TRANSPOWER

Transpower Analysis of the Electricity Commission's Transmission Options

SUPPLEMENTAL INFORMATION

10 February 2006

Supplementary Documentation

1. **Internal Document - Assessment of Transmission Losses**
2. **Roam Consulting Report to Transpower - Assessment of Reliability of Supply into Auckland – 2010**
3. **Internal Document – Transpower Analysis of the Electricity Commission’s Transmission Options: Analysis Spreadsheets**

1 Assessment of Transmission Losses

The difference in the transmission losses under each transmission option is evaluated using the simplified model.

Transmission losses under winter peak load conditions (assuming medium growth average half hour demand forecasts) are evaluated using ac load-flow studies, for each of the options and for each of the generation scenarios described in the Statement of Opportunities 2005. The generation scenarios considered in the assessment are:

- Gas and Thermal (SC1)
- Coal Thermal (SC2)
- Large Hydro (SC3)
- Renewables (SC4) and
- Low demand (SC5):

The average annual power loss in the transmission system assumed to be equal to "annual loss factor x peak power loss", where annual loss factor represents the ratio "(total annual energy loss in the transmission system) / (2 x 8,760 x energy loss in the transmission system during the peak half hour)". Analysis of the dispatch data during 2005 indicates that the "loss factor" could be as high as 0.6. In comparing the transmission options, the market benefits are assessed assuming a wide variation in the loss factor, from 0.38 – 0.6.

Table 1: Transmission Losses (winter peak) under Generation Scenario 1

unit: MW

Year	Transmission Option				
	T0	T1	T2	T3	T4
2010	43.3	44.4	52.0	52.0	52.0
2011	40.1	34.1	39.0	39.0	39.0
2012	40.6	36.6	41.9	41.9	41.9
2013	41.3	39.4	45.4	45.4	45.4
2014	42.1	42.7	49.4	49.4	49.4
2015	43.2	46.5	54.2	54.2	54.2
2016	39.4	34.4	38.8	38.8	38.8
2017	40.1	37.1	36.3	40.9	34.2
2018	40.9	40.2	38.1	45.0	35.2
2019	48.5	44.2	48.4	50.8	47.4
2020	49.1	46.4	49.5	52.0	48.0
2021	49.9	42.6	50.9	54.1	48.8
2022	50.9	43.6	52.6	57.1	49.7
2023	57.8	48.7	58.8	61.8	56.5
2024	61.9	51.4	60.7	61.5	60.4
2025	62.1	51.8	61.2	62.9	60.6
2026	62.5	52.4	62.0	64.9	61.0
2027	63.0	53.0	63.1	65.7	61.5
2028	63.7	53.9	64.4	67.4	62.2
2029	64.6	54.8	66.1	70.1	63.0
2030	65.7	56.0	68.0	73.7	64.1
2031	67.0	57.3	70.3	78.4	65.3
2032	68.4	58.7	72.9	70.6	66.7
2033	70.1	60.4	75.8	72.5	68.3
2034	71.9	62.2	79.1	74.6	70.2
2035	74.0	64.2	82.8	77.2	72.2
2036	76.4	66.5	86.9	80.3	74.5
2037	79.0	68.9	91.5	83.8	77.1
2038	81.9	71.7	91.5	85.6	79.9
2039	85.1	74.7	91.5	88.0	83.1
2040	88.6	77.9	91.5	91.3	86.6
2041	92.5	81.5	91.5	95.6	90.4
2042	96.8	85.4	91.5	100.8	94.5
2043	101.4	89.6	91.5	107.0	99.1
2044	101.4	94.1	91.5	107.0	99.1
2045	101.4	98.9	91.5	107.0	99.1
2046	101.4	98.9	91.5	107.0	99.1
2047	101.4	98.9	91.5	107.0	99.1
2048	101.4	98.9	91.5	107.0	99.1
2049	101.4	98.9	91.5	107.0	99.1
2050	101.4	98.9	91.5	107.0	99.1

Table 2: Transmission Losses (winter peak) under Generation Scenario 2

unit: MW

Year	Transmission Option				
	T0	T1	T2	T3	T4
2010	43.3	44.4	52.0	52.0	52.0
2011	40.1	34.1	39.0	39.0	39.0
2012	40.6	36.6	41.9	41.9	41.9
2013	41.3	39.4	45.4	45.4	45.4
2014	49.4	41.9	48.4	48.4	48.4
2015	50.1	44.8	51.9	51.9	51.9
2016	50.8	48.1	55.9	55.9	55.9
2017	47.6	36.5	39.8	42.0	39.1
2018	47.9	38.4	40.7	43.0	39.6
2019	48.3	40.8	42.0	44.9	40.3
2020	48.9	43.6	43.5	47.9	41.1
2021	49.7	37.6	45.3	51.8	42.1
2022	50.7	38.9	47.4	56.7	43.3
2023	51.8	40.2	49.9	48.6	44.7
2024	53.2	41.8	52.5	50.5	46.2
2025	54.7	43.4	55.5	52.7	47.9
2026	56.3	45.2	58.8	55.2	49.7
2027	58.2	47.2	62.3	58.1	51.7
2028	60.2	49.2	66.2	61.3	54.0
2029	62.4	51.5	70.4	63.0	56.3
2030	60.7	53.9	74.9	64.5	58.9
2031	63.5	56.5	79.8	66.5	61.7
2032	66.6	59.3	85.1	69.1	64.7
2033	69.9	62.3	90.7	72.4	68.0
2034	73.5	65.5	96.9	76.4	71.4
2035	77.3	69.0	103.6	81.1	75.2
2036	81.4	72.7	110.8	86.7	79.3
2037	85.9	76.6	118.6	93.1	83.7
2038	90.8	81.0	127.0	100.5	88.4
2039	95.9	85.6	136.0	109.1	93.5
2040	101.5	90.5	145.8	118.7	99.0
2041	107.5	95.8	145.8	129.4	104.9
2042	113.9	101.4	145.8	129.4	111.2
2043	120.7	107.4	145.8	129.4	117.8
2044	128.0	107.4	145.8	129.4	125.1
2045	135.7	107.4	145.8	129.4	132.7
2046	135.7	107.4	145.8	129.4	137.6
2047	135.7	107.4	145.8	129.4	142.7
2048	135.7	107.4	145.8	129.4	147.9
2049	135.7	107.4	145.8	129.4	147.9
2050	135.7	107.4	145.8	129.4	147.9

Table 3: Transmission Losses (winter peak) under Generation Scenario 3

unit: MW

Year	Transmission Option				
	T0	T1	T2	T3	T4
2010	45.0	48.9	57.8	57.8	57.8
2011	46.2	53.3	63.4	63.4	63.4
2012	47.7	58.2	69.7	69.7	69.7
2013	49.3	63.5	76.5	76.5	76.5
2014	54.7	64.7	77.6	77.6	77.6
2015	56.4	70.2	84.8	84.8	84.8
2016	58.2	76.2	92.6	92.6	92.6
2017	60.3	83.2	67.2	75.6	54.4
2018	62.6	90.4	71.6	80.7	56.9
2019	65.1	98.2	76.3	86.5	59.6
2020	63.6	106.5	81.3	67.0	62.4
2021	66.7	59.1	86.7	69.8	65.4
2022	70.0	62.0	92.4	73.3	68.7
2023	73.4	65.2	98.4	77.3	72.0
2024	77.0	68.4	104.7	81.9	75.6
2025	80.8	71.8	111.4	87.1	79.3
2026	84.8	75.4	118.4	92.9	83.2
2027	89.0	79.1	125.7	99.3	87.3
2028	93.3	82.9	133.4	106.5	91.6
2029	98.0	87.1	141.4	114.3	96.1
2030	102.8	91.4	150.0	122.9	100.9
2031	107.9	95.8	159.0	132.3	106.0
2032	113.2	100.5	159.0	132.3	111.2
2033	118.9	105.5	159.0	132.3	116.8
2034	124.8	110.7	159.0	132.3	122.7
2035	131.1	116.2	159.0	132.3	128.9
2036	137.8	122.0	159.0	132.3	135.5
2037	144.9	128.2	159.0	132.3	142.5
2038	152.5	134.7	159.0	132.3	149.9
2039	152.5	141.6	159.0	132.3	149.9
2040	152.5	149.0	159.0	132.3	149.9
2041	152.5	156.8	159.0	132.3	149.9
2042	152.5	165.0	159.0	132.3	149.9
2043	152.5	173.7	159.0	132.3	149.9
2044	152.5	173.7	159.0	132.3	149.9
2045	152.5	173.7	159.0	132.3	149.9
2046	152.5	173.7	159.0	132.3	149.9
2047	152.5	173.7	159.0	132.3	149.9
2048	152.5	173.7	159.0	132.3	149.9
2049	152.5	173.7	159.0	132.3	149.9
2050	152.5	173.7	159.0	132.3	149.9

