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Report (Trp00006) to

TRANSPOWER

NATIONAL ELECTRICITY MARKET DEVELOPMENT

Pre-Augmentation EUE Assessment

5 October 2006

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1) INTRODUCTION

This report provides a summary of work completed by ROAM Consulting (ROAM) for Transpower since submission of the revised report; *Report Trp00006 Key Assumptions 2006-08-24.pdf*.

The 2006-08-24 report provided Expected Unserved Energy (EUE) forecasts for the network corresponding with the Draft 400kV determination for the years 2012, 2014 and 2016 prior to commissioning of a major augmentation. The EUE forecasts were completed on the following basis:

- ROAM's 2-4-C database as developed for the Draft 400kV determination;
- For peak demand corresponding with the High EC SOO demand forecast;
- With all common network augmentation and load switching out to 2014 including the Huntly East switching station;
- With the ARI110 to PAK110 circuit switched out;
- Without any alternate arrangements such as phase shifting transformers on the 110kV network;
- During construction of a major network augmentation into Auckland.

2) REVISED BENCHMARK ASSESSMENT

The EUE outcomes presented in ROAM's 2006-08-24 report are significantly different to those presented by the EC in their Draft 400kV determination.

Transpower requested ROAM to complete a revised benchmark assessment to replicate the conditions for the 2016 year for the medium peak demand forecast (50% POE) corresponding with the EC/SSG/PBA analysis (EC analysis) presented in the data file *400KV-2017-20Y-data-only-r3.xls*.

2.1) 2-4-C SC-DCOPF EUE OUTCOMES

ROAM has applied the 2-4-C Security Constrained DC Optimal Power Flow (SC-DCOPF) simulation engine to develop a revised benchmark EUE assessment for the Upper North Island. In addition to setting the ARI-PAK line back into service we have completed a full revision of the 2-4-C simulation database to include every distinct generation unit as contained in the EC power flow files. Additionally, compared with previous ROAM studies (*2006-08-24 and prior)*, the Huntly Coal units' forced outage rate has been lowered from 4% to 3%, based on Table 3: *Assumed probabilities of component failure* in the PB Associates EUE report[1] (PBA Report). The revised 2-4-C generator data is presented in Appendix A. This revised database has been used for all further work presented in this report.

[1] PB Associates, Transmission Augmentations into Auckland : Investigation into the Anticipated Un-Served Energy, 5 April 2006.

The EUE outcomes from the benchmark study are as follows:

Table 2.1 – Benchmark Study for 2016 Medium Demand – Prior to Augmentation

Demand Forecast	North Isthmus Demand (MW)	Auckland Demand (MW)	Supportable Load Requirement (MW)	MWh EUE	Hours of Supply Shortfall	Average MW Lost
2016 50% POE	1043	1742	2785	18.20	0.37	49.20
2016 10% POE	1130	1878	3008	1567.02	17.01	92.12

The 50% POE outcome shows a significantly lower EUE than the apparently equivalent EC analysis which indicates around 200MWh for 2016. A key difference is that the EC analysis results in the majority of EUE occurring in the extreme summer period, however in the ROAM simulation studies all EUE occurs in the winter months, mainly June through to September.

Comparing this new 10% POE outcome with ROAM's previous assessment for 2016 this shows 1567MWh EUE compared with 4223MWh previously. The reduction is due to the combination of reduced generator FOR on Huntly and Southdown, return to service of the ARI-PAK line and to a lesser degree modelling each individual generation unit in the simulation.

Additionally ROAM completed a sensitivity simulation study which limited the Huntly Coal power station to 400MW in summer (from 570MW previously). This resulted in negligible change in EUE from the table above. It was concluded that the summer EUE events presented in the EC analysis were due to non-optimised network configuration and generation dispatch.

2.2) REVIEW OF THE EC EUE ASSESSMENT

ROAM completed an independent assessment of the EC analysis EUE estimate workbook. This independent assessment has been labeled the 'ROAM Assessment'. The 'ROAM Assessment' of the deterministic methodology for estimating EUE from the SSG contingency set data should not be confused with ROAM's SC-DCOPF Monte Carlo simulation assessment, as presented in Table 2.1.

The analysis concentrates on the same 2016 benchmark case (50% POE) discussed previously. The outcomes from the ROAM Assessment of the EC analysis were provided to Transpower and the EC for discussion. Based on the ROAM Assessment provided, PBA found an error in their calculation scripts. With these errors corrected the revised PBA EUE figures came into line with the ROAM Assessment of the SSG contingency sets. The revised EUE outcomes of the SSG/PBA deterministic assessment are discussed below.

The ROAM Assessment has been made for the Non Leap year Winter for 2016, Summer 2016 and Non leap year for Extreme Summer 2017, in line with the contingency set data. The reference Load Duration Curves (LDCs) have been linearly grown to meet the target peak demand forecasts for the three parts of the year. The following EUE outcomes correspond with rounding up to the nearest 50MW block for each interval of EUE as described in the PBA report.

- The Extreme Summer shows 119.19MWh EUE.
- The Summer shows 49.36MWh EUE.
- The Winter shows 39.01MWh EUE.

Further to this, the EUE estimate may be calculated without rounding up each interval of EUE to the nearest 50MW block. In this case the estimated EUE for the Winter period is 24MWh.

2.3) SUMMARY OF REVISED BENCHMARK ASSESSMENT

ROAM identified an error in the PBA analysis which estimates EUE from the SSG contingency set data (EC analysis). Fixing this error leads to very different EUE estimates from the material previously published by the EC. The error was not a systematic error. That is, after fixing the error, some EUE estimates become much higher, and some become much lower than the previous estimates.

ROAM has completed a benchmark SC-DCOPF Monte Carlo simulation of the 2016 year. This benchmark assessment resulted in 18MWh EUE. The Monte Carlo assessment reveals EUE events occur almost entirely within the winter period. This aligns very well with the revised PBA deterministic assessment for the 2016 winter period without rounding up to the nearest 50MW block of 24MWh.

ROAM analysis of the power flow files shows that the SSG contingency analysis which determines the maximum supportable load for the contingencies in each of the three segments of the year (Extreme Summer, Summer and Winter) provides a sub-optimal outcome with regard to supportable load in the extreme summer and summer periods. This analysis and the outcome from the SC-DCOPF simulation shows that there will be negligible EUE potential in the summer months (for the benchmark study case). A detailed summary of ROAM's assessment of the summer period is presented in Appendix B.

3) PRE-AUGMENTATION EUE ASSESSMENT

Following the revised benchmark assessment ROAM has applied the 2-4-C SC-DCOPF simulation engine to develop EUE forecasts for the Upper North Island for a range of demand, generator availability and network conditions. All studies are completed for the transmission network state prior to a major network augmentation.

