

Pterra Consulting

Technical Report R125-07

South Island Grid Upgrade Project Dynamic Voltage Stability Study Final Report



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Ltd.**

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Executive Summary

Pterra LLC ("Pterra") was contracted by Transpower New Zealand, Ltd. ("Transpower") to conduct planning review studies to determine the need for enhancing transmission capacity to the Christchurch area, specifically, with respect to voltage stability, and to conduct the necessary dynamic simulations to confirm or modify the plan for enhancement.

Pterra reviewed technical reports and documents performed and prepared by Transpower, and confirmed the simulation results with Pterra's own independent simulations using the PSS/E software. Furthermore, Pterra performed dynamic simulations related to voltage stability of the South Island Upgrade.

Considering the existing Transpower criteria, international practice and simulations conducted of the South Island grid, planning criteria for voltage stability were proposed for this study that included:

- A MW margin, measured on the PV curve
- Contingencies to test using dynamic simulations
- Transient response criteria for the timeframe immediately following a contingency up to a few seconds later
- Post-transient response criteria that apply to the timeframe from 10 seconds to minutes after a contingency

The databases used for this study were provided by Transpower. For the power flow model, Pterra developed a detailed model based on the model case provided by Transpower, with minor adjustments to match the 2007 system conditions. Additional power flow cases were developed representing future years by increasing load at constant power factor, taking into account non-scaleable load. For the dynamic simulation model, Pterra reviewed the provided data and provided additional models to represent complex load, contactor shedding, switched capacitors and proposed static var compensators.

PV curve analyses indicate that the MW margins, which measure additional load that can be supported within voltage stability criteria, for future Upper South Island (USI) load are less than 100 MW for the existing system operating during winter wet conditions. The most severe contingency with respect to voltage stability is the loss of the Islington-Tekapo B 220 kV line. QV curve analyses confirm this finding.

The dynamic simulation assessment showed that load modeling had a significant impact on the assessment for voltage stability of USI. Various load models were studied and qualified in accordance with the level of risk that a model will provide sufficient MW margin to support additional load in the USI. Two models are proposed for conducting dynamic assessments voltage stability

- A moderate risk model comprising of 19% motors with a 10% constant power load component

- The low risk (or conservative) model comprising of 38% motor with a 15% constant power load component, with a provision for shedding of some motors on contactor tripouts below 0.6 pu voltage

Limits on additional USI load supported by the existing system, as determined using dynamic simulation, are similar or greater than those determined by PV and QV curve methods. Hence, steady-state analyses for the cases studied provide a conservative measure of voltage stability.

However, dynamic simulation assessment provided improved differentiation of options to defer the need for a new 220 kV line. Of several options studied, the following offered the best potential to support additional USI load, in order of effectiveness:

- Large SVC in combination with fixed capacitor banks at Islington. This solution has the potential for supporting levels of USI load up to 2022. In combination with series compensation, even higher levels of USI load may be supported. However, certain technical issues beyond the scope of this study need to be addressed.
- Series compensation. Technically, this solution offers additional MW capacity for up to 2014 in either the moderate or the low risk load model. Because of this characteristic, the solution addresses a wide range of risk associated with load response, and offers a robust option for mitigating the need for a new 220 kV line.
- Capacitors and SVCs at Islington, Kikiwa and Ashburton. Incremental additions at the three sites provide for USI load of up to 1475 for the moderate risk model and 1375 for the low risk model are possible.
- The specific extreme contingencies studied, involving double circuit outages, are no more severe than the worst normal or design contingency (single line to ground fault with delayed clearing). This may be partly due to not immediately re-connecting some circuits which are connected in a T configuration to the faulted lines. Hence stability countermeasures specified for normal contingencies would also provide support for these types of extreme contingencies. Extreme contingencies involving autoreclosure on a fault event and a bus section outage with fault are more severe than the most severe normal contingency. Hence, in order to mitigate these extreme contingencies, solutions applied to normal contingencies need to be augmented beyond 2015. For example, an additional +500 MVAR SVC at Islington is needed to support USI load of up to 1800 MW under these extreme contingencies.

As the available surplus transmission capacity decreases in the South Island, and mitigating measures are implemented to defer the need for a new 220 kV line, it would be of benefit to future system operators to provide increased capability for observability and controllability of the power system. This would include an expanded RPC at Islington and online dynamic security assessment.

Section 1. Introduction

Pterra LLC ("Pterra") was contracted by Transpower New Zealand, Ltd. ("Transpower") to conduct planning review studies to determine the need for enhancing transmission capacity to the Christchurch area, specifically, with respect to voltage stability, and to conduct the necessary dynamic simulations to confirm or modify the plan for enhancement.

1.1. Background

Transpower is planning to enhance the supply capacity to Christchurch and the regions North of Christchurch in the South Island. By approximately 2010, the transmission capacity to these regions will be constrained by the voltage stability concerns even though some thermal capacity would still be available in the transmission lines.

Transpower has completed the planning studies, assessing the need for a new transmission investment as well as comparing the benefits of alternative transmission options. The transmission capacity of the existing power system was assessed using VQ and PV analysis. The studies indicated that the transmission system is close to the practical transmission capacity with shunt reactive compensation (at the receiving end).

The analysis results are sensitive to the planning assumptions, especially the assumptions on modelling of the behaviour of the loads and on the prudent stability margins to be maintained in operation. By varying the assumptions and using different analysis techniques, it may be possible to show an increased capacity limit is achievable through further shunt compensation and thus defer transmission investments.

Transpower is planning to submit a grid upgrade proposal to the Electricity Commission (the Electricity Regulator in New Zealand) by mid September 2007 and requires this advice to support the 'need date' for further investment in the transmission system.

1.2. Objectives

The objectives of Pterra's work are to determine whether it is practicable and/or desirable to extend the transmission capacity beyond that identified in the Transpower report¹ with respect to:

- International practice and the extent of shunt compensation employed;
- Operating the power system with the required shunt compensation;
- Control systems and requirements; and
- Any other relevant technical issues.

¹ See Section 1.4, reference no. 2.

Pterra is to review technical reports and documents already performed and prepared by Transpower, and if necessary, confirm the simulation results. Furthermore, Pterra is to perform dynamic simulations related to voltage stability of the South Island Upgrade.

1.3. Scope of Services

To meet the objectives, Pterra conducted its Services in two parallel tasks.

In Task 1, Pterra reviewed the planning studies already carried out by Transpower. This review included an assessment of the assumptions and analytical methods applied by Transpower with respect to Good Industry Practice. From the preceding review, Pterra assessed the appropriateness of conclusions made by Transpower for planned investments and need dates. In particular, Pterra identified options for deferring the investments using low cost shunt compensation. In the course of conducting Task 1, Pterra carried out power flow studies and voltage stability analysis to confirm various aspects of the transmission plan.

In Task 2, Pterra planned and implemented a dynamic study to assess voltage stability of Transpower's transmission plan. As with Task 1, a key objective of the dynamic study was to defer major investments in favor of using lower cost shunt compensation. Where such deferment was indicated, Pterra identified the critical planning assumptions that allowed the deferment, the stability margins on which such assumptions were based and the level of risks associated with such planning assumptions. Pterra also developed comments on the operability of the shunt compensated system with deferred investments, with specific reference to necessary control systems, practicability, consistency with international practice and other relevant aspects.

1.4. Documents Provided for Reference

The following documents were provided by Transpower for reference in conducting the Services.

1. "Transmission System Planning Criteria," Grid Planning, Transpower, July, 2005, ("**Planning Criteria**").
2. Hill, C., Love, G., Macdonald, S., Yu, K., Pahalawaththa, N., Boyle, D., "South Grid Island Upgrade Investigations, Report No. NP340," Transpower, May, 2007, ("**Planning Study**").
3. Macdonald, S. J., Boyle, D., George, T., Pahalawaththa, N., "Dynamic Voltage Stability of Auckland Metropolitan Load Area," Transpower, IEEE conference - Power Systems Conference & Exposition 2006 (PSCE'06).
4. Love, G., Macdonald, S., "Dynamic Modeling of Reactive Support in Upper South Island," Transpower, June 2007.
5. Love, G., "Reactive output of South Island generators during an Islington 3 phase fault," Memo dated 2 July 2007.

