voltage change on switching of the TSCs would be mitigated to some extent by the TCR but may still exceed tolerable levels depending on the frequency of switching. Some reduction in module size may be required, which would increase both footprint size and costs.

The costs of SVCs do not appear to include cost of major spares based the equipment specification given in report [1]. It is not known if the SVCs are critical to system performance, but if the SVCs are required to avoid load shedding in critical contingency events then some level of redundancy and/or major spares such as the step-up transformer would need to be considered. This could result in a cost increase that could approach 20-25% of the base cost of the SVC.

### **4.4 HVDC Converter Costs**

In report [1] the costs of HVDC options have been selected based on the two lower prices received from three vendors. This is not considered to be appropriate for a number of reasons most of which have already been stated in the report [1]. The report notes that the following costs are not included:

- a) The Owner's own engineering and project management costs,
- b) The cost of Public Enquiries and other planning activities,
- c) The cost of the procurement and preparation of the land area,
- d) The cost of access roads,
- e) The provision of services (e.g. auxiliary power, potable water, sewage and surface water drainage),
- f) Taxes and other duties,
- g) Owners insurance, etc.

Of these items, only a) seems to have been addressed in the PB Associates cost estimates. The remaining items could add between 15 and 25% to the total cost.

Report [1] also notes that the HVDC converter costs could be subject to wide variation depending on market conditions, and other factors as follows:

- a) Whether or not the Owner prepares a functional or prescriptive specification (a 5-10% increase is possible for a prescriptive specification)
- b) Local costs (up to 5 % higher in high cost areas)

- c) Cost of losses - Higher loss compensation figures generally result in higher equipment prices. The \$2700 (NZD) figure suggested in the report is low compared to value of \$5000 to \$6000 (USD) that is used by some utilities in North America. (cost increase of 2-5% is possible)
- d) Cost of the civil works – poor soil conditions could result in cost increase of 5% or more.
- e) Environmental constraints – could increase costs by 2% for noise abatement and 2-5% for visual impact
- f) Transport constraints – possible cost impact of up to 5% if necessary to provide single-phase 2-winding units rather than 3-winding units due to transport constraints.
- g) Spares requirements - The equipment specification used by Dr. Anderson for obtaining budgetary costs from vendors [1] did not request the vendors to include the cost of major spares such as converter transformers, smoothing reactors and significant thyristor valve spares.

Because of the specialized one-off design that is common with converter equipment, it would not be possible to obtain replacements for major equipment within a reasonable length of time, nor would it generally be possible to use spares carried by the utility for other portions of the system. Thus any failure of a major piece of equipment would mean the facility could be unavailable for a duration of up to one year while a replacement transformer or other major spare is obtained. If the HVDC link is a core facility, this represents an unacceptable loss-of-capacity risk for the operating utility. Consequently if the HVDC were needed for firm transfer capability, as we assume this facility would be, the purchase of major spares would be a necessary expenditure.

The cost of major equipment spares for converter equipment can add significantly to the cost possibly as much as 15% of the base cost of the HVDC equipment. To avoid risk of prolonged outage, the spare equipment would need to be purchased at the time of installation of the first monopole. If the second monopole does not have identical equipment to the first monopole, then it may be necessary to purchase spare equipment for the second monopole as well.

- h) Commercial terms and conditions – terms and conditions that place a high premium on meeting an inflexible in-service date and assign liquidated damages can have a major influence on cost. Even if suitable limits are place on the total liquidated damage amount, the total amount is likely to flow through to the final price. (Cost increase of 5-10% is possible.)

By summing the potential cost impacts from each of these factors, the combined total cost impact could be between 56% and 82% of the base cost of the HVDC system. Admittedly, not all of the above factors would apply and some would apply to ac options as well as HVDC options. However, many of the above considerations would certainly be applicable and in general would tend to increase capital cost of the equipment. It is not clear whether the PB Associates Report [2] takes these factors into account and makes the necessary adjustments to the cost. Cost of performance enhancing features, such as converter overload, has also not been considered.

Lastly, it is noted that [1] includes a figure of \$NZ 3.5 million for conversion of the two monopoles to a bipolar configuration at the time that the second monopole is installed. Such a conversion offers definite performance and reliability advantages and would almost certainly be carried out. In the cost estimates [2] the cost of conversion to a bipolar system is not addressed nor is the methodology for such conversion discussed.

From a utility point of view, steps should be taken in the first stage of HVDC development to facilitate the conversion to a bipolar system that would minimize outage time of the first monopole for modifications and testing when the second monopole is installed. This would generally include installation of necessary switches for the first monopole at time of installation, as well as provision of bipolar controls together with the first monopole. Other preparations for the second stage that may also be cost effective include preparation of the site area for the second pole, provision of switches/ breakers within a GIS for a second pole, provision of common areas of a converter building suitably sized for both poles. All of these factors would tend to increase the cost of the first monopole compared with the second.

#### **4.5 HVDC Cable Costs**

The estimates of underground cable costs for the HVDC options given in report [2] indicate that equal costs have been allowed for both the first and second monopoles being comprised of costs for one pole cable and one neutral cable at each stage. This is in contrast to the HVDC line where both pole conductors and neutral conductors have been installed at the time of installation of the first monopole.