The SC-DCOPF takes a list of transmission contingencies that must be enforced as input to the simulation. The following single credible transmission contingencies have been considered:

- OTA-WKM Outage;
- OTA-HLE Outage;
- WKM-HLE Outage;

- TAK-OTA Outage;
- HLY-TAK Outage;
- HLY-BOB Outage; and
- ARI-PAK Outage[2].

Multiple transmission contingencies have not been included in this assessment as the probability of even a second order transmission contingency is low enough such that there will be negligible effect on forecast EUE. The SC-DCOPF dispatches generation such that all network flows will remain within 100% of rating following a transmission contingency without generation re-dispatch or transmission system re-configuration. In this way the model will enforce pre-contingent load shedding to maintain the security constrained dispatch.

For this pre-augmentation assessment flows on the transmission system are allowed to reach thermal limits on all line sections. Over-riding voltage stability limits have not been enforced as it is expected that sufficient voltage stability devices can be installed within the network to reach the thermal capacity of the system. Voltage stability limits on total imports into the Upper North Island from the south may have to be considered when modeling the system following a major transmission augmentation.

3.1) EUE OUTCOMES

Studies have been completed to assess the network capability when Phase Shifting Transformers (PSTs) have been installed on the 110kV network as per the intermediate investments outlined in the Draft 400kV determination. Additionally Transpower has provided an alternate intermediate transmission augmentation development path which has been assessed as follows:

- As for the EC common augmentations to 2014 with the following differences;
- No PSTs on the 110kV network;
- ARI-PAK 110kV circuit out of service;
- ARI-HAM 110kV 1 & 2 circuits re-conductored to Nitrogen 75C. This increases the winter rating from 62MVA to 134MVA on each circuit;
- New substation at Drury between BOB-GLN-TAK 220kV circuits. This makes GLN a radial feed from the new Drury Substation and shortens the electrical distance from BOB-TAK substantially, removing around 45km of circuit on the round trip to GLN. A schematic of the 220kV augmentation is presented in the figure below.

[2] For the studies completed with the ARI-PAK 110kV circuit assumed to be out of service, the ARI-PAK contingency has been removed.

Figure 3.1 – Transpower Alternate 220kV Intermediate Augmentation (Drury Substation)

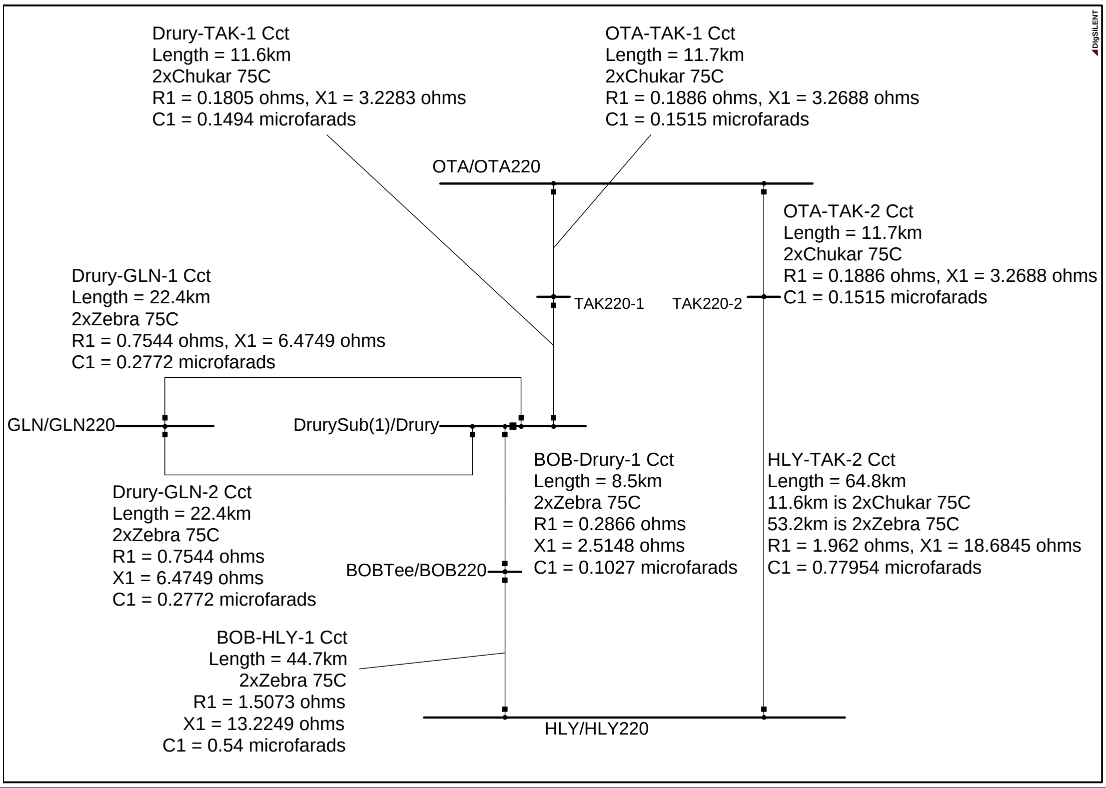


Table 3.1 below shows the EUE outcomes for a number of studies with the ARI-PAK 110kV circuit assumed to be in service. Table 3.2 below shows the EUE outcomes for a number of studies with the ARI-PAK 110kV circuit assumed to be removed from service.