1.5. Contents of This Document

This Report presents the results of analysis conducted under the Scope of Services in the following order:

- Planning Criteria
- Data and Assumptions
- Analyses and Results
- Conclusions

Section 2. Planning Criteria

Voltage stability is the focus of recent changes in planning criteria used by utilities and regulatory agencies worldwide. The trend is away from the steady-state methods of assessing stability to increased emphasis on dynamic response. However, steady-state-methods and criteria based on these methods have not been eliminated entirely and continue to be the initial method for screening voltage stability response in power systems.

This section discusses, in the following order:

- General principles of voltage stability related planning criteria,
- Comments on the planning criteria currently applied by Transpower,
- Planning Criteria applied by Transpower to a study of North Island
- Proposed planning criteria for this study, based on dynamic response.
- At the end of this section, we provide a list of references that supplement the discussions and provide further background material for present use and future development of planning criteria for Transpower.

2.1. Voltage Stability-related Planning Criteria

As the power system transitions from a normal operating state to an emergency state following a contingency, the response of voltage throughout the system is influenced by several factors that are modeled differently in steady-state and dynamic simulation models. Among the aspects that are different are:

- The transient response of rotating equipment provides for higher reactive power available (over short durations) than is defined by the steady-state reactive power capability.
- Static VAR devices (SVD) such as thyristor-controlled reactors and switched capacitor banks respond to different voltage conditions (typically lower than normal) during transient conditions than what steady-state simulations provide. The actual reactive power of SVDs would vary as a square of the voltage at their terminals at the point in time of the dynamic simulation.
- Load characteristics change during, after and in the extended time period following a contingency in a significantly different way than may be simulated in a steady-state "ZIP" model.

ZIP is a shorthand notation for a type of model of electrical loads. The model specifies that load is represented by the formula:

$$P_v = P_o * (Z * V^2 + I * V^1 + P * V^0)$$

Where P_v is the load at voltage V , P_o is the nominal value of the load and Z , I and P are constants whose sum equals 1.

- Onload tap-changing transformers would respond tap-step by tap-step in accordance with the control response characteristics of the transformers rather than the assumed response in a power flow model.

- Capacitors that switch in based on monitored conditions may do so within a timeframe that impacts voltage stability. The voltage at which the switch in occurs determines the actual MVARs delivered to the system. Multiple capacitor banks would switch in sequence and this time delay also has an impact on voltage stability.

Hence, voltage stability related planning criteria tend to specify the acceptable transient response as defined by the power system controls and equipment, taking into account the differences with steady-state modeling listed above. This transient response may be divided into time regimes or defined by a nomogram.

Time regimes may be defined as:

1. Transient - takes place in the first few cycles to several seconds following the initial disturbance. This would account for the "fast" phenomena such as response of relays, voltage regulators, breaker action, SVDs, etc. This would also account for some of the "slow" phenomena such as a capacitor switching, load self-modifying response, tap-changing transformers, generator excitation limiters, governors, etc.
2. Post-transient – takes place from about 10 seconds following the disturbance to the minutes time frame when oscillations from the initial events of the disturbance have died down and voltages are quiescent. The time regime defines the post-contingency steady-state voltage determined through dynamic simulation.

Example transient criteria are:

1. Step response – voltage recovery defined by meeting voltage level checkpoints during the transient period. For example, a two step criteria²:
 - a. Voltages should recover to above 0.5 pu after 0.5 seconds following clearing of a fault in a contingency
 - b. Voltages should recover to within 90% of the pre-contingency voltage after 5 seconds.
2. Nomogram response – voltage recovery is qualified based on a voltage nomogram that system voltages must remain above throughout the transient. An example of this type of criteria is shown in Figure 2-1, based on a proposed standard for low voltage ride-through of wind farms by FERC.

² See 6 in References.

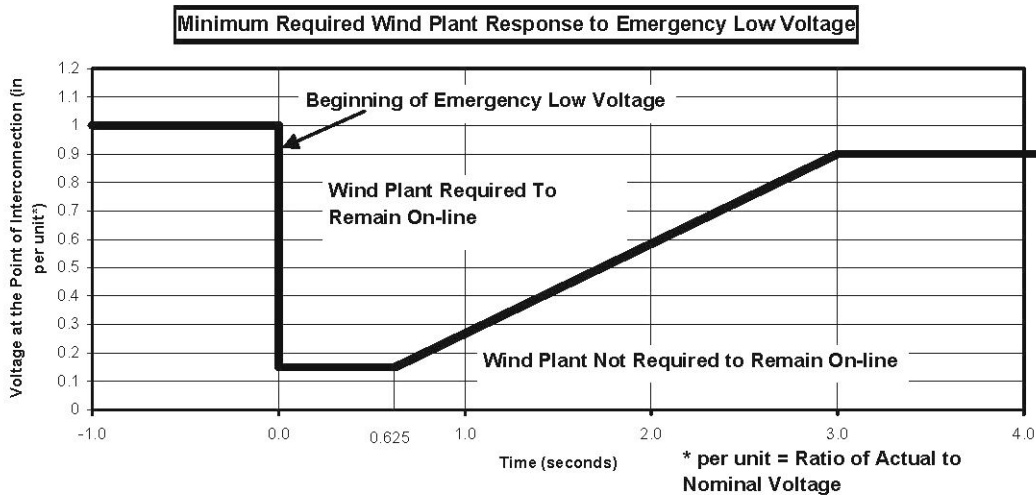


Figure 2-1: Sample Voltage Response nomogram as proposed by the US FERC for wind farm low-voltage ride through characteristics (United States Federal Energy Regulatory Commission, order No. 661, Appendix B, June 2, 2005)

An example of post-transient criteria taken from the US WECC³ planning guidelines:

1. Voltage to rest within 95% of the pre-contingency value
2. Voltages are damped.

Load modeling is a critical aspect of determining voltage stability. The typical model used for stability simulations, described as the 'PIQZ' model, where the real power portion of the load varies as voltage (also referred to as "constant current or I" characteristic) and the reactive portion of the load varies as the square of voltage (also referred to as "constant impedance or Z" characteristic) is not preferred since it ignores important characteristics of load response.

Two types of load modeling are seeing increasing use and application as part of planning standards, as follows:

1. Complex load model - this model represents distinct portions of the load. A typical breakdown includes: small motors, large motors, discharge lighting, transformer saturation, constant power and PIQZ loads. The percentage of each component is important to voltage stability and may be specified as part of standards. For example, WSCC requires modeling of at least 20% motor loads in planning studies⁴. The complex load also seeks to capture the effect of step-down transformation and distribution feeder impedances.

³ Western Electricity Coordinating Council.

⁴ From experience of Pterra's investigators, this is the largest motor component requirement to represent consumer air conditioning used as a planning standard. Saudi Arabia uses a larger motor component but this includes large pumps that are not air conditioning load. The comparison is difficult to make with the

2. Self-restoring load – this model represents load on modifiers which attempt to adjust the average demand of the load in response to changes in voltage at the terminals. This model is used for equipment on thermostats and consumer voltage controllers. The load may respond initially to a voltage change in a PIQZ or motor characteristic, but through the action of the controllers recover the demand level to the pre-contingency value. Over the long-term (or in steady-state analysis), the load looks and behaves like constant power, but during the transient period, the load may have two or more distinct demand-voltage characteristics.

Load modeling is important to voltage stability and all efforts to obtain accurate modeling improve the planning and supporting simulations. In order to ensure consistent application, criteria may specify the load model to use for conducting performance tests.

2.2. Comments on Planning Criteria applied by Transpower

The following discussion contains comments on the Planning Criteria as applied by Transpower to the Planning Study.

1. Contingencies. A contingency analysis is a useful tool for screening contingencies that are critical to voltage stability. This is also a necessary tool whenever there is a change in system configuration. Although the critical contingencies with respect to voltage stability are well-defined and recognized in the Planning Studies, it would be useful to add a section describing the list of potential contingencies and the results of contingency analysis. It would also be useful to see similar discussion when the bussing and series compensation options are presented.

There is a variance between the Planning Study and the Planning Criteria in that in the former, transmission circuits on the same tower are treated individually as n-1 events, and in the latter⁵, the loss of both circuits may be treated as an n-1 event subject to likelihood of occurrence. International practice shows both forms being used and it is typically a planning determination based on probability, cost and other factors that establishes which of the two forms is applied.

2. Loading of existing transformers. Transformers will typically have overload capacity to support 120% loading on cyclical basis. We note that transformer aging is affected by magnitude, frequency and duration of overloading events, and criteria may be more specific about how long or how often the overload conditions are allowed. This is not an issue that is central to the voltage stability problem but may have an impact if the system model does not match the planned reinforcement of transformation capacity and leads to false load response.

primarily heating motors in the South Island load. The level of penetration is as high as 38% per a study of the Auckland load (see Reference 3, Section 1.4).

⁵ See p. 6 of the Planning Criteria.

3. 5% demand. Several utilities and operators in the US and worldwide use a similar criteria, including the PJM⁶ Interconnection. We note that voltage stability is also dependent on the power factor of load and the component mix of load. As load components change with increasing demand, the margin provided by the 5% demand assumption also changes.
4. Generator voltages. The setpoint for generator voltage regulators determines the reserve that each generator would have to respond to voltage-related events. Within the limits of acceptable plant operation, the setpoints may be viewed as adjustable parameters in a planning study to optimize the operations of the grid with respect to voltage stability.
5. Post contingency capacitor switching. The dynamic voltage recovery of the grid to specific disturbances can vary. In stiff sections of the grid, the dynamic response may be fast, and indeed capacitor switching would be inadequate. If the characteristic response is slower, there may be sufficient time for capacitor switching to help. From a steady-state assessment point of view, the applied criteria has an inherent safety margin but may be overly restrictive if the dynamic response provides for sufficient response time.
6. Critical nose point voltage at 0.98 p.u. The value is determined on a post-contingency basis as the point where the power flow solution no longer solves. For operability and controllability concerns, monitoring the nose point voltage is important. A high nosepoint voltage could mean that operators may not have the warning of dropping voltages before a voltage collapse event. Likewise, the high nosepoint voltage implies that the shape of the nosecurve has been “flattened” by a large component of shunt static vars; leading to a very high $\Delta V/\Delta P$ ratios, a state where voltages may be difficult to control.
7. For planning purposes, we observe that utilities more typically determine the nosepoint voltage pre-contingency or under normal, all-in conditions. This relates to the limits of observability in that if the pre-contingency nosepoint is high, operators will not have the benefit of dropping voltages as a warning of incipient voltage collapse. In the case of the New York Independent System Operator ('NYISO'), the voltage limit is set based on the shape of the knee of the nosecurve. (See Figure 2-2).

⁶ Located in the Midwest and Eastern Seaboard areas of the United States that includes Washington, D.C., Chicago, Pittsburgh and New Jersey.

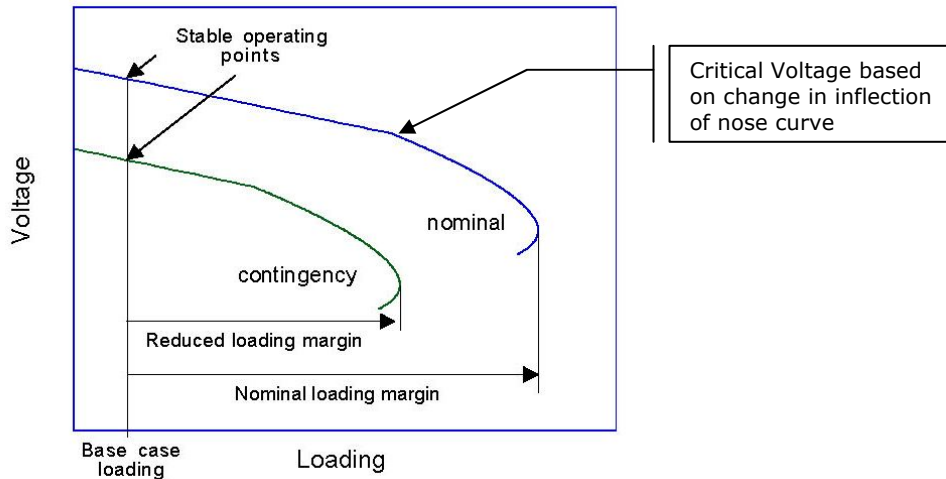


Figure 2-2: Example nose curves for pre- and post-contingency conditions.

Because of differences in power flow solution methods and embedded heuristics, the point on the nose point when the power flow no longer solves may vary from one power flow software to another. Methods such as eigenvalue analysis and continuation power flows have been applied to clearly establish that the nose point indeed represents a singularity⁷ where such is in question. However, in our opinion, these efforts to clarify the nose point are mooted by the fact that the steady-state model of the power flow is an approximation that requires confirmation using dynamic simulation, especially where the nose curve is based on response to a contingency.

8. Modeling of static var devices and synchronous condensers. Another means of ensuring reactive reserve is to apply criteria wherein the pre-contingency reactive output of these devices is near zero ('floating') or absorbing vars. The amount of reserve would need to be determined from QV and PV curve results or from dynamic simulations. The Planning Study indicates that Transpower is already applying some form of this criteria, and it may useful to state so explicitly in Section 5.2 of the Planning Study report.
9. Because of the interaction of time-dependent response from dynamic loads, excitation systems and limiters, tap-changing under load and static var devices as the grid changes from an (n) state to an (n-1) state, which are not captured in a power flow analysis, time simulation is now more widely used as a determinant for dynamic reactive support.

Figure 2-3 illustrates the form of dynamic response used in the Western Electricity Reliability Council ('WECC') of North America as a determinant for dynamic reserve.

⁷ Singularity in the power flow is typically defined based on the form of the Jacobian matrix.

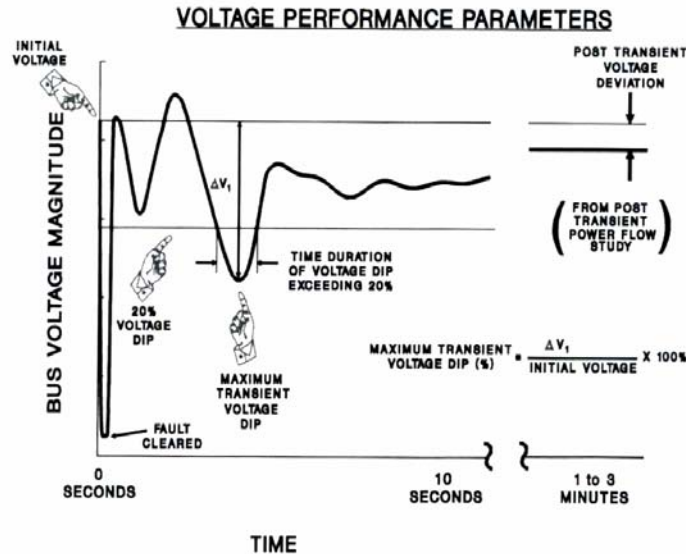


Figure 2-3: Sample voltage dynamic response to a contingency as monitored at a load bus.
(Source: WECC public documents)

In this form of dynamic response, the distinct criteria for voltage recovery are specified for each of several time periods following the fault clearing portion of the contingency, including:

- a. Maximum transient voltage dip – the drop in pre-contingency voltage measured during the first few cycles following fault clearing.
- b. Time duration of voltage dip – the duration that voltage remains below a specified value following fault clearing
- c. Post-transient voltage – the voltage several minutes after fault clearing when all relevant dynamic phenomena are quiescent in the simulation. Note that this voltage may not necessarily coincide with the power flow post-contingency voltage.

2.3. Planning Criteria Applied by Transpower

In a technical paper (see Reference 3 of Section 1.4) Transpower planning staff described a set of performance criteria for dynamic analysis. This set provides a basis for establishing voltage stability criteria that are based on dynamic simulation. The key criteria specified in the paper are as follows.

- Voltage must be greater than 0.5 pu immediately following an N-1 event which removes an item of equipment from service without transmission system short circuit fault.
- Voltage must recover to above 0.8 pu in less than 4 sec following an n-1 event with a three-phase fault
- Motor current must not be greater than 6 times the rated current for more than 3 sec and not be greater than 3 times the rated current for 8 sec.

- Voltage overshoot must be limited to below 1.3 pu.
- Voltage overshoot must not be above 1.1 pu for more than 0.5 sec.

These criteria are consistent with the current and evolving practice in planning for voltage stability in power systems. It is expected that the criteria will continue to evolve as more information about the characteristic response of the grid to various contingencies is obtained.

2.4. Proposed Planning Criteria for the Present Study

Considering the existing Transpower criteria, international practice and simulations conducted of the South Island grid (see Section 4), following are criteria proposed for use in this study:

- A MW margin, measured on the PV curve of at least 5% from the annual peak steady-state model total USI load, the 5% measured from one of the following points on the PV curve: the nosepoint, the point where the power flow solution fails to converge or the point where voltage dips below 0.9 pu, whichever results in the lower margin.
- Contingencies to test using dynamic simulations:
 - Design contingencies: Three-phase fault with normal clearing and single-line to ground fault with delayed clearing
 - Extreme contingencies: Loss of a bus section (without a fault applied)
- Transient response:
 - The voltage to recover to at least 0.9 p.u. voltage⁸ in 5 seconds⁹ after the clearing of the initial fault and disturbance for normal or design contingencies, and
 - The voltage to recover to at least 0.6 pu voltage¹⁰ in 0.5 seconds for extreme contingencies with no fault applied
- Post-transient response: the voltage to recover to within 10% of the pre-contingency voltages, with no undamped oscillations after 30 seconds.

The above criteria is intended as a preliminary set of modifications to the existing criteria used by Transpower, taking into account dynamic reactive response to voltage stability. The criteria are further intended to be modified as more accurate information becomes available and further system and load characteristics are applied.

⁸ This is about the voltage level where distribution tap-changers are able to maintain voltage at customer loads.

⁹ The 5 second target is a system-dependent characteristic. It marks the point in time when most of the voltage transient responses from the initial contingency have rung down (but before the frequency response from governors becomes evident). This is an aspect of the criteria that can be fine tuned over time.

¹⁰ This is about the voltage level above the range of contactor tripouts (0.4 to 0.6 pu); hence the specific criterion avoids motor trips on low voltage for short durations.

2.5. References

1. FERC (United States Federal Energy Regulatory Commission) Final Order on interconnection of wind farms.
<http://elibrary.ferc.gov/idmws/common/opennat.asp?fileID=10594521>
2. NERC (North American Electric Reliability Corporation) Transmission Planning Criteria (TPL-00 to TPL-04).
ftp://www.nerc.com/pub/sys/all_updl/standards/rs/TPL-001-0.pdf
3. NERC Voltage Performance Criteria.
ftp://www.nerc.com/pub/sys/all_updl/standards/rs/VAR-001-1.pdf
4. WECC (Western Electricity Coordinating Council) Reliability Criteria, August 2002.
5. California ISO Planning Standards, February 2002.
6. PJM Interconnection Planning Criteria.
<http://www.pjm.com/committees/planning/planning.html>
7. ISO New England Planning Criteria. http://www.iso-ne.com/rules_proceeds/isone_plan/index.html
8. New York ISO Planning Criteria.
http://www.nyiso.com/public/webdocs/documents/manuals/planning/rel_assmnt_mnl.pdf

Section 3. Data and Assumptions

The databases used for this study were provided by Transpower. Some modifications and clarifications were subsequently made to the models as documented in this section.

3.1.1. Data for Steady-State Assessments

For the power flow model, Pterra developed a detailed model based on the model case provided by Transpower, with minor adjustments to match the 2007 system conditions. In addition, Pterra developed generator reactive capability ('GCAP') curve models to supplement the power flow model. The purpose of GCAP models is to provide for a means to reflect the steady-state reactive capability of the sending end (Waitaki Valley area) and receiving end (USI) generators based on their real power dispatch.

A summary of the items confirmed in relation to the power flow model follows:

- Confirmed that the existing reactive devices as listed in Table 1 of the Planning Study are modeled explicitly.
- Removed cap banks at Ashburton (ASB).
- Confirmed that dispatch is for winter wet conditions based on Table 5 of the Planning Study.
- Confirmed which of the transmission upgrades listed in Table 6 of the Planning Study are modeled. Those that were not so modeled were added to the power flow model.
- Confirmed that the two circuits to Islington are bussed at Ashburton.
- Confirmed the setting and operating mode of OLTC transformers.
- Applied the GCAP data to the base case. This essentially sets the reactive power limits for generators to the Qmax and Qmin limits specified by their reactive capability curves.
- Conducted an overload and voltage limit check and confirmed that the power flow case is in compliance with Planning Criteria.

The resulting power flow after the above modifications was designated as the "**Base Case**" power flow. It represents a condition where total South Island demand is 2253 MW under winter wet generation dispatch.

Additional power flow cases were developed representing future years by increasing load at constant power factor, taking into account non-scaleable load.

3.1.2. Data for Dynamic Simulation Assessments

For the dynamic simulation model, Pterra reviewed the provided data and applied the following changes and tests:

- Reviewed machine model data versus manufacturer data provided.
- Added excitation limiters where data was provided.

- Revised exciter models based on manufacturer data provided.
- Developed additional models for loads using a complex load configuration.
- Added remote control setpoints for the SVDs at Islington.

The resulting database was tested for compatibility with the power flow Base Case to ensure that all models are connected and the data is consistent with typical range of values.

Exciter testing was conducted on this database with results that are generally within the acceptable range of values and response. Plots of the exciter tuning are included in Appendix B.

Section 4. Analysis and Results

This section presents the methodology, analytical results and discussion of voltage stability assessments conducted under the Scope of Services.

4.1. Steady-State Assessment

The following analyses were conducted using steady-state methods (power flow):

1. Contingency analysis
6. Nose or PV curve analysis
7. QV curve analysis

Each is discussed in the following subsections.

4.1.1. Contingency Analysis

An initial filtering of contingencies that impact voltage stability, steady-state contingency analysis was performed. Since the analysis is performed at load levels that may not be at or near where voltage stability occurs, at best the method provides for a list of contingencies with a potential impact on voltage stability.

The 220 kV contingencies identified based on the magnitude of voltage dip are listed in Table 4-1.

Table 4-1: List of contingencies with potential impact on voltage stability.

CONTINGENCY	BUS #	BUS NAME	V-CONT	V-INIT	DELTA PU
46761 OPI220-A TO 47961 TIM220-A CKT 1	47961	TIM220-A 220	0.9708	1.0293	-0.0585
44960 ISL220 TO 45160 KIK220 CKT 1	45160	KIK220-- 220	1.0278	1.0576	-0.0298
44960 ISL220 TO 48160 TKB220 CKT 1	41660	ASB220-- 220	1.0118	1.0388	-0.027
46761 OPI220-A TO 48560 TWZ220 CKT 1	47962	TIM220-B 220	1.0043	1.0293	-0.025
43161 CUT220-A TO 45160 KIK220 CKT 1	47760	STK220-- 220	1.0254	1.0495	-0.0241
44960 ISL220 TO 45360 LIV220 CKT 1	41660	ASB220-- 220	1.0157	1.0388	-0.0231
41660 ASB220 TO 44960 ISL220 CKT 1	41660	ASB220-- 220	1.0176	1.0388	-0.0212
41660 ASB220 TO 42360 BRY220 CKT 1	41660	ASB220-- 220	1.0204	1.0388	-0.0184
41660 ASB220 TO 46761 OPI220-A CKT 1	41660	ASB220-- 220	1.0215	1.0388	-0.0173
41660 ASB220 TO 46762 OPI220-B CKT 1	41660	ASB220-- 220	1.0215	1.0388	-0.0173

Prominent in this list are contingencies involving the circuits between Waitaki Valley and the Christchurch area.

4.1.2. PV Curve Analysis

In the Planning Study, the P-V characteristic was developed by increasing USI demand and monitoring voltage at the Islington 220 kV bus. The Planning Study concludes that the critical voltage of the system is close to 1.04 p.u. The voltage stability limit is in the range of 1188 MW Upper South Island (USI) load, taking into account a 5% margin from the nose point.

Using the Base Case described in Section 3.1.1, Pterra developed PV curves at various load levels and various contingencies. The most limiting contingency is the loss of the Islington-Tekapo B 220 kV line. This is consistent with the Planning Study basis.

A useful measure of reserve for voltage stability is the MW margin measured from the P-V curve. An example of the MW margin is illustrated in Figure 4-1. For the purposes of this study, the steady-state voltage limit is defined as the lowest of the following: the MW value at the nosepoint, the MW value at the point where the power flow solution fails to converge or the MW value at the point where voltage drops below 0.9 pu. The MW margin is determined with a safety margin of 5% of the steady-state voltage limit.

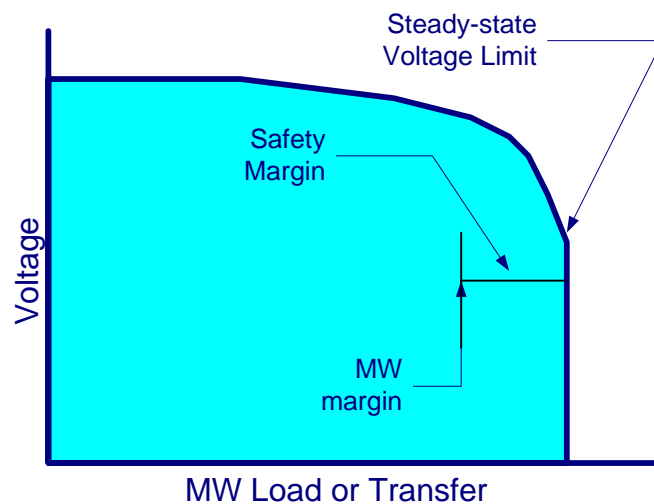


Figure 4-1: MW margin as measured from the P-V Curve.

A summary of maximum USI load levels for various contingencies is shown in Table 4-2.

Table 4-2: Summary of Maximum USI Load Levels for various contingencies

System Condition	Maximum USI Load (MW)	Approx Forecast Year
Loss of Islington-Tekapo B 220 kV line	1180	2008
Loss of Islington-Livingston 220 kV line	1190	2008
Loss of Islington-Ashburton 220 kV line	1210	2009

The results indicate that the surplus transmission capacity available is less than 100 MW for the existing system operating during winter wet conditions. The most severe contingency with respect to voltage stability is the loss of the Islington-Tekapo B 220 kV line. Plots of the PV curves for Islington and other buses are included in Appendix C.

4.1.3. QV Curve Analysis

By means of QV analysis, the Planning Study determines that present reactive support is exhausted when load demand (in USI) is about 1150 MW, or just after year 2007.

A useful measure of reserve from QV Curve analysis is the reactive margin. This is the measure of MVAR from the lowest point of the curve to the reactive supply curve (either the Q=0 line or the curve/s of proposed capacitor/s). This is illustrated in Figure 4-2.

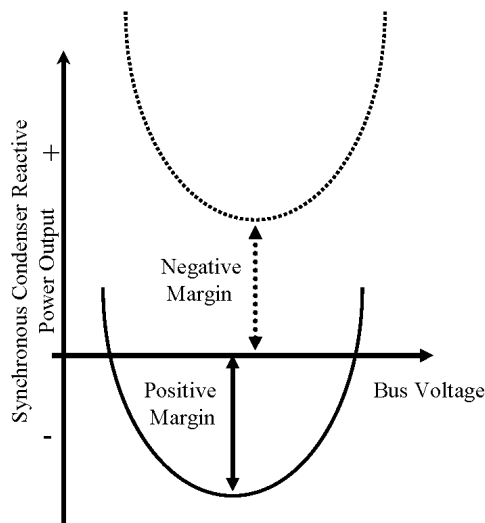


Figure 4-2: Reactive margins determined from QV curves.

Using the Base Case as developed in Section 3.1.1, QV curves were developed for various load levels and contingencies. The resulting reactive reserves are summarized in Table 4-3.

Table 4-3: Summary of Reactive Margins from Q-V Curves

System Condition	MVAR margin	Total SI Load (MW)
Loss of Islington-Tekapo B 220 kV line	90	1167
Loss of Islington-Livingston 220 kV line	106	1167
Loss of Islington-Ashburton 220 kV line	157	1167

The loss of the Islington-Tekapo B 220 kV line leaves the lowest MVAR margin of the contingencies tested. The margin is relatively low compared to the total reactive demand in USI, and indicates that additional reactive support will be needed with load growth.

The plots of the QV curves are included in Appendix D.

4.2. Dynamic Simulation Assessment

Dynamic simulation assessment was applied to confirm the response characteristic to various contingencies. Appendix F lists the various simulations performed. The plots of stability cases are included in Appendix G.

The following subsections discuss the aspects of assessments:

- Load modeling
- Stability tests
- Solutions for voltage stability prior to addition of new 220 kV line

4.2.1. Load Modeling

As load modeling was deemed to be a critical aspect of voltage stability of the South Island, attention was given at the early stages of study to obtaining range of values and characteristics to different possible load models.

We started by considering two load models:

- PIQZ¹¹ model for all load
- Complex load model described in Reference 4 of Section 1.4¹².

To obtain a sense of the range of response, nomograms were developed for each of the possible load models. The assumptions applied to the nomograms are:

- No additional shunt compensation or SVD to the Base Case
- Both the Islington SVC and synchronous condensers are remotely controlling voltage at the Islington 220 kV bus
- Solid 3-phase fault applied at Islington 220 at 0.1 sec, cleared in 120 msec, with opening of the Islington-Tekapo B line. (This is the worst contingency as identified in the steady-state assessment.)
- Where there is motor contactor shedding, these are initiated at $v < 0.6$ p.u.

¹¹ Where the real power portion of the load varies as voltage (also referred to as "constant current or I" characteristic) and the reactive portion of the load varies as the square of voltage (also referred to as "constant impedance or Z" characteristic).

¹² However, for this study, the constant power component of the complex load model has a braking characteristic that starts at 0.7 p.u and changes the load-voltage characteristic as voltage drops below 0.7 pu.

- Complex load is applied only to USI. The rest of the island load is modeled as PIQZ
- Response voltage is monitored at Islington 220 kV bus.

The following nomograms to study load characteristics were developed. The nomograms are shown in Appendix E.

- Complex load ('CLOD')¹³ model with 38% motor load component and with a portion of group 1 motor loads shed due to assumed contactor dropout. Portions shed range from 35% to 100% (See nomogram 1). Non rotating loads are modeled as PIQZ (46%) or constant P (15%).
- Complex load model with motor load component of 9%, 19%, 29% and 38% with no motor contactor shedding (See nomogram 2). Non rotating loads are modeled as PIQZ or constant P.
- Complex load model with 19% motor load component and with constant P component of 0, 5, 10 and 20% (See nomogram 3). The balance of the loads in each case is modeled as PIQZ. No contactor dropout is assumed.

Various load models were proposed based on the preceding nomograms. Each proposed load model was tested over a range of load levels to measure the maximum USI load level where proposed criteria are met and the approximate year when the maximum level is reached. The summary of results is shown in Table 4-4.

Table 4-4: Summary of Dynamic Simulation Results to test Load Models

Nomogram No.	Proposed Load Model	USI Load MW¹⁴	Forecast Year¹⁵
4	All loads represented as PIQZ model	>1450	>2012
5	CLOD model with 38% motor load. Non rotating loads are modeled as PIQZ (46%) or constant P (15%). No motor shedding.	1175	2007
6	CLOD model with 38% motor. Non rotating loads are modeled as PIQZ (46%) or constant P (15%). 75% of group 1 motors shed on low voltage.	1250	2007
7	CLOD model with 19% motors. Non rotating loads are modeled as PIQZ (61%) or constant P (20%). No motor shedding.	1250	2007
9	CLOD Model with 19% motor and 10% constant P load. The balance of loads are modeled as PIQZ. No motor shedding.	1325	2009

¹³ CLOD is the generic complex load model in the PSS/E dynamic simulation program.

¹⁴ Rounded to lower 25 MW intervals, and without adding a 5% margin.

¹⁵ Taking into account 5% margin in the forecast levels.

Absent further reference for actual load-voltage response characteristic, it is difficult to conclude just from simulations which would be an appropriate load model. One can argue that given the P-V Curve maximum USI load of 1264 MW, normally a conservative measure, that the dynamic load model should support at least 1275 MW of USI load. Furthermore, the load model should be generally applicable to future load conditions.

Hence, we can say that for a **low risk** model, Transpower can consider either:

- A complex load model with 38% motor load, 15% constant P component (as described in Reference 4 of Section 1.4) and the remainder modeled as PIQZ. Of the motor load, 50% of the Group 1 motors have contactor shedding at voltages below 0.6 pu (See nomogram 6).
- A complex load model with 19% motor load component with no motor shedding. Non rotating loads are modeled as PIQZ (61%) or constant P (20%). No motor shedding. (See nomogram 7).

A **moderate risk** model is:

- A complex load model with 19% motors, 10% constant P load¹⁶ and the remainder as PIQZ (See nomogram 9).

Finally, a higher risk model is:

- 100% PIQZ model, i.e., no motors modeled explicitly (See nomogram 5).

Clearly there is a variety of choices each with significant impact on the reliability and cost of the planned system.

For purposes of further study, we proceeded with the following:

- The moderate risk model (as described above)
- A low risk model - with 38% motor load, 15% constant P component and the remainder modeled as PIQZ. Of the motor load, 50% of the Group 1 motors have contactor shedding at voltages below 0.6 pu

In using these two models, two plans were developed, providing a range of solutions that can be directly associated with load modeling risks.

4.2.2. Voltage Stability Tests

An initial screening of the possible contingencies was performed to identify the ones which are critical to voltage stability. The list of contingencies tested:

¹⁶ The constant P component represents load that is not voltage-dependent during the transient. Typically, this may comprise of power supplies and certain types of loads with electronic controls. Since the penetration of this type of load is not generally high, it is reasonable to assume a smaller percentage. Also, some of the load classified as constant P may be self-restoring load that has a fast time response. But even in this case, self-restoration requires sensing and feedback response that would have transducer and other time delays embedded in the response. It is more practical to assume this type of load as PIQZ during the transient and self-restore in the post-transient.

Design Contingencies:

1. 3-ph fault at Islington 220 kV bus, cleared in 120 msec with loss of Islington-Tekapo B line
2. 3-ph fault at Islington 220 kV bus, cleared in 120 msec with loss of Islington-Livingston line
3. 3-ph fault at Islington 220 kV bus, cleared in 120 msec with loss of Islington-Ashburton line
4. SLG fault at Islington 220 kV bus, cleared in 350 msec with loss of Islington-Tekapo B line
5. SLG fault at Islington 220 kV bus, cleared in 350 msec with loss of Islington-Livingston B line
6. SLG fault at Islington 220 kV bus, cleared in 350 msec with loss of Islington-Ashburton line

Extreme Contingencies

7. Loss of interconnector T3, the SVC, a 60 Mvar capacitor, supply transformer T2, and the 220 kV circuit to Ashburton
8. Loss of interconnector T6 (and the condensers on its 11 kV tertiary), a 60 Mvar capacitor, and the Livingstone line
9. Loss of interconnector T7, the TKB line, and an ISL-CUL-WPR-KIK circuit

The tests were made at a load level of 2254 MW total South Island load, for each of the low and moderate risk load models.

The most severe design contingency is the single-line-to-ground (SLG) fault at Islington, cleared by the line to Tekapo B (contingency no. 6). In general, the SLG contingencies are more severe than the three-phase (3ph) faults for the same fault location and line outage. The extended duration of the SLG, 350 msec, with respect to the 3ph fault, 120 msec, results in a slower recovery for voltages in the transient.

The most severe extreme contingencies involve either loss of the T6 (contingency no. 8) or the T7 (contingency no. 8) connectors.

Stability tests were conducted on system response to the various contingencies at higher levels of forecasted load. A summary of the test results is shown in Table 4-5.

Table 4-5: Highest SI Load Levels achievable and the forecast year when these levels are reached, without system reinforcements, and for different load models¹⁷

Load Model	Highest SI Load (MW)	Forecast Year ¹⁸
Moderate Risk	1325	2009
Low Risk	1175	2007

Given that the earliest that a new 220 kV line can be put in service is 2014, there is clearly a need for intermediate reinforcements for voltage stability. These are addressed in the next sub-section.

4.2.3. Assessment of Possible Intermediate Solutions

In the timeframe between 2009 (when the first intermediate solutions may be implemented) to 2014, the types of solutions to voltage instability would be characterized as incremental and short-term. When a new 220 kV line is built between Waitaki Valley and the Christchurch area, the intermediate solutions may become superfluous or have a secondary function.

Hence solutions that are easy to implement and relatively cheap are desired. Also, for as long as the solutions are economic, they may continue to be applied to further defer the investment in a new 220 kV line subject to the aspects of technical feasibility, reliability and controllability. Some of the solutions are as proposed in the Planning Study. The solutions tested herein are as follows:

- Switched capacitors under RPC control operating in corrective mode. These would normally be offline, but are switchable during a transient at a maximum delay of 2 seconds per block. The location is at Islington 220 where the existing RPC is located.¹⁹
- Additional SVCs at Islington, Kikiwa and Ashburton in combination with fixed capacitor banks.
- Series compensation of lines between Waitaki Valley and the Christchurch area – 50% on all four circuits
- Bussing of all four 220 kV circuits between the Waitaki Valley and Christchurch at Geraldine.

Feasible solutions based on the options listed above are measured in terms of the highest SI total load supported while still meeting the proposed criteria. Table 4-6 shows a summary of feasible solutions for both the moderate risk and high risk load models. A full list of all tested solutions is included in Appendix F.

¹⁷ Rounded to nearest 25 MW. Based on meeting the Proposed Criteria.

¹⁸ Taking into account a 5% margin on the forecasted load.

¹⁹ Operating capacitor banks on corrective mode during transients requires an intelligent controller such as an RPC and switching through a breaker, or in other cases, using thyristor technology and controls similar to those of an SVC. Attempting to implement this function via a voltage-sensing relay and breaker alone could lead to incorrect switching. Care must be taken to ensure that the delta-V when the capacitor switches in can be tolerated by equipment, noting that normally, the voltage at switching may be quite low. This could lead to designs with smaller blocks of capacitors on individual breakers.

Table 4-6: Summary of Dynamic Simulations to Test Solutions with most severe Design Contingency

Sol'n ID	Components ²⁰	Moderate Risk Model		Low Risk Model	
		Max USI Load MW ²¹	Forecast Year ²²	Max USI Load MW	Forecast Year
0	None	1325	2009	1175	2007
A	Switched capacitors at Islington under RPC corrective mode – 75 MVAR	1350 ²³	2010	- ²⁴	-
B1	75 MVAR capacitor bank ²⁵ and +/-100 MVAR SVC at Islington	1400	2011	1325	2009
	Additional +/-60 MVAR SVC at Kikiwa	1425 ²⁶	2012	1325	2009
B2	B1 plus Additional 2x60 MVAR cap at Ashburton	1475	2013	1375	2010
B3	B1 plus +/- 120 MVAR SVC at Ashburton	1525	2014	1375	2010
	Add 120 MVAR shunt capacitors at Islington	1575	2015	1375	2010
B4	615 MVAR ²⁷ shunt capacitors and +/-500 MVAR SVC at Islington	1800	2022	1750	2020
C1	50% Series compensation of lines between Waitaki Valley and the Christchurch area	1550	2014	1550	2014
D	Bussing of four 220 kV circuits at Geraldine	1575	2015	1400	2011

Following is a discussion of each of the proposed solutions.

1. For the Moderate Risk Load Model

- a. Solution A. Switched capacitors in corrective mode respond during transient conditions when the decision to switch in or out is made on a short time frame and under depressed voltage conditions. As more such banks are applied, smaller block sizes are required to avoid

²⁰ Shown in order of implementation.

²¹ No margin included.

²² Taking into account 5% margin on USI load.

²³ Delta-V when capacitor switched is 0.045 pu. The MW/MVAr ratio is .67 where MW is the incremental USI load and MVAr is the additional capacitor.

²⁴ Not tested.

²⁵ Operated in preventive mode.

²⁶ This is the forecast level for winter conditions for year 2014, the first year that a new 220 kV line may be placed into service.

²⁷ Comprised of blocks of 1x75 and 9x60 MVARs.

switching over-voltages²⁸. For Solution A, starting with 75 MVAR blocks, the solution is limited to an incremental 50 MW of USI load. Beyond this, the delta-V exceeds acceptable levels. With smaller block sizes, the time delay as each block is switched keeps the solution from being able to meet to the proposed transient criterion (which specifies 5 sec to return voltage to 0.9 pu or above).

- b. Solution B1-B4. The set of solutions B1 through B4 use a combination of fixed capacitors and SVCs to meet the proposed voltage stability criteria. Solution B1 starts with a 75 MVAR fixed capacitor bank added at Islington in combination with an additional SVC on T7 with a control range of +100/-100 MVAR. This combination yields an incremental USI load capacity of 75 MW. Adding an SVC at Kikiwa rated at +/- 60 MVAR would further increase the USI supported load by 25 MW. In Solution B2, B1 is extended, adding two 60 MVAR fixed capacitor banks at Ashburton. This increases USI load capacity by 25 MW. Note the decreasing MW/MVAR ratio, where MW is measured in terms of incremental USI load, and MVAR in terms of additional capacitive capability. At very low MW/MVAR ratios, starting from 0.5 and less, additional shunt capacitors tend to be infeasible without being accompanied by dynamic control range to mitigate high voltages and respond to reactive demand during contingencies. The reason for this is that the lower ratio requires increasing MVAR additions from capacitors, but the large cap banks introduce over-voltages during normal if operated in preventive mode or during switching conditions if operated in corrective mode.

Solution B3 applies an additional SVC at Ashburton in place of the cap bank from B2. USI load levels of up to 1575 MW, corresponding to forecasted load for 2014, are possible with this approach. A wide area RPC may be needed to coordinate the response of the dispersed SVCs.

Solution B4 addresses the concern with overlapping control response of SVCs at multiple sites²⁹ (Islington, Kikiwa and Ashburton) by placing a single large SVC installation at Islington. A large SVC, sized +/- 500 MVAR in combination with fixed shunt capacitor banks offers a solution for supporting higher levels of US load that comply with

²⁸ For cases where high voltages are observed in simulation just after fault clearing, consideration could be given to include some inductive range of compensator (i.e., thyristor-controlled reactor, TCR), which would help to control the voltage, converting this into an AVC solution. Additionally, manufacturers may implement strategies in the thyristor valve control circuit (associated with the thyristor-controlled capacitor, or TSC, branch) to mitigate or self-protect the system and/or the thyristor valve from high voltages. Some examples of mitigation measures are (1) temporarily "blocking" the thyristor valve firing pulses for pre-defined overvoltage and/or undervoltage conditions, and (2) applying break-over diodes and/or surge arresters across the thyristor valve.

²⁹ Controlling multiple SVCs at different sites/substations requires specific studies to determine the appropriate response rates for each of the SVCs while considering the combined effect of all SVCs acting together (for all probable contingency conditions). Alternatively, wide area controller or RPC may be used for the purpose of coordination.

planning criteria. However, this solution is subject to confirmation of security against common mode failures, effects of harmonics and excitation of resonant modes in neighboring facilities. At the time of this report, no existing SVC of this control range yet exists.³⁰ Given these considerations, 615 MVARs of additional shunt capacitors in bank sizes of 9x60 and 1x75 MVARs, in combination with the large SVC can potentially support USI load of 1800 MW, or out to planning year 2022.

- c. Solution C considers the option of adding series compensation. For study purposes, 50% compensation was applied to each of the four existing 220 kV lines between Waitaki Valley and Christchurch. Without any other additions to the Base Case, this solution can support up to 1550 MW of USI load, or up to forecast year 2014.

Series compensation may require significant upgrades or revisions in the protection schemes, in particular, relaying and monitoring that is dependent on the line impedance, such as line relays. Once implemented, the series capacitors tend not to be relocatable. And with series compensation in place, future new transmission lines may need series compensation as well. A further technical note about series compensation is that the potential for subsynchronous resonance impacts needs to be assessed.

Solution C can be extended to support additional USI load growth in combination with shunt capacitors and SVCs. The limits on additional USI load growth are subject to those technical issues noted in solutions B3 and B4 above.

- d. Solution D considers the bussing of four circuits between the Waitaki Valley and the Christchurch area at a substation designated as Geraldine. This solution reduces the net effect of the loss of the worst contingencies – Islington to Tekapo B, and Islington to Livingstone – by providing a switching station at Geraldine. This solution supports up to 1575 MW of USI load, or up to a forecast year of 2015.

As with Solution C, this solution may be extended with the addition of shunt capacitors and SVCs.

2. For the Low Risk Model

- a. Using the Low Risk load model, wherein there is a larger component of motor and constant power load than the moderate risk model, Solutions B1, B2 and B3 provide minimal incremental capacity, up to 1375 MW of USI load, or until 2010.

The large SVC option for Solution B4, on the other hand, provides support for up to 1750 MW of USI load, or until forecast year 2020. The reason for the response is that the SVC offers dynamic control

³⁰ The largest existing SVCs as of the date of this report are +500/-150 MVAR device in the Allegheny Power service territory in Pennsylvania, USA, and the Chamouchouane SVC (actually two SVCs at one site) rated +330/-330 MVAR in Quebec, Canada.

that mitigates the impact of the more severe motor and constant P loads of the low risk model, better than the smaller SVCs in Solutions B2 and B3. However, the technical concerns, noted in item 1a above are still applicable and need to be addressed for the large SVC solution.

- b. Series compensation (Solution C) also provides a fairly high MW margin supporting USI load of up to 1550 MW, or until 2014.
- c. Bussing at Geraldine (Solution D) offers a modest increase in supported USI load, up to 1400 MW or year 2011.

All of the assessed solutions to provide support against voltage instability offer some level of additional USI load. A summary of the best solutions, in order of effectiveness:

- Large SVC in combination with fixed capacitor banks at Islington. This solution has the potential for supporting levels of USI load up to 2022. In combination with series compensation, even higher levels of USI load may be supported. However, the technical issues noted in item 1b above need to be addressed.
- Series compensation. Technically, this offers additional MW capacity for up to 2014 in either the moderate or the low risk load model. Because of this characteristic, the solution addresses a wide range of risk associated with load response, and offers a robust option for mitigating the need for a new 220 kV line.
- Capacitors and SVCs at Islington, Kikiwa and Ashburton. Incremental additions at the three sites provide for USI load of up to 1475 for the moderate risk model and 1375 for the low risk model are possible.

Overall, the dynamic simulation results provide MW margins that are about the same (for the low risk model) or a couple of hundred MW higher (for the moderate risk model) than those of steady-state results using PV and QV curves. The dynamic simulation results show an additional dimension of system response not available to the steady-state models that allow differentiation amongst the potential mitigation measures to defer the need for a new 220 kV line. Hence, dynamic simulation points towards SVCs and series compensation as robust solutions to deferring the need for a new 220 kV line.

4.2.4. Observability and Controllability Issues

As noted earlier in this Section, the high levels of compensation present a concern for the observability and controllability of the South Island grid.

Observability is the aspect of the planned operating system that provides future system operators with sufficient indicators to anticipate potential voltage instability. The indicators need to be of a form that operators can observe and monitor in order to have sufficient time to respond to a system disturbance. For voltage stability, the traditional observed quantities are voltages at various nodes of the power system. However, given that from both the PV curve and the dynamic simulation assessment

the pre-contingency voltage can be high, as much as 1.04 pu for events that may lead to voltage instability, voltage may not be a sufficient monitored parameter if the intermediate solutions are implemented.

To enhance observability in the future system, prior to the addition of a new 220 kV line between Waitaki Valley and Christchurch, additional monitored parameters are required. One of the most commonly used indicators is the reactive reserve. This is a measure of the level of reactive output of generators and static devices. We recommend that this measure not be determined from QV curves but from dynamic simulation that identifies optimal levels of reactive output from various reactive sources. One aspect of this measurement may be to consider SVCs as operating in floating mode during normal conditions with the dynamic control range available for contingencies. Other indicators that have been used in Europe and the United States include the rate of voltage change per MW change in load, the rate of reactive output change per MW change in load, and online dynamic security assessment tools.

Controllability is the aspect of the planned system that provides future system operators with sufficient control and response capability to maintain voltage stability. The controls available to the operators of today include dispatch, voltage schedules and switching of capacitors and lines. At the levels of shunt compensation existing and planned prior to the addition of a new 220 kV line the sensitivity of voltage to the controls is quite high. By this we mean that small shifts in dispatch and voltage schedules may result in significant shifts in the voltage stability of the system. The primary causes of this sensitivity are shunt compensation devices in SVCs and capacitor banks whose reactive output vary as the square of the terminal voltage. As voltage shifts take place, the total reactive output from the static devices changes, and needs to be balanced by the reactive output from rotating devices. In the case of USI, the closest rotating machines are at Coleridge, Cobb and Kumara. However, these units are relatively small, and the larger machines are located in Waitaki Valley, on the other end of relatively long 220 kV lines. To improve controllability, additional supervisory and supplementary controls may be specified. For example, the RPC at Islington may be designed to respond to voltage stability conditions for the whole of USI instead of monitoring local voltage. Another option is a wide area RPC that controls switching of SVDs in various locations in USI.

As MW margins decrease in the South Island, and mitigating measures are implemented to defer the need for a new 220 kV line, it would be of benefit to future system operators to provide increased capability for observability and controllability of the power system.

4.2.5. Sensitivity Analysis

Additional assessments were requested by Transpower to consider the sensitivity of the dynamic simulation results to contingencies other than those discussed in the above sections. Specifically, the following contingencies were tested (numbering continued from Section 4.2.2):

10. Autoreclose onto fault event
 - o 3ph fault at Islington cleared by opening the ISL-TKB line at both ends after 120msec.

- Auto-Reclose the line onto the fault 6.5 seconds later.
- Clear the fault after 120 msec by opening the ISL-TKB line at both ends (and leaving it open).

11. Bus section outage with fault³¹

- a 3 phase fault on ISL-TKB line occurs close to Islington 220 bus
- At the TKB end of the line, the line breaker opens correctly after 120 msec. However at the Islington end of the TKB-ISL line the breaker remains closed (i.e. has stuck) when allows the fault to persist.
- Breaker failure detection operates after 300 msec to remove a bus section at Islington and hence clear the fault.
- This results in loss of ISL-TKB line, the T7 interconnector, and the ISL-WPR-CUL-KIK line, i.e. refer to contingency #9 (sec 4.2.2 of report).

12. Double circuit outage³²

- a 3 phase fault at ASB 220 cleared by opening both ASB-TIM-TWZ circuits after 120 msec.
- Successful auto-reclose after 1 second of both circuits at Twizel end and Ashburton end.
- Successful reclose of circuits at Timaru 220 occurs after 3 seconds.

Applying the above contingencies to the Moderate Risk load model and the 'B4' solution of Table 4-6, the resulting maximum USI load that meets the proposed voltage stability criteria are summarized in Table 4-7.

Table 4-7: Summary of Additional Contingencies Tested under Moderate Risk Model with Solution 'B4' Applied.

Contingency	Max USI Load MW ³³	Forecast Year ³⁴
10: Autoreclose onto fault event	1575	2015
11: Bus section outage with fault	1575	2015
12: Double circuit outage	1800	2022

³¹ The duration of the three-phase fault is 300 msec.

³² The following island is created after the loss of the double-circuit: 41010 ABY11---11.0, 41050 ABY110—110, 47930 TIM33---33.0, 47950 TIM110—110, 47961 TIM220-A 220, 47962 TIM220-B 220, 48010 TKA11---11.0, 48030 TKA33---33.0, 48050 TKA110—110, 48330 TMK33---33.0, 48351 TMK110-A 110, and 48352 TMK110-B 110. The load in the island is much greater than the generation. Hence, this island is assumed to shut down, and remain disconnected through the remainder of the simulation.

³³ No margin included.

³⁴ Taking into account 5% margin on USI load.

Furthermore, reactive requirements to allow support for up to 1800 MW of USI load for each of the additional contingencies were determined. These are summarized in Table 4-8. The reported reactive reinforcements are in addition to the 'B4' solution.

Table 4-8: Summary of Additional Reactive Reinforcements to support 1800 MW in USI Load for each of the Additional Contingencies Tested. Load model is the Moderate Risk Model. Solution 'B4' is a baseline.

Contingency	Additional Reactive Reinforcements
10: Autoreclose onto fault event	+500 MVAR SVC at Islington
11: Bus section outage with fault	+500 MVAR SVC at Islington
12: Double circuit outage	None

The double circuit outage contingency (no. 12) is no more severe than the worst normal or design contingency (single line to ground fault with delayed clearing), for the cases studied. This may be partly due to not immediately re-connecting some circuits which are connected in a T configuration to the faulted lines. Hence stability countermeasures specified in Table 4-6 would also provide support for these types of extreme contingencies.

The solution identified as 'B4' will not be sufficient to support USI load beyond 2015 for the extreme contingencies involving autoreclosure on fault events (contingency no. 10) and bus section outage with fault (contingency no. 11). In order to be able to support USI load of up to 1800 MW under these extreme contingencies, an additional +500 MVAR SVC is needed at Islington.

Section 5. Conclusions

Pterra was tasked with reviewing Transpower technical reports and documents and confirming simulation results. To this end, we conclude that

- Transpower has conducted a thorough and technically correct assessment of the USI system that is consistent with international planning practice.
- Pterra has provided comments on planning criteria in Sections 2.2 and 2.4 of this report that offers suggestions for further aligning Transpower practice with international standards. A proposed set of planning criteria for voltage stability is included in Section 2.4.
- Pterra confirms the results of the PV and QV analysis by Transpower through independent simulations using the PSS/E software.

Pterra was further tasked with performing dynamic simulations related to voltage stability of the Upper South Island. The dynamic simulations were performed to determine the appropriate load and equipment modeling, to identify the levels of USI load supported by various mitigating measures to defer a new 220 kV line between the Waitaki Valley and Christchurch and to assess controllability and observability to voltage stability of the planned power system. Based on these assessments, we conclude that

- Load modeling has a significant impact on the dynamic simulation assessment for voltage stability of USI. We qualify various load models in accordance with the level of risk that the model will provide sufficient MW margin to support additional load in the USI. Two proposed models for conducting dynamic assessments are:
 - The moderate risk model is a complex load model with 19% motors and with 10% constant P load component
 - The low risk model is a complex load model with 38% motor/15% constant power load and 50% group 1 motor contactor shedding
- Limits on additional USI load supported by the existing system, as determined using dynamic simulation, are similar or greater than those determined by PV and QV curve methods. Hence, steady-state analysis provides a conservative measure of voltage stability.
- Dynamic simulation assessment provides improved differentiation of options to defer the need for a new 220 kV line. Of several options studied, the following offer the best potential to support additional USI load, in order of effectiveness:
 - Large SVC in combination with fixed capacitor banks at Islington. This solution has the potential for supporting levels of USI load up to 2022. In combination with series compensation, even higher levels of USI load may be supported. However, certain technical issues beyond the scope of this study need to be addressed.

- Series compensation. Technically, this offers additional MW capacity for up to 2014 in either the moderate or the low risk load model. Because of this characteristic, the solution addresses a wide range of risk associated with load response, and offers a robust option for mitigating the need for a new 220 kV line.
- Capacitors and SVCs at Islington, Kikiwa and Ashburton. Incremental additions at the three sites provide for USI load of up to 1475 for the moderate risk model and 1375 for the low risk model are possible.
- Extreme contingencies involving double circuit outages are no more severe than the worst normal or design contingency (single line to ground fault with delayed clearing) for the case studied. This may be partly due to not immediately re-connecting some circuits which are connected in a T configuration to the faulted lines. Hence stability countermeasures specified for normal contingencies would also provide support for these types of extreme contingencies.
- Extreme contingencies involving autoreclosure on a fault event and a bus section outage with fault are more severe than the most severe normal contingency. Hence, in order to mitigate these extreme contingencies, solutions applied to normal contingencies need to be augmented beyond 2015. For example, an additional +500 MVAR SVC at Islington is needed to support USI load of up to 1800 MW under these extreme contingencies.
- As the available surplus transmission capacity decreases in the South Island, and mitigating measures are implemented to defer the need for a new 220 kV line, it would be of benefit to future system operators to provide increased capability for observability and controllability of the power system.