From a practical and safety point of view, two HVDC pole cables should be installed on separate rights of way with sufficient separation to ensure that magnetic coupling between the two pole conductors is reduced to very low levels. This is required to ensure that current surges in the operating cable do not transfer to a faulted cable during repair operations. Such transferred surges could result in unsafe conditions for crews performing jointing or repair operations on a faulty cable. These considerations also apply for the neutral cables since current surges on the neutral cable would also couple to any adjacent pole or neutral cables and raise safety concerns unless adequate separation is provided.

Given the above, the allocation of equal costs for cable installation for the first monopole and the second monopole appears to be reasonable. However, it is noted that a spare cable has not been allowed for at either the first monopole stage or at the second monopole stage. As the time to locate and repair a cable fault may be between 20 days and one month, it is considered advisable to install a spare cable for at least one of the monopoles, preferably the first monopole. However, to avoid having to take a pole outage to complete repairs on a faulty cable, it would be preferable to have the spare cable installed on a separate right of way.

If the spare pole and neutral cables are installed on a separate right of way at the time of installation of the first monopole, the question of how to provide a spare cable at the bipolar stage should logically also be addressed when the first monopole is installed. If provision of a spare cable for the bipolar stage is not addressed at this time, it would be necessary to construct a third trench on a third separate right of way for the spare cable at a later date.

If it were necessary to limit the number of cable rights of way to only two, then one option would be to install two pole cables and two neutral cables (one main and one spare) in each of the two cable trenches, all at the first stage. This would mean doubling the cost of HVDC cables compared to the PB cost estimates [2] and installing four pole cables at the first monopole stage.

If it is considered acceptable to have three cable rights of way, then two pole cables and two neutral cables should be installed at the first monopole stage and a third set of cables should be installed at the second monopole stage. This would mean the cable capital cost would be 150% of that considered in the PB Associates report [2].

In the foregoing it is assumed that the pole and neutral conductors would be installed by direct burial in a trench since this is thermally the most favourable case.

## **5. Summary and Conclusions**

This review of the cost analysis indicates that the ranking of options can be influenced by the assumptions and technical considerations used in the analysis. Generally operating utilities such as Transpower would tend to make their investment decisions with full consideration of factors that would reduce risk, ensure continuity of service and ease of operation and upgrading. They would also be more concerned with ongoing costs such as cost of losses. All of these are legitimate concerns and are considered reasonable and prudent.

It is considered highly likely that, when these factors are considered, there may be significant changes to the relative costs of the alternative options described in the PB Associates report [2]. The changes may be sufficient to change the cost ranking of the options. The primary factors that would influence the relative costs of the options are:

- Cost of losses.
- Provision of major spares for the converters, converter transformers, SVCs, and HVDC cables.
- Early installation of features needed to facilitate future upgrades or avoid shutdowns at the time of upgrading.

## **6. References**

- [1] “Costing of Power Electronic Equipment for Alternative Transmission Augmentation into Auckland” - prepared by Dr. B.R. Anderson, dated 29<sup>th</sup> Sept 2005.
- [2] “Transmission Augmentations Into Auckland Capital Cost Estimates For Short-Listed Alternatives To Transpower’s 400 kV Transmission Line Proposal” – prepared by Parsons Brinckerhoff Associates, dated 26<sup>th</sup> March 2006
- [3] “DOE G 430.1-1 - Cost Estimating Guide” prepared by United States Department of Energy, dated 28<sup>th</sup> March 1997

**Excerpt from DOE G430.1-1  
Cost Estimating Guide**

DOE G 430.1-1  
03-28-97

4-13

<b>TABLE 4-1</b>		
<b>DEGREES OF ACCURACY</b>		
<b>TYPE</b>	<b>PURPOSES</b>	<b>ACCURACY RANGE</b>
<b>Conventional Construction</b>		
Planning/Feasibility or Order of Magnitude Estimate  (Proposal)	<ol style="list-style-type: none"> <li>1. Scoping Studies.</li> <li>2. Preliminary budget estimates of Total Project Cost.</li> <li>3. Support Key Decision 0.</li> </ol>	± 40%
Budget/Conceptual Design Estimate  (Equipment Factored)	<ol style="list-style-type: none"> <li>1. Ensure project feasibility.</li> <li>2. Develop reliable project cost estimate.</li> <li>3. Establish baseline project definitions, schedules, and costs.</li> <li>4. Support Key Decision 1.</li> </ol> <p style="text-align: center;">(Design 10% to 15% Complete)</p>	± 30%
Title I Estimate	<ol style="list-style-type: none"> <li>1. Verify that Title I design details still remain within the project funding.</li> <li>2. Support Key Decision 2.</li> </ol> <p style="text-align: center;">(Design 25% to 35% complete)</p>	± 20%
Title II or Definitive Estimate  (Detailed)	<ol style="list-style-type: none"> <li>1. Estimate construction costs as accurately as possible, prior to the commencement of competitive bidding and construction activities.</li> <li>2. Support Key Decision 3.</li> </ol> <p style="text-align: center;">(Design 60% to 100% Complete)</p>	- 5% to + 15%
Construction Estimate	<ol style="list-style-type: none"> <li>1. Estimate is based on bid information.</li> </ol> <p style="text-align: center;">(Design 100% complete)</p>	- 5% to + 10%