Table 3.1 – EUE Forecast Studies with ARI-PAK in Service

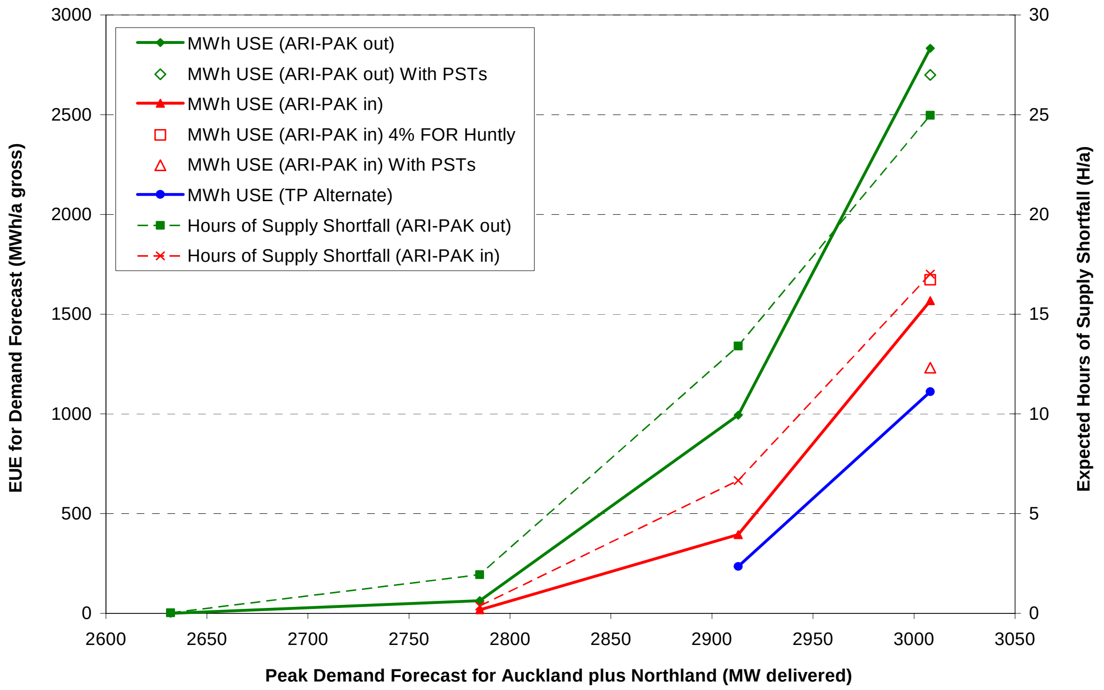
System State Peak Demand	North Isthmus Demand (MW del.)	Auckland Demand (MW del.)	Upper North Island Peak Demand	EUE (MWh gross)	Hours of Supply Shortfall	Average MW Lost
2016 50% POE	1043	1742	2785	18.20	0.37	49.20
2015 10% POE	1095	1818	2913	395.17	6.67	59.29
2016 10% POE	1130	1878	3008	1567.02	17.01	92.12
2016 10% POE 4% FOR Huntly	1130	1878	3008	1672.32	18.63	89.76
2016 10% POE With PSTs	1130	1878	3008	1231.47	14.60	72.40

Table 3.2 – EUE Forecast Studies with ARI-PAK out of Service						
System State Peak Demand	North Isthmus Demand (MW del.)	Auckland Demand (MW del.)	Upper North Island Peak Demand	EUE (MWh gross)	Hours of Supply Shortfall	Average MW Lost
2014 50% POE	987	1645	2632	0.21	0.03	8.41
2016 50% POE	1043	1742	2785	63.74	1.94	32.94
2015 10% POE	1095	1818	2913	994.04	13.40	74.18
2016 10% POE	1130	1878	3008	2832.66	24.97	113.44
2016 10% POE With PSTs	1130	1878	3008	2698.95	24.42	108.09
2015 10% POE TP Alternate	1095	1818	2913	234.99	3.89	60.49
2016 10% POE TP Alternate	1130	1878	3008	1111.16	13.91	79.91

These results can be combined to develop an 'EUE curve'. The EUE curve provides an indication of the EUE for a particular Upper North Island peak demand forecast. Two alternate EUE curves have been developed from the data set which represent the EUE forecast for the network with and without the ARI-PAK 110kV circuit in service.

The EUE curve for the data set provided in Tables 3.1 and 3.2 is presented in the figure below. Three additional points on the graph corresponding with the 2016 10% POE peak demand forecast show the EUE forecast with the alternate Huntly Coal Station 4% forced outage rate and for the two network states with PSTs in service.

Figure 3.2 – Forecast EUE vs Upper North Island Peak Demand



As can be seen, EUE increases exponentially as peak demand increases. There is a 'break point' around 2800MW peak demand in the Upper North Island at which EUE begins to rise rapidly, regardless of the status of the ARI-PAK 110kV circuit.

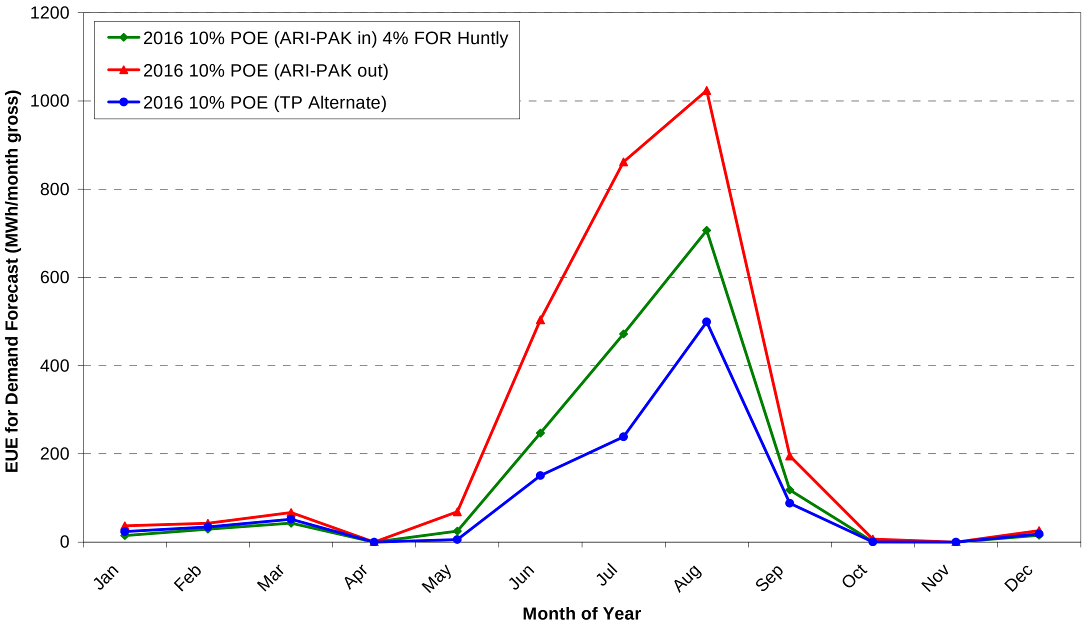
3.2) SEASONAL EUE

A standard set of analysis is completed for each simulation study outcome. Part of this is an assessment of the seasonality of EUE events. As described previously, and discussed in depth in Appendix B, the 2-4-C simulation outcomes yield very few EUE events outside of the winter period.

The following figure provides an indication of the EUE outcomes by month for the 2016 10% POE demand cases with and without the ARI-PAK 110kV circuit in service. The case where Huntly Coal power station has a 4% forced outage rate has been presented for the ARI-PAK in service case.

In these extreme 2016 10% POE demand forecast cases, EUE events start to occur in summer as demand begins to exceed the supportable load for the summer period. The summer EUE remains very small compared to the EUE that accumulates in the winter period.

Figure 3.3 – Forecast EUE by Month 2016 10% POE Peak Demand



3.3) *CAPACITY BENEFIT OF ALTERNATE NETWORK CONFIGURATIONS*

ROAM has developed a methodology for examining EUE outcomes from 2-4-C simulations to determine *the additional capacity required to reduce EUE to a target value*. This methodology can be applied to a set of study outcomes to determine the *equivalent capacity* that a change in system conditions has had, to effect a change in the EUE outcome.

