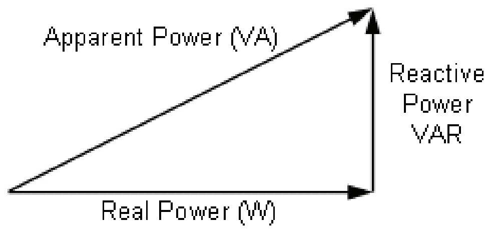
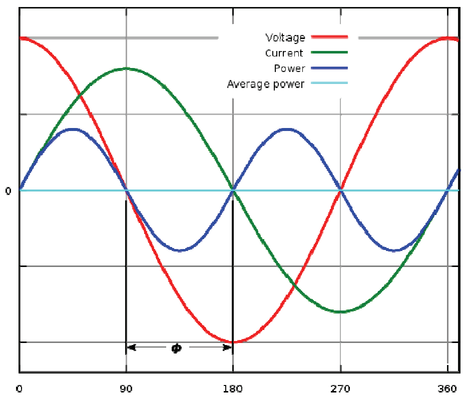
Review of EGR Connection Code



$$\textit{Power factor} = \frac{\textit{Real Power}}{\textit{Apparent Power}}$$



UNI & USI POWER FACTOR REQUIREMENTS

- GXPs and Grid Supply Points
- Ver 1
- 24 September 2010

Review of EGR Connection Code

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- Ver 1
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Contents

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Executive Summary

Schedule 8 in Schedule F2 of section II of part F of the Electricity Governance Rules (EGR) requires electrical demand drawn from supply substations to be maintained at specific power factors during peak regional grid loading periods.

The Electricity Networks Association (ENA) contracted Sinclair Knight Merz (SKM) to undertake a review of the power factor requirements associated with the upper north island (UNI) and upper south island (USI), with a focus on specific key issues.

As a result of our investigations we note the following conclusions/comments:

- A key finding is that at system peak the average power factor of the GXP's in both the UNI and USI regions is approximately 0.98.
- The characteristics of the UNI/USI GXP power factors vary widely. A general feature is that power factors (and reactive power demands) are not tightly controlled.
- Capacitor banks need to be switched to cater for light load conditions. The switches and control equipment have a significant impact on installation costs. The costs associated with installing capacitor banks (fitted with switching equipment) at 0.4kV (LV) are prohibitively expensive.
- In order to ensure unity power factor during peak network loading conditions power factor control is required for all (if not most) capacitor bank installations.
- It is not sensible to expect Electrical Distribution Businesses (EDBs) to correct power factors at the 0.4kV level. The most likely economic location for capacitor banks is on 11kV lines/cables close-in to zone substations (if not at 33kV). Given this fact a significant amount of the downstream distribution network losses will not be minimised by EDBs installing capacitors in distribution networks. This reduces the economics of the installations.
- The requirements of international transmission authorities, in relation to power factor, vary widely. However, there is clear evidence of other transmission authorities (grid codes) requiring grid off-take substations/loads to operate at close-to or unity power factor. There is also evidence of transmission authorities allowing power factors as low as 0.8.
- The costs associated with meeting the unity power factor requirement in the UNI and USI regions are collectively estimated to be NZ$75M.
- The long run costs to reinforce the transmission grid in the USI and UNI regions are comparable to the costs to install reactive compensation within the distribution network (improving power factors 0.98 to 1.00 at GXPs).

- The Electricity Commission's (EC) economic evaluation of capacitor bank installations:
  - Overstated the extent of the distribution resistance and thus the possible loss reduction.
  - Under-estimated the costs associated with capacitor banks (primarily due to switching costs).
- If one only considers the benefits associated with network loss reduction then a sensible target power factor for New Zealand EDBs would be ≈0.95.
- As the power factors of GXPs approach unity the economic viability of further improvements (i.e. closer to pf=1.0) become less and less economically viable. This is exacerbated by the fact that significant numbers of switching devices are required (at relatively high cost) to prevent overcompensation (i.e. operating at leading power factors).
- The analysis undertaken by the EC does not appear to be sufficient to initiate NZ$75M of capital expenditure.

1. Introduction

In response to a number of concerns electricity industry participants have expressed in relation to the power factor requirements in the Connection Code, the Electricity Commission (EC) began a process of investigations and consultation. As part of the consultation the EC released a consultation paper (Ref 1) and an issues paper (Ref 2) and requested submissions from industry participants.

The EC then proceeded to insert a new Schedule 8 in Schedule F2 of section II of part F (Rule Change Number 59) which is titled "Connection Code" (refer to Appendix D). This schedule includes the following requirement in relation to power factors at grid exit points/substations (GXPs):

If electricity is being drawn off the grid, the Power Factor at any Point of Service the Customer must:

(1) up until 31 March 2010, in the case of demand, maintain a Power Factor of not less than 0.95 lagging at any Point of Service during each relevant regional peak demand period.

(2) from 1 April 2010, in the case of demand, maintain a Power Factor of not less than:

(i) 1.0 (unity) at each relevant Point of Service during each relevant regional peak demand period in the Upper North Island Region and the Upper South Island Region; and

(ii) 0.95 lagging at each relevant Point of Service during each relevant regional peak demand period in the Lower North Island Region and the Lower South Island Region.

Given the above requirements the ENA contracted Sinclair Knight Merz (SKM) to undertake an investigative review of a number of key issues relating power factors at GXPs in the upper north island (UNI) and upper south island (USI) regions. The definition of the UNI and USI regions are outlined in Appendix D and shown graphically in Figure 1 and Figure 2 respectively.

This report discusses and documents SKM's findings and opinions.

An explanation/definition of electrical power factor is not included in this document on the basis that there are a number of excellent explanations/definitions of power factor on the World Wide Web (i.e. refer to Ref (3) and Ref (6)).

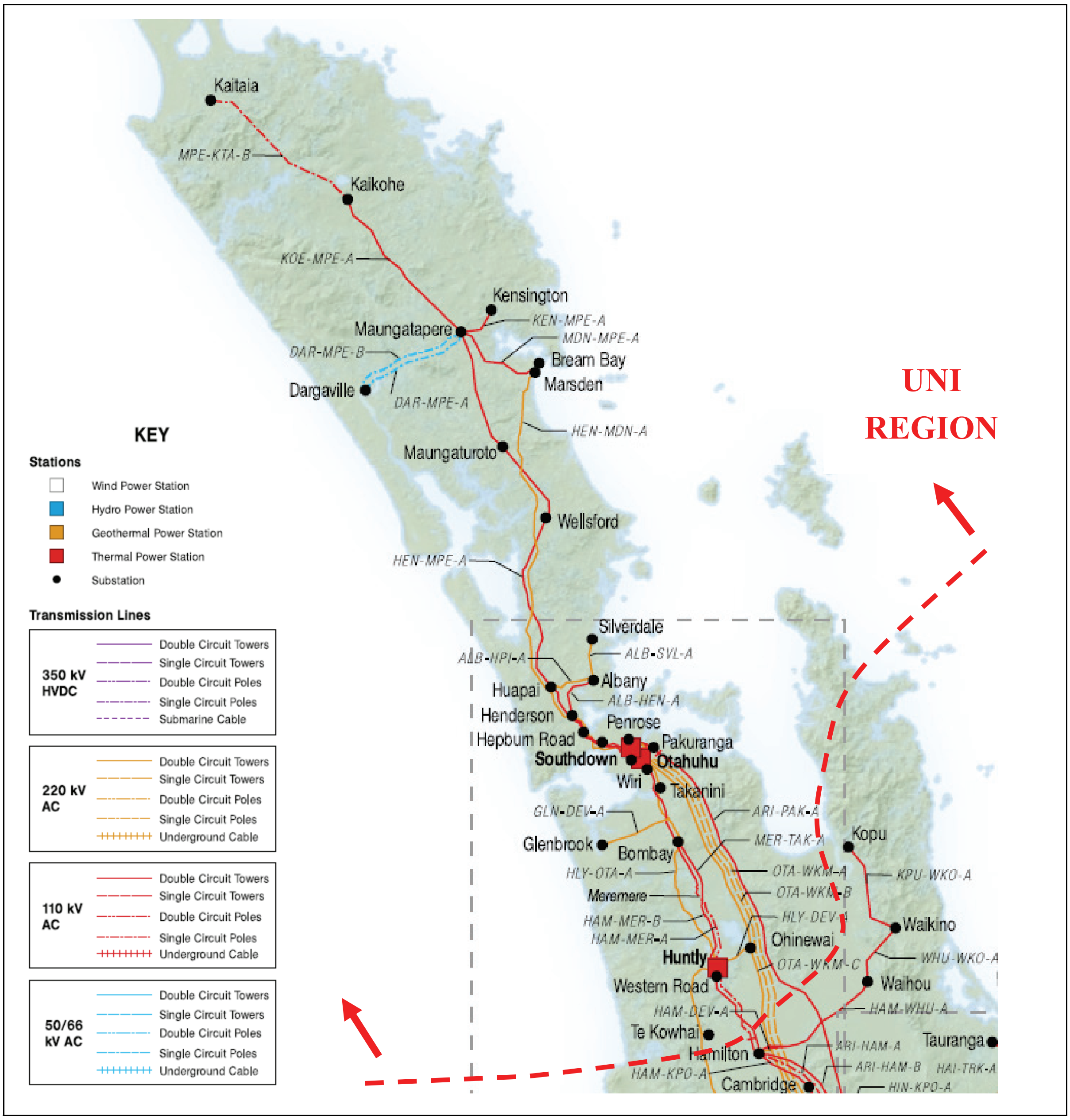
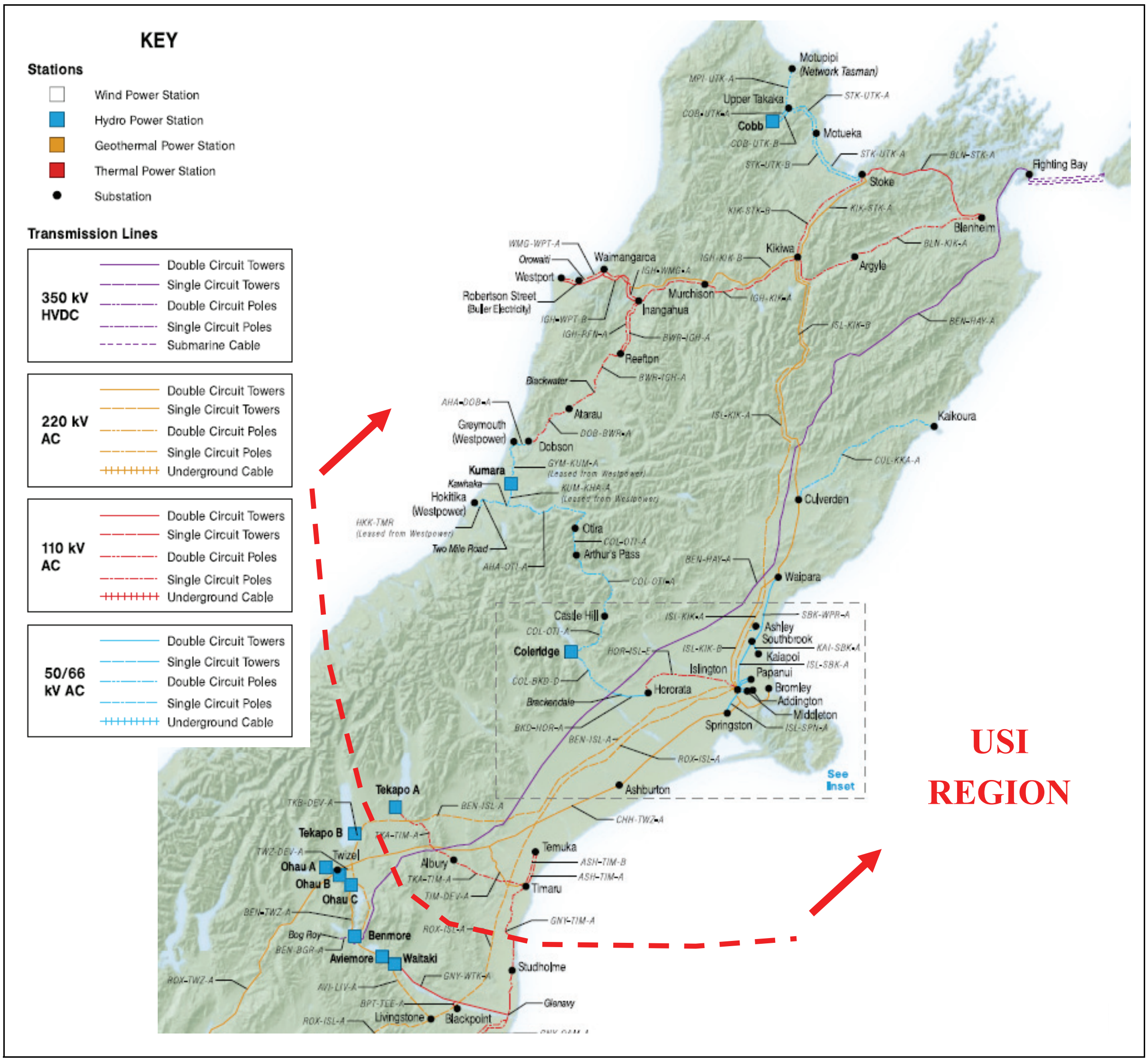


Figure 1 Upper North Island (UNI) Region



■ **Figure 2 Upper South Island (USI) Region**

2. Scope of Work

The scope of work, as outlined by the ENA, sought to cover the following:

1) Whether a minimum power factor of unity at peak times in the Upper North Island and Upper South Island is a more cost effective and economically efficient means of deferring transmission investment or reducing losses than a requirement of better than 0.95 lagging;
2) The extent to which the Electricity Commission's analysis is a robust justification for requiring unity power factor in the UNI and USI;
3) What the likely total cost would be of each UNI and USI DTC meeting the unity power factor requirement, and the associated benefit in terms of deferred transmission upgrades and reduced losses;
4) International practice on minimum power factor requirements (i.e. is there any other jurisdiction which requires a minimum power factor of better than 0.95 lagging, or which operates a market for reactive power); and
5) What an efficient minimum power factor requirement for New Zealand would be.

3. Existing GXP Power Factors

Appendix D outlines all the names of the GXPs in the UNI and USI regions.

Figure 3 and Figure 4 illustrate the reported power factors of the GXPs in the respective UNI and USI regions[1]. Table 1 and Table 2 illustrate the reported GXP loadings during regional peaks[1]. SKM notes the following:

- The average power factor (at regional peak) of the GXP's in the UNI region is 0.976.
- The average power factor (at regional peak) of the GXP's in the USI region is 0.973.
- There are ten GXPs within the UNI and UNI regions (13%) that are reported to operate at leading power factors during regional peak network loading.

Figure 5 through Figure 12 illustrate a set of loading data for eight randomly selected GXPs in the UNI and USI regions (four graphs for each region). The graphs demonstrate the following:

- The power factor of the load drawn by GXPs can vary significantly, in terms of active power.
- There are GXPs where the power factor varies significantly at similar active loadings, for example, the Albany GXP (Figure 6), which SKM believes is due to capacitor bank switching.
- There are GXPs with relatively good power factors during peak loading conditions, but during light loading conditions operate at significant leading power factors, for examples, Maungatapere (Figure 7) and Wellsford (Figure 8).
- There are GXPs with leading power factors for significant periods of time, for example Greymouth (Figure 12). SKM believes that this is the result of capacitor banks used to manage network voltages.