Table 4: Transmission Losses (winter peak) under Generation Scenario 4

unit: MW

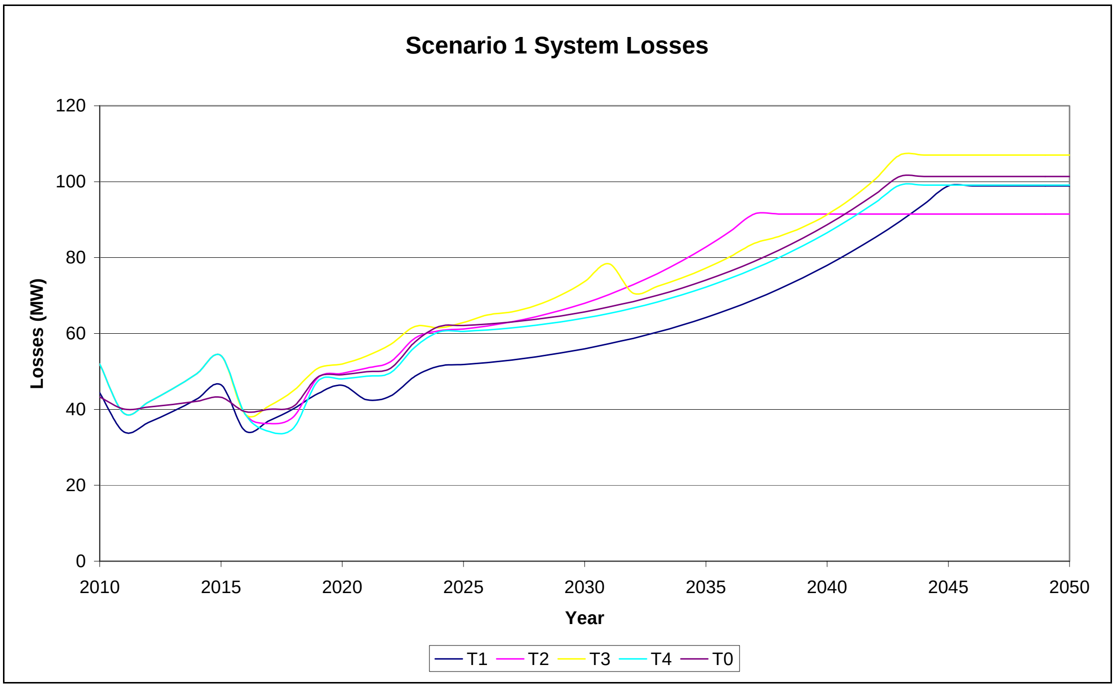
Year	Transmission Option				
	T0	T1	T2	T3	T4
2010	45.0	48.9	57.8	57.8	57.8
2011	46.2	53.3	63.4	63.4	63.4
2012	47.7	58.2	69.7	69.7	69.7
2013	49.3	63.5	76.5	76.5	76.5
2014	51.0	69.1	84.0	84.0	84.0
2015	53.0	75.4	92.2	92.2	92.2
2016	55.2	82.2	101.3	101.3	101.3
2017	57.7	89.9	69.0	78.5	53.3
2018	60.3	97.9	73.9	84.7	56.1
2019	63.1	106.5	79.2	91.5	59.0
2020	66.2	115.6	84.7	66.6	62.2
2021	69.4	59.6	90.6	70.3	65.5
2022	72.8	62.8	96.9	74.7	69.1
2023	76.4	66.2	103.4	79.7	72.8
2024	80.2	69.7	110.4	85.3	76.7
2025	84.1	73.3	117.6	91.5	80.7
2026	88.3	77.1	125.1	98.4	84.9
2027	92.6	81.1	133.0	105.8	89.4
2028	97.1	85.4	133.0	114.1	94.0
2029	100.7	89.7	133.0	123.0	98.8
2030	105.9	94.2	133.0	123.0	104.0
2031	111.3	98.9	133.0	123.0	109.4
2032	117.0	103.9	133.0	123.0	115.0
2033	123.0	109.1	133.0	123.0	120.9
2034	129.4	114.7	133.0	123.0	127.0
2035	136.1	120.5	133.0	123.0	133.7
2036	143.1	126.6	133.0	123.0	140.7
2037	150.7	133.1	133.0	123.0	140.7
2038	150.7	140.0	133.0	123.0	140.7
2039	150.7	147.3	133.0	123.0	140.7
2040	150.7	155.0	133.0	123.0	140.7
2041	150.7	163.2	133.0	123.0	140.7
2042	150.7	163.2	133.0	123.0	140.7
2043	150.7	163.2	133.0	123.0	140.7
2044	150.7	163.2	133.0	123.0	140.7
2045	150.7	163.2	133.0	123.0	140.7
2046	150.7	163.2	133.0	123.0	140.7
2047	150.7	163.2	133.0	123.0	140.7
2048	150.7	163.2	133.0	123.0	140.7
2049	150.7	163.2	133.0	123.0	140.7
2050	150.7	163.2	133.0	123.0	140.7

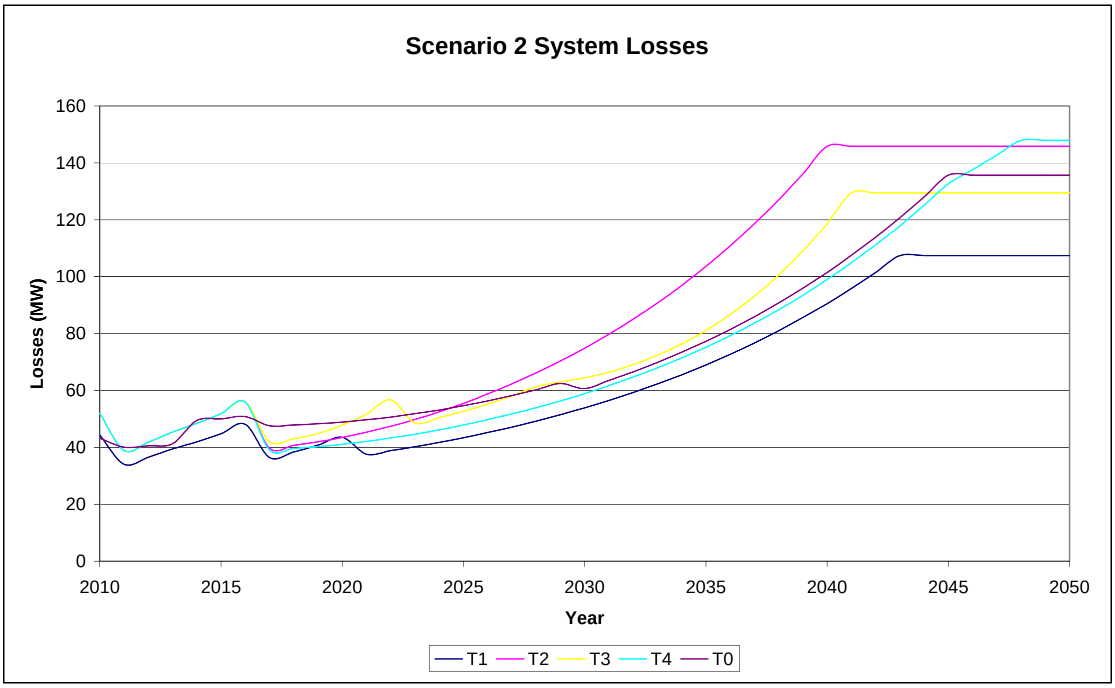
Table 5: Transmission Losses (winter peak) under Generation Scenario 5