3.3.1) ARI-PAK 110kV Line

The equivalent capacity methodology can be applied to find the additional MW capacity (generation or increased transmission capability) that is required in the case with the ARI-PAK circuit out of service, to meet the EUE outcome for the case with ARI-PAK in service. It may be stated then that the MW capacity outcome of this analysis is the additional support capability that the ARI-PAK 110kV line provides to the Upper North Island. Applying this methodology shows that an additional 60MW is required in the case with ARI-PAK out of service to reduce the EUE from 2830MWh to 1560MWh to meet the EUE outcome for the simulation case with ARI-PAK in service. Therefore, the ARI-PAK line contributes around 60MW to the supportable load in the Upper North Island.

3.3.2) 110kV Phase Shifting Transformers

The estimation methodology has also been applied to the simulation studies for the 2016 10% POE demand cases without PSTs on the 110kV network, to assess the additional capacity that would be required to reduce EUE to meet the outcomes from the simulation studies that have the PSTs in service. For the case with the ARI-PAK 110kV circuit in service, analysis shows that the PSTs can provide around an additional 20MW import capability into Auckland from the south. When the ARI-PAK 110kV circuit is out of service however, the PSTs on the HAM-WES and ARI-BOB 110kV circuits provide only around 6MW of additional import capability.

3.3.3) Transpower Alternate Intermediate Network Augmentations

To assess the capacity benefit of Transpower's proposed alternate intermediate network developments the equivalent capacity methodology has been applied to the 2016 10% POE demand case with ARI-PAK out of service and without PSTs. This analysis shows that in order to reduce the EUE from 2830MWh to 1110MWh a 90MW reduction in EUE events would be required. This shows that the Transpower alternate intermediate developments provide around 90MW additional import capability into the Upper North Island when the ARI-PAK 110kV circuit remains out of service.

3.4) POE DEMAND WEIGHTING AND COMPARISON WITH THE AUSTRALIAN NEM USE STANDARD

ROAM has completed EUE forecast studies for the year 2016 corresponding with demand forecasts for both Medium (50% POE) and High (10% POE) outlooks. These outcomes may be combined to develop a POE weighted EUE outcome which takes into account the POE demand distribution curve. Based on a significant body of reliability analysis completed for the Australian NEM, a 30:70 weighting for the 10:50 % POE EUE outcomes has been found to provide a reasonable approximation for a POE weighted EUE outcome. It should be noted however that the demand shape and system conditions are very different in Australia than that of New Zealand. The following is provided for indicative use only. Further work would be required to develop appropriate weightings for the POE demand cases for the New Zealand conditions.

Applying a 30:70 weighting to the case with the ARI-PAK circuit assumed to be out of service results in the following POE weighted EUE outcome for the 2016 year:

Table 3.3 – Example POE Weighted EUE Outcome
(2016, ARI-PAK Out of Service)

POE Demand	Weighting	EUE Outcome (MWh gross)
2016 10% POE	30%	2832.66
2016 50% POE	70%	63.74
Weighted		**894.41**

The following paragraphs provide a brief discussion for information purposes only. The calculations test the application of the Australian NEM Reliability Standard to the Upper North Island EUE outcomes for the 2016 study presented in Table 3.3. The Australian NEM Reliability Standard requires the long term average level of EUE to be less than 0.002% of the energy consumed in a region in a year.

The delivered energy forecast for the Upper North Island in 2016 is around 15400GWh for the Medium growth forecast and 16600GWh for the High growth forecast. Applying the same 30:70 weighting factor for simplicity results in an average 2016 energy forecast of around 15800GWh. The POE weighted EUE outcome for the 2016 year, with the ARI-PAK circuit out of service is 894MWh. The POE weighted EUE is 0.00566% of the 2016 Upper North Island energy forecast. This exceeds the Australian NEM Reliability Standard by a factor of more than two.

ROAM has applied the methodology for calculating the additional capacity that would be required to meet 0.002% in this 2016 year. It is estimated that an additional 100MW of generation or transmission import capability would be required to meet the Australian NEM Reliability Standard in the 2016 year. As the average demand growth for the Upper North Island is around 75MW to 100MW, it is estimated that the POE weighted EUE in the 2015 year will be close to the 0.002% EUE standard and the 2014 year EUE would remain safely within the Standard.

4) SUMMARY

An EUE assessment has been completed for the Upper North Island of New Zealand. The assessment has been completed by applying the 2-4-C SC-DCOPF simulation engine to develop EUE forecasts for the Upper North Island for a range of demand, generator availability and transmission network conditions. All studies presented have been completed for the transmission network state prior to a major network augmentation.

An independent review of the deterministic EUE assessment presented in the Electricity Commissions Draft 400kV determination has been completed. An error in the application of the methodology has been found. Fixing this error results in the deterministic EUE outcome for the Winter Period closely matching the EUE outcome from the probabilistic Monte Carlo 2-4-C simulation. An assessment of the estimated supportable load for the summer period has found differences between the EC analysis and the 2-4-C generation dispatch outcomes. It has been found that generation dispatch can be optimally configured to provide a supportable load of up to 2100MW under the worst likely summer contingency conditions. As such EUE will remain very low for the summer period until demand during this period begins to exceed 2100MW for significant periods of time.

Detailed assessment of the 2-4-C simulation outcomes has shown that the ARI-PAK circuit provides around 60MW of import capability into the Upper North Island. Analysis shows that introduction of PSTs on the 110kV network can provide around an additional 20MW import capability into Auckland from the south. When the ARI-PAK 110kV circuit is out of service however, the PSTs on the HAM-WES and ARI-BOB 110kV circuits provide only around 6MW of additional import capability. Transpower's proposed alternate intermediate developments provide around 90MW additional import capability into the Upper North Island, compared with the EC case with ARI-PAK out of service. This is equivalent to around one years demand growth.

The pre-augmentation assessment has shown that EUE increases exponentially as peak demand increases. There is a 'break point' around 2800MW peak demand in the Upper North Island at which EUE begins to rise rapidly, regardless of the status of the ARI-PAK 110kV circuit.

It is likely that the ARI-PAK 110kV circuit will have to be removed from service during construction of a major transmission augmentation into Auckland. With the ARI-PAK circuit out of service EUE is estimated to be below 100MWh for peak demand conditions of around 2800MW. As the Upper North Island peak demand reaches 2900MW EUE is estimated to increase to almost 1000MWh and at 3000MW peak demand EUE approaches 3000MWh. With Transpower's intermediate developments EUE outcomes are expected to be delayed by approximately one year compared with this.