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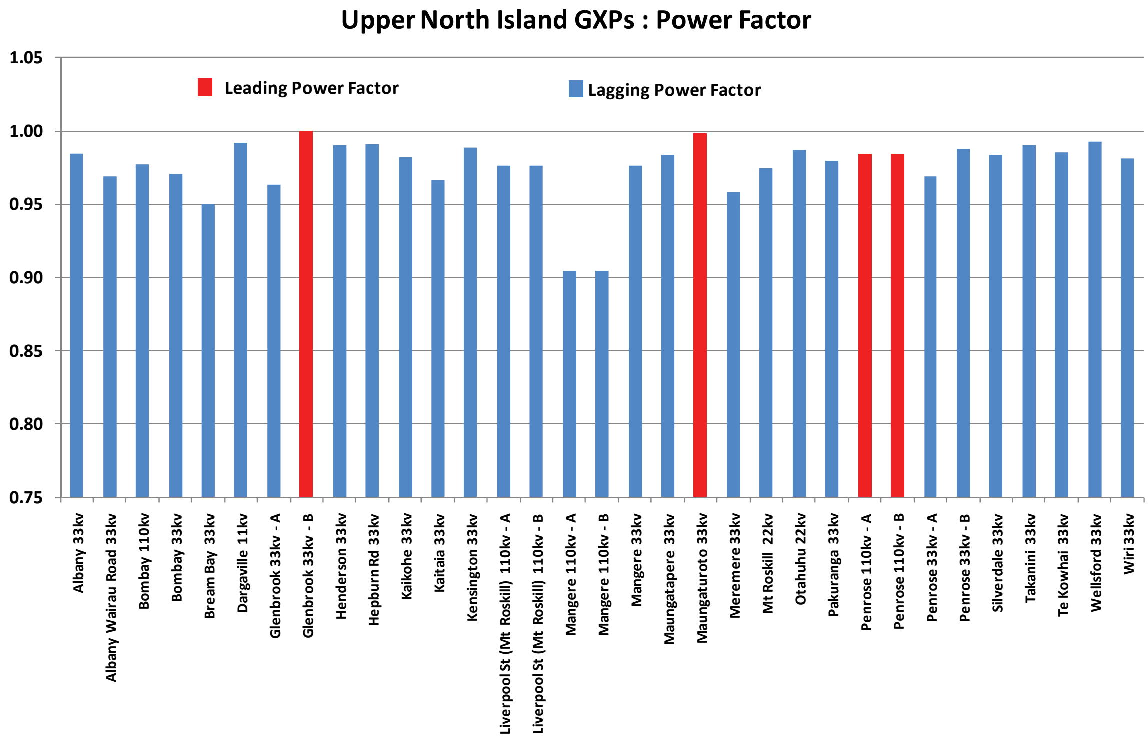
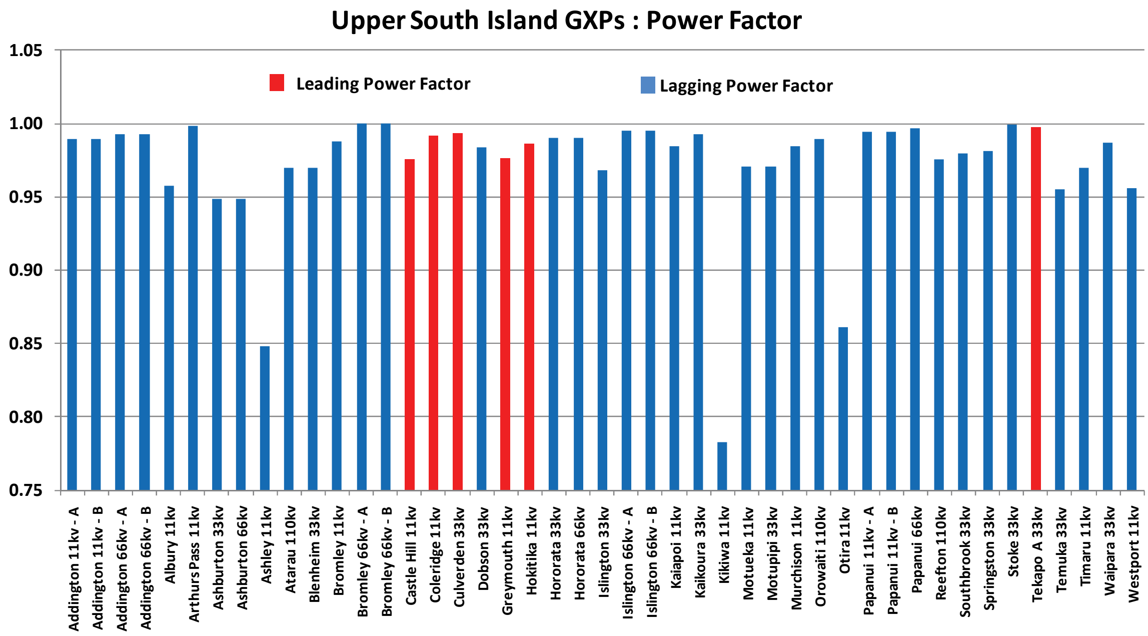
[1] Electricity Commission Demand Forecasts
Hhttp://www.electricitycommission.govt.nz/opdev/modelling/demand



■ **Figure 3 UNI GXP Power Factors: 2007: During Regional Peak Grid Loading**



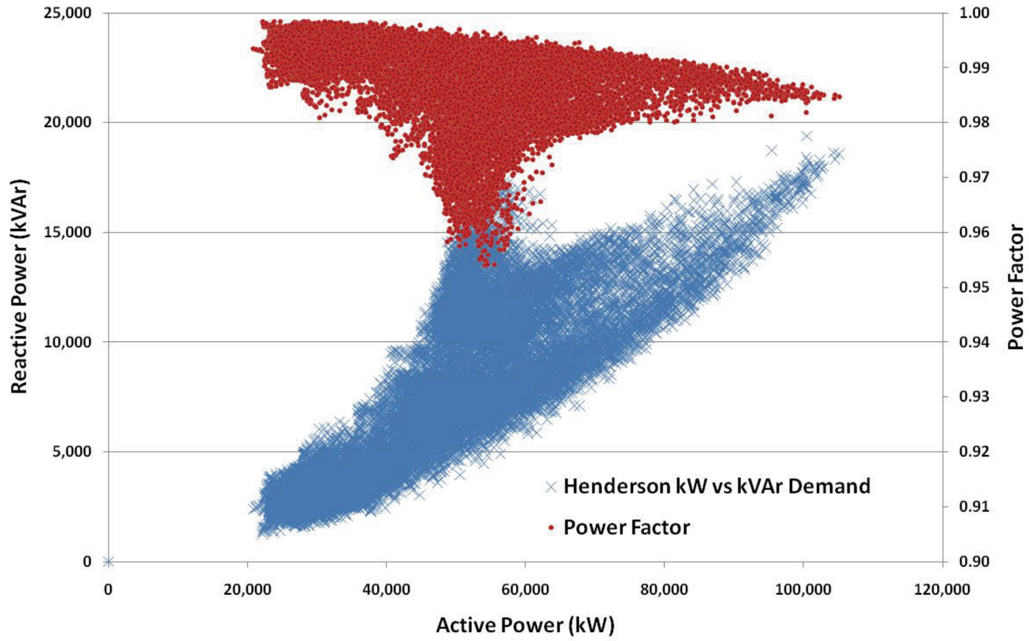
■ **Figure 4 USI GXP Power Factors: 2007: During Regional Peak Grid Loading**

- **Table 1 UNI Region: 2010 GXP Loadings**[1]

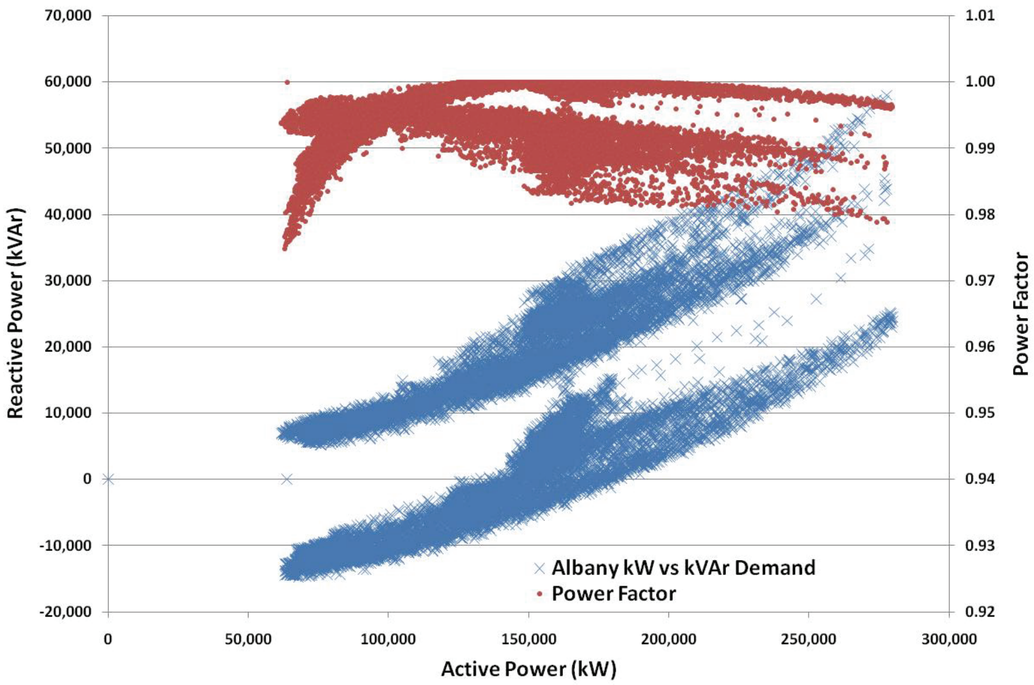
GXP Code	Description	MVA	MW	MVAr	PF
ALB_33	Albany 33kV	164	162	29	0.984
BOB_110	Bombay 110kV	51	50	11	0.977
BOB_33A	Bombay 33kV	25	24	6	0.971
BOB_33B	Meremere 33kV	8	8	2	0.959
BRB_33	Bream Bay 33kV	48	46	15	0.951
DAR_11	Dargaville 11kV	11	11	1	0.992
GLN_33A	Glenbrook 33kV - A	34	33	9	0.963
GLN_33B	Glenbrook 33kV - B	120	120	-3	-1.000
HEN_33	Henderson 33kV	110	109	15	0.990
HEP_33	Hepburn Rd 33kV	158	157	22	0.991
KEN_33	Kensington 33kV	54	53	8	0.988
KOE_33	Kaikohe 33kV	34	33	6	0.982
KTA_33	Kaitaia 33kV	28	27	7	0.966
LST_110A	Liverpool St (Mt Roskill) 110kV - A	104	102	22	0.977
LST_110B	Liverpool St (Mt Roskill) 110kV - B	85	83	18	0.977
MNG_110A	Mangere 110kV - A	28	25	12	0.904
MNG_110B	Mangere 110kV - B	28	25	12	0.904
MNG_33	Mangere 33kV	104	102	23	0.976
MPE_33	Maungatapere 33kV	49	48	9	0.984
MTO_33	Maungaturoto 33kV	15	15	-1	-0.999
OTA_22	Otahuhu 22kV	56	55	9	0.987
PAK_33	Pakuranga 33kV	149	146	30	0.980
PEN_110A	Penrose 110kV - A	99	98	-17	-0.985
PEN_110B	Penrose 110kV - B	81	80	-14	-0.985
PEN_33A	Penrose 33kV - A	74	71	18	0.969
PEN_33B	Penrose 33kV - B	305	301	47	0.988
ROS_22	Mt Roskill 22kV	118	115	26	0.975
SVL_33	Silverdale 33kV	71	70	13	0.984
TAK_33	Takanini 33kV	116	115	16	0.990
TWH_33	Te Kowhai 33kV	80	79	14	0.985
WEL_33	Wellsford 33kV	33	33	4	0.993
WIR_33	Wiri 33kV	74	73	14	0.981
WRU_33	Albany Wairau Road 33kV	182	176	45	0.969
	TOTAL	**2699**	**2647**	**430**	**0.98**

- **Table 2 USI Region: 2010 GXP Loadings[1]**

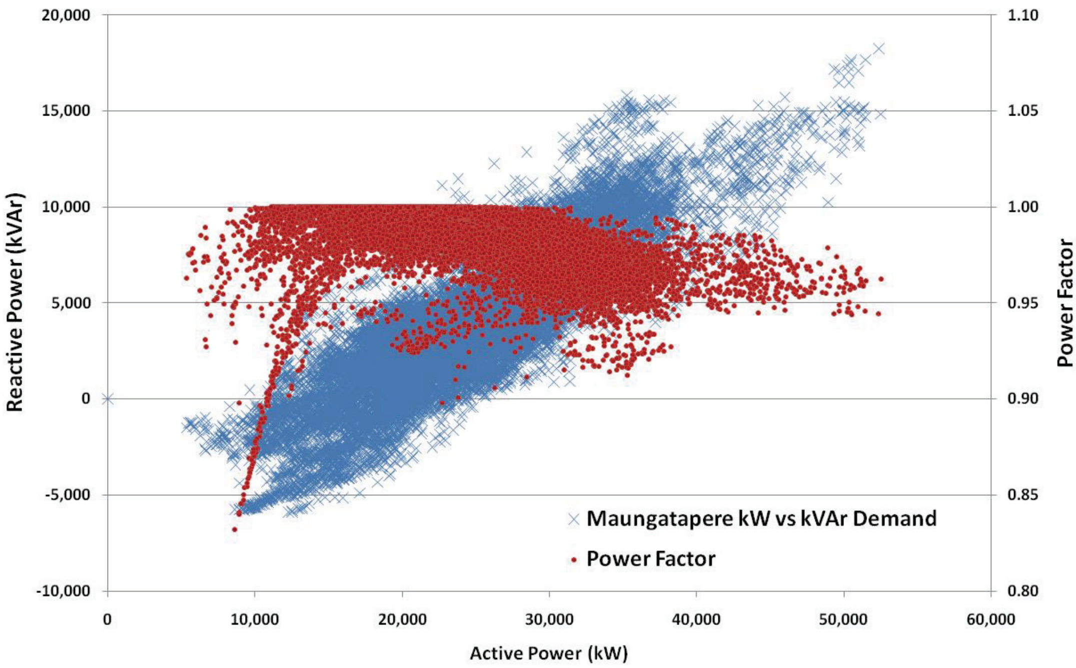
GXP Code	Description	MVA	MW	MVAr	PF
BLN_33	Blenheim 33kV	70	68	17	0.970
KIK_11	Kikiwa 11kV	4	3	2	0.782
MOT_11	Motueka 11kV	21	21	5	0.971
MPI_33	Motupipi 33kV	8	7	2	0.970
STK_33	Stoke 33kV	134	134	6	0.999
APS_11	Arthurs Pass 11kV	0	0	0	0.998
ATU_110	Atarau 110kV	16	15	4	0.970
CLH_11	Castle Hill 11kV	1	1	0	-0.976
DOB_33	Dobson 33kV	11	11	2	0.983
GYM_11	Greymouth 11kV	12	12	-3	0.000
HKK_11	Hokitika 11kV	19	19	-3	-0.977
MCH_11	Murchison 11kV	3	3	0	-0.986
ROB_110	Orowaiti 110kV	8	8	1	0.984
OTI_11	Otira 11kV	1	1	0	0.989
RFT_110	Reefton 110kV	9	8	2	0.861
WPT_11	Westport 11kV	10	10	3	0.975
ADD_11A	Addington 11kV - A	23	23	3	0.956
ADD_11B	Addington 11kV - B	46	45	7	0.989
ADD_66A	Addington 66kV - A	74	73	9	0.989
ADD_66B	Addington 66kV - B	74	73	9	0.993
ASB_33	Ashburton 33kV	52	49	16	0.993
ASB_66	Ashburton 66kV	68	64	21	0.949
ASY_11	Ashley 11kV	13	11	7	0.949
BRY_11	Bromley 11kV	62	61	10	0.848
BRY_66	Bromley 66kV - A	101	101	0	0.988
BRY_66_2	Bromley 66kV - B	25	25	0	1.000
CUL_33	Culverden 33kV	11	11	-1	1.000
HOR_33	Hororata 33kV	19	19	3	-0.992
HOR_66	Hororata 66kV	29	29	4	-0.993
ISL_33	Islington 33kV	90	87	23	0.991
ISL_66	Islington 66kV - A	84	83	8	0.991
ISL_66_2	Islington 66kV - B	21	21	2	0.968
KAI_11	Kaiapoi 11kV	21	21	4	0.995
KKA_33	Kaikoura 33kV	8	8	1	0.995
PAP_11A	Papanui 11kV - A	33	32	4	0.985
PAP_11B	Papanui 11kV - B	33	32	4	0.992
PAP_66	Papanui 66kV	45	45	4	0.994
SBK_33	Southbrook 33kV	36	36	7	0.994
SPN_33	Springston 33kV	45	45	9	0.997
WPR_33	Waipara 33kV	12	12	2	0.980
ABY_11	Albury 11kV	5	4	1	0.981
TIM_11	Timaru 11kV	68	66	17	0.987
TKA_33	Tekapo A 33kV	3	3	0	0.958
TKA_33	Tekapo A 33kV	53	51	16	0.970
	TOTAL	**1479**	**1451**	**226**	**0.981**