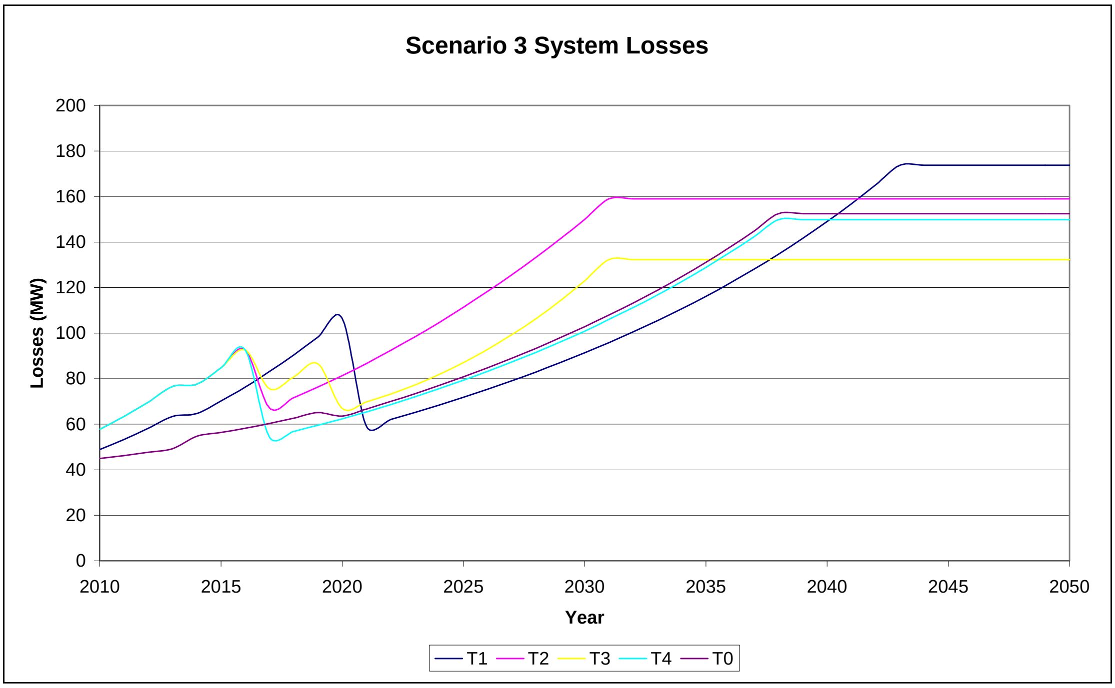
unit: MW

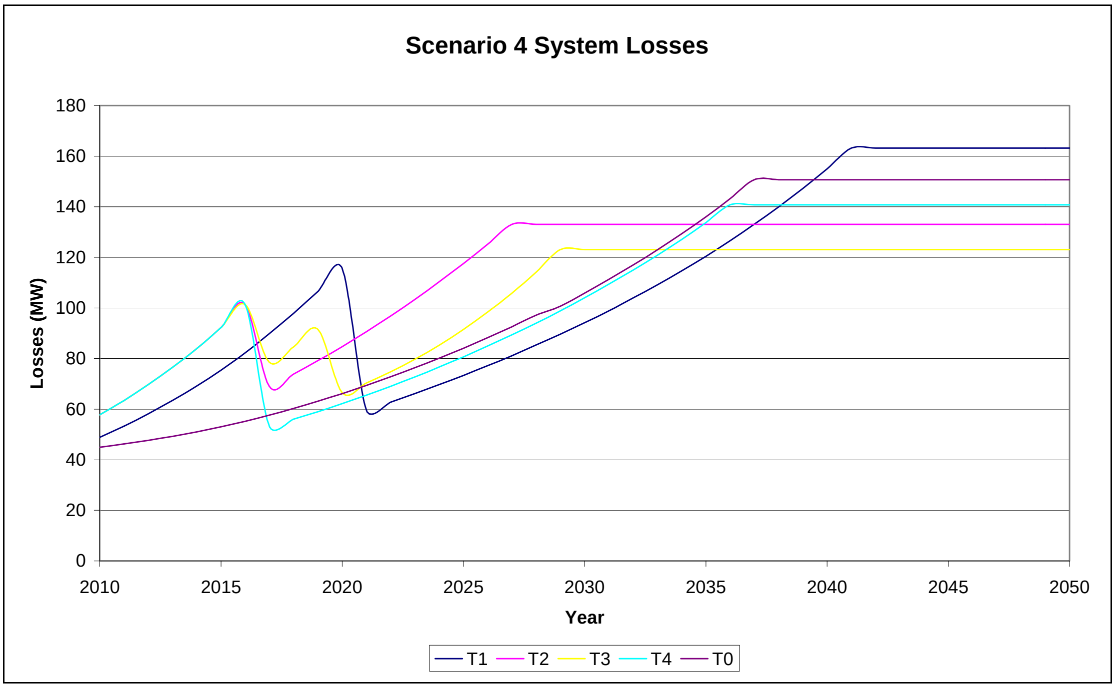
Year	Transmission Option				
	T0	T1	T2	T3	T4
2010	45.0	48.9	57.8	57.8	57.8
2011	46.2	53.3	63.4	63.4	63.4
2012	47.7	58.2	69.7	69.7	69.7
2013	49.3	63.5	76.5	76.5	76.5
2014	42.4	42.8	49.6	49.6	49.6
2015	43.5	46.6	54.3	54.3	54.3
2016	44.7	50.8	59.6	59.6	59.6
2017	46.2	55.6	47.8	56.2	41.0
2018	47.8	61.0	51.0	58.9	42.8
2019	49.6	66.8	54.5	62.3	44.8
2020	51.6	73.0	58.3	54.1	46.9
2021	53.8	45.0	62.4	56.6	49.3
2022	56.2	47.4	66.8	57.8	51.8
2023	58.8	49.9	71.6	59.5	54.5
2024	61.5	52.6	76.6	61.8	57.4
2025	64.4	55.4	81.9	64.7	60.4
2026	67.5	58.3	87.5	68.1	63.6
2027	70.8	61.4	93.5	72.2	67.0
2028	74.3	64.6	99.8	76.8	70.6
2029	78.0	68.1	106.6	82.1	74.4
2030	81.9	71.7	113.6	88.0	78.4
2031	86.0	75.5	121.1	94.7	82.6
2032	90.4	79.6	129.2	102.1	87.1
2033	95.1	83.9	129.2	110.4	91.8
2034	100.1	88.4	129.2	119.5	96.9
2035	105.4	93.1	129.2	119.5	102.3
2036	110.3	98.2	129.2	119.5	108.0
2037	116.5	103.6	129.2	119.5	114.1
2038	123.0	109.3	129.2	119.5	120.5
2039	130.1	115.4	129.2	119.5	127.5
2040	137.6	121.9	129.2	119.5	134.9
2041	145.6	128.8	129.2	119.5	134.9
2042	145.6	136.1	129.2	119.5	134.9
2043	145.6	143.8	129.2	119.5	134.9
2044	145.6	152.0	129.2	119.5	134.9
2045	145.6	152.0	129.2	119.5	134.9
2046	145.6	152.0	129.2	119.5	134.9
2047	145.6	152.0	129.2	119.5	134.9
2048	145.6	152.0	129.2	119.5	134.9
2049	145.6	152.0	129.2	119.5	134.9
2050	145.6	152.0	129.2	119.5	134.9

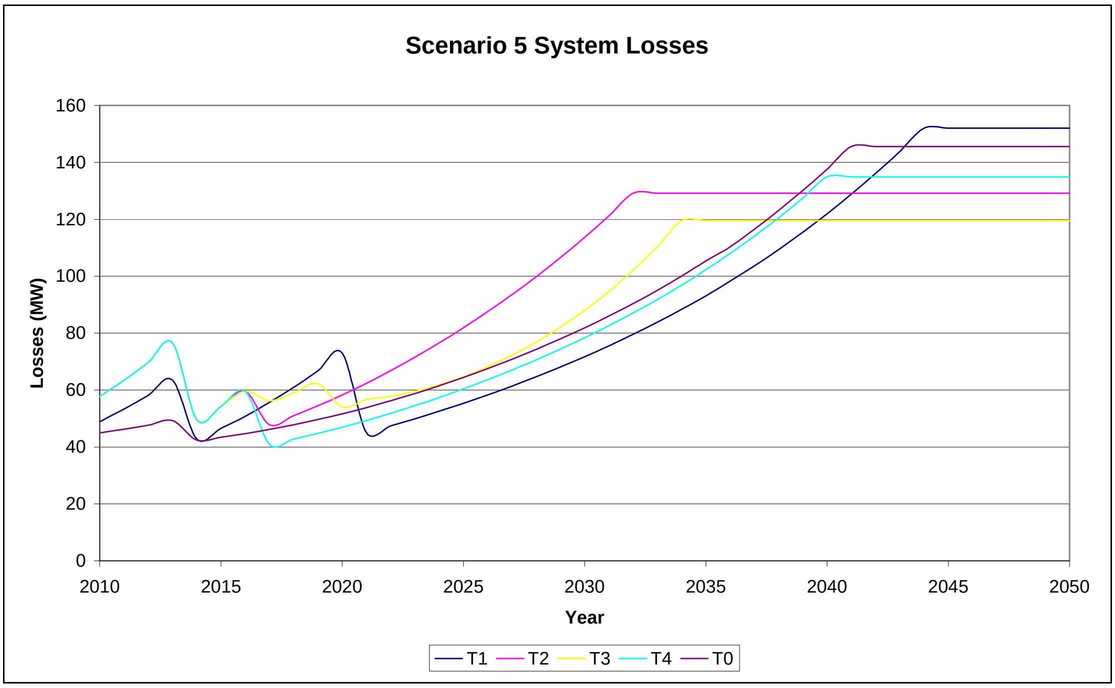
Loss graphs


Scenario 1 System Losses
Losses (MW)
0
20
40
60
80
100
120
2010
2015
2020
2025
2030
2035
2040
2045
2050
Year
T1
T2
T3
T4
T0


Scenario 2 System Losses
Losses (MW)
0
20
40
60
80
100
120
140
160
2010
2015
2020
2025
2030
2035
2040
2045
2050
Year
T1
T2
T3
T4
T0


Scenario 3 System Losses
Losses (MW)
200
180
160
140
120
100
80
60
40
20
0
2010
2015
2020
2025
2030
2035
2040
2045
2050
Year
T1
T2
T3
T4
T0


Scenario 4 System Losses
Losses (MW)
180
160
140
120
100
80
60
40
20
0
2010
2015
2020
2025
2030
2035
2040
2045
2050
Year
T1
T2
T3
T4
T0


Scenario 5 System Losses
Losses (MW)
0
20
40
60
80
100
120
140
160
2010
2015
2020
2025
2030
2035
2040
2045
2050
Year
T1
T2
T3
T4
T0

2 Roam Consulting Report

ROAM Consulting®

ROAM Consulting Pty Ltd
A.B.N. 54 091 533 621

Report (Trp00001) to

TRANSPOWER

NATIONAL ELECTRICITY MARKET FORECASTING

Assessment of Reliability of Supply into Auckland - 2010

13 February 2006

TABLE OF CONTENTS

LIST OF TABLES

LIST OF FIGURES

3 Introduction

Transpower is in the process of applying to the Electricity Commission for approval for a new 400kV HVAC transmission line, approximately 190km in length, connecting Whakamaru and Otahuhu substations. The proposed transmission augmentation will be required to ensure continued reliable supply into the Auckland and Northland regions of the North Island. Transpower has identified that the reliability of supply is at risk from the winter of 2010.

ROAM Consulting (ROAM) will undertake modelling for reliability of supply into Auckland in two stages.

This report details the initial stage where reliability studies have been completed for the 2010 calendar year using a three zone model of Auckland, Huntly and Whakamaru. The model incorporates two radial feeds to Auckland, one from Huntly and one from Whakamaru with transmission limits based on the 'firm' rating between zones.

The second stage will expand the analysis to an 8 zone model of the North Island with the HVDC Link and South Island modelled as a single zone.

4 Modelling Methodology and Assumptions

ROAM's modelling methodology using the 2-4-C market simulation software and a detailed summary of assumptions are contained in an accompanying Assumptions Report dated 19th January 2006.

Market and reliability simulations have been developed for six sensitivity cases as described in the table below:

Table 2.1 – Summary of Studies Completed

Case	Energy and Demand Forecast	Transmission Configuration
Case #01-M10 **Case #01-M50** **(Base Case)**	Mean Energy Forecast High (10% POE[1]) demand and Mean (50% POE) demand	Maximum Limit assumes three limit increases from current 2005 situation: 1. Huntly E3P generator support; 2. Huntly East Switching; 3. OTA-WKM retensioning.
Case #02-M10 **Case #02-M50**	Mean Energy Forecast High (10% POE) demand and Mean (50% POE) demand	Sensitivity assumes Otahuhu CCGT is out of service for the entire year with associated n-1-1 limits in effect.
Case #02-M10-90	As for Base Case	As for Case #02 but with 10% reduction in all individual thermal transmission limits.

[1] ROAM uses the term Probability of Exceedence (POE) to define the confidence intervals of demand forecasting. A 10% POE thus corresponds with a demand forecast that is expected to be exceeded only 1 year in 10, on average.

Table 2.1 – Summary of Studies Completed		
Case	**Energy and Demand Forecast**	**Transmission Configuration**
Case #03-M10 **Case #03-M50**	Mean Energy Forecast High (10% POE) demand and Mean (50% POE) demand	Sensitivity assumes Whakamaru–Huntly East section of WKM-OTA line 3 is out of service for entire year.
Case #04-M10 **Case #04-M50**	Mean Energy Forecast High (10% POE) demand and Mean (50% POE) demand	Combined worst case with both Otahuhu CCGT and Whakamaru–Huntly East section of WKM-OTA line 3 out of service for entire year.
Case #05-M10-1 **Case #05-M10-2** **Case #05-M10-4** **Case #05-M10-6**	Sensitivity to demand growth with a 1%, 2%, 4% and 6% increase in demand and energy	As for Base Case
Case #06-M10-1 **Case #06-M10-2** **Case #06-M10-4** **Case #06-M10-6**	Sensitivity to demand growth with a 1%, 2%, 4% and 6% increase in demand and energy	Sensitivity assumes Otahuhu CCGT is out of service for the entire year with associated n-1-1 limits in effect.