Appendix A) Generator Data

Generator unit ratings have been sourced from the EC powerflow files developed for the Draft 400kV determination. Where necessary these have been scaled up to represent as generated ratings for modelling in the 2-4-C dispatch engine. For example, Huntly Coal units have been assumed to have a 250MW as generated rating. After station auxiliary loads the unit maximum output is 243MW which aligns with the EC powerflow files. Note that most wind and hydro units have been assumed to have negligible station auxiliary loads. Generator Forced Outage Rates (FOR) have been sourced directly from the referenced PBA report. The assumed average annual Number of Full Forced Outages (NFULL) has been set based on a reasonable assumed mean time to repair for each unit type.

Table A.1 – Generator Data for 2-4-C Simulation Studies

Region Name	Station Name	DUID	Winter Rating	Summer Rating	FOR	NFULL	New Entry Start Date
North Isthmus	Ngawha	NWA11_1	5.8	5.8	0.02	7	
North Isthmus	Ngawha	NWA11_2	5.8	5.8	0.02	7	
North Isthmus	Southdown	SWN_G1_1	42.0	42.0	0.02	7	
North Isthmus	Southdown	SWN_G1_2	42.0	42.0	0.02	7	
North Isthmus	Southdown	SWN_G1_3	35.0	35.0	0.02	7	
Auckland	Glenbrook	GLN_G3	55.0	55.0	0.02	7	
Auckland	Otahuhu CCGT	OTAHU_B1	365.0	328.5	0.05	18	
Waikato	Arapuni	ARI11_G5	23.4	23.4	0.015	7	
Waikato	Arapuni	ARI11_G6	23.4	23.4	0.015	7	
Waikato	Arapuni	ARI11_G7	23.4	23.4	0.015	7	
Waikato	Arapuni	ARI11_G8	23.4	23.4	0.015	7	
Waikato	Arapuni	ARI11G1-1	24.4	24.4	0.015	7	
Waikato	Arapuni	ARI11G1-2	24.4	24.4	0.015	7	
Waikato	Arapuni	ARI11G1-3	24.4	24.4	0.015	7	
Waikato	Arapuni	ARI11G1-4	24.4	24.4	0.015	7	
Waikato	Huntly Coal	HUNT_1	250.0	0.0	0.03	17	
Waikato	Huntly Coal	HUNT_2	250.0	0.0	0.03	17	
Waikato	Huntly Coal	HUNT_3	250.0	0.0	0.03	17	
Waikato	Huntly Coal	HUNT_4	250.0	0.0	0.03	17	
Waikato	Huntly Coal	HUNT_Summer[3]	0.0	400.0	0.00	0	
Waikato	Huntly E3P	HLY_E3P_1	374.0	336.6	0.050	18	
Waikato	Huntly GT	KAW_G1	48.0	43.2	0.020	7	
Waikato	Karapiro	KPO11_G1	32.0	32.0	0.015	7	
Waikato	Karapiro	KPO11_G2	32.0	32.0	0.015	7	
Waikato	Karapiro	KPO11_G3	32.0	32.0	0.015	7	

[3] The Huntly Coal Station summer derating has been modelled as a separate ‘summer’ unit with a capacity of 400MW. This summer unit has a 0% forced outage rate to ensure that 400MW is always available for the summer period.

Table A.1 – Generator Data for 2-4-C Simulation Studies							
Region Name	**Station Name**	**DUID**	**Winter Rating**	**Summer Rating**	**FOR**	**NFULL**	**New Entry Start Date**
Waikato	Maraetai	MTI11_G1	36.0	36.0	0.015	7	
Waikato	Maraetai	MTI11_G10	36.0	36.0	0.015	7	
Waikato	Maraetai	MTI11_G2	36.0	36.0	0.015	7	
Waikato	Maraetai	MTI11_G3	36.0	36.0	0.015	7	
Waikato	Maraetai	MTI11_G4	36.0	36.0	0.015	7	
Waikato	Maraetai	MTI11_G5	36.0	36.0	0.015	7	
Waikato	Maraetai	MTI11_G6	36.0	36.0	0.015	7	
Waikato	Maraetai	MTI11_G7	36.0	36.0	0.015	7	
Waikato	Maraetai	MTI11_G8	36.0	36.0	0.015	7	
Waikato	Maraetai	MTI11_G9	36.0	36.0	0.015	7	
Waikato	Te Awamutu	ANC11_G1	52.0	52.0	0.020	7	
Waikato	Te Awamutu	KINLEITH	40.0	36.0	0.020	7	
Waikato	Te Rapa	TRC_11	42.0	42.0	0.020	7	
Waikato	Waipapa	WPA11_1	19.0	19.0	0.015	7	
Waikato	Waipapa	WPA11_2	19.0	19.0	0.015	7	
Waikato	Waipapa	WPA11_3	19.0	19.0	0.015	7	
Waikato	Whakamaru	WKM_G1	25.0	25.0	0.015	7	
Waikato	Whakamaru	WKM_G2	25.0	25.0	0.015	7	
Waikato	Whakamaru	WKM_G3	25.0	25.0	0.015	7	
Waikato	Whakamaru	WKM_G4	25.0	25.0	0.015	7	
Bay Of Plenty	Aniwhenua	ANI_G1	13.5	13.5	0.015	7	
Bay Of Plenty	Aniwhenua	ANI_G2	13.5	13.5	0.015	7	
Bay Of Plenty	Aratiatia	ARA_G1	30.0	30.0	0.015	7	
Bay Of Plenty	Aratiatia	ARA_G2	30.0	30.0	0.015	7	
Bay Of Plenty	Aratiatia	ARA_G3	30.0	30.0	0.015	7	
Bay Of Plenty	Atiamuri	ATI_G1	21.0	21.0	0.015	7	
Bay Of Plenty	Atiamuri	ATI_G2	21.0	21.0	0.015	7	
Bay Of Plenty	Atiamuri	ATI_G3	21.0	21.0	0.015	7	
Bay Of Plenty	Atiamuri	ATI_G4	21.0	21.0	0.015	7	
Bay Of Plenty	Kaitawa	KTW_G6	18.5	18.5	0.015	7	
Bay Of Plenty	Kaitawa	KTW_G7	18.5	18.5	0.015	7	
Bay Of Plenty	Kawerau	KAW_G1	100.0	100.0	0.020	7	01/01/2013
Bay Of Plenty	Matahina	MAT11_G1	36.0	36.0	0.015	7	
Bay Of Plenty	Matahina	MAT11_G2	36.0	36.0	0.015	7	
Bay Of Plenty	Mohaka	TUI_G8	75.0	75.0	0.015	7	01/01/2014
Bay Of Plenty	Ohaaki	OKI13	52.0	52.0	0.020	7	
Bay Of Plenty	Ohaaki	OKI-T5/6	10.0	10.0	0.020	7	