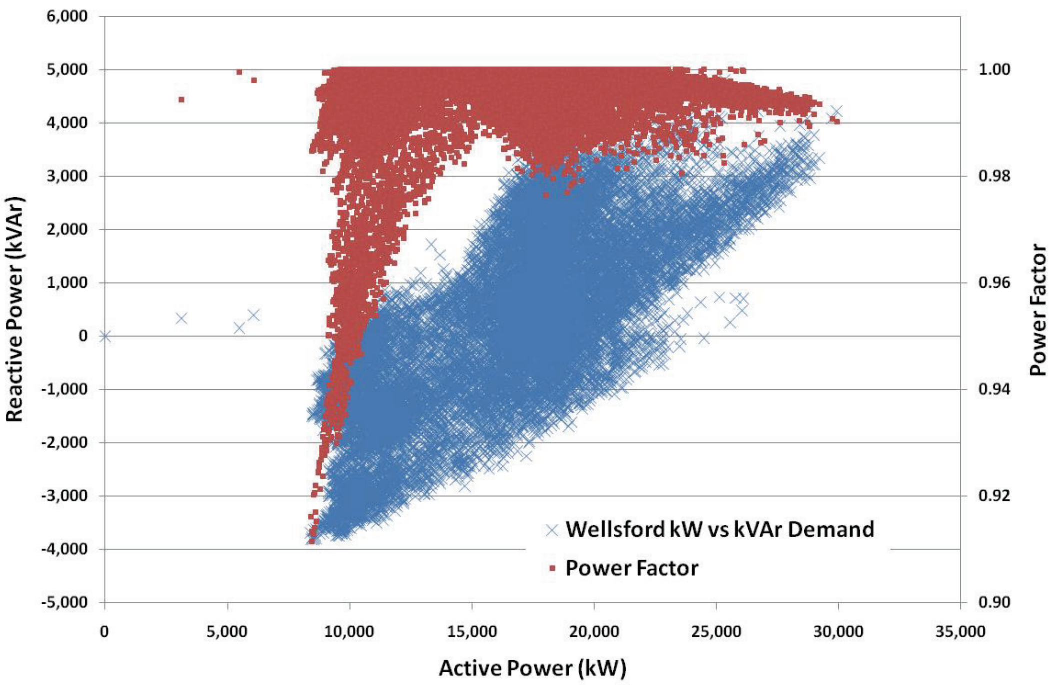
- **Figure 5 UNI: Henderson GXP: kW demand versus kVAr & Power Factor**



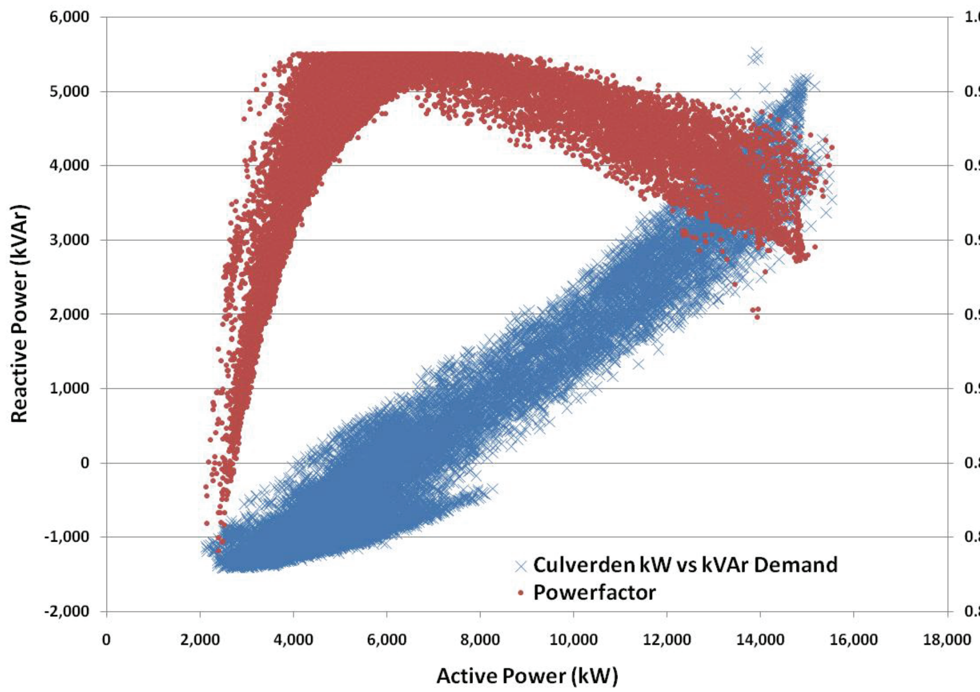
- **Figure 6 UNI: Albany GXP: kW demand versus kVAr & Power Factor**



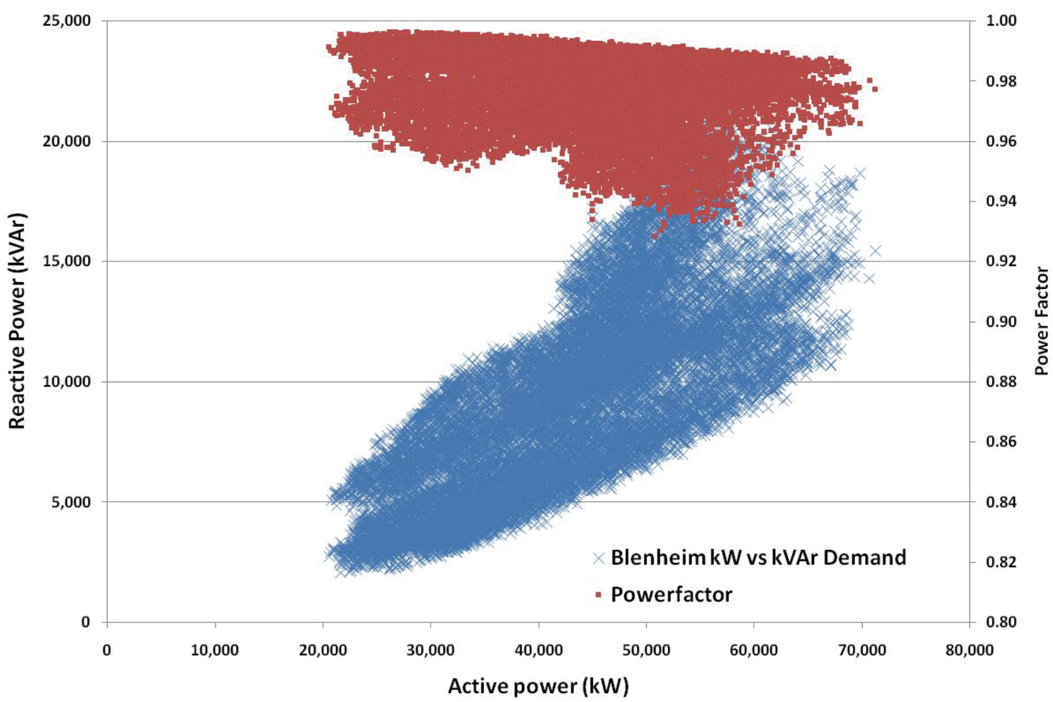
■ **Figure 7 UNI: Maungatapere GXP: kW demand versus kVAr & Power Factor**



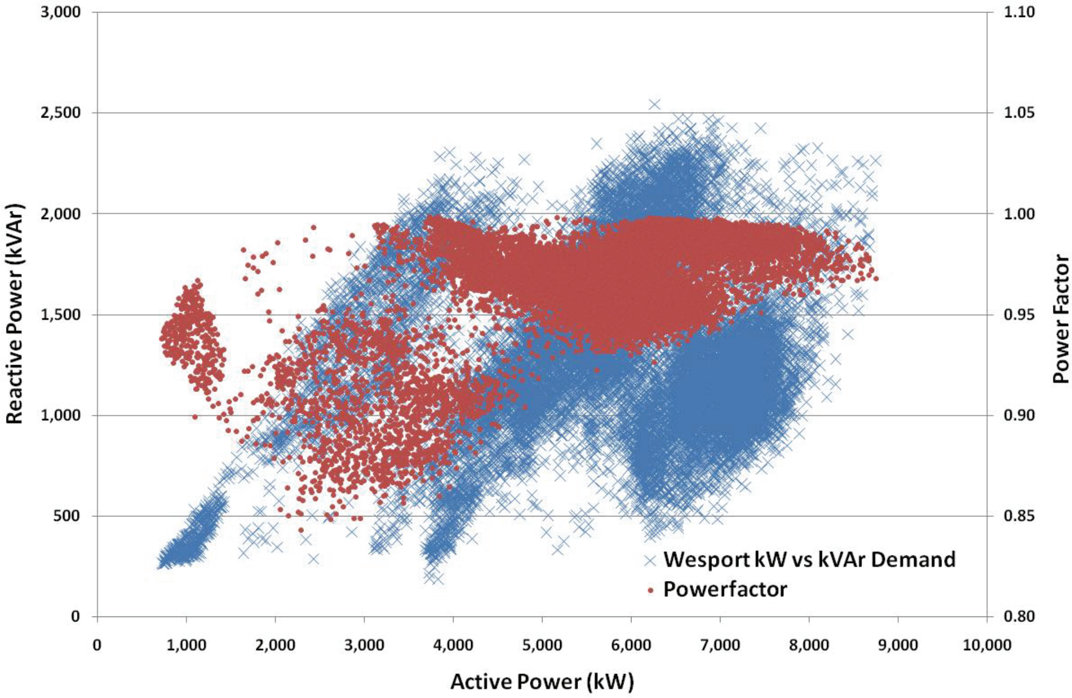
■ **Figure 8 UNI: Wellsford GXP: kW demand versus kVAr & Power Factor**



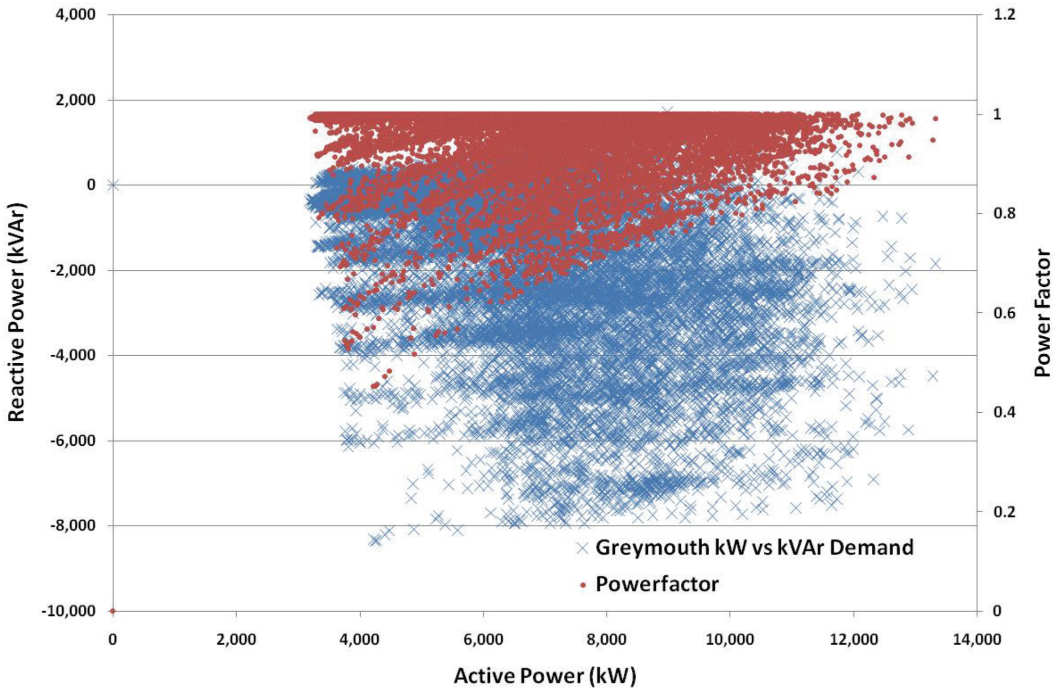
■ **Figure 9 USI: Culverden GXP: kW demand versus kVAr & Power Factor**



■ **Figure 10 USI: Blenheim GXP: kW demand versus kVAr & Power Factor**



- **Figure 11 USI: Westport GXP: kW demand versus kVAr & Power Factor**



- **Figure 12 USI: Greymouth GXP: kW demand versus kVAr & Power Factor**

4. International Practice on Minimum Power Factor

SKM has undertaken a review of international practice in relation to the power factor requirements of electrical utilities and industry regulators. The review has involved in internet search coupled with discussions with other SKM offices and contacts.

Table 3 summarises SKM's findings which shows the following:

- Most regulators/utilities enforce a minimum power factor to reduce the reactive power burden on the transmission system and manage system losses.
- Power factor requirements vary considerably (typically 0.8 to 1.0).
- Some regulators/utilities impose tariffs in relation to reactive power consumption
- There is evidence of regulators/utilities requiring off-take power to be drawn at unity power factor, but this is relatively unusual.
- Some utilities specify power factor requirement in connection agreements.
- Some regulators have relatively complex power factor requirements. For example, requiring the inter-area reactive power transfer to be zero during peak loading conditions for the worst case equipment outage (determined via simulation). Regional distributors are then required to maintain power factors at a prescribed calculated level during peak load condition. In a similar manner the required power factors are calculated at other network load levels as well (i.e. 10%... 90%).

There is clear evidence of other transmission authorities (grid codes) requiring grid off-take substations/loads to operate at close-to or unity power factor. However, there is also evidence of transmission authorities allowing power factors as low as 0.8.

SKM suspects that transmission authorities that allow low power factors operate relatively under-utilised transmission assets with little need to improve power factor. In contrast, those transmission authorities who specify off-take loads close to unity power factor have well utilised transmission assets and likely have relatively static electrical demand. These transmission authorities have opted to defer transmission investment via requiring unity power factor off-take loads (distribution connected capacitor banks).

In some jurisdictions the unity power factor requirement can be driven by the lack of network transformers equipped with on load tap changers (OLTC). In these systems the network voltages are primarily controlled using a large number of distribution connected capacitor banks. SKM has observed this situation in a number of jurisdictions, particularly where there has been significant North American network design influence.