5 Study Outcomes

The reliability of supply in the Auckland area is determined by the simulation model given the demand, generation and transmission capability throughout the year. To simulate the reliability of supply into the Auckland and Northland regions, ROAM has conducted single year, 100-iteration simulations using the 2-4-C monte-carlo market simulation software. The year of interest for the study is the 2010 calendar year.

5.1 Expected Levels of Unserved Energy

Table 3.2 below provides a summary of unserved energy events for each of the sensitivity cases included in this study. The summary table includes additional information on the state of the system at times of USE as follows:

Table 3.1 – USE Summary Terms	
Total # Periods USE	The total number of periods (½ hourly trading intervals) in which the demand in Auckland + Northland could not adequately be served in all 100 iterations. Divide by 100 to estimate the average number of periods in which you would expect USE in a single year.
# Otahuhu CCGT Off	The total number of periods in which the Otahuhu CCGT was NOT on-line and operating AND there was USE.
# Otahuhu CCGT On	The total number of periods in which the Otahuhu CCGT was on-line and operating AND there was USE.
# WKM-HLY Constrained	The total number of periods in which flows on the Whakamaru to Huntly line section was constrained at the limit AND there was USE.
# WKM-OTA Constrained	The total number of periods in which flows on the Whakamaru to Otahuhu line section was constrained at the limit AND there was USE.
Annual Average USE (GWh)	The annual average expected USE expressed in GWh.

Table 3.2 – Summary of USE Outcomes

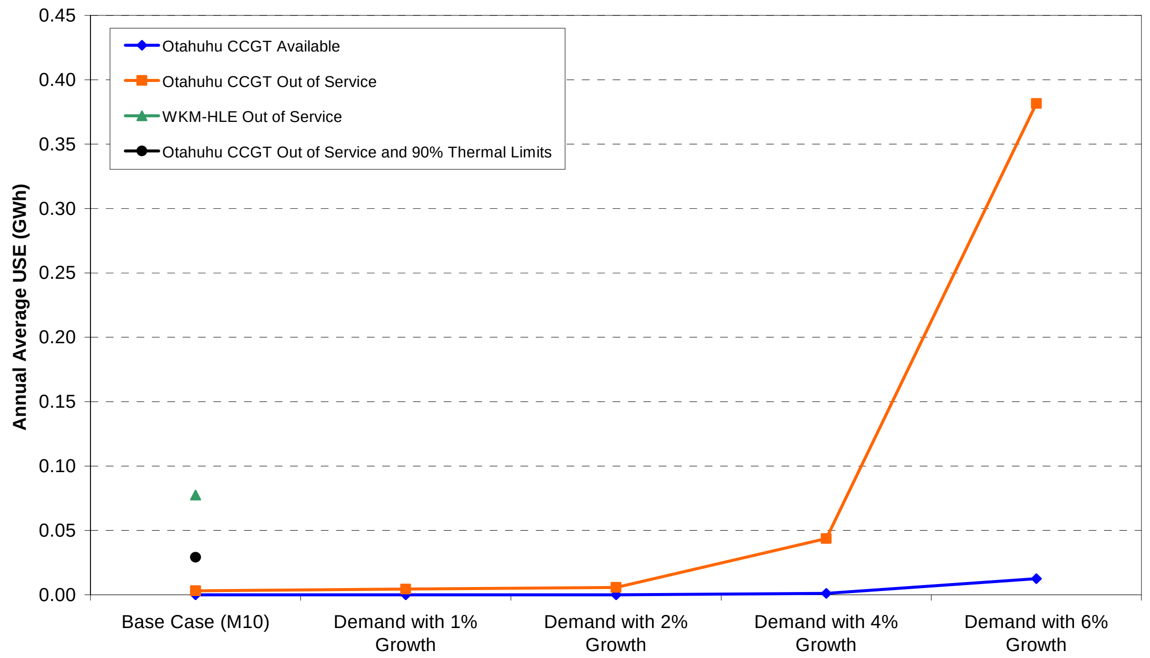
Case Descriptions	Total # Periods USE	# Otahuhu CCGT Off	# Otahuhu CCGT On	# WKM-HLY Constrained	# WKM-OTA Constrained	Annual Average USE (GWh)
Base Case (M10)	0	0	0	0	0	0.00000
Base Case (M50)	0	0	0	0	0	0.00000
Base Case with Otahuhu Off all year (M10)	10	10	0	0	10	0.00321
Base Case with Otahuhu Off all year (M50)	0	0	0	0	0	0.00000
Base Case with Otahuhu Off all year (M10) and 90% Flow Limits	107	107	0	0	107	0.02920
Base Case with WKM-HLE line off all year (M10)	235	225	10	182	53	0.07755
Base Case with WKM-HLE line off all year (M50)	118	118	0	111	7	0.01938
Base Case with Otahuhu Off and WKM-HLE line off all year (M10)	5282	5282	0	4310	972	1.86107
Base Case with Otahuhu Off and WKM-HLE line off all year (M50)	3110	3110	0	2847	263	0.59000
M10 Demand with 1% Growth	0	0	0	0	0	0.00000
M10 Demand with 2% Growth	0	0	0	0	0	0.00000
M10 Demand with 4% Growth	13	13	0	0	13	0.00117
M10 Demand with 6% Growth	116	116	0	0	116	0.01254
M10 Demand with 1% Growth and Otahuhu Off all year	11	11	0	0	11	0.00442
M10 Demand with 2% Growth and Otahuhu Off all year	13	13	0	0	13	0.00584
M10 Demand with 4% Growth and Otahuhu Off all year	412	412	0	0	412	0.04368
M10 Demand with 6% Growth and Otahuhu Off all year	3128	3128	0	0	3128	0.38158

Case #04 where both the Otahuhu CCGT and the WKM-HLY line are out of service for the entire year provides an extreme outlier in the analysis and would carry a corresponding extremely low probability of incidence. Analysis of the individual half hours of simulation shows that for this case the average of 1860MWh of USE would typically be consistent with a number of individual events involving loss of Otahuhu CCGT plus a major line to Auckland at time of winter system peak in Auckland.

With the exception of Case #04, Figure 3.1 below provides an illustration of the trend in USE for the range of sensitivity cases evaluated. The chart shows the sensitivity to demand and generation/transmission availability. In the case of Otahuhu CCGT out of service and increased demand growth the outcomes clearly show the highly non-linear nature of reliability of supply with each parameter and the compounding effect of each of the main power system parameters.

The sensitivities to demand growth could represent possible outcomes for the 2010 year if demand growth exceeds current expectations. Alternatively the demand sensitivity cases may represent the forecast USE outcomes for a number of years following 2010. Assuming a 2% annual load growth the sensitivities for 2%, 4% and 6% increased demand may be viewed as representing the forecast years 2011, 2012 and 2013 respectively.

Figure 3.1 – USE Trends for Sensitivity Cases
M10 Demand Forecasts



The reliability simulations have been based on the ability of lines to be loaded to their thermal ratings. Further limitations on supply to Auckland imposed by the voltage stability limits on imports to the Auckland area have been included in the model, but the thermal limits have been found to be the binding constraints in all cases. This is an obvious outcome for the M10 base case, since the peak demand of 2418MW as modelled is less than the stability limit on imports, even with Otahuhu CCGT out of service.

5.1.1 Allowance for Uncertainty in Flows and Limits

Since the transmission system into Auckland will be heavily loaded by 2010, this places more onerous requirements to ensure that there is close correlation between the actual line parameters (flows and limits) and the simulated parameters.

To assess the sensitivity to errors in the knowledge of flows and limits, which are further discussed in Appendix A, a further study has been conducted for which limits have been reduced by 10% below the normal limits.

This sensitivity covers uncertainties such as:

- The dc load flow model is less accurate in predicting flows than the ac load flow model (as discussed further in Appendix A);
- The dc flow model assumes that the individual thermal limits of lines in a given corridor, such as the Huntly to Auckland corridor, share flows in the same ratio as their limits, which may not be the case;
- The MW limits on the lines have been assumed to be the same as the MVA limits but the MW limits may be lower in reality since some reactive power will be carried on the lines.

The sensitivity has been carried out on Case #02, which shows only a small number of instances of unserved energy. The sensitivity case shows a ten fold increase in the forecast level of USE following reduction in the thermal transmission limits by just 10%, again providing an indication of the high level of sensitivity that the input assumptions have on the expected level of USE.

5.2 Estimated Cost of Unserved Energy

The value of this unserved energy can be estimated by applying the value of lost load, as per the Grid Investment Test (GIT), of $20,000/MWh. To satisfy the sensitivity analysis suggested by the GIT, the value of unserved energy can also be valued at $10,000/MWh and $30,000/MWh.

A summary of the estimated cost of unserved energy is presented in Table 3.3 below:

Table 3.3 – Estimated Cost of USE (2006 Dollars)

Case Descriptions	Annual Average USE (GWh)	Cost of USE ($10,000/MWh) [$M]	Cost of USE ($20,000/MWh) [$M]	Cost of USE ($30,000/MWh) [$M]
Base Case (M10)	0.00000	0.00	0.00	0.00
Base Case (M50)	0.00000	0.00	0.00	0.00
Base Case with Otahuhu Off all year (M10)	0.00321	0.03	0.06	0.10
Base Case with Otahuhu Off all year (M50)	0.00000	0.00	0.00	0.00
Base Case with Otahuhu Off all year (M10) and 90% Flow Limits	0.02920	0.29	0.58	0.88
Base Case with WKM-HLE line off all year (M10)	0.07755	0.78	1.55	2.33
Base Case with WKM-HLE line off all year (M50)	0.01938	0.19	0.39	0.58
Base Case with Otahuhu Off and WKM-HLE line off all year (M10)	1.86107	18.61	37.22	55.83
Base Case with Otahuhu Off and WKM-HLE line off all year (M50)	0.59000	5.90	11.80	17.70
Demand with 1% Growth	0.00000	0.00	0.00	0.00

Table 3.3 – Estimated Cost of USE (2006 Dollars)

Case Descriptions	Annual Average USE (GWh)	Cost of USE ($10,000/MWh) [$M]	Cost of USE ($20,000/MWh) [$M]	Cost of USE ($30,000/MWh) [$M]
Demand with 2% Growth	0.00000	0.00	0.00	0.00
Demand with 4% Growth	0.00117	0.01	0.02	0.04
Demand with 6% Growth	0.01254	0.13	0.25	0.38
Demand with 1% Growth and Otahuhu Off all year	0.00442	0.04	0.09	0.13
Demand with 2% Growth and Otahuhu Off all year	0.00584	0.06	0.12	0.18
Demand with 4% Growth and Otahuhu Off all year	0.04368	0.44	0.87	1.31
Demand with 6% Growth and Otahuhu Off all year	0.38158	3.82	7.63	11.45

The above values could further be combined to produce a weighted average forecast unserved energy value, taking account of the relative probability of incidence of line outages and Otahuhu generation. The weightings would be equivalent to the probabilities of occurrence for each of the scenarios. At this stage, these probabilities have not been finalised.