Table A.1 – Generator Data for 2-4-C Simulation Studies							
Region Name	**Station Name**	**DUID**	**Winter Rating**	**Summer Rating**	**FOR**	**NFULL**	**New Entry Start Date**
Bay Of Plenty	Ohakuri	OHK_G1	28.0	28.0	0.015	7	
Bay Of Plenty	Ohakuri	OHK_G2	28.0	28.0	0.015	7	
Bay Of Plenty	Ohakuri	OHK_G3	28.0	28.0	0.015	7	
Bay Of Plenty	Ohakuri	OHK_G4	28.0	28.0	0.015	7	
Bay Of Plenty	Piripaua	PRI_G4	22.0	22.0	0.015	7	
Bay Of Plenty	Piripaua	PRI_G5	22.0	22.0	0.015	7	
Bay Of Plenty	Poihipi	POIHIPI	55.0	49.5	0.020	7	
Bay Of Plenty	Rotokawa	RKA_11_1	16.0	16.0	0.020	7	01/01/2006
Bay Of Plenty	Rotokawa	RKA_11_2	5.0	5.0	0.020	7	01/01/2006
Bay Of Plenty	Rotokawa	RKA_11_3	5.0	5.0	0.020	7	01/01/2006
Bay Of Plenty	Rotokawa	RKA_11_4	5.0	5.0	0.020	7	01/01/2006
Bay Of Plenty	Rotokawa II	RKA_TWOH	100.0	100.0	0.020	7	01/01/2012
Bay Of Plenty	Ruahihi	RHI_G1_1	10.0	10.0	0.015	7	01/01/2020
Bay Of Plenty	Ruahihi	RHI_G1_2	10.0	10.0	0.015	7	01/01/2020
Bay Of Plenty	Tuai	TUI_G1	16.0	16.0	0.015	7	
Bay Of Plenty	Tuai	TUI_G2	16.0	16.0	0.015	7	
Bay Of Plenty	Tuai	TUI_G3	28.0	28.0	0.015	7	
Bay Of Plenty	Wheao	WEO_11	27.0	27.0	0.015	7	
Bay Of Plenty	Whiranaki	WHIRI_1	52.0	46.8	0.020	7	
Bay Of Plenty	Whiranaki	WHIRI_2	52.0	46.8	0.020	7	
Bay Of Plenty	Whiranaki	WHIRI_3	52.0	46.8	0.020	7	
Central	Central Wind	TARARUA_2	100.0	100.0	0.020	7	
Central	Central Wind	TE_APITI	90.0	90.0	0.020	7	
Central	Mangahao	MANG	37.0	37.0	0.015	7	
Central	Rangipo	RPO_G5	60.0	60.0	0.015	7	
Central	Rangipo	RPO_G6	60.0	60.0	0.015	7	
Central	Tokaanu	TKU_G1	60.0	60.0	0.015	7	
Central	Tokaanu	TKU_G2	60.0	60.0	0.015	7	
Central	Tokaanu	TKU_G3	60.0	60.0	0.015	7	
Central	Tokaanu	TKU_G4	60.0	60.0	0.015	7	
Taranaki	New Plymouth	NEWPLYMOIL	300.0	270.0	0.040	14	
Taranaki	New Plymouth	NEWPLYM_1	100.0	100.0	0.040	14	01/01/2014
Taranaki	New Plymouth	NEWPLYM_2	100.0	100.0	0.040	14	01/01/2014
Taranaki	New Plymouth	NEWPLYM_3	100.0	100.0	0.040	14	01/01/2014
Taranaki	Patea	PTA11_1	10.4	10.4	0.015	7	
Taranaki	Patea	PTA11_2	10.4	10.4	0.015	7	
Taranaki	Patea	PTA11_3	10.4	10.4	0.015	7	

Table A.1 – Generator Data for 2-4-C Simulation Studies							
Region Name	**Station Name**	**DUID**	**Winter Rating**	**Summer Rating**	**FOR**	**NFULL**	**New Entry Start Date**
Taranaki	Taranaki CCGT	TCC	357.0	321.3	0.050	18	
Taranaki	Tauhara	SFD_KIWI	15.0	15.0	0.020	7	01/01/2024
Wellington	Makara Wind	WIL_WF1	24.0	24.0	0.020	7	01/01/2008
Wellington	Southern Cogen	KAPUNI	25.0	22.5	0.020	7	
Wellington	Southern Cogen	WAA11_T2_1	10.0	10.0	0.020	7	
Wellington	Southern Cogen	WAA11_T2_2	10.0	10.0	0.020	7	
Wellington	Southern Cogen	WAA11_T3_1	10.0	10.0	0.020	7	
Wellington	Southern Cogen	WAA11_T3_2	10.0	10.0	0.020	7	
Wellington	Southern Cogen	WAA11_T4	29.0	29.0	0.020	7	
Wellington	Southern Geothermal	MOK11_1	22.6	22.6	0.020	7	
Wellington	Southern Geothermal	MOK11_2	5.4	5.4	0.020	7	
Wellington	Southern Geothermal	MOK11_3	5.4	5.4	0.020	7	
Wellington	Southern Geothermal	MOK11_4	5.4	5.4	0.020	7	
Wellington	Southern Geothermal	MOK11_5	5.4	5.4	0.020	7	
Wellington	Southern Geothermal	MOK11_6	5.4	5.4	0.020	7	
Wellington	Southern Geothermal	MOK11_7	5.4	5.4	0.020	7	
Wellington	Southern Geothermal	WRK_T3_S_1	11.2	11.2	0.020	7	
Wellington	Southern Geothermal	WRK_T3_S_2	11.2	11.2	0.020	7	
Wellington	Southern Geothermal	WRK_T3_S_3	11.2	11.2	0.020	7	
Wellington	Southern Geothermal	WRK_T4_T	30.0	30.0	0.020	7	
Wellington	Southern Geothermal	WRK_TF_S	30.0	30.0	0.020	7	
Wellington	Southern Geothermal	WRK_TF3	30.0	30.0	0.020	7	
Wellington	Southern Geothermal	WRK11(2)_1	11.2	11.2	0.020	7	
Wellington	Southern Geothermal	WRK11(2)_2	11.2	11.2	0.020	7	
Wellington	Southern Geothermal	WRK11(2)_3	11.2	11.2	0.020	7	
Wellington	Southern Geothermal	WRK_EXT1	14.0	14.0	0.020	7	01/01/2005
Wellington	Southern Geothermal	WRK_G11H	180.0	180.0	0.020	7	01/01/2012

Appendix B) Review of EC Summer PSS/E Contingency Analysis and EUE Assessment

ROAM has applied the 2-4-C Security Constrained DC Optimal Power Flow (SC-DCOPF) Monte Carlo simulation software to determine Expected Unserved Energy (EUE) for the Upper North Island of New Zealand.

The Electricity Commission of New Zealand (EC) has completed an assessment of EUE by applying a deterministic calculation methodology from solved power flow cases. The solved power flow cases have been analysed to find the maximum supportable load in the Upper North Island for a given set of generation dispatch and transmission system availability.

ROAM has completed a benchmark SC-DCOPF Monte Carlo simulation of the 2016 year. This benchmark assessment resulted in 18MWh EUE. The Monte Carlo assessment reveals EUE events occur almost entirely within the Winter period. This aligns very well with the revised PBA deterministic assessment for the 2016 Winter without rounding up to the nearest 50MW block of 24MWh.

This appendix discusses the findings of an assessment into the difference between the ROAM and EC analysis for the Extreme Summer period. The revised PBA deterministic assessment for the 2016 Extreme Summer shows up to 119MWh EUE, whereas the ROAM 2-4-C simulation studies result in very little to nil EUE for periods outside of Winter.

B.1) Load Trace Data

Discussion in the EC's supporting documentation states that the Winter and Extreme Summer periods have been assigned the same growth factors for developing future load duration curves[4]. The same report also states that the 'reference' load year is the 2004 year.

ROAM has also used the metered data for the 2004 calendar year as the reference year for developing load trace forecasts. ROAM has also applied a linear growth factor for all periods of the year to meet the peak Winter forecast demand target. The figure below illustrates the 2016 Medium growth (50% POE) forecast load duration curves for the three periods of the year as described in the SSG report. The PB Associates report[5] states that evenings from the Extreme Summer and Winter periods have been shifted to the Winter load duration curve for their analysis. For the illustration show in Figure B.1 below, that has not been completed. The PBA report also states that their analysis is based on a year ending February (1 March to 28/29 Feb). The ROAM analysis presented below and throughout this report is based on the 2016 calendar year.

[4] SSG Report, Transmission Augmentations into Auckland : Technical Analysis of Transpower's Proposal and Short-listed Alternatives Part I, 21 April 2006. [p18]

[5] PB Associates, Transmission Augmentations into Auckland : Investigation into the Anticipated Un-Served Energy, 5 April 2006.

Figure B.1 – ROAM Forecast Load Duration Curves
2016 Medium Growth Delivered (50% POE)

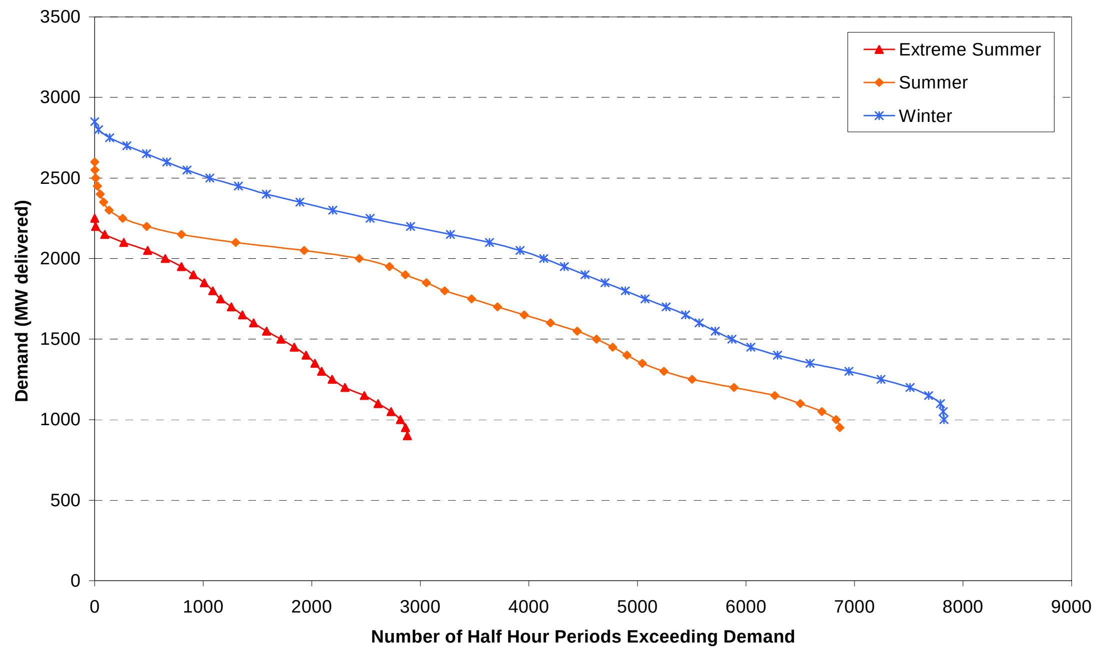


Table B.1 below provides a comparison of the ROAM and EC forecast peak demand for the three periods of the year. The ROAM forecast Upper North Island peak Winter demand is marginally higher than that presented by the EC. This is due to developing the forecast to meet the published forecast demand which is at time of whole of North Island peak demand. ROAM has found that the following day results in a marginally higher Upper North Island peak demand when applying the growth factors to achieve the (2785MW) peak demand at time of whole of North Island peak demand.

Table B.1 – Comparison of ROAM and EC Peak Demand Load Trace Forecast
2016 Medium Growth Delivered (50% POE)

YEAR	WINTER	SUMMER	E.SUMM
EC	2785.02	2601.34	2198.70
ROAM	2799.14	2505.09	2180.10

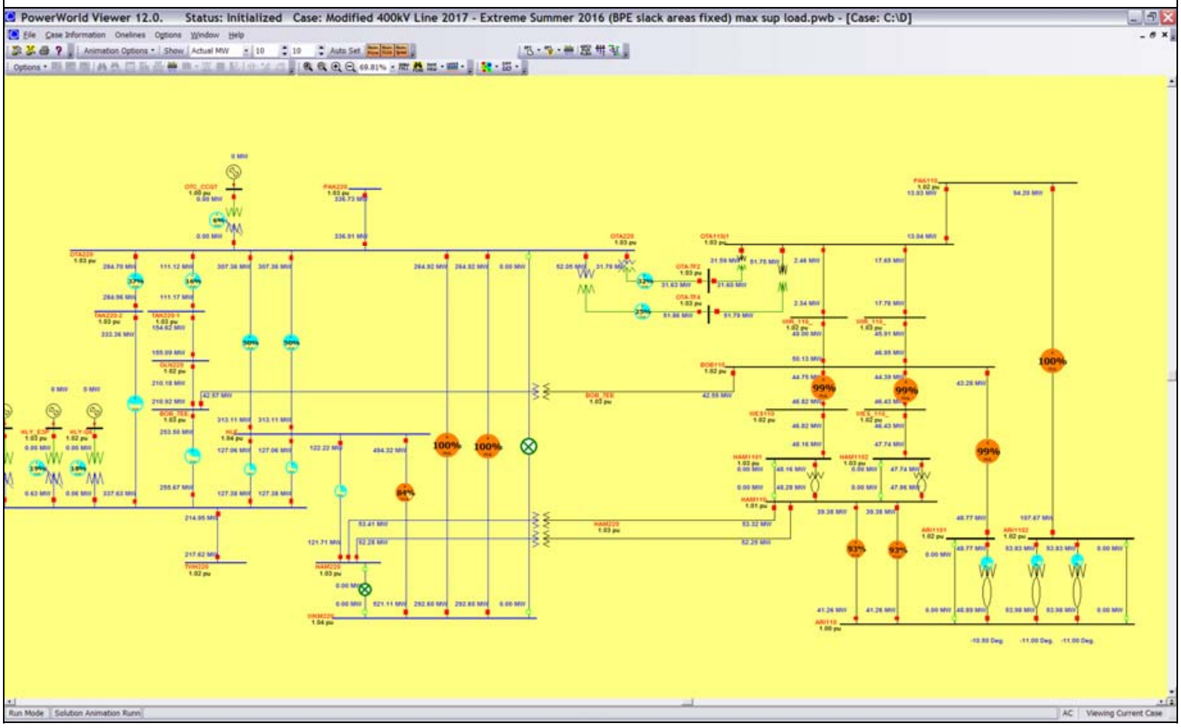
Given that the Winter and Extreme Summer peak demand forecast for both ROAM and the EC are very similar it has been determined that it is not the load trace forecasts that have resulted in the differing Extreme Summer EUE forecast.

B.2) AC Power Flow Analysis

ROAM has analysed the Extreme Summer power flow file, *Modified 400kV Line 2017 - Extreme Summer 2016.raw*, to verify the contingency tables on which the EC EUE analysis is based. For the 2016 Extreme Summer a single dominant contingency leads to almost 100% of the EUE forecast. The conditions for this are outage of the Otahuhu CCGT, Huntly E3P CCGT and a WKM-HAM 220kV line contingency. The limiting factor is overload of the parallel WKM-OTA 220kV lines. The EC analysis has determined that the maximum supportable load under these conditions is 1994MW.

ROAM has found that up to 2100MW can be supported under the worst Extreme Summer contingency as described above whilst maintaining all network flows within 100% of their Summer thermal rating. In order to achieve this, the assumed installed Phase Shifting Transformers (PST's) on the 110kV system have been set to around -11 degrees. Additionally, as 2-4-C optimises generation dispatch to reduce the impact of constraints where these might cause EUE, a balance of the 220kV and 110kV networks is achieved where possible by dispatching generation appropriately. Figure B.2 below shows the loadings in percentage terms of the main transmission system into Auckland from a PowerWorld solved AC load flow. The load and generation dispatch has been loaded in from a 2-4-C dispatch period. In this case the worst contingency conditions have been set and the Upper North Island demand has been set to 2105MW delivered. It may be noted that in this example 2-4-C dispatch case the Huntly GT is also unavailable.

Figure B.2 – Extreme Summer Supportable Demand – PowerWorld AC Load Flow



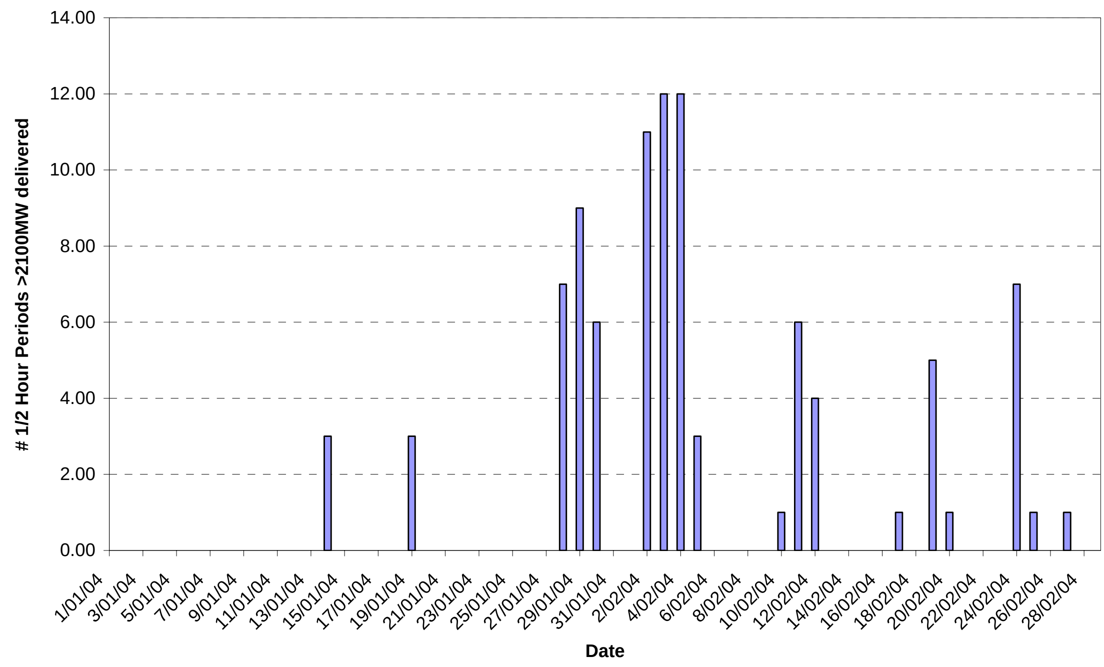
With the PST's assumed to not be in service the supportable load reduces to around 2050MW. If the Huntly GT was assumed to be available, up to 2075 MW may be supplied to the Upper North Island.

B.3) Monte Carlo Time Sequential Simulation

The 2-4-C simulation is a time sequential Monte Carlo dispatch engine. It applies random generator forced outages in conjunction with time sequential half hourly load trace forecasts. Further analysis of the forecast load trace reveals that there are 93 half hour periods where the Upper North Island forecast demand trace for Extreme Summer for

2016 50% POE conditions exceeds 2100MW delivered. These 93 periods are distributed across the days of the Extreme Summer period and generally occur in the morning up until the early afternoon. It follows that the likelihood of coincidence of the worst contingency conditions in conjunction with periods where the demand exceeds 2100MW is very low.

Figure B.3 – ROAM Forecast Load Trace
2016 Medium Growth Delivered (50% POE)
Periods Exceeding 2100MW on Extreme Summer Days



B.4) Summary

As 2-4-C optimises generation dispatch to reduce the impact of constraints where these might cause EUE, a balance of the 220kV and 110kV networks is achieved where possible by dispatching generation appropriately. ROAM has found that generation dispatch can be optimally configured to provide a supportable load of up to 2100MW under the worst likely Extreme Summer contingency conditions.

As the 2-4-C Monte Carlo simulation is a time sequential dispatch engine the likelihood of coincidence of the worst generator availability and transmission contingency conditions at times which exceed 2100MW of demand in the Upper North Island is further reduced.