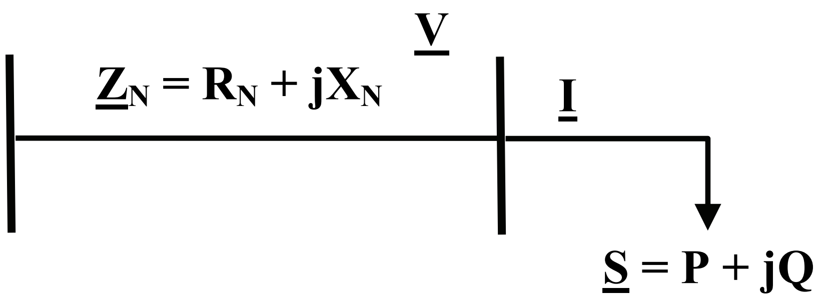
■ **Table 3 Minimum Power Factor Requirement**

Organization	Power Factor (peak load time)	Load level	Reference
Alberta Electric System Operator, Canada	> 0.9 lag,	Continuous	Ref (7)
Independent System Operator, New England, USA	~0.99 lag	At peak load	Ref (8)
Independent System Operator –New York, USA	Close to unity		Ref (9)
Western Electricity Coordination Council, USA	Close to unity		Ref (11)
Northeast Utilities, USA	unity	Any load cycle	Ref (12)
Central Electricity Regulatory Commission, India	Close to unity (at inter states grid interface) Discourage reactive power draw at customer level by - Beneficiary pays for VARs drawn when voltage at the metering point is below 97% - Beneficiary gets paid for VAR return when voltage is below 97% - Beneficiary gets paid for VAR draw when voltage is above 103%		Ref (13)
Energy Regulation Board Zambia	>0.92	Continuous	Ref (14)
NSW Government, Australia	>0.9 At customer level	Continuous??	Ref (15)
Victorian Government, Australia	>0.75 to 0.98 depending on the voltage level and load at customer level		Ref (16)
Department of Consumer & Employment Protection, Western Australia	>0.8 At customer level	At peak load	Ref (17)
ETSA Utilities, South Australia	>0.8 to 0.9 depending on the voltage and load at customer level		Ref (18)
Electricity and Co-generation Regulatory Authority, Saudi Arabia	>0.85	Any time	Ref (19)

Organization	Power Factor (peak load time)	Load level	Reference
National Electric Power Regulatory Authority, Pakistan	>0.95	Any time during system normal	Ref (20)
Electricity Regulatory Commission, Philippines	>0.85		Ref (21)
National Grid, UK	None defined.		Ref (22)
Westernpower, Australia	> 0.8, 0.9, 0.95, 0.96 Depending on voltage level	Half-hourly average	Ref (23)
Australian Energy Market Company	As per connection agreements (Refer to Appendix B)		Ref (24)

5. Network Loss Reduction: Theory vs Practice

SKM believe it is useful to consider the theoretical effects that power factor has on the upstream network losses. This may be demonstrated by considering the simple network supply arrangement illustrated in Figure 13, which consists of two busbars, an interconnecting transmission line and an electrical load.



- **Figure 13 Demonstration Network**

Figure 13 illustrates an apparent load $\underline{S}$ (MVA) that consists of active and reactive components P (MW) and Q (MVAr). The load is supplied via a network with an impedance $\underline{Z}_N$ which consists of resistive and reactive components R_N and X_N. If one assumes that the voltage applied to the load $\underline{V}$ is constant[2] then the following is true:

$$\underline{S} = P + jQ \quad \text{and} \quad \underline{I} = \underline{S} / \underline{V}$$

Assuming $\underline{V} = V\angle 0^{o}$ then:

$$\underline{I} = (P + jQ) / V \quad \text{and} \quad I^2 = (P + jQ)^2 / V^2 = (P^2 + j2PQ - Q^2) / V^2$$

The network losses can then be calculated to be:

$$\text{Network Losses} = I^2R_N = R_N \text{ x } (P^2 + j2PQ - Q^2) / V^2$$

If V and R_N are assumed to be constant then the network losses have the following proportional relationship to the off-take active and reactive load:

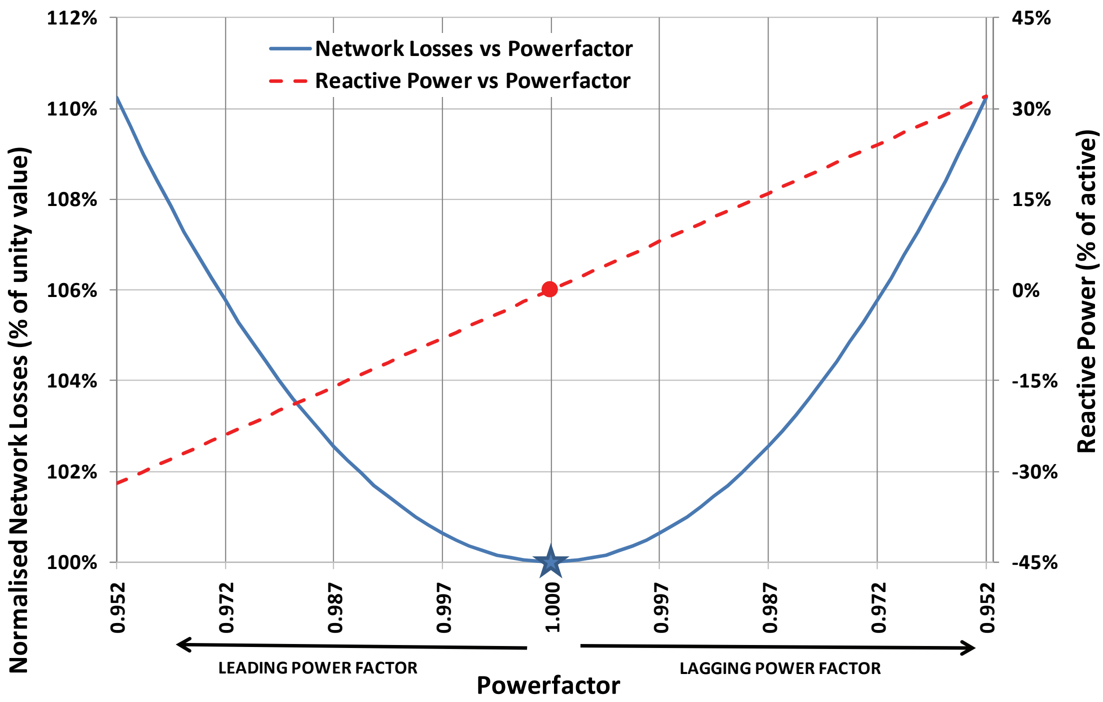
$$\text{Network Losses} \propto \sqrt{((P^2 - Q^2)^2 + (2PQ)^2}$$

[2] It could be argued that this is physically the case given that zone substations are generally equipped with on-load tap changers (OLTC).

Using the above equation it is possible to plot Figure 14 which illustrates the relationship that an off-take load's power factor & reactive power have on the upstream network losses.

Figure 14 shows that (in theory):

- Allowing a load's power factor to slip from unity to 0.97 and 0.95 (leading or lagging) will increase network losses by approximately 5% and 10% respectively.
- The loss reduction benefits associated with power factor improvement are not linear (i.e. not a one to one relationship) and as the power factor approaches unity the incremental loss reduction (with power factor improvement) reduces.
- Given the respective UNI and USI power factors outlined in Section 3 (0.976 and 0.973 respectively) a maximum theoretical loss reduction of approximately 5% at system peak might be expected.



- **Figure 14 Normalised Network Losses as a function of PF and VAR consumption**

SKM have then proceeded to "confirm" the above theoretical system peak loss reduction conclusions using the North Island and South Island grid models[3]. SKM's thinking here was to:

- Confirm the benefits associated power factor improvement in the UNI and LNI regions.
- Capture/highlight any issues that might prevent the loss reductions being accrued.

The results of SKM's investigations are illustrated in:

- **Table 4;** outlines the North Island (NI) generation, load and network losses for the following three case:
  - *Case A*; The existing NI peak demand case.
  - *Case B*; The existing NI peak demand case but with the GXP loads in the UNI region operating at unity power factor.
  - *Case C*; identical to Case B but with 130MVAr of capacitor banks switched out at the Transpower Henderson and Albany substations.

- **Table 5**; outlines the South Island (SI) generation, load and network losses for the following three case:
  - *Case A*; The existing SI peak demand case.
  - *Case B*; The existing SI peak demand case but with the GXP loads in the USI region operating at unity power factor.

- **Table 4 North Island: Generation/Loading/Losses: Existing & Unity PF in UNI Region**

Item	Existing NI Power factors		Unity Power Factor in UNI			
	Case A		*Case B*		*Case C*	
	MW	MVAr	MW	MVAr	MW	MVAr
Generation	3958.08	198.41	3958.08	-77.46	3958.91	-11.32
Load*	3830.28	1061.37	3830.28	714.30	3830.28	714.30
Losses	127.80	404.88	128.11	417.55	127.63	400.37
ΔLoss	-	-	**+0.31**	**+12.67**	**-0.17**	**-4.51**
ΔLoss (%)	-	-	**+0.2%**	-	**-0.1%**	-

* Approximately 55% of the peak demand due to UNI GXPs

[3] These models were sourced from the Centralised Data Set (CDS) available from the Electricity Commission.

- **Table 5 South Island: Generation/Loading/Losses: Existing & Unity PF in USI Region**

Item	Existing SI Power factors		Unity Power Factor in SI	
	Case A		*Case B*	
	MW	MVAr	MW	MVAr
Generation	3086.40	358.31	3085.47	230.75
Total Load*	2965.26	773.70	2965.26	599.25
Losses	120.98	380.99	120.12	359.09
ΔLoss	**-**	**-**	**-0.86**	**-21.9**
ΔLoss (%)	**-**	**-**	**-0.7%**	

* Approximately 40% of the peak demand being due to USI GXPs

The above summarised power flow investigations demonstrate:

- The difficulty associated with managing network voltages whilst operating the transmission grid close to unity power factor in order to reduce network losses.
- The USI transmission network (as opposed to GXP loads) is relatively well compensated. If network loss reduction is a key driver, the proposed improvement of GXP power factors during system peak will likely require some existing grid connected capacitor banks being switched out. SKM expects the grid connected capacitor banks will still be required to support network voltages during contingency situations.
- The difficulty associated with securing network loss reductions if switched capacitor banks (grid or distribution connected) are not sized with network loss reduction in mind (i.e. switched bank sizes not small enough).

Figure 14 illustrates that if off-take power factors are improved from 0.97 to 1.00 then the peak network loss reduction might be around 5%. However this is the loss reduction during peak loading conditions. If one considers that network loading varies from hour to hour and from season to season it is possible to estimate the network losses based on the use of a classical formulae called the Load Loss Factor (LLF) which is as follows:

$$LLF = a \times LF + b \times LF^2$$

Where: LF = Load Factor (typically 0.5 for the NZ loads).

Constants a and b are selected based on the load profile (typically chosen to be 0.3 and 0.7 respectively).

If one uses the above factor one arrives at an annual loss reduction of:

$$(0.3 \times 0.5 + 0.7 \times 0.5^2) \times 5\% \approx 1.6\%$$

Or, based on SKM's load flow results in Table 4 and Table 5, one can generate an indicative annual cost saving due to loss reduction in the UNI and USI regions as follows:

- **Table 6 UNI & USI Regions: Approximate Loss Reduction Cost Saving**

Region	Peak Network Loss Reduction (MW)	Annual Losses[1] (GWh)	Annual Loss Saving[2] (NZ$)
UNI	0.2	2	NZ$100k
USI	0.9	9	NZ$450k

[1] Based on a load factor (LF) of 0.5 and a load loss factor (LLF) of 0.33

[2] Based on an energy cost of $0.05/kWh

If one considers the total UNI and USI cost savings outlined in Table 6 (NZ$100k + NZ$450k) coupled with additional distribution network loss savings[4] the capitalised savings associated with loss reduction would be of order of 20 x NZ$550k/annum ≈ **NZ$10M**. However, SKM notes that the estimate should be viewed as being indicative and that the actual losses will depend on a number of factors, for example, grid operational requirements, energy costs, and capacitor installation locations & control.

[4] If capacitor banks are installed embedded within the distribution systems (i.e. at 11kV) additional distribution network loss reduction will be achieved, which is not accounted for in Table 6.

6. Reactive Power: Equipment Costs

Table 1 and Table 2 outline the collective reactive power off-takes within the UNI and USI regions to be 430MVAr and 230MVAr respectively. However, given that **each GXP** needs to operate at unity power factor Electrical Distribution Businesses (EDB) would need to provide both leading and lagging power factor compensation and involve 697MVAr (capacitive) and 41MVAr (inductive) respectively. In order to simplify things SKM have assumed 740MVAr of capacitive compensation equipment would be required.

In order to estimate the capital costs associated with 740MVAr of distribution connected capacitor banks SKM have:

- Secured equipment cost estimates from multiple capacitor bank suppliers.
- Used other internal SKM capacitor banks cost estimates, where available.
- Considered a range of connection location options (i.e. outdoor pole mounted 11kV vs indoor 33kV.
- Assumed that the capacitor banks would be installed as small independent projects and not as a large programme of works for which there would likely deliver efficiencies.
- Not considered the marginal benefits associated with locating capacitor banks closer to consumer loads[5].

Appendix A contains a set of per MVAr costs that that have been estimated by SKM which vary from \$34k/MVAr through \$95k/MVAr depending on the location of the banks (11kV pole mounted un-switched vs 33kV substation connected switched). Given the approximate nature of the cost estimates SKM coupled with the need to (i) control the capacitor banks in appropriately selected sizes and (ii) manage ripple injection signals, SKM believes that an average per-unit cost of NZ\$100k/MVAr[6] is reasonable. This means that costs associated with elevating existing GXP power factors to unity would be approximately:

740MVAr x NZ\$100k/MVAr ≈ **NZ\$75M**[6]

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[5] The loss reduction and voltage support benefits associated with, say, a 1MVAr capacitor bank are greater when connected at 11kV as opposed to 33kV. This means that to deliver the equivalent benefits a smaller capacitor bank size is required at 11kV than at 33kV.

[6] Appendix A clarifies the accuracy and assumptions associated with this estimate. SKM notes that:

- Ref (6) estimated the 2004 installed reactive power compensation costs to be ≈A\$55k/MVAr.
- Ref (10) estimated the 2009 installed reactive power compensation costs to be US\$20k/MVAr to US\$50k/MVAr.
- SKM's cost estimate is at the higher end of the estimates outlined in Appendix A on the basis that we expect a significant number of switched capacitor banks.

7. Transmission Investment: Long-run Costs

The costs associated with transmission investment tend to be very specific and are relatively lumpy and costly. The examination of the details associated with the individual transmission investments in the UNI and USI regions is beyond SKM's scope of work. We specifically note that Transmission projects typically involve large lumps of capital expenditure (not small increments) and the "final answer" can only be delivered by examining all the future transmission upgrades planned for the UNI and USI regions. However, a conservative estimate of the costs associated with transmission investment can be obtained by considering the long-run costs associated with transmission investment based on the existing Transmission asset base and demand levels.

Table 7 outlines the estimated replacement costs of the existing New Zealand transmission system.

- **Table 7 Transpower: 2006 Network Valuation: Replacement Cost[7]**

Item	RC (NZ$'M)
AC Stations	$2,258M
AC Transmission Lines	$2,027M
HVDC Systems	$1,058M
Communications	$175M
Subtotal: System Fixed Assets	**$5,545M**
Other Assets Total	$482M
TOTAL	**$6,027M**

If one considers that the peak loading of the grid during 2006 was approximately 6.4GW[8] the long run cost of transmission capacity can be estimated to be NZ$6,027M/(6.4GW) ≈ NZ$1000/kW ≈ NZ$1000/kVA [9].

[7] Transpower 2006 Asset Valuation dated June 2006 (Hhttp://www.transpower.co.nz/n1260.htmlH)
[8] "Peak Electricity Demand Nationally", Electricity Commission, Hhttp://www.electricitycommission.govt.nz/opdev/modelling/wip/cdswebinterface/peak-electricity-demand-nationally
[9] SKM considers this value to be a conservative (costs expected be higher) but a useful indicator. Due to approximate nature of the value it has not been inflated to present day. Furthermore, the estimate could be viewed to be high due to the inclusion of the HVDC costs. In contrast the costs could be viewed to be low due to the exclusion of consenting costs.

8. Capacitor Banks vs Transmission Investment

Whilst relatively simplistic, if one is seeking to secure more transmission capacity in the UNI and USI regions the provision of additional capacity could be achieved via (i) the installation of transmission assets or (ii) improving load power factors at GXPs.

Table 1 and Table 2 illustrate the loadings in the UNI and USI regions, which indicate that, the GXP loads are collectively operating at a power factor of 0.98 during regional peaks. Also, that if the GXP load's are compensated to unity power factor the MVA loadings on the respective UNI/ LNI regions will reduce from approximately 2,699MVA/1,479MVA to 2,647MVA/1,451MVA. This translates to a collective reduction in load of 80MVA, or an increase in "network capacity margin" available for demand growth.

Section 6 estimates the costs associated with capacitor banks to facilitate this "additional capacity margin" to be **NZ$75M**[10].

In contrast the equivalent cost associated with the provision of 80MVA of "long run" transmission network capacity can be estimated (from Section 7) to be NZ$1,000/kVA x 80MVA ≈ **NZ$80M**[11].

Both capacitor bank installation and transmission enhancement are likely to reduce network loading and thus reduce network losses. In the case of capacitor bank installation Section 5 estimates the capitalised value of loss savings to be around **NZ$10M**.

Given the approximate nature of the above cost estimates it would be sensible to conclude that the economic viability of the two options (reactive compensation versus transmission enhancement) are relatively close (for power factors 0.98 to 1.0). Furthermore there are a number of additional factors that may influence the decision making process, as follows:

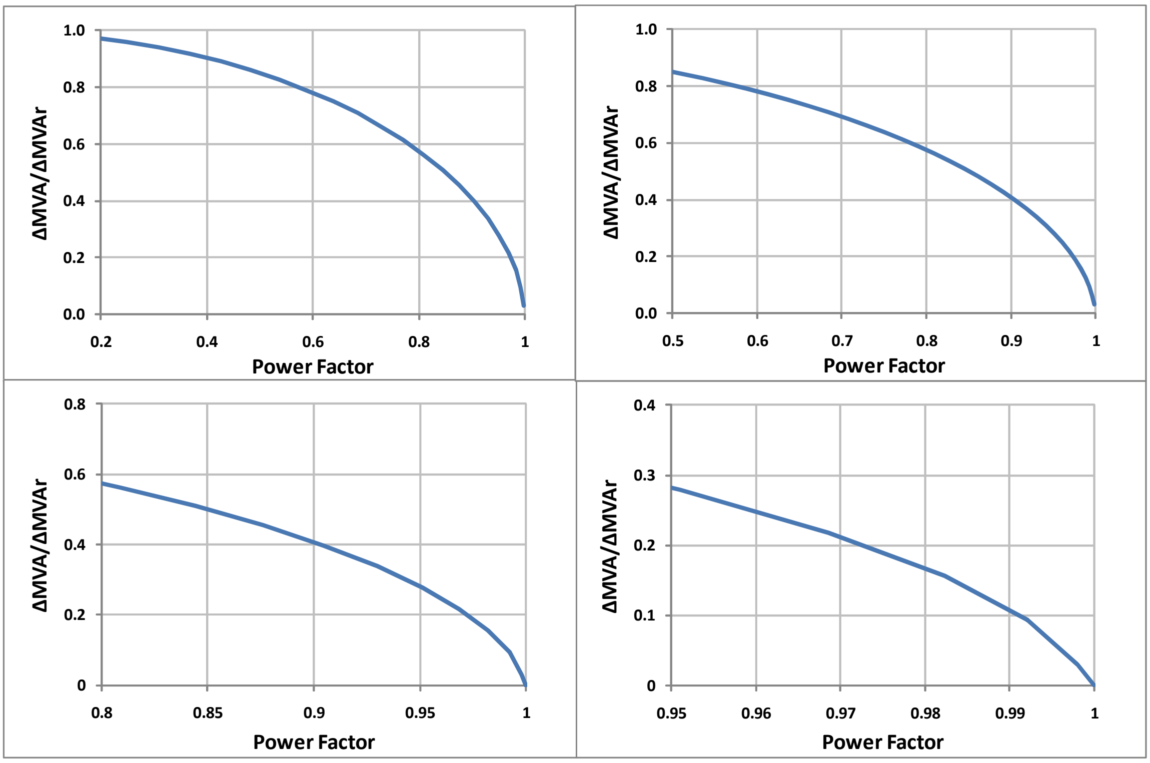
- The installation of new transmission lines has the potential to have significant lead times and cost uncertainty.
- Reactive power compensation, at the distribution level, tends to be more "scalable" than large transmission projects.
- Improving power factors in the UNI and USI regions to unity will defer transmission expenditure by only approximately one year and the deferral of transmission reinforcement may not be economic.

[10] Based on a set of generic capacitor bank cost estimates and should only be considered to be indicative.
[11] Based on long run transmission costs and should only be considered to be indicative.

There are a significant numbers of examples/papers detailing power factor improvement initiatives that have delivered significant value (i.e. Ref 26). However, these cases involve situations where the existing power factors are well below 0.95.

The relative network capacity release benefits that are associated with the installation of capacitor banks are demonstrated in Figure 15 which shows the ratio of (network capacity release in MVA) to (capacitor bank installation in MVAr) as a function of a network's power factor. Note that Figure 15 shows four different views of the same curve, but with different x-axis. Figure 15 shows that, for a fixed MW load operating at a power factor of 0.2 (top left), the incremental rate of capacitor bank installation (MVAr) to capacity release (MVA) is effectively 1.0. In contrast, when operating at a power factor of 0.99 the incremental rate of capacitor bank installation to capacity release drops to 0.1 (bottom right). In other words, from a capacity release perspective, the economics of installing capacitor banks are ten times less attractive at a power factor of 0.99 than at a power factor 0.2.

Figure 15 clearly demonstrates that the benefits associated with improving GXP power factors from 0.95 to 0.97 (≈0.25MVA capacity release per 1MVAr of capacitance) are significantly higher than that from 0.97 to 0.99 (≈0.15MVA capacity release per 1MVAr of capacitance).



- **Figure 15 Network Capacity Release: Power Factor vs ΔMVA/ΔMVAr**
(same curve for each graph but with different x-axis)

9. EC Documentation

SKM has the following comments in relation to whether the EC documentation constitutes a robust argument:

- The most sensible/economic VAR source available to EDBs are fixed and switched capacitor banks. These are discrete items and thus the provision of exactly unity power factor will not be achievable and the outcome will be a leading or lagging power factor. The intent appears to signal to EDBs that GXPs must operate with leading power factors during peak loading periods. It would seem sensible and pragmatic to require a minimum power factor value of somewhere between, 0.95 and 0.98 lagging.
- The practicality of controlling individual capacitor banks to meet the 0.95 power factor requirement during *regional peaks* is questionable. SKM expects that the supply of an instantaneous regional peak loading signal (via SCADA) to Electricity Distribution Businesses (EDBs) coupled with the control systems to facilitate capacitor bank control will be costly. Having said this, SKM notes that, given the information published by the EC (referenced in Section 3), the majority of GXPs in the UNI and USI appear to be meeting the 0.95 power factor requirement.
- Section 3.2 of Ref (1), titled "*Problem being Addressed*", appears to take for granted that unity power factor at GXP's **will** deliver the most the efficient outcome. There is no consideration of whether this target is a sensible and efficient outcome. SKM suspects that the reason for this is the belief that the analytical work outlined in Appendix 4 of Ref (1) clearly demonstrated that distribution capacitor banks are extremely economic (this Appendix is discussed below). As a result Ref (1)'s starting position appears to be that power factor improvement (or VAR sources) within the distribution networks is required. We would have thought that *the problem to be addressed* is wider than considered and that the USI and UNI regions are capacity constrained and the options are, for example, demand management, reactive power sources or transmission investment.
- Section 4.4 of Ref (2), titled "*Options*", considers four options as follows:
    a) The Connection Code option
    b) The market option
    c) The administered charge option, and
    d) The no-obligation option

  All the above options are seeking to secure more reactive power sources, again on the basis that improving grid power factors at GXPs is the most cost effective solution.

- Appendix 4 of Ref (1) concludes that distribution capacitors are extremely economic and infers this to be the case up to GXP power factors of 0.99. Whilst SKM believes that analytical methodology is generally sensible we believe the input data is flawed. In order demonstrate our argument we have recreated the analysis contained within Appendix 4 of Ref (1). This is illustrated in Figure 16 and effectively constitutes "the EC view". SKM believe that the EC have overstated the network losses by using a distribution resistance of 0.078 p.u. The annual disclosures of EDBs outline an average loss ratio of 4.5% (Ref 32). We expect that the loss value used is reflective of the entire distribution asset and includes, for example, non-technical losses, 0.4kV conductor losses and 11/0.4kV transformer losses. The network losses through the low voltage system contribute a significant amount to entire network losses faced by an EDB. Furthermore SKM's experience is that the opportunities to install 11kV capacitor banks within an electrical distribution are generally close into zone substations, if not at 33kV. Given these facts SKM is of the view that a distribution resistance closer to 0.02 p.u. is more sensible. We also note that Appendix 4 of Ref (1) assumes a capacitor bank cost of $34,690/MVAr. SKM believe that this value is generally too low and reflective of fixed bank 11kV capacitor installations. Figure 17 illustrates the EC methodology using an updated distribution resistance, and which infers that fixed bank capacitors are economic up to a power factor of 0.96. SKM notes that the analysis does not include the transmission resistance. Assuming that the collective transmission and distribution resistance is 0.03 p.u.[12] the EC methodology delivers the result outlined in Figure 18. Figure 18 infers that if one only considers the benefits associated with electrical loss reduction $50k/MVAr capacitor bank installations are economic up to a power factor of 0.95.

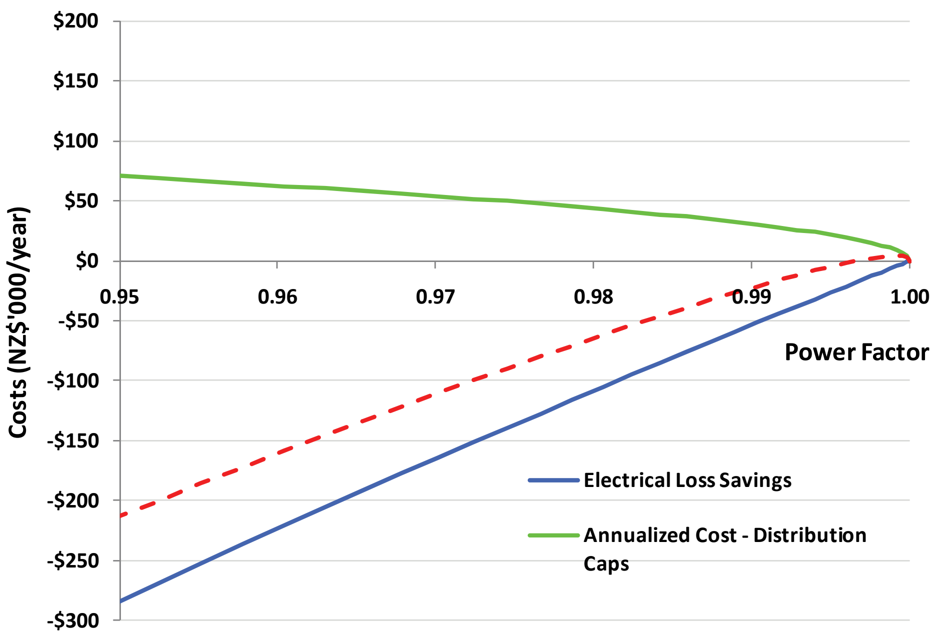
- For comparative purposes SKM have used an optimum capacitor calculation methodology outlined in Ref (33). Some of the details of this methodology (and SKM's input assumptions) are outlined in Appendix C. Figure 19 summarises SKM's conclusions using this methodology across the entire electrical distribution network. This figure pertains to a load of 1kW over the power factor range of 0.9 to 1.0. For each power factor Figure 19 shows the optimum/economic capacitor compensation for the following scenarios:
  - Low capacitor compensation costs and high energy costs (green line)
  - High capacitor compensation costs and low energy costs (red line)

  The blue area between the green and red lines encapsulates the optimum compensation for the capacitor and energy costs between the above two scenarios. For example, if capacitor costs are NZ$75k/MVAr and energy costs are NZ$0.075/kWh the methodology indicates that capacitor compensation above approximately 0.92 is not economic. In contrast for capacitor/energy costs of NZ$25k/MVAr/NZ$0.125/kWh compensation up to approximately 0.98 is economic. Given the analysis undertaken coupled with the variability of the input variables (particularly capacitor and energy costs) SKM considers that the methodology

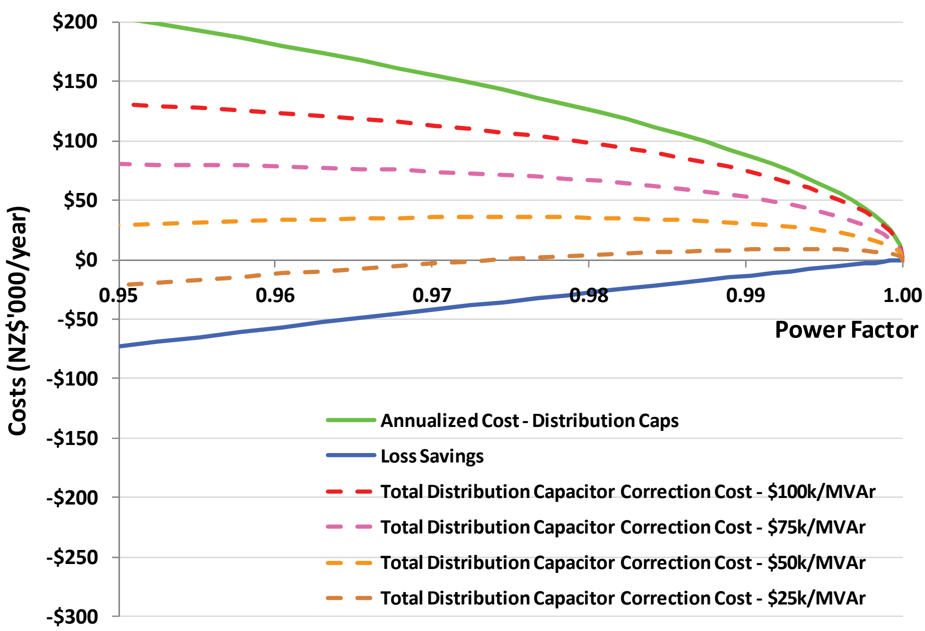
[12] A transmission resistance of 0.01p.u. is believed to be conservative. Table 4 and Table 5 outline possible peak transmission loss (not resistance) reductions of between 0.1% and 0.7%.

indicates that, in the New Zealand EDB context, a power factor of 0.95 is a sensible target value. We specifically note that the comparative calculations undertaken by SKM (methodology outlined in Appendix C) are based on locating power factor correction close to consumer loads (in the same manner as that done by the EC) and thus all distribution losses. In the case that power factor correction equipment is not located close to consumer loads (many of which take supply at 0.4kV) the economic viability reduces significantly.

- We noted during our investigations that if GXPs in the UNI and USI regions operated at unity power factor a number of the grid connected capacitor banks needed to be switched out in order to ensure electrical losses did not increase. SKM has not found any EC documentation that considers the practicality of what is proposed and to what extent existing grid connected capacitor banks may be stranded and/or need to be relocated. Given the issues associated with over voltages during light loading periods (as highlighted in Ref 1) it would appear sensible to consider (and provide guidance) regarding power factors during light loading conditions. This issue may impact on existing EDBs whose GXPs operate at leading power factors during light loading conditions.
- The EC documentation does not appear to consider the efficiency associated with the multiple EDBs (within the USI & UNI regions) individually engineering and procuring capacitor bank installations. In some situations a centralised capacitor bank solution is likely to be more cost effective that requiring unity power factor at all GXPs.
- The EC does not appear to have considered the different profiles associated with the UNI and USI GXPs. It is SKM's experience that in built up urban or central business locations the costs associated with installing capacitor banks increases significantly due to land/space and consenting issues (over and above those outlined in Appendix A). SKM expects that in these cases the economics of the unity power factor GXP requirement will become very questionable.
- We note that the benefits associated with the proposed move to unity power factor are effectively changed subsequent to transmission reinforcement. Given the planned transmission expansion we believe that these costs and benefits should be included.

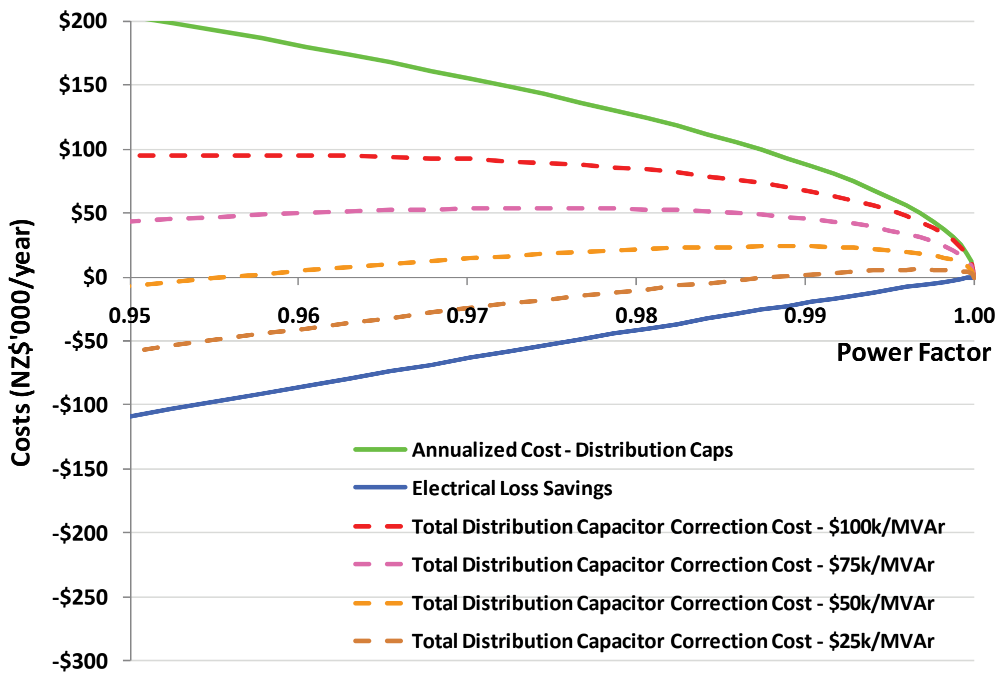


■ **Figure 16 Annualised Costs Associated with Distribution Capacitor Banks: EC view**[13]

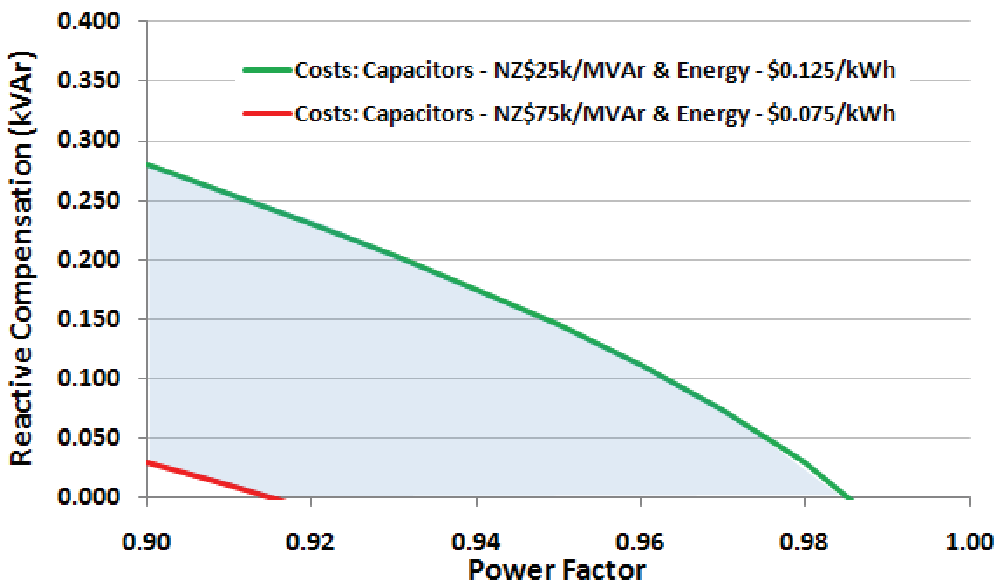


■ **Figure 17 Annualised Costs Associated with Distribution Capacitor Banks: SKM View: Distribution Resistance of 0.02 p.u.**

[13] This figure is a replication of Figure 2 in Appendix 4 of Ref (1) and demonstrates the validity of SKM's reproduction of the methodology used.



- **Figure 18 Annualised Costs Associated with Distribution Capacitor Banks: SKM View: Distribution & Transmission Resistance of 0.03 p.u.**



- **Figure 19 Economic Capacitor Compensation: Ref (33): Refer to Appendix C**

10. Conclusion/Discussion

Based on investigations undertaken SKM has concluded the following:

- At system peak the average power factor of the GXP's in both the UNI and USI regions is 0.98.
- The characteristics of the UNI/USI GXP power factors vary widely. A general feature is that power factors (and reactive power demands) are not tightly controlled.
- The requirements of international transmission authorities, in relation to power factor, vary widely. However, there is clear evidence of other transmission authorities (grid codes) requiring grid off-take substations/loads to operate at close-to or unity power factor. There is also evidence of transmission authorities allowing power factors as low as 0.8.
- The costs associated with meeting the unity power factor requirement in the UNI and USI regions are collectively estimated to be **NZ$75M**.
- The capitalised cost savings associated with electrical loss reduction within the transmission system due to capacitor bank installation are estimated to be approximately **NZ$10M**. The following factors will vary the savings:
  - The size of the capacitor banks and the switching regime employed.
  - The location of the capacitor banks (i.e. 11kV vs 33kV).
- The existing GXPs in UNI and USI regions are, on average, operating at a very cost effective level, and the long run cost to reinforce the transmission grid in the USI and UNI is comparable to the cost to install reactive compensation within the distribution network to facilitate a power factor improvement from 0.98 to 1.00 at GXPs.
- The EC's economic evaluation of capacitor bank installations:
  - Overstated the extent of distribution resistance.
  - Under estimated the costs associated with capacitor banks (due to switching costs).
- If one only considers the benefits associated with network loss reduction then a sensible target power factor for New Zealand EDBs would be $\approx$0.95.

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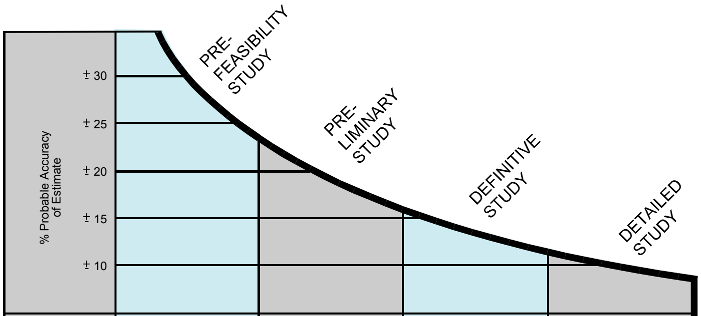
Appendix A VAR/Capacitor Bank Costs

SKM has assessed a set of generic costs to install capacitor banks at different voltage levels and different locations. These costs have been obtained for use with the high level analysis undertaken by SKM and which is presented in the main body of the report (i.e. for comparison with transmission investment). We note that the costs are based on generic installations and as such are only indicative. Also that cost estimates for projects are prepared at various stages of development of a project from the feasibility stage through to detailed estimates prior to construction. In general there are four stages in project development (i) investigation and planning stage, (ii) pre-design (concept) stage, (iii) pre-tender stage, and (iv) construction stage. The following diagram is illustrative of the level of accuracy that can be expected at the various stages of the development of a project. SKM's estimates clearly fit into the "pre-feasibility study" stage.



Type of Estimate	Order of Magnitude	Preliminary	Definitive	Detailed
Provided Documentation	• Product capacity and Location • Cost Data on Similar Projects • Major Equipment List	• Preliminary Equipment List • Engineering Line Diagram • Plant Outline General Arrangement • Maps and Surveys • Bench Test Results • Nature of Facilities	• Equipment Specifications and Vendor Quotations • Construction Schedule • Electrical One Lines • Piping and Instrumentation Flow Diagrams • Soil Data and Architect Features • Site Survey and Labour Complete	• Bulk Material Specifications and Vendor Quotes • Construction Specification and Sub Contractor Quotations • Engineering Advanced Approximately 10%
Definition of Scope of Work	Conceptual	Approximate	Clearly Described Essentially Complete	Complete. Well Detailed
Estimating Procedure	Factoring	Combination of Factoring and Quantity Take-Off	Most Quantity Take-Off. Very little Factoring	Complete Quantity Take-Off
Use of Study	Comparison/ Rejection	Final Feasibility	Budget	Funding

The costs exclude the following:

- Consenting.
- Land acquisition or leases.
- Any contingency allowance to cater for uncertainty.
- Changes in exchange rates.

- **Table 8 11kV Capacitor Banks: 15 x 0.75MVAr: Pole-mounted: Fixed**

Item	Cost (NZ$'000)
Design	$76k
Installation	$82k
Project Management	$73k
Equipment	$172
Total Cost	**$377k**
Cost/MVAr	**$36k**

Notes: Costs to install 15 individual 0.75MVAr pole mounted capacitor banks.
Each bank to be mounted on an existing pole in the same manner as a distribution transformers (wider cross-arm).
All banks connected directly to the 11kV overhead line via DDOs.
No allowance has been made for replacing the existing pole or for series reactors or ripple signal rejection filters

- **Table 9 11kV Capacitor Banks: 15 x 0.75MVAr: Pole-mounted: Switched**

Item	Cost (NZ$'000)
Design	$117k
Installation	$98k
Project Management	$75k
Equipment	$372
Total Cost	**$661k**
Cost/MVAr	**$59k**

Notes: Costs to install 15 individual 0.75MVAr pole mounted capacitor banks.
All banks to be fitted with 11kV switches, capacitor bank controllers and linked via RTU to SCADA
Each bank to be mounted on an existing pole in the same manner as existing distribution transformers (wider cross-arm).
No allowance has been made for replacing the existing pole or for series reactors or ripple signal rejection filters.

- **Table 10 11kV Capacitor Banks: 1 x 5MVAr: Outdoor 11kV Switchyard**

Item	Cost (NZ$'000)
Design	$162k
Installation	$102k
Project Management	$60k
Equipment	$207
Total Cost	**$531k**
Cost/MVAr	**$106k**

Notes: Costs to install 1 x 5MVAr capacitor bank located within an existing switchyard (separate fenced enclosure).
Switched via an 11kV CB equipped with appropriate protection, controller and SCADA connection,
Costs include series reactor/filter for managing harmonics, ripple signals and inrush currents.

- **Table 11 33kV Capacitor Banks: 1 x 10MVAr: Outdoor 33kV Switchyard**

Item	Cost (NZ$'000)
Design	$110k
Installation	$155k
Project Management	$67k
Equipment	$385
Total Cost	**$770k**
Cost/MVAr	**$77k**

Notes: Costs to install 1 x 10MVAr capacitor bank located within an existing switchyard (separate fenced enclosure).
Switched via a 33kV indoor CB equipped with appropriate, protection, controller and SCADA connection,
Costs include series reactor/filter for managing harmonics, ripple signals and inrush currents.

Appendix B National Electricity Rules, Australian Energy Market Commission, June 2010

S5.3.5 Power factor requirements

Automatic access standard: For *loads* equal to or greater than 30 percent of the *maximum demand* at the *connection point* the *power factors* for *Network Users* and for *distribution networks connected* to another *transmission network* or *distribution network* are shown in Table S5.3.1:

Table S5.3.1

Permissible Range	
Supply Voltage (nominal)	**Power Factor Range**
> 400 kV	0.98 lagging to unity
250 kV - 400 kV	0.96 lagging to unity
50 kV - 250 kV	0.95 lagging to unity
1 kV < 50 kV	0.90 lagging to 0.90 leading

For *load* less than 30 percent of the *maximum demand* at the *connection point* a *Network Service Provider* may accept a *power factor* outside the range stipulated in Table S5.3.1 provided this does not cause the *system standards* to be violated.

Minimum access standard: A *Network Service Provider* may permit a lower lagging or leading *power factor* where the *Network Service Provider* is advised by *AEMO* that this will not detrimentally affect *power system security* or reduce *intra-regional* or *inter-regional power transfer capability*.

General:

If the *power factor* falls outside the relevant *performance standard* over any critical *loading* period nominated by the *Network Service Provider*, the *Network User* must, where required by the *Network Service Provider* in order to maintain satisfactory *voltage* levels at the *connection point* or to restore *intra-regional* or *inter-regional power transfer capability*, take action to ensure that the *power factor* falls within range as soon as reasonably practicable. This may be achieved by installing additional *reactive plant* or reaching a commercial agreement with the *Network Service Provider* to install, operate and maintain equivalent *reactive plant* as part of the *connection assets* or by alternative commercial arrangements with another party.

A *Registered Participant* who installs *shunt capacitors* to comply with *power factor* requirements must comply with the *Network Service Provider's* reasonable requirements to ensure that the design does not severely attenuate audio *frequency* signals used for *load* control or operations, or adversely impact on harmonic *voltage* levels at the *connection point*.

Appendix C Optimum Reactive Compensation: Bayliss

Ref (33) outlines a methodology for determining the optimum technical and economic power factor correction capacitor size, for a utility, to improve power factor, reduce network losses and assist voltage regulation.

The calculation equations are as follows:

$$\mathbf{V} \quad = \mathbf{L \times E \times F \times 8760 \times [1\text{-}(1\text{+}I)^{-V}] / I}$$

$$\mathbf{K} \quad = \mathbf{2 \times PF \times (1\text{-}PF^2)^{1/2}}$$

$$\textbf{Optimum Capacitance} \quad = \mathbf{V \times K - C / (2 \times V \times PF^2)} \ \text{kVAr per kW of load}$$

$$\textbf{New Power Factor} \quad = \mathbf{1 / [\ (C / (2 \times V \times PF^2))^2 + 1]^{1/2}}$$

And the input variables are:

Variable name	Description	Units
PF	Average load power factor	-
L	Net losses on the system (load losses to the point of connection of the proposed correction capacitors)	Per unit
F	Load loss factor (LLF)	-
I	Interest or discount rate	Per unit
Y	Estimated life of capacitor installation	Years
E	Energy costs	$/kWh
C	Installed capacitor bank costs	$/kVAr
V	Capitalised value of losses on the existing system	$/kW

SKM have calculated a typical Load Loss Factor (for NZ) based on the following:

$$\mathbf{LLF} \quad = \mathbf{a \times LF \ \ b \times LF^2}$$

Assuming a = 0.3, b = 0.7 and load factor LF = 0.5

For the calculations SKM have assumed the following constant values:

I = 7%

Y = 20 years

LLF = 0.325

L = 0.05 p.u.[14]

And we have also validated our calculations against a tabulated set of calculations outlined on page 983 of Ref (33) as follows:

Table 12 Sample Calculations[15]

Description	Symbol	Unit	Values	Values	Values
Original Active Power	P	kW	1.000	1.000	1.000
Orginal Apparent Power	Q	kVA	1.333	1.176	1.176
Original Reactive Power	S	kVAr	0.882	0.620	0.620
Power Factor	PF		0.75	0.85	0.85
Net Losses	L	p.u.	0.09	0.09	0.12
Load Factor	LF	-	-	-	-
a	-	-	-	-	-
b	-	-	-	-	-
Load Loss Factor	F	-	0.395	0.395	0.395
Discount Rate	I	%	12%	12%	12%
Life of Capacitor Installation	Y	years	10	10	10
Energy Cost	E	$/kWh	$ 0.027	$ 0.027	$ 0.027
Installed Cost of Caps	C	$/kVAr	$ 27	$ 27	$ 33
Capitalised value of losses	V	-	47.5	47.5	63.3
-	K	-	0.992	0.896	0.896
Optimum kVAr per kW load	-	-	46.6	42.2	56.4
New Power Factor	-	-	0.893	0.931	0.941
New Apparent Power	-	KVA	1.120	1.075	1.063
New Reactive Power	-	kVAr	0.505	0.393	0.361
Optimum Capacitance added	-	kVAr	0.377	0.226	0.259

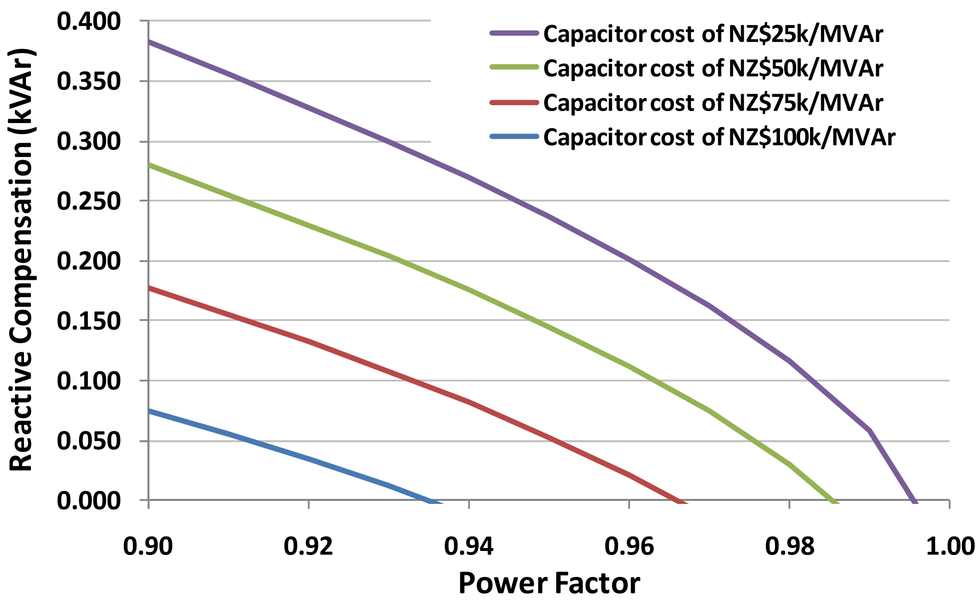
[14] Ref (32) indicates the average loss ratio associated with NZ EDBs to be 4.5%/0.045p.u. This includes losses across the entire distribution network.

[15] This table repeats the calculations outlined in Table 25.9 of Ref (33) and serves as verification.

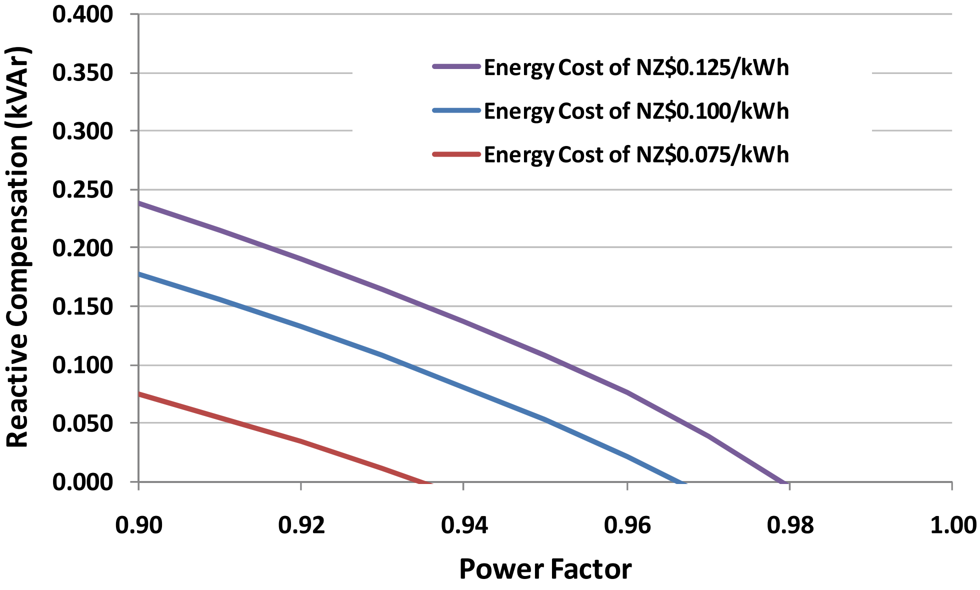
Given that above assumptions SKM have used Ref (33)'s calculation methodology to determine the optimum/economic capacitor compensation for:

- Varying capacitor costs (refer to Figure 20).
- Varying energy costs (refer to Figure 21).

Note that information outlined in Figure 20 and Figure 21 pertains to a load of 1kW and outlines the optimum capacitor bank installation recommended in kVAr.



- **Figure 20 Optimum/Economic Compensation: Variable Capacitor Costs: Energy Cost of $0.10/kWh**



- **Figure 21 Optimum/Economic Compensation: Variable Energy Costs: Capacitor Cost of $75k/MVAr**

Appendix D EGR Documents

SCHEDULE 8
CONNECTION CODE

1. INTERPRETATION

1.1 Preliminary:

Nothing in this Connection Code limits or derogates from any provision of the Agreement.

1.2 Definitions:

In this Connection Code, unless the context otherwise requires:

Earth Fault Factor

means at a given location of a three-phase electrical power system, and for a given system configuration, the ratio of:

(a) the highest r.m.s. phase-to-earth power frequency voltage on a healthy phase during a fault to earth affecting one or more phases at any point on the system; to

(b) the r.m.s value of phase-to-earth power frequency voltage which would be obtained at the given location in the absence of any such fault (IEC 50 (604-03-06)).

Equipment

means any of:

(a) **assets** or a **network** physically connected to the **grid**;

(b) **assets** or a **network** forming part of the **grid**;

(c) **assets** or a **network** not physically connected to the **grid** but which, in the reasonable opinion of **Transpower**, can affect the management, security, operation or performance characteristics of the **grid**; or

(d) other Equipment not physically connected to the **grid** but which, in the reasonable opinion of **Transpower**, can affect the security or operation of the **grid**, or power quality.

Power Factor

means MW divided by MVA at a Point of Service where the MW and MVA are measured.

Safety Manual - Electricity Industry (SM-EI)

means the Safety Manual – Electricity (SM-EI) 2004, published by the Electricity Engineers' Association (as may be amended from time to time).

Secondary Plant

all Equipment that is not **primary transmission equipment**.

1.3 Interpretation:

References to **Transpower** are references to **Transpower** in its capacity as **grid owner** as a party to the Agreement. References to the Customer are references to the Customer in its capacity as a party to the Agreement.

1.4 Procedure for obtaining Transpower's agreement to non compliance:

Transpower may enter into an agreement with the Customer as to the manner and extent by which the Customer need not comply with this Connection Code in accordance with the process set out in Appendix A. If the agreement would have a material adverse effect on any other **designated transmission customer** or end use customer, **Transpower** and the Customer must first comply with **rules** 5.1 to 5.4 of section II of part F, as applicable, before entering into the agreement.

If an agreement is entered into, **Transpower** and the Customer must comply with that agreement. A non-confidential summary of that agreement must be made publicly available.

1.5 Customer's responsibilities for third parties:

(a) The Customer must ensure that any third party who has Equipment directly connected to the Customer's Equipment, but not to the **grid**, that may adversely affect the reliability, availability or integrity of the **grid** complies with the obligations on the Customer as set out in this Connection Code.

(b) For the purposes of this clause, but without limiting the application of subclause (a), any **generating units** with a combined installed capacity of greater than 1MW, or motors with a combined installed capacity of greater than 1MW capacity will be treated as having the potential to adversely affect the reliability, availability or integrity of the grid, unless **Transpower** and the Customer agree that a higher capacity is more appropriate taking into account the load at a **point of connection**.

1.6 Customer's responsibilities when other designated transmission customer

If the Customer is requested by another **designated transmission customer** or **Transpower** to agree to the bonding of that **designated transmission customer's** earthing systems as required by the equivalent clause to clause 4.2(d)(4) that applies under any **transmission agreement** between the Customer and **Transpower**, the Customer must not unreasonably withhold that agreement.

2. CONNECTION REQUIREMENTS

2.1 Requirements for equipment capability:

As and when the Customer must provide an **asset capability statement** to the **system operator** under the **rules**, the Customer must also provide the same **asset capability statement** to **Transpower** (in the same manner in which it provides the **asset capability statement** to the **system operator**) but including the information specified in clause 2.2 (b), (c) and (d).

2.2 Additional information:

The Customer must provide to **Transpower**, in a format specified by **Transpower** (acting reasonably) from time to time:

(a) as and when it must provide an **asset capability statement** to the **system operator** under the **rules**, the information referred to in subclauses 2.2(b), (c) and (d) in respect of that Equipment.

(b) in respect of its Equipment:

(1) the normal and emergency limits within which the Equipment is intended to operate;

(2) the information as to the limitations in the operation of the Equipment that **Transpower** requires (acting reasonably) for the safe and efficient management of the **grid**; and

(3) all modelling data in respect of Equipment capability which **Transpower** requires (acting reasonably) for planning purposes;

(c) sufficient information concerning the Equipment at the **grid interface** to verify compliance with this Connection Code and to enable **Transpower** to approve the connection; and

(d) details of protection systems, including settings, to ensure the requirements of clause 4.2(e) are met.

2.3 Special requirements:

If the Customer proposes to connect Equipment to the **grid**, or to **assets** connected to the **grid**, or to make changes to Equipment connected to the **grid** or to **assets** connected to the **grid** and **Transpower**:

(a) acting reasonably and after having consulted other Customers who may be affected by the connection of the Equipment to the **grid**, or the changes to the Equipment or otherwise; or

(b) having regard to the environmental conditions in which the Equipment at the **grid interface** is located;

identifies special requirements for the Equipment, **Transpower** may notify the Customer of the special requirements and the Customer must ensure those special requirements are complied with to **Transpower's** satisfaction (acting reasonably).

2.4 Pre-commissioning requirements:

(a) Before the Customer commissions any Equipment to be connected to the grid, or any asset connected to the **grid**, the Customer must obtain **Transpower's** written approval (not to be unreasonably withheld):

(1) to the design and specifications of the Equipment;

(2) that the requirements of this Connection Code can be met;

(3) that upon connection of the Equipment, the reliability, availability and integrity of the **grid** can be maintained; and

(4) that the proposed connection of the Equipment can be made reliably and safely without any material adverse affect on the management, security or operation of the **grid**.

(b) In considering whether or not to grant approval **Transpower** may (amongst other things) consider:

(1) the effect of daily, seasonal, annual and likely long-term variations in supply and demand levels;

(2) the effect of contingency conditions; and

(3) the effect of any future changes required to the **grid**, or to other Equipment.

2.5 Requirements for commissioning or testing of equipment:

(a) The Customer must:

(1) as and when the Customer must provide a commissioning or test plan to the **system operator** under the **rules**, also provide a commissioning or test plan to **Transpower** that complies with clause 2.6; and

(2) if the Equipment is not connected to the **grid** but is connected to an asset connected to the **grid** and in the reasonable opinion of **Transpower**, could affect the security or operation of the **grid**, the Customer must provide to **Transpower** a commissioning or test plan that complies with clause 2.6.

(b) **Transpower** must, as and when required to provide a commissioning or test plan under the **rules** in respect of the Connection Assets, also provide a commissioning or test plan to the Customer that complies with paragraphs (a) to (d) of clause 2.6.

2.6 Requirements of a commissioning or test plan:

The commissioning or test plan required under clause 2.5 must:

(a) include a timetable containing the sequence of events necessary to connect the Equipment and conduct any test;

(b) contain the protection settings to be applied before livening of the Equipment;

(c) contain the procedures for commissioning or testing the Equipment that safeguards against risk of injury to personnel or damage to any Equipment and to the ability of **Transpower** and the Customer to comply with its obligations under the Agreement;

(d) have been prepared by the Customer in consultation with **Transpower** or by **Transpower** in consultation with the Customer, as the case may be; and

(e) in the case of a commissioning or test plan provided by the Customer, be approved in writing by **Transpower** (such approval not to be unreasonably withheld).

2.7 Customer to comply with commissioning or test plan:

The Customer in commissioning or undertaking any testing of the Equipment must comply with the commissioning or test plan approved by **Transpower** in accordance with clause 2.6.

2.8 Responsibility following approval:

The Customer must ensure that the construction or manufacture of Equipment does not depart from the design or specifications of Equipment approved by **Transpower** unless the departure is approved in writing by **Transpower**. **Transpower** will not withhold such approval unreasonably.

2.9 Final approval:

On completion of connection of any Equipment to the **grid**, including to any associated **grid interface**, the Customer must obtain final approval of such connection in writing from **Transpower** (such approval not to be unreasonably withheld) before the Equipment commences service.

2.10 Withdrawal:

Transpower may withdraw any approval provided by **Transpower** (acting reasonably) if the Equipment is not as described in the information provided under clauses 2.2 and 2.3.

2.11 Co-operation:

The Customer must comply with any reasonable direction of **Transpower** to change the connection of any Equipment to the **grid** (or the Equipment itself), if the connection or the Equipment may adversely affect the performance of the **grid** or the Equipment of other customers.

2.12 New Connections:

Where the Customer wishes **Transpower** to provide a new connection, it must make a written request to **Transpower** and **Transpower** must within 20 Business Days of the Customer's request provide an initial response in writing to the Customer that sets out the process to be followed by **Transpower** and the Customer and a proposed timetable for provision of the new connection.

3. GENERAL REQUIREMENTS

3.1 Published requirements:

Transpower must ensure that its Connection Assets (and, in the case of subclauses (b) and (c), the operation of its Connection Assets) and the Customer must each ensure that its Equipment (and, in the case of subclauses (b) and (c), the operation of its Equipment):

(a) is designed, tested and commissioned in accordance with **good electricity industry practice**;

(b) complies with the Safety Manual - Electricity Industry (SM-EI); and

(c) complies with all relevant legislation.

4. TECHNICAL REQUIREMENTS

4.1 Instrumentation and control circuits:

The Customer:

(a) may connect an instrumentation and control circuit to secondary plant at the **grid interface** provided:

(1) the **grid** is not adversely affected;

(2) the safety of the public and any other persons is not adversely affected; and

(3) the Customer has prior written approval from **Transpower** (such approval not to be unreasonably withheld).

(b) must provide a means by which both the Customer and **Transpower** may disconnect each instrumentation or control circuit connected to the **grid**; and

Transpower must ensure that each instrumentation and control circuit connected at the **grid interface** is designed to withstand the hazards of earth potential rise and induced currents and voltages appropriate to the location of the secondary circuit and comply with the requirements of clause 4.2(d).

4.2 Requirements at the grid interface:

(a) Grid interface switchgear to be provided:

The Customer or **Transpower** must provide for each **Point of Connection**:

(1) a single location where it is practicable, in accordance with **good electricity industry practice**, for the owner of the **circuit-breaker** to operate each **circuit-breaker** by remote control;

(2) the operational status of each **circuit-breaker** to be signalled to the single location in (1) from which the **circuit-breaker** is controlled; and

(3) Equipment to isolate and earth its own Equipment each **Point of Connection.**

(b) Insulation co-ordination:

Transpower and the Customer must each ensure:

(1) the insulation of Equipment at the **grid interface** is co-ordinated with the insulation of Equipment to which it is to be connected;

(2) that transient, dynamic, continuous and any other over-voltages are calculated, analysed and taken into account in accordance with **good electricity industry practice** and that the recommendations of IEC 71 (Insulation Co-ordination) are complied with;

(3) that the rated insulation level and rated short duration power frequency withstand voltage meets the levels specified in Appendix B Table B3; and

(4) that for any connection of Equipment to the **grid** at a voltage of 220 kV and for each **Point of Connection**, an Earth Fault Factor of not more than 1.4 (an effectively earthed system) is maintained. For the purposes of this clause 4.2(b)(4), any Equipment connected to the **grid** that operates at a nominal voltage of less than 220 kV, is deemed to have an Earth Fault Factor of greater than 1.4 (non-effectively earthed). Any connection of such Equipment to the **grid** must not increase the Earth Fault Factor to an extent which leads to over-voltages which have an adverse effect on the management or operation of the **grid**.

(c) **Rating of equipment at the grid interface:**

Transpower and the Customer must each ensure that:

(1) the normal current ratings of Equipment at the **grid interface** are sufficient to carry currents at all reasonably foreseeable ratings;

(2) neither the short-circuit current ratings nor the effects of the earthing of the Equipment interfere with, or adversely affect, the management or operation of the **grid**; and

(3) it modifies or replaces the Equipment or changes the configuration of the Equipment before any of the short-circuit current ratings of the Equipment are exceeded, in order to ensure those ratings are not exceeded.

(d) **Earthing of the grid interface:**

Transpower and the Customer must ensure that:

(1) the earthing arrangements for the **grid interface** do not adversely affect the safety of any person;

(2) the earthing arrangements for the **grid interface** allow the efficient management of protection systems;

(3) the Equipment has an earthing arrangement that keeps hazards within limits required by **good electricity industry practice** without requiring bonding to the earthing systems of any other **designated transmission customer**;

(4) without derogating from the foregoing, where bonding to the earthing systems of any other **designated transmission customer** is beneficial, undertake the bonding to the earthing system of that other **designated transmission customer** as agreed by the **designated transmission customer**; and

(5) earthing of the Equipment at the **grid interface** is sufficient to withstand earth fault currents (including the contribution from the **grid**) up to the limits specified in Appendix B Table B2 for at least 3 seconds.

(e) **Protection of equipment and the grid:**

Transpower and the Customer must each ensure that the Equipment is designed and maintained so that, for fault impedances of less than one ohm on either the **grid** or at the **grid interface**, the following applies:

(1) the fault will be cleared by main protection systems within the design fault clearance time specified in Appendix B table B4;

(2) the fault clearance time for back up protection systems, including high impedance faults, is as short as reasonably practicable and does not adversely affect other Equipment, and must not exceed the final fault clearance time in Appendix B table B4; and

(3) no fault on the **grid assets** or on the **grid interface** persists for longer than the final fault clearance time stated in Appendix B table B4.

(f) **Common and shared facilities and equipment:**

If **Transpower** and the Customer share facilities or Equipment, each shall:

(1) physically secure the facilities or the Equipment against unauthorised access or operation by a third party;

(2) provide electrically safe Equipment in accordance with **good electricity industry practice**; and

(3) provide facilities and Equipment that comply with AS/NZS 1170 Structural design actions.

(g) **Expected minimum and maximum fault levels:**

Transpower must publish annually a 10 year forecast of the expected minimum and maximum fault level at each Point of Service.

4.3 Specific requirements for generating units:

If the Customer is a **generator**, the Customer must ensure that the connection at the **point of connection** of its **generating units** has an Earth Fault Factor complying with the requirements of clause 4.2(b)(4) and the earthing of the generating unit and associated Equipment ensures the reliable operation of protection systems and safe management of the **grid**. This requirement also applies in respect to the **grid interface** for any **network** to which a generating unit is connected and may affect the management of the **grid**.

4.4 Minimum power factor:

(a) The Customer must ensure that its Equipment does not unreasonably draw on the reactive power resources of the **grid** during each regional peak demand period. If **electricity** is being drawn off the **grid**, the Power Factor at any Point of Service the Customer must:

(1) up until 31 March 2010, in the case of demand, maintain a Power Factor of not less than 0.95 lagging at any Point of Service during each relevant regional peak demand period.

(2) from 1 April 2010, in the case of demand, maintain a Power Factor of not less than:

(i) 1.0 (unity) at each relevant Point of Service during each relevant regional peak demand period in the Upper North Island Region and the Upper South Island Region; and

(ii) 0.95 lagging at each relevant Point of Service during each relevant regional peak demand period in the Lower North Island Region and the Lower South Island Region.

(b) For the purposes of this clause:

(1) the regional peak demand periods and regions are as defined in Schedule F of the **transmission pricing methodology**; and

(2) the relevant regional peak demand period is the regional peak demand period for the region in which the Point of Service is located.

4.5 Provision for effects of disconnection:

The Customer must each ensure that it manages the consequences of an unplanned disconnection of any of its Equipment from the **grid assets** in accordance with **good electricity industry practice**.

4.6 Maintenance:

Transpower and the Customer must each maintain its Equipment so that it always complies with this Connection Code.

4.7 Harmonic levels:

Transpower and the Customer must each comply with:

(a) the New Zealand Electrical Code of Practice for harmonic levels (NZECP 36.1993), as amended from time to time; or

(b) any other equivalent or similar AS/NZS, IEC, IEEE standard; or

(c) any other requirements specified by **Transpower** (acting reasonably) that cover similar matters to those set out in NZECP 36.1993.

4.8 Voltage flicker levels:

Transpower and the Customer must each comply with the Australian Standard (AS2279.4 191) for voltage levels as amended from time to time or such other local or international standards that may be reasonably applicable.

4.9 Voltage imbalance of less than 1%:

Transpower and the Customer must each use reasonable endeavours to maintain negative sequence voltage of less than 1% and to ensure that negative sequence voltage will be no more than 2% in any part of the **grid**.

5. OPERATING REQUIREMENTS

5.1 Operational performance of equipment:

Transpower and the Customer must each ensure that its Equipment:

(a) has no adverse effect on the **grid** or the ability of **Transpower** to manage the **grid**;

(b) can be operated within the minimum and maximum system voltages set out in Appendix B, Table B1;

(c) has no adverse effect on other Customers or their ability to manage their Equipment;

(d) is designed and installed so that maintenance can be carried out;

(e) does not present a safety hazard to **Transpower** or other Customers (or their respective employees and agents) or the general public;

(f) does not cause **Transpower** or the Customer to breach any legislation;

(g) performs its intended function to the standard required by this Connection Code at the maximum and minimum short-circuit currents resulting from any reasonably foreseeable configuration of the New Zealand electricity system;

(h) does not cause the maximum short circuit power and current limits specified in Appendix B, Table B2 to be exceeded on or nearby to the **grid**;

(i) is capable of being operated and operates within the limits stated in the **asset capability statement** and other information provided under clauses 2.1 and 2.2 respectively;

(j) complies with this Connection Code; and

(k) meets any other requirements imposed by **Transpower** in writing acting reasonably and in accordance with **good electricity industry practice**.

6. MONITORING REQUIREMENTS

6.1 Monitoring requirements:

Transpower and the Customer must each monitor the performance of its Equipment in accordance with **good electricity industry practice**.

7. INFORMATION REQUIREMENTS

7.1 For approval of the grid interface:

(a) In addition to information provided in the **asset capability statement** and the other information provided under clauses 2.2 and 2.3 respectively, the Customer must provide **Transpower** as and when requested by **Transpower** (acting reasonably) with:

(1) sufficient information concerning the **grid interface** to verify compliance with this Connection Code and to enable **Transpower** to approve the connection at the **grid interface**;

(2) details of protection systems, including settings, to ensure the requirements of clause 4.2 (ef) are met; and

(b) **Transpower** must provide the Customer as and when requested by the Customer (acting reasonably) with details of protection systems relating to the Connection Assets, including settings, to ensure the requirements of clause 4.2(e) are met.

7.2 For revisions to information previously supplied:

(a) Whenever revised information as to the performance of Equipment is obtained by the Customer, the Customer must provide to **Transpower** a revised **asset capability statement** and any revisions to the other information required under clauses 2.2 and 2.3 respectively, as soon as reasonably practicable.

(b) Whenever revised information as to the performance of a Connection Asset is obtained by **Transpower, Transpower** must provide to the Customer a revised **asset capability statement** and any revisions to the other information required under clauses 2.2 and 2.3 respectively, as soon as reasonably practicable.

7.3 Supporting information:

(a) The Customer must maintain up to date manuals or protocols required in accordance with **good electricity industry practice** for the operation of its Equipment.

(b) **Transpower** must maintain up to date manuals or protocols required in accordance with **good electricity industry practice** for the operation of its Connection Assets.

7.4 Equipment records to be kept:

(a) The Customer must in accordance with **good electricity industry practice** maintain records for its Equipment that, in its discretion, either:

(1) record the performance of its Equipment as monitored by the Customer over each consecutive three month period for the purpose of verifying or otherwise that the Equipment meets the requirements of this Connection Code; or

(2) record any tests undertaken in accordance with **good electricity industry practice** that establish that the Equipment meets the requirements of this Connection Code.

(b) **Transpower** must in accordance with **good electricity industry practice** maintain records for its Connection Assets that, in its discretion, either:

(1) record the performance of its Connection Assets as monitored by the **Transpower** over each consecutive three month period for the purpose of verifying or otherwise that the Connection Assets meets the requirements of this Connection Code; or

(2) record any tests undertaken in accordance with **good electricity industry practice** that establish that the Connection Assets meets the requirements of this Connection Code.

7.5 Access to records or equipment:

The Customer must as soon as reasonably practicable following written notice by **Transpower**, provide to **Transpower**:

(a) access to any records of the Customer's monitoring or testing of the performance of any Equipment carried out in accordance with clause 7.4; and

(b) access to inspect any Equipment;

as **Transpower** requires (acting reasonably).

7.6 Status of Transpower approval:

Any approval by **Transpower** provided to the Customer does not relieve the Customer from its obligations to meet the requirements of this Connection Code.

8. PERFORMANCE REQUIREMENTS FOR SCADA

The Customer must ensure that the interface between its Equipment and the **grid** for the exchange of data provided by SCADA must comply with **Transpower's** policy for the same as published from time to time in consultation with **designated transmission customers**.

APPENDIX A: TRANSPOWER'S AGREEMENT TO NON-COMPLIANCE WITH THE CONNECTION CODE

1. APPLICATION AND SUPPORTING INFORMATION

The Customer may apply in writing to **Transpower** for **Transpower's** agreement authorising non-compliance with this Connection Code.

An application shall:

(a) Specify the non-compliance:

specify the clauses of the Connection Code for which **Transpower's** agreement to non-compliance is sought;

(b) Provide supporting information:

provide information in support of the application with reasonable particularity (including information as to the capability of the non-compliant Equipment);

(c) Describe any remedial action to be undertaken:

describe any remedial action to be undertaken to ensure compliance with this Connection Code;

(d) Specify required term:

specify the term of the agreement which is sought; and

(e) Identify confidential information:

identify any information for which confidentiality is sought on the ground that it would, if disclosed, unreasonably prejudice the commercial position of the Customer (or other person who is the subject of the information) or on the ground that it is information that is subject to an obligation of confidence, and the period for which confidentiality is sought.

2. TRANSPOWER OBLIGATIONS ON RECEIPT OF APPLICATION

Within 5 business days of receipt of the application made under clause 1 of this appendix, **Transpower** must provide the Customer with an estimate of the time it will take to consider the application and the costs associated with processing the application:

3. RIGHTS AND OBLIGATIONS DURING THE PROCESSING OF APPLICATIONS

(a) **Reasonable endeavours:**

Transpower will use reasonable endeavours to consider and decide whether or not to agree to the application within the estimated time and costs provided in accordance with clause 2 of this appendix.

(b) **Transpower to act reasonably:**

Transpower will act reasonably in deciding whether or not to enter into an agreement under this Appendix A, and in determining the terms and conditions on which it is prepared to enter into an agreement.

(c) **Additional information:**

Transpower may require the Customer to provide information in support of the application and the Customer shall provide the same in order for the application to be considered.

(d) **Withdrawal of application:**

If the Customer withdraws an application, it must on demand pay the actual and reasonable costs incurred by **Transpower** up to and including the date of withdrawal of the application in considering the application.

4. OBLIGATION OF THE CUSTOMER TO PAY COSTS

The Customer must on demand pay **Transpower's** actual and reasonable costs incurred in considering an application under this appendix.

5. AGREEMENT

Transpower will notify the Customer of the outcome of any application by it for **Transpower's** agreement to non-compliance with this Connection Code but if the application is granted there shall be no legally binding agreement between **Transpower** and the Customer unless and until they enter into a formal and final supplementary written agreement signed by each of them, which is expressed to be legally binding as between them. Such an agreement shall be supplementary to and form part of the Agreement.

APPENDIX B. VOLTAGE AND FAULT LEVELS

Table B1: Maximum and Minimum Voltage Limits

Nominal Voltage (kV)	Maximum System Voltage (kV)	Minimum System Voltage (kV)
220	242	198
110	121	99
66	69.3	62.7
50	52.5	47.5
33	36	30
22	24	20
11	12	10

Table B2: Maximum Short-Circuit Power and Current Limits

Nominal voltage (kV)	Maximum short-circuit power and current limits	
	(MVA)	(kA)
220	12,000	31.5*
110	6,000	31.5*
66	1,800	16*
50	1,350	16
33	1,400	25
22	950	25
11	475	25

* The values shown are the default existing fault maximum levels. At some sites the levels already exceed the levels shown and the number of sites that exceed the default levels will increase in the future. Ten year forecast maximum figures will be published annually.

Table B3: Voltage Levels for Insulation Co-ordination

Nominal voltage (kV)	Highest voltage for Equipment (kV)	Rated insulation level (kV)	Rated short duration (1 minute) power frequency withstand voltage (kV)
220	245	950	395
110	123	550	230
66	72.5	325	140
50	55	250	95
33	36	170	70
22	24	125	50
11	12	75	28

Table B4: Fault Clearance Times

Nominal Voltage (kV)	Design fault clearance time (ms)	Final fault clearance time (s)
220	120	4■
110	200	3
66	200	3
50	200	3
33*	200	3
22*	200	3
11*	200	3
33υ	1000	3
22υ	1000	3
11υ	1000	3

* Only bus and LV Transformer zone, not feeders

υ For close in high impedance feeder faults

■ The figure for 220 kV is higher than those below because of the grading required with protection at lower voltages

Appendix B

Regions

North Island

The Upper North Island (UNI) is described in the Annual Planning Report (APR) as "the geographical area north of Huntly, including Glenbrook, Takanini, Auckland and the Northern Isthmus".

The **connection locations** in the UNI region are:

Code	Name
ALB	Albany
BOB	Bombay
BRB	Bream Bay
DAR	Dargaville
GLN	Glenbrook
HEN	Henderson
HEP	Hepburn Rd
HLY	Huntly
KEN	Kensington
KOE	Kaikohe
KTA	Kaitaia
MDN	Marsden
MER	Meremere
MNG	Mangere
MPE	Maungatapere
MTO	Maungaturoto
OTA	Otahuhu
PAK	Pakuranga
PEN	Penrose
ROS	Mt Roskill
SVL	Silverdale
SWN	Southdown
TAK	Takanini
TWH	Te Kowhai
WEL	Wellsford
WES	Western Rd
WIR	Wiri

The remainder of the **connection locations** in the North Island are in the LNI region.

South Island

The USI is defined in terms of all GXPs supplied from the major concentration of generation in the Waitaki Valley and south of the Waitaki Valley. These GXPs are supplied by the 220kV system from Tekapo B, Twizel and Livingstone (refer Fig 5-19 in the APR).

The **connection locations** in the USI region are:

Code	Name
ABY	Albury
ADD	Addington
APS	Arthurs Pass
ARG	Argyle
ASB	Ashburton
ASY	Ashley
BLN	Blenheim
BRY	Bromley
CLH	Castle Hill
COB	Cobb
COL	Coleridge
CUL	Culverden
DOB	Dobson
GYM	Greymouth
HKK	Hokitika
HOR	Hororata
ISL	Islington
KAI	Kaiapoi
KIK	Kikiwa
KKA	Kaikoura
KUM	Kumara
MCH	Murchison
MOT	Motueka
MPI	Motupipi
ORO	Orowaiti
OTI	Otira
PAP	Papanui
RFT	Reefton
SBK	Southbrook
SPN	Springston
STK	Stoke
UTK	Upper Takaka
TIM	Timaru
TKA	Tekapo A
TMK	Temuka
WPR	Waipara
WPT	Westport

The remainder of the **connection locations** in the South Island are in the LSI region.