5.3 Duration, Severity and Seasonality of Unserved Energy

Table 3.2 provides an indication of the expected frequency and annual average volume of USE events for the set of sensitivity cases. This does not however provide information relating to the duration of each individual event and hence the instantaneous level of demand not served, nor the seasonality of such events. As the monte-carlo modelling completed is fully time-sequential with every ½ hour trading interval simulated these statistics can be gathered and analysed to provide a more detailed understanding of the reliability of supply.

Figure 3.2 below provides an indication of the spread of *Duration* of USE events for Cases #02, #03 and #04 with the M10 demand. There are very few samples (only two) for Case #02, both of which lasted five trading intervals. For Case #03 there are a significant number of USE events mostly lasting less than seven trading intervals or 3 ½ hours. For the low probability Case #04 there are many hundreds of USE events over the 100 simulation iterations and again most of these were short lasting less than four hours.

Figure 3.2 – Average Duration of USE Events for Selected Sensitivity Cases

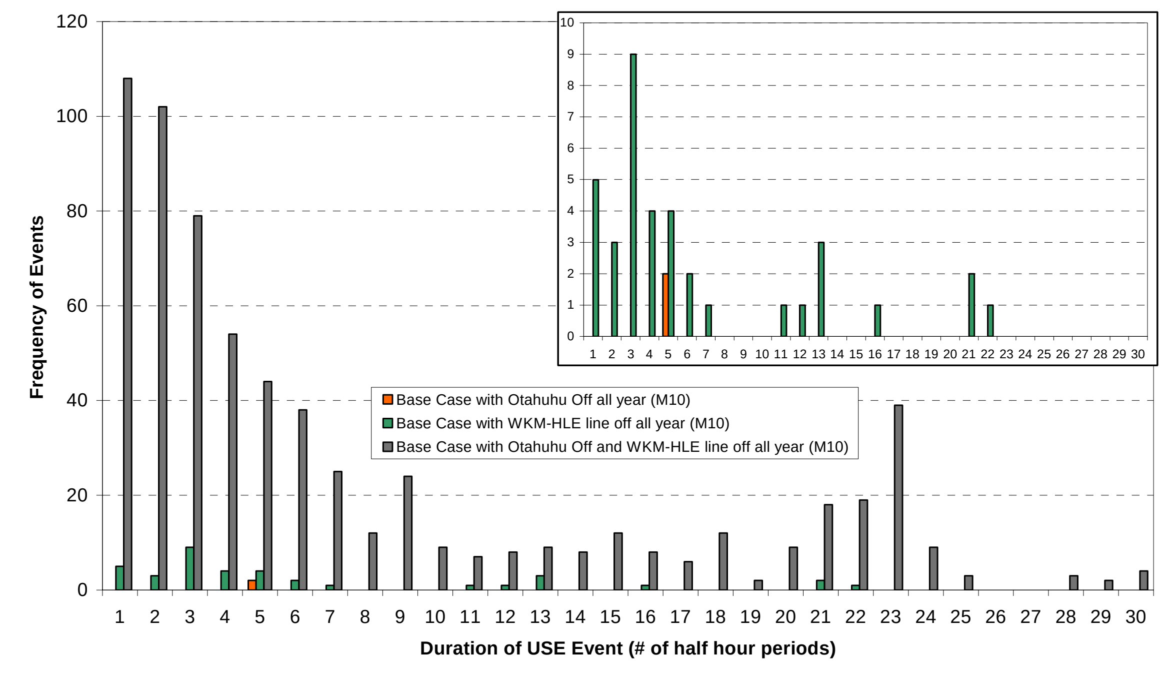


Figure 3.3 shows the average *MW Lost* during each USE event and as such provides an indication of the *severity* of each event. This shows for example that for Case #02 the two USE events incurred a 31 to 45MW loss of load and 75 to 90MW loss of load respectively.

Figure 3.3 – Average MW Lost During USE Events for Selected Sensitivity Cases

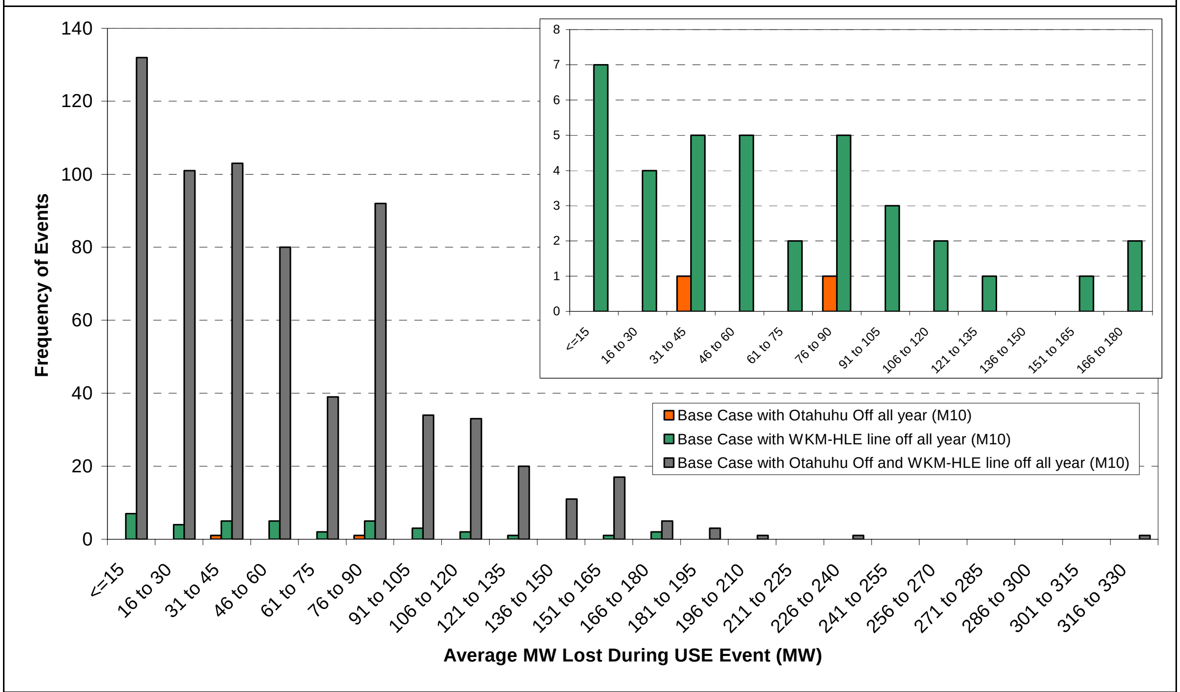


Figure 3.4 provides an indication of the total *Energy Lost* during each discrete USE event and Figure 3.5 shows the annual distribution of USE events and energy lost between summer and winter.

Figure 3.4 – Average Energy Lost During USE Events for Selected Sensitivity Cases

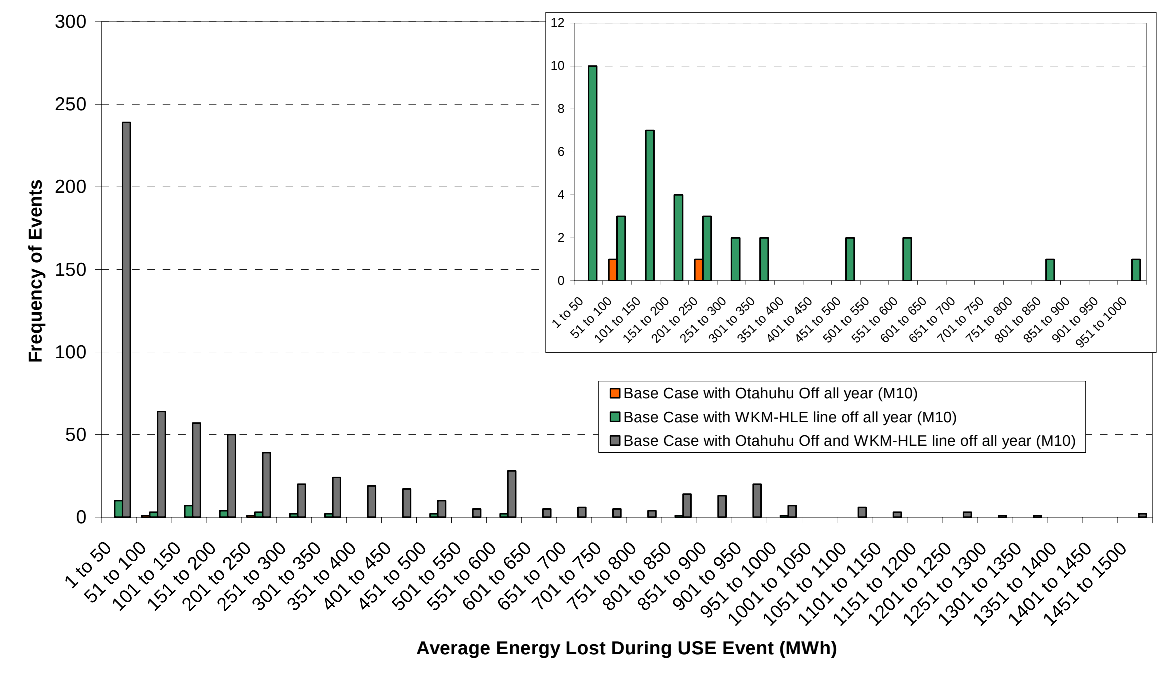
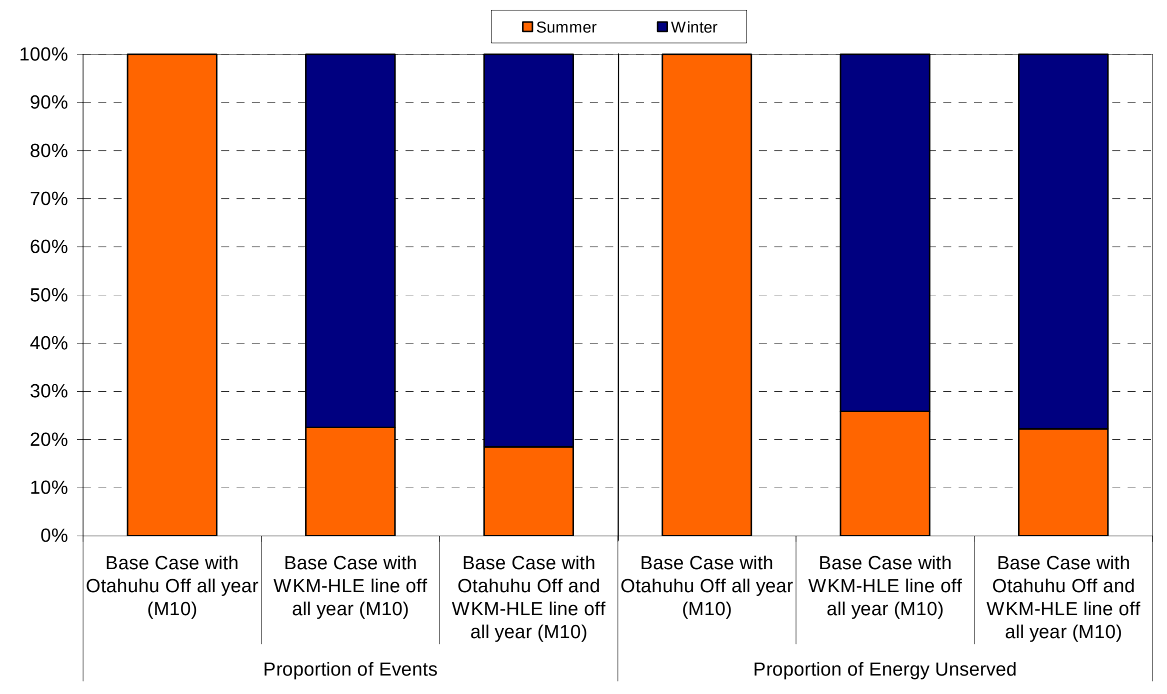


Figure 3.5 – Seasonality of USE Events for Selected Sensitivity Cases



The duration, severity and energy lost due to each discrete event provides important information to the grid planner and operator to aid in the development and design of the system to maintain adequate security of supply for the electricity system. The seasonality of events generally highlights the distribution of high demand events across the year but also takes into account operation limits such as lower thermal transmission ratings and generator capability due to higher summer temperatures.

5.4 Inter-Regional Transmission Flows

As part of ROAM's modelling outputs, the inter-regional transmission flows are calculated for the 2010 base year. For the first stage of this study, the regions include Whakamaru, Huntly, Auckland and Northland.

Figures 3.6 to 3.8 below demonstrate the levels of flows into the Auckland region from Huntly and Whakamaru for the first three sensitivity cases. It can be seen that the maximum combined flow into Auckland is approximately 2400MW. This is the combined Huntly to Auckland flow and the Whakamaru to Auckland flow across both transmission corridors and equal to the coincident peak demand in Auckland plus Northland indicating that in at least one instance that all demand was supported by transmission alone.

Note that:

1. The Base Case shows a reduced incidence of high flows into Auckland due to the availability of the Otahuhu CCGT;
2. Case #02 shows the highest level of flows into Auckland due to the unavailability of Otahuhu CCGT. Essentially all demand in Auckland and Northland must be met by transmission flows. This is illustrated in Figure 3.9 which shows the demand curve in a similar way;
3. Case #03 shows reduced levels of high imports into Auckland due to the lower import capacity when the WKM-HLE line section is assumed out of service.

Figure 3.6 – Transmission Flows From Huntly into Auckland (Selected Cases)

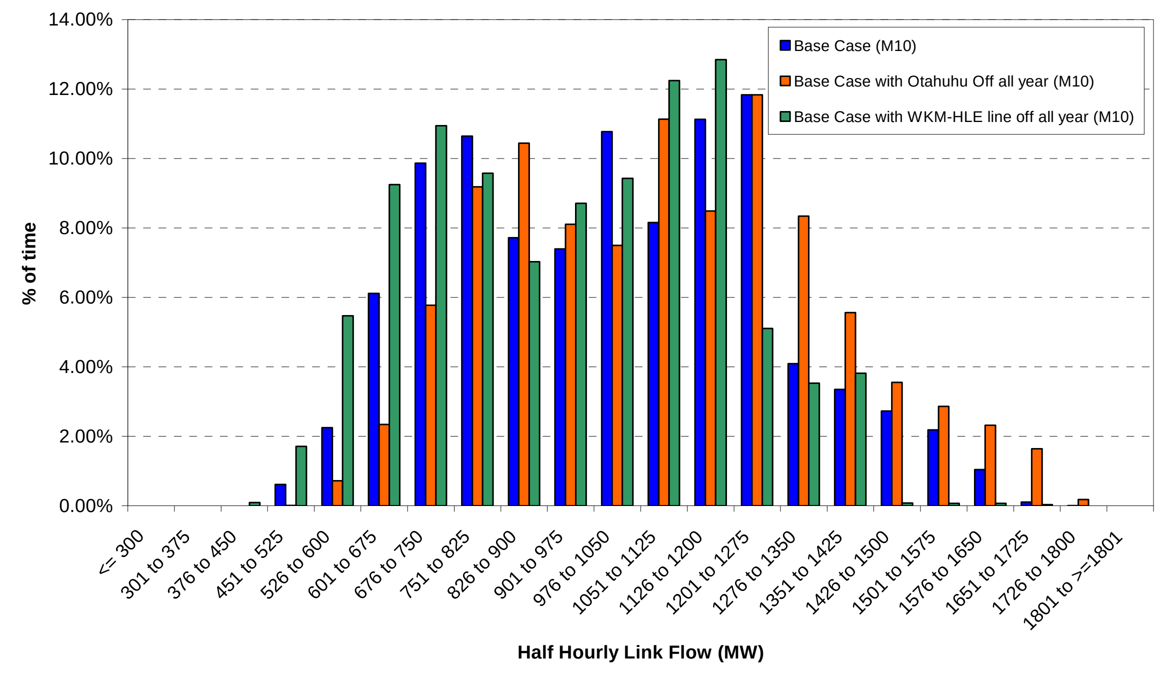


Figure 3.7 – Transmission Flows from Whakamaru into Auckland (Selected Cases)

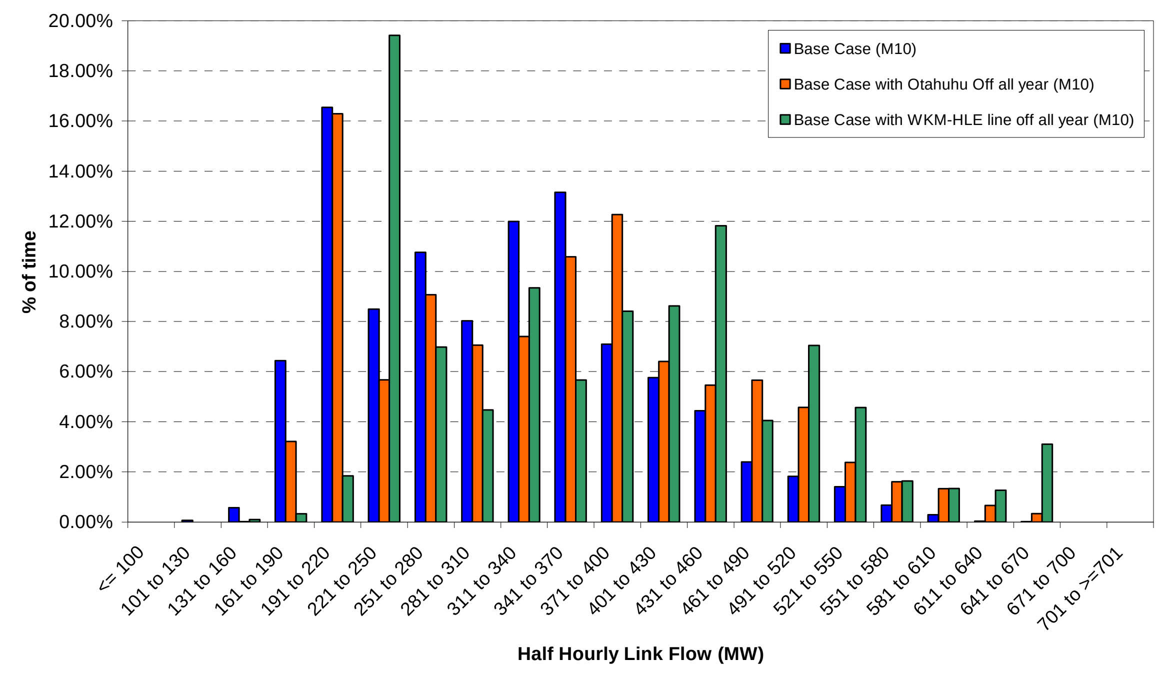


Figure 3.8 – Combined Transmission Flows into Auckland (Selected Cases)

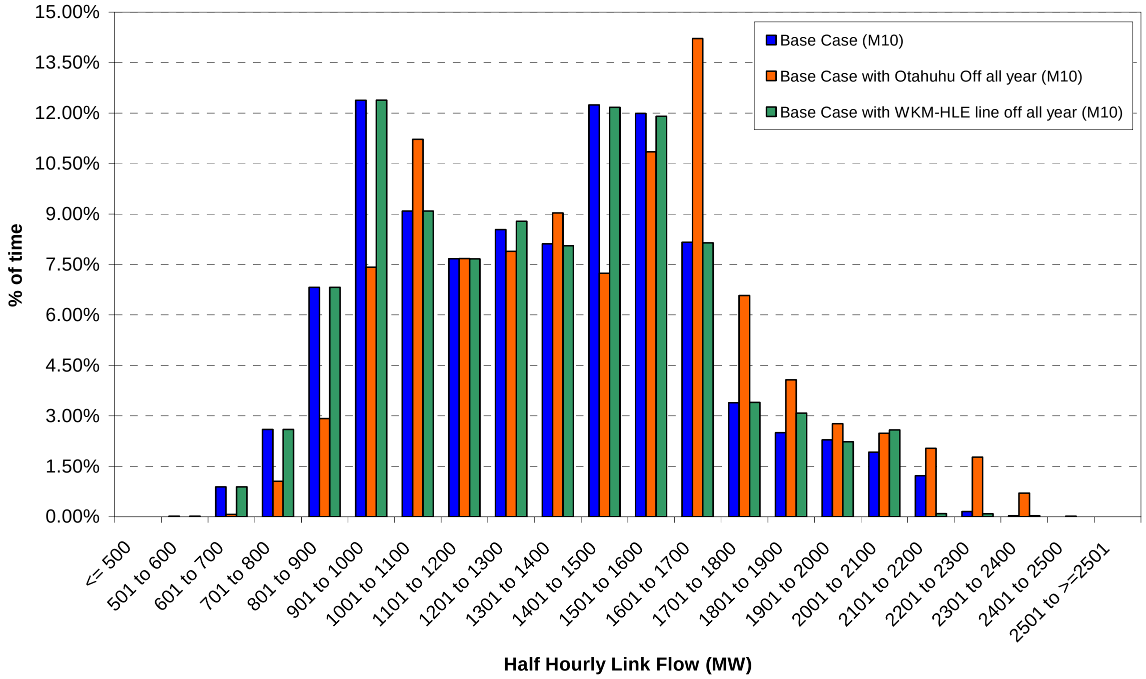
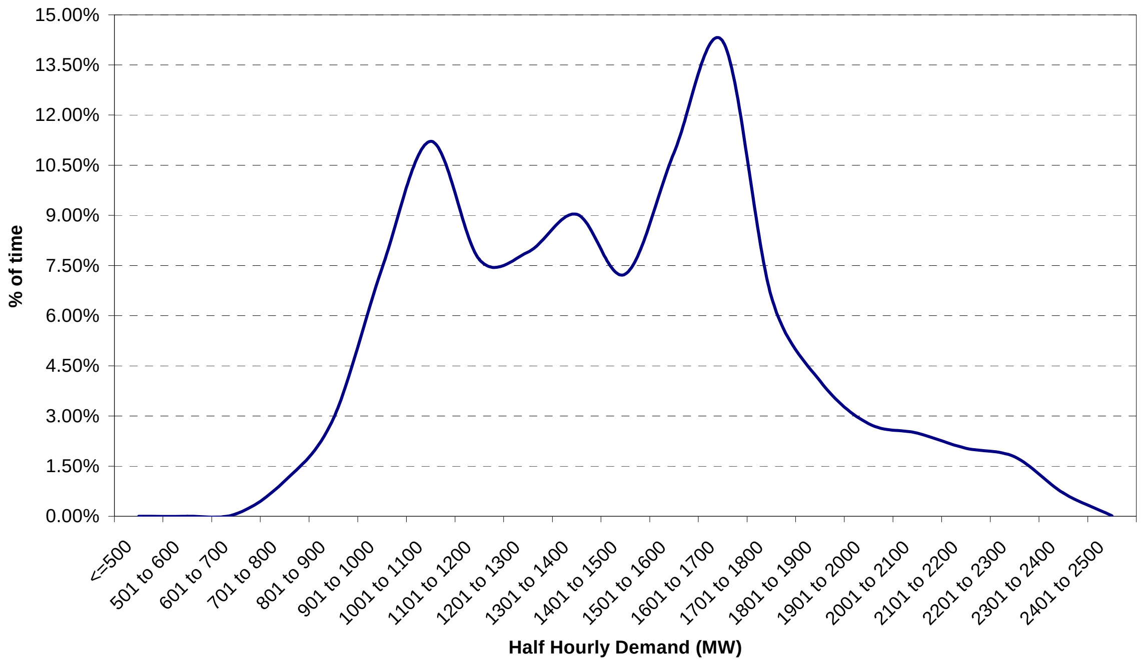


Figure 3.9 – Demand Distribution Curve for Auckland plus Northland



ROAM has developed and implemented a security constrained dc load flow within the 2-4-C dispatch engine to ensure that the physics of the transmission system cannot be violated at times of transmission constraints. The following three charts show the flows and limits on the modelled interconnector sections to demonstrate the outcomes of the modelling.

The illustrations show:

- The regional demands at the time of the snapshot;
- The transmission line flow / limit on each line section;
- If the transmission flow is constrained by a limit the line is drawn in red.

Figure 3.10 – Interregional Transmission Flows Snapshot (Unconstrained – Peak Demand)

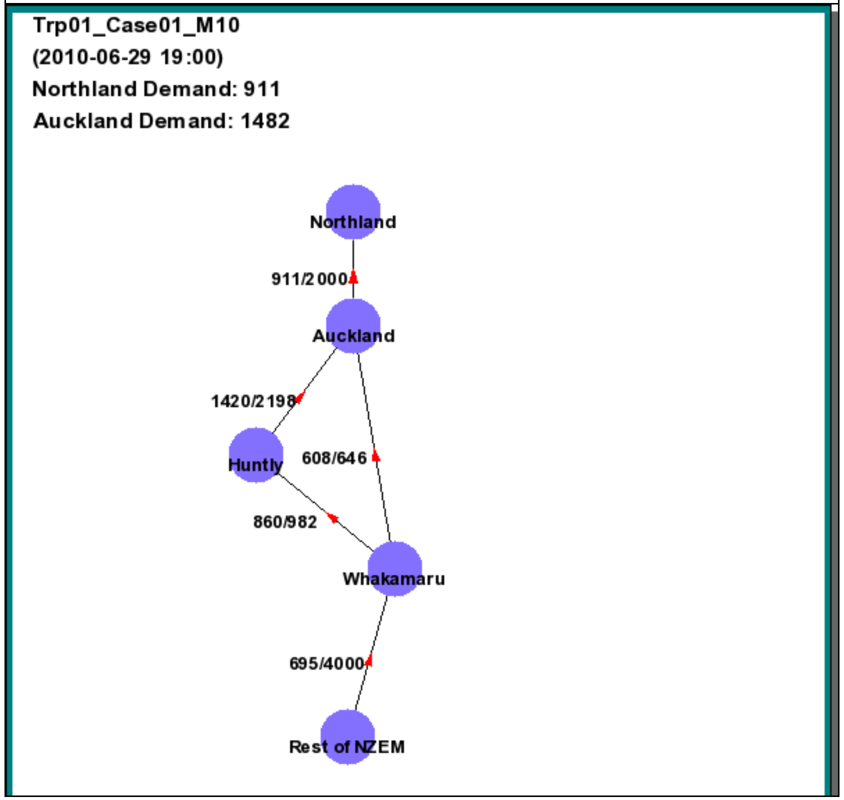


Figure 3.11 – Interregional Transmission Flows Snapshot (WKM-OTA Constrained – Peak Demand)

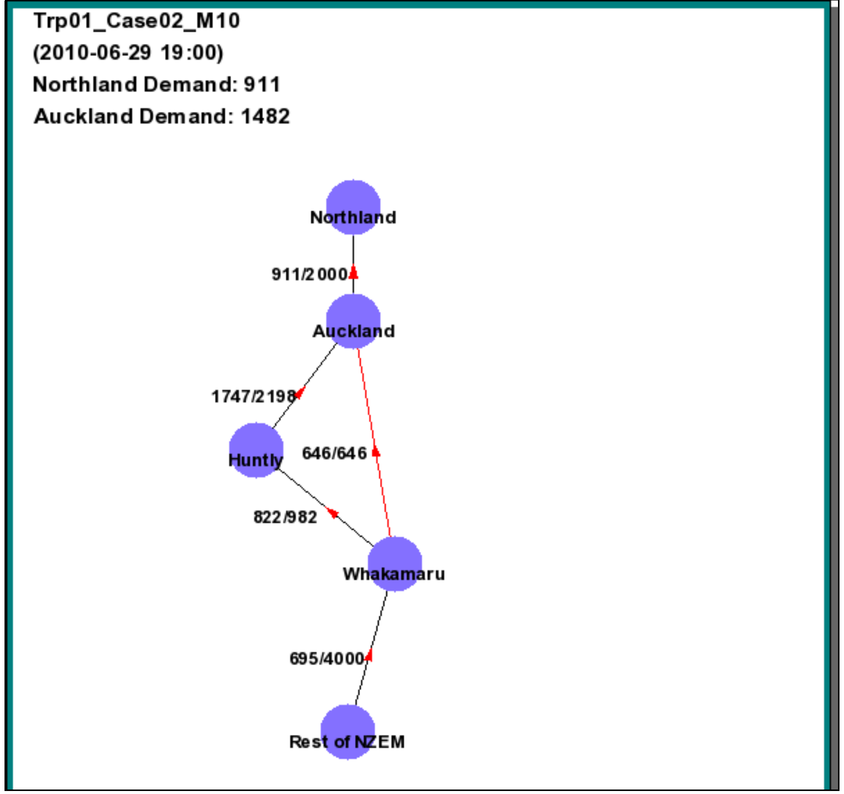
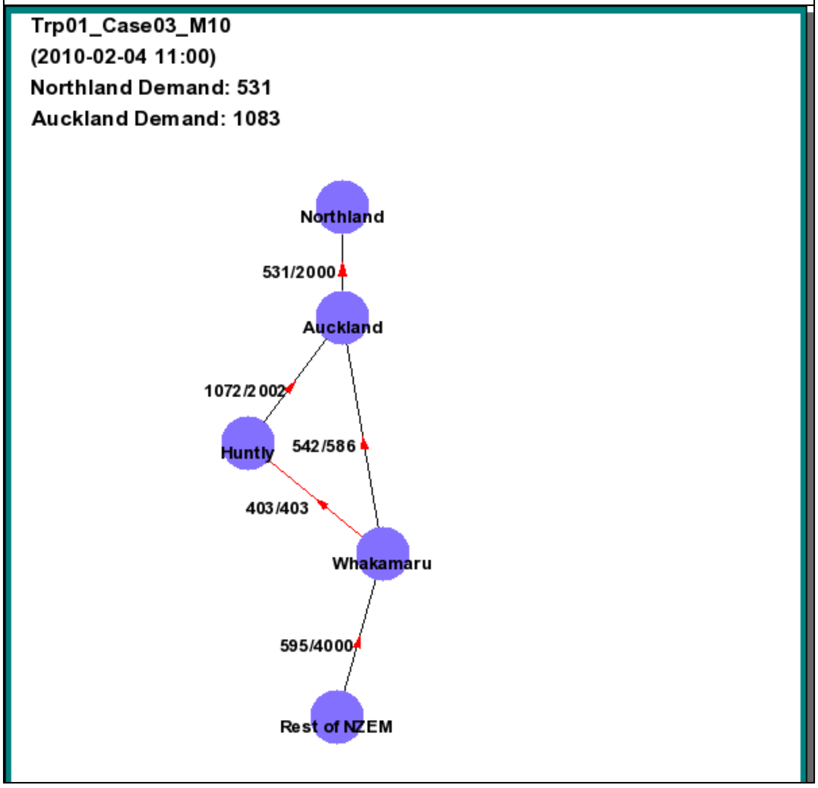


Figure 3.12 – Interregional Transmission Flows Snapshot (WKM-HUN Constrained with Outage – Moderate Demand)



5.5 *Causes of Unserved Energy*

In a single region loss of supply can be caused only by a shortfall in local generation capacity. In an interconnected region loss of supply must be caused by a combination of both insufficient local generation *and* a lack of interconnector capacity.

Through monte-carlo simulation the probability of the coincidence of high demands, low generation availability and insufficient transmission capability may be assessed. In this study an analysis of events of USE shows that:

1. Predominantly the cause of USE in Auckland is the loss of the local Otahuhu CCGT combined with:
    a. In Winter, thermal transmission constraints on the Whakamaru to Otahuhu corridor: and
    b. In Summer, thermal transmission constraints on the Whakamaru to Hamilton/Huntly corridor.
2. With loss of the WKM-HUN circuit transmission capability is significantly reduced and as such increased transmission constraints coupled with generator outages of either Otahuhu CCGT or one or more Huntly units are a common cause of USE.

6 Conclusions

Preliminary conclusions from Stage 1 are that supply to Auckland will meet reliability standards in 2010 with expected levels of availability of Otahuhu CCGT and normal load growth.

However, maintenance of satisfactory reliability will be dependent particularly on:

- Completion of the program of reinforcement of the 220kV system as planned, including additional generating capacity at Huntly, switching the existing Whakamaru to Auckland line at Huntly East and uprating of the remaining Whakamaru to Otahuhu lines;
- Ensuring a low incidence of forced outages of lines which could constrain power from Huntly and the Whakamaru area from delivering sufficient generation to Auckland through thermal line overloading;
- Availability of Otahuhu CCGT in both summer and winter peak periods;
- Actual load growth in Auckland area;
- Accurate knowledge of line limits and sharing of flows between parallel lines in the same flow path.

The outcome shows that, to allow for uncertainties, the following conditions are recommended as the reference conditions for further TransGrid modeling at peak times:

- Remove Whakamaru to Huntly East line from service; or
- Remove Otahuhu from service and increase load to 4% above M10.

Adopting either of these operating states should be consistent with the principle of determining the *'assets that are reasonably expected to be in service'* (Section 4.2 of the Grid Reliability Standards).

If the program of reinforcement of the 220kV system cannot be assured, then this will require possible advancement of the 400kV system relative to the conditions assumed for this report.

Further work is intended in Stage 2 to cover a wider range of conditions, including:

- Modeling the North Island in eight areas;
- Considering the effect of energy limited generation.

Appendix A) Correlation of AC power flows with DC power flows within 2-4-C dispatch model

To ensure that a high level of correlation between ac power flows and the dc power flow approximation used in the 2-4-C generation dispatch model, a comparison of flows has been made. The following diagrams show the correspondence between the two models for a single time interval corresponding with high load conditions when reliability is most likely to be compromised. In all other intervals that have been assessed over a range of loading and generation dispatch conditions, close correlation between ac and dc power flow outcomes has been found.

Figure A.1 – Interregional Transmission Flows Snapshot (Unconstrained – Peak Demand)

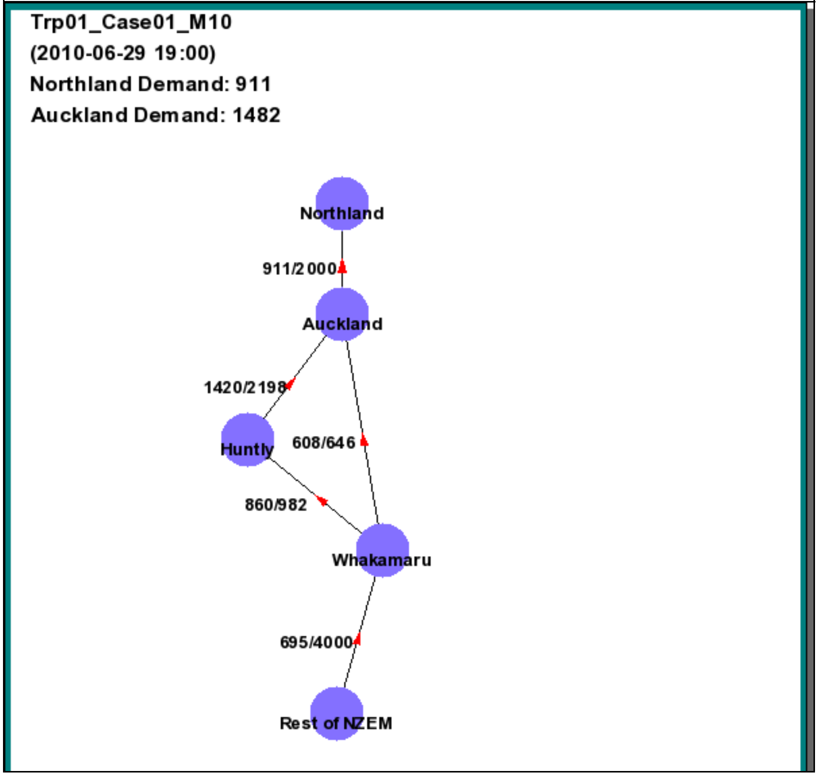
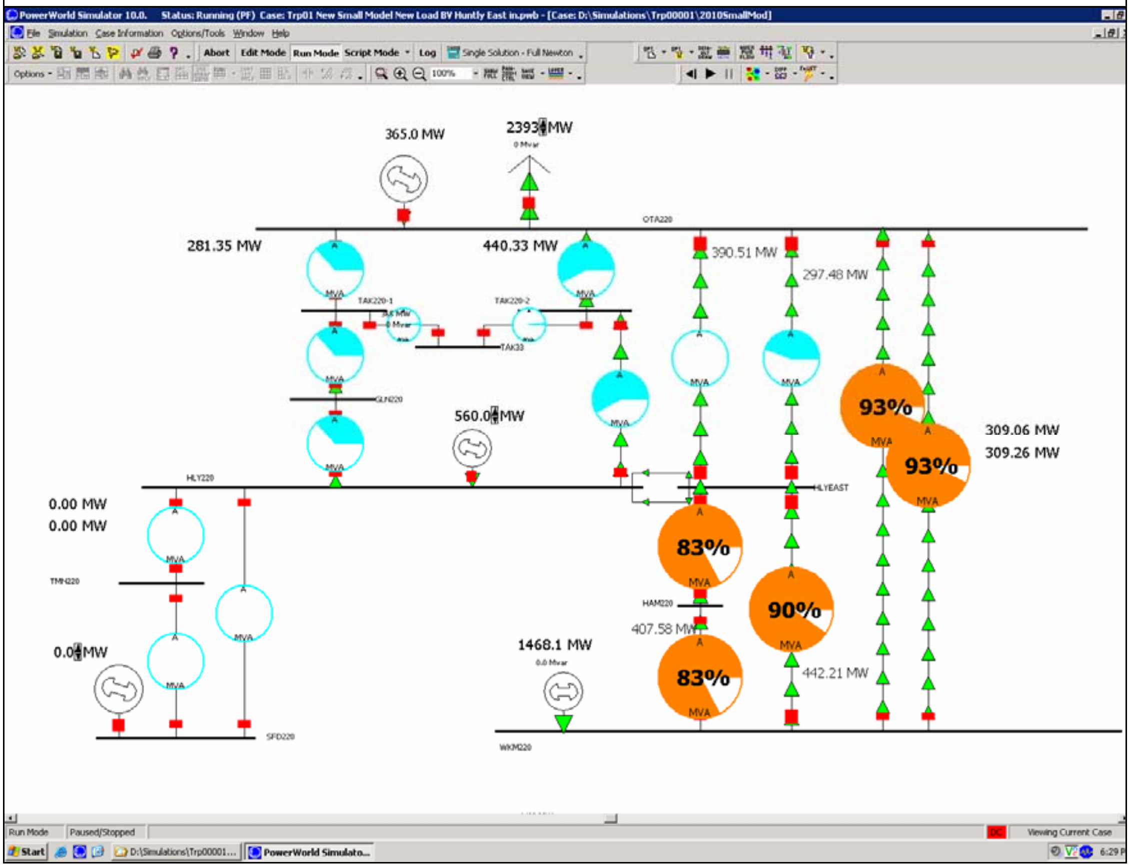


Figure A.2 – AC Load Flow Snapshot from PowerWorld



The diagrams show that there is correlation between the two to within a few percent.

Below is a printout of the calculations: