Transmission Code of Practice – Technical Commentary

TRANSPOWER **APPROVED** STANDARD

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PREFACE

This Transmission Code of Practice Technical Commentary (Technical Commentary) sets out the supporting planning information relevant to each technical area considered under the Transmission Code of Practice (**TCOP**).

The Technical Commentary draws together the technical information and reference material which assists Transpower in designing and developing the **grid** with respect to Good Electrical Industry Practice (GEIP).

The Technical Commentary is owned by Transpower's Chief Engineer, and should be read in conjunction with the Transmission Code of Practice. The principal audience for the Technical Commentary are the technical specialists within Transpower and the wider Electricity Industry

This Technical Commentary is a "living" document that will be reviewed, updated and reissued as required (at least as frequently as the primary **TCOP** document).

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1. PURPOSE

The Transmission Code of Practice (**TCOP**) is a statement of certain **transmission** design practices and judgements that Transpower considers reflect **Good Electricity Industry Practice (GEIP)**. Its purpose is to assist Transpower (and others with an interest in **transmission** system planning) to assess whether such good practice is reflected in new **transmission** system designs.

The Technical Commentary is a companion document to the **TCOP**, which provides the technical detail on the high level planning principles that that Transpower applies to ensure the **transmission** grid as a whole remains resilient and fit for purpose.

2. INTRODUCTION

2.1 Objective of the Technical Commentary

The Technical Commentary provides a mechanism for the controlled implementation of new technologies and methods, seeking to avoid moving unknowingly into unchartered territory with unintended risks to **security** of supply.

The Technical Commentary also provides for explanation and reference to international practices which influence the determination of what constitutes **GEIP** in the New Zealand context.

2.2 Content of the Technical Commentary

The **TCOP** is "principle focused" and outlines a set of technical planning considerations that Transpower takes into account when invoking **GEIP** arguments in Grid Upgrade Plans. This edition of the Technical Commentary provides supporting information and explanation of the technical areas covered within the **TCOP**.

Over time the document is expected to be updated to reflect:

- Additional matters Transpower considers ought to be included in the **TCOP**;
- Changes in good international practice (including in response to new technologies and methods);
- Further analytical work that may, from time to time, be undertaken; and
- The relative size, duty, age, and technological status of New Zealand's **transmission** network from time to time.

2.3 Structure of the Technical Commentary

The content of the Technical Commentary is structured in a manner consistent with the **TCOP**. The technical areas covered are:-

- Special Protection Schemes;
- Planned Outages;
- Reactive Compensation;
- Grid Connection;
- Substation Configuration; and
- Fault Levels

Each technical area contains the following information:

- Introduction - General description of the topic;
- Planning Principles – what are the principles that are required to be considered in planning; and
    - Outcomes – What outcomes (if any) are expected.

3. DEFINITIONS

Terms used in the Transmission Code of Practice – Technical Commentary (Technical Commentary) have the same meaning as given to them in the Electricity Industry Participation Code, except those terms expressly defined in this document.

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Terms not defined in the Electricity Industry Participation Code (shown in **bold**) have the following meanings, unless the context requires otherwise.

"**capacity**" in relation to a transmission grid, means the capability of the grid to convey electricity under a range of load and generation conditions in accordance with reasonable and prudent operating practice and includes the maximum rating to which the transmission circuit can be operated.

"**compensation factor**" (CF) means the capacitive reactive compensation connected to an importing group of the grid divided by the maximum power demand of that importing group.

CF = MVArInstalled / MWmax

The capacitive reactive compensation includes:

- All grid fixed shunt capacitors; the value of output used for the calculation will be the nominal voltage of capacitor connection;
- All variable capacitive reactive compensation (which includes continuously variable and blocked switched units) connected at transmission voltages; the value of output used for the calculation will be the maximum nominal capacitive reactive output;
- All capacitive compensation connected at the low voltage side of all grid supply points that is used in support of the transmission system.

The capacitive reactive compensation does NOT include the reactive compensation embedded within local networks or the reactive output of generating units (unless these are the subject of long term service contracts).

"**failure**" means failure of the equipment to operate as designed. When used in the context of SPS it means either failure to initiate the designed remedial actions following system conditions for which the scheme is designed to operate, or spurious operation in which remedial actions are triggered when system conditions do not require it. Either of these two conditions may be termed false operation.

"**high impact**" means cascade operation and/or significant loss of supplies and/or system wide collapse, and/or damage to equipment, and/or have the potential to impact on public safety.

"**importing group**" means a topologically contiguous group of grid exit points that has a net import of electricity.

"**line**" means a series of structures carrying overhead one or more transmission circuits.

"**low impact**" means possible operation of the system outside operational limits but no cascade operation, no system wide collapse, and no significant loss of supplies.

"**maintenance outages**" are outages that have been scheduled with at least 24 hours notice to carry out maintenance work on an out-of-service asset. Such work includes inspection, repairs, replacement, and refurbishment of existing assets.

"**major project**" is non-maintenance work and is significant in nature. Such work would normally require more than a 5 days continuous outage window.

"**outage window**" means a period during which an asset could be taken out of service and work could be carried out on the asset.

"**planned maintenance**" is maintenance work that has been scheduled with at least 24 hours notice. Such work includes inspection, repairs, replacement, and refurbishment of existing assets.

"**reliability**" is the probability that a device, system, or process will perform its prescribed duty without failure for a given time (e.g. 10 years of more) when operated correctly in a specified environment, generally expressed as a percentage (%). e.g. (1- failure rate) - 99% reliability is same as 1% failure rate.,

"**security**" means a term used to describe the ability or capacity of a network to provide service after one or more equipment failures. It can be defined by deterministic planning criteria such as (n), (n-1), (n-2) security contingency. A security contingency of (n-*m*) at particular location in the network means that *m* concurrent component failures can be tolerated without loss of service.

"**stable**" means the system meets the criteria for transient, voltage, and dynamic stability given in the Grid Planning Guidelines.

"**transmission**" means the conveying of bulk electricity from power stations to points of supply.

"**TCOP**" means the Transmission Code of Practice.

"**VoLL**" means Value of Lost Load. The Value of Lost Load (**VoLL**) is the estimated amount that customers receiving electricity would be willing to pay to avoid a disruption in their electricity service. The default figure ($20,000 per MWh) reflects the value of expected unserved energy that applies under Clause 4 of Schedule 12.2 of the Electricity Industry Participation Code

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4. SPECIAL PROTECTION SCHEMES COMMENTARY

4.1 Introduction

Special protection schemes (SPS) are arrangements for protecting the **security** of the grid. They detect abnormal system conditions and take automatic, pre-determined, corrective actions.

Special Protection Schemes are those designed to detect one or more predetermined system conditions that have a high probability of causing unusual stress on the power system, and for which planned remedial action is considered necessary.

Internationally, the most common types of SPS are generator rejection, load rejection, under-frequency load shedding, system separation, turbine valve control, load and generator rejection, stabilizers, HVDC controls, out-of-step relaying, discrete excitation control, dynamic braking, generator runback and VAR compensation.

This Technical Commentary defines some specific applications of SPS to the New Zealand **transmission** system and how these applications are consistent with **GEIP**. These New Zealand applications (a subset of all the available SPS options) are consistent with international practice.

For the purpose of the **TCOP**, SPS have been categorised according to application:

1. As part of robust system design for which **transmission** reinforcement is not a solution;
2. As a short term or long term means of deferring **transmission** reinforcement; or
3. As a defence measure for the purpose of minimising the effects of multiple contingences for which the **transmission** system has not been designed to withstand.

Applications 1 and 3 are sensible and prudent measures that provide for robustness of operation and do not impact on the fundamental design and construction of a **transmission** system. For these reasons, applications 1 and 3 are not considered within the code.

However, application 2 impacts directly on the **transmission** system itself by seeking to defer **transmission** reinforcement, either temporarily or permanently (in the short or long term), by what is essentially a control scheme. In common with other significant changes to the transmission grid this introduces the risk of mal-operation and the possible consequences of damage to equipment, loss of supply, personal injury, and environmental damage. For this reason, the Technical Commentary seeks to address these issues and provide criteria for the appropriate application of SPS in these circumstances.

The inclusion of HVDC controls and protection within Application 1 is intended for normal HVDC controls. Application 2 is intended to cover generator run back schemes, but HVDC schemes could also be included. Application 2 gives examples of what is included, but does not preclude the use of run back schemes in this category

4.2 Planning principles

A Special Protection Scheme (SPS) is designed for the specific power system conditions associated with the intended function.

SPS must operate safely. They must also operate reliably, because they are commonly critical to maintaining system integrity and **security**, protecting plant, and ensuring supply to customers.

SPS are deemed to have failed if they do not operate when they should, operate when they should not, or interact spuriously with other SPS or control systems (such as normal governor action).

SPS are to have sufficient redundancy to reduce the likelihood of **failure** to an acceptable level (this may require duplicate hardware and communication with route diversity to the extent possible)

4.2.1 Monitoring, testing, and maintenance

Certain SPS applications are perceived as highly reliable because they have substantial redundancy and self-diagnostic features that identify error or **failure** mechanisms before mal-operation of the SPS occurs. However, SPS are inherently difficult to test, so that even with comprehensive maintenance it is difficult to confirm their overall functionality. Where possible, the design should be such that routine tests can be carried out in a manner similar to that used for normal power system protection. SPS's must also go through comprehensive acceptance testing.

Nevertheless, continuing testing and maintenance of an SPS must be part of the specification of the scheme, because the continuing verification of the scheme may well alter the design or even the whole viability of the scheme.

4.2.2 Risk assessment

Various factors (causes of **failure**) give rise to a risk of malfunction.

Quantitative **reliability** measures can be assigned to some of these factors (e.g. hardware, software, and communications). However, others (design errors, human intervention errors) must be assessed qualitatively.

4.3 International Experience

International experience[1] has shown that while the performance of SPS have not been completely as expected, individual protection mechanisms may provide a backstop should an SPS fail, although the outcome is not as favourable as correct operation.

CAISO planning standards attempt to limit complexity in ISO G7 by stating that:

> *"The SPS must be simple and manageable. Generally, there should be no more than 4 local contingencies (single or credible double contingencies) that would trigger the operation of a SPS and the SPS should not be monitoring the loading on more than 4 system elements".*

ISO G7 does not define a local contingency, and Transpower's view is that a better method of determining acceptability, other than for those schemes that have a **high impact** on **failure**, is to carry out a detailed risk assessment.

Some SPS are simple, have limited impact on malfunction, and are thus easily classified as acceptable (in the "green" zone). Others are clearly unacceptable (red zone). Those in the amber zone are subject to a risk assessment, which evaluates their complexity and impact.

The definitions of '**high impact'** and "**low impact'** contain the words 'significant loss of supplies'. The categorisation of such terms inevitably requires some degree of judgement and is deliberately left so, in order not to be too prescriptive.

4.3.1 Causes of failure

The causes of SPS **failure** can be classified into a collection of hardware **failure**s, software **failure**s, inadequate design, human error (including incorrect setting), and other. Results emphasise the need to take into account:

- Hardware robustness;
- Increasing complexity;
- Lack of design standards;
- Monitoring, testing, and maintenance.

Hardware robustness

SPS should be adequately robust for the tasks they are to perform and the impact of **failure**. This means such measures as:

- Hardware redundancy;
- Design against spurious operation, when itself experiencing a credible **failure**;
- Thermal capability to withstand the conditions to which the power system is subjected; and
- Communications diversity.

SCADA is not generally considered sufficiently reliable within an SPS scheme. However, the **TCOP** does allow its use under certain limited circumstances in which the effects of **failure**, owing to insufficient **reliability** would be minimal.

Complexity

[1] IEEE PSRC Report on Global Industry Experiences with Systems Integrity Protection Schemes (SIPS) – 2009 www.pes-psrc.org

SPS can be particularly complex. For example, the Basslink system monitors the power transfer in the link and the status of 18 circuits, it controls load shedding at up to 10 substations, and it can send trip signals to up to 18 generators.

Situations where there is complexity, coupled with the continued proliferation of SPS, increasingly degrades the robustness of the system by exposing it to design errors (inability to foresee credible system conditions) and the human factor (e.g. incorrectly setting the SPS in response to changed system conditions).

Furthermore, it is a recognised hazard that such degradation can occur without the system operator being aware of the risks being incurred. Moreover, maintenance, testing, and extension of complex SPS can be particularly difficult. Ideally, SPS design should be based on regions and minimise overlaps of operation to reduce complexity and the risk of **failure**.

Standards

Historically, there has been a lack of design standards relating to the implementation of SPS. In 1994[2] only 35 % of SPS put into service had undergone **reliability** calculation and modelling.

Since this time, the international community has recognised the need for standards:

- The Western Systems Coordinating Council (WSCC) requires that system studies assess the consequence of SPS **failure**. However, most requirements are qualitative, rather than quantitative. There is little industry guidance as to how to develop, study, assess, and maintain SPS **reliability**;
- WECC has a specific Remedial Action Scheme Reliability Task Force that approves, reviews, and registers all schemes. Its standards contain numerous caveats that reflect the caution with which WECC permits SPS to be addressed. WECC members produce their own guidelines for compliance; CAISO imposes limits on scheme complexity;
- NERC established standards in 2005, to which all new and existing schemes must comply. Fines are imposed for non-compliant schemes.

Mid Atlantic Area Council (MAAC) Special Protection System Criteria (Document A-3) states:

> "*To enhance dependability, …SPS shall be designed with sufficient redundancy such that the SPS is capable of performing its intended function while itself experiencing a single component failure…..*"

This principle has been included in the **TCOP**'s Design Principles, but enhanced to provide examples of the components that need to be considered.

Northeast Power Coordinating Council (NPCC) Regional Reliability Reference Directory # 7 Special Protection Systems specifies a number of SPS design requirements that provide for **reliability** and acceptability. Section 3.3.1.1 states that:

> "*To enhance dependability, a Special Protection System shall be designed with sufficient redundancy such that the Special Protection System is capable of performing its intended function while itself experiencing a single failure*."

The **TCOP** therefore requires SPS to have sufficient redundancy.

The NERC/WECC Planning Standards provide a number of standards and guidelines for SPS. Guideline G1 states that:

> "*Complete redundancy should be considered in the design of an SPS with diagnostic and self-check features to detect and alarm when essential components fail or critical functions are not operational*."

This has been simplified in the **TCOP** to "Diagnostic and self-check features to detect and raise an alarm when essential components fail or critical functions (including inputs) are not operational must be incorporated into the design".

Other terms, such as "sufficient redundancy", have been used to ensure adequacy of design while allowing some scope on how it should be achieved.

Additional principles have been added that are specific to the New Zealand context.

[2] IEEE Transactions on Power Systems, Vol 11, No 3, August 1996, Industry Experience with Special Protection Schemes Paper

4.4 Outcomes

SPS differ from normal protection mechanisms in that they protect all or a section of the grid, not just an individual component, e.g. line, generator, etc.

SPS can be a substitute for or defer grid investment. It should be noted though, that they can take considerable time to implement, although usually less than the time required for a **transmission line** augmentation.

4.4.1 Application of SPS

The **TCOP** has been developed in consideration of international standards and practice, with particular reference to NPCC Regional Reliability Reference Directory # 7, Special Protection Schemes, California ISO Planning Standards, and Mid Atlantic Area Council (MAAC) Special Protection System Criteria (Document A-3).

However, applications are particularly system and country specific and the applications described in the **TCOP** are those required by Transpower, in liaison with customers, to provide effective management of particular conditions and governance requirements.

4.4.2 Acceptability

In order to simplify the assessing of SPS, Transpower classifies them according to acceptability. Acceptability is a function of perceived **reliability** and the reckoned impact of malfunction and is affected by the SPSs complexity.

For various reasons, SPS need to be highly reliable, as the impact of malfunction can be severe. In addition, the required **reliability** cannot be easily assigned a quantitative measure; this is particularly true of those that are required to manage a complex set of system conditions. Therefore, any decision to deploy and SPS requires a degree of engineering judgement, and it is prudent to deploy them only if the impact of malfunction is low or where they can be exhaustively tested (examples include the HVDC simulator, RPC controllers or future AGC plus wide area systems). The basic design principles must expressly cater for the consequences of incorrect operation.

5. PLANNED OUTAGES COMMENTARY

5.1 Introduction

Assets making up the **transmission** grid require regular maintenance. Some maintenance can be carried out while the asset is in service (e.g. live line work), but other maintenance requires the asset, along with certain adjacent assets, to be removed from service, i.e. an outage.

Planning of the **transmission** grid needs to take into account this need for **maintenance outages**. There must be sufficient time when the system has sufficient redundancy that the outages can be taken without materially reducing the power system's **security** or the quality of supply during the outages.

There are constraints on when some outages can occur, such as obtaining access to assets sited on other parties' property. The outage may require fair weather conditions to proceed. One of the most important considerations is whether during the outage the grid has enough **capacity** to securely supply demand.

The **TCOP** provides the criteria to ensure that **planned maintenance outages** can take place while ensuring appropriate power system conditions are maintained.

The **TCOP** does not make provision for **outage window**s for **major project**s. Planning for **major project**s is to be such that appropriate outages are available or alternative project implementation methods are adopted and included in the project scope.

The window of opportunity (or **outage window**) for certain outages can be quite limited. The Outage Protocol (incorporated by reference in the Electricity Industry Participation Code) describes the process by which outages are scheduled. The Outage Protocol does not ensure that there are sufficient **outage window**s available for planned outages.

Mitigation measures can be applied during outages to ensure system **security**. These measures allow outages with limited **outage window**s to proceed. These measures include splitting the grid, load reduction, appropriate offers from generators or temporary generation. These measures can have high costs and place load at increased risk of being interrupted. There will come a point where the high maintenance outage costs justify **transmission** investment to relieve the issue.

In cases where the available **outage window**s do not meet the **outage window** criteria (refer **5.5.1)**, it is likely that there are material benefits in alleviating the maintenance issue which should be considered in the Grid Planning process.

Planning of the **transmission** grid needs to take into account **maintenance outages**. The costs associated with certain outages such as load management or constrained on or off costs for generation are included where appropriate into the Grid Investment Test (refer Electricity Industry Participation Code).

5.2 Planning Principles

Planning principles take into account the need for maintenance outages of existing assets and new assets when delivering the nature and timing of new investments in the grid.

5.2.1 Maintenance requirements

The ability to carry out **maintenance outages** at appropriate times and under satisfactory system and environmental conditions (e.g. weather, ground conditions) is a key factor in maintaining grid **security** and **reliability**. Assets that are not maintained are more prone to faults and are less likely to operate correctly. Assets that fail from lack of proper maintenance are likely to take longer to be repaired and restored to service. They may also present a safety or environmental hazard.

Generally, it is desirable that planned outages are taken without interrupting supply and with minimum disruption to connected parties and other stakeholders such as land owners and large industry.

During planned outages, there is, of course, risk of a fault causing a second (unplanned) outage. The risk and impact of a second outage is recognised in the outage planning process.

Some loads are supplied by a single circuit, e.g. Kaitaia. In these situations, an outage results in loss of supply unless there is local generation within the islanded area.

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When an asset must be taken out of service for maintenance, three assessment factors apply:

- The time required to complete the maintenance. Assets cannot necessarily be taken out of service and returned to service at the beginning and end of each day. A single activity may require a lengthy period to complete and the taking out and returning to service may involve major switching (with attendant risks), significant safety issues, and significantly increased time and cost;
- The grid must be capable of accommodating the outage without contravening any relevant **security** criteria. This is best achieved during lighter load conditions when assets are less stressed. Hence, summer has been the traditional season for maintenance activities; and
- Emergency return-to-service time and contingency arrangements.

5.2.2 Project outages requirements

Transmission projects may require long term outages of **transmission** assets in order to upgrade the assets. These outages and any other measures required to facilitate the outages (e.g. bypass lines, load management or temporary generation) need to be considered as part of investment decision making. The project outage requirements will affect the timing of the investment and may change the preferred option when the costs of construction outages are taken in account. Project outages should not materially affect the ability to carry out **maintenance outages**. Where **maintenance outages** are deferred in favour of project outages, any additional maintenance costs and increased risk to **reliability** arising from the deferral should be accounted for in investment decision making.

5.2.3 Outage planning

Outages need to be coordinated with generators and demand. An outage may constrain transmission from a generating export area. This means:

- **Transmission** maintenance and generation maintenance should coincide − when the generator is out of service the demand for **transmission** is reduced; and
- A hydro generator may be prevented from selling surplus energy (rather than spilling water) during the periods of peak flow (spring and early summer in the South Island).

An outage may constrain transmission into a demand import area and, if the area has some local generation, it may be crucial to have that generation fully available during the outage.

Customers and other parties may be affected by planned outages, e.g.:

- Planned outages may exacerbate the impact of a fault; some customers are sensitive to increased risk to supply during certain seasons, e.g. milk processing plants, whose production peak occurs during the summer;
- Outages may require land-owner consent. Farmers do not want crops damaged or stock disturbed at critical times by maintenance teams;

Some outages require coordination between many parties. In the Christchurch area, for example, 18 parties must agree to a load reduction before a planned outage can proceed, even during the summer demand period. If any one of these parties subsequently withdraws, the outage may be postponed or cancelled.

Sometimes multiple circuit outages are necessary to allow maintenance on an asset e.g. 66 kV circuits to West Coast have two circuits on the same pi-pole construction, so one circuit cannot be worked on while the other is live.

Ensuring adequate grid **capacity** to meet demand is an important factor when scheduling outages. The impact of an outage on the system is minimised if outages are scheduled during periods of low (off-peak) demand**.**

Interaction between maintenance and project outages must be carefully managed to ensure that both are accorded appropriate priority. Project work should not cause maintenance work to be cancelled. Issues arising when generation outages change close to a **planned maintenance** date need to be managed similarly.

SPS can be used to enable maintenance outside the summer minimum, but they are not a panacea, as extensive use leads to interaction between SPS, and can result in added complexity.

5.2.4 Transpower outage co-ordination procedure

Transpower's coordination procedure is mandated via the Outage Protocol, the key points of which are that:

- Transpower produces a draft outage plan by 31 January of each year, covering the outages for the next "outage year", which begins on 1 July;
- Transpower then has two months to consult with interested parties; and
- Transpower publishes its final outage plan on 19 May. This is six weeks before the outage year begins, but at least five months before most outages occur, as most are scheduled during the summer.

The System Operator reviews the acceptability of outages 10 weeks prior to the outage. This may involve further connected party discussions.

This 10-week period is relatively short. While it is undoubtedly workable if outages are easy to obtain, resource planning problems for contractors (and higher contractor prices) are likely if a significant number of outage requests are turned down or changed.

By comparison, outage planning and coordination in Britain spans a five-year period

5.3 New Zealand Outage Requirements

5.3.1 Peak and off peak demand

Historically, demand in New Zealand has been winter peaking. The traditional maintenance cycle was to do most outages in the summer months and fewer in the winter months.

Previously, it has been possible to take outages without reducing power system **security** or quality. Traditionally, maintenance is scheduled for the summer, when demand is low compared with the winter peak. However, the difference between summer and winter demand is becoming less marked. Outages are becoming increasingly difficult to accommodate because demand is increasing, but associated system **capacity** is not. The shortness of New Zealand low summer demand period (8 weeks) has historically made the scheduling of substation outages particularly difficult. Changes in electricity usage (e.g. increased air conditioning and irrigation) have altered when peaks occur in some areas.

In outage planning, the critical issues are (a) how much outage time is required (over the course of a year) to complete the needed maintenance and (b) how much load reduction is required to enable the needed outages.

Dependent on the nature of the load (summer peaking versus winter peaking) outages in particular areas may be scheduled for "non-traditional" times.

Figure 1 and **Figure 2** show demand through the year at Wilton and Oamaru respectively. The Wilton demand is winter peaking with highest demand in the months June through August. Oamaru is summer peaking, the highest demands occur during the period from October to March. **Maintenance outages** for equipment supplying Oamaru will be easier over the winter period, weather permitting.

In addition the introduction of shoulder ratings, as well as variable line ratings, will assist in increasing the opportunities to schedule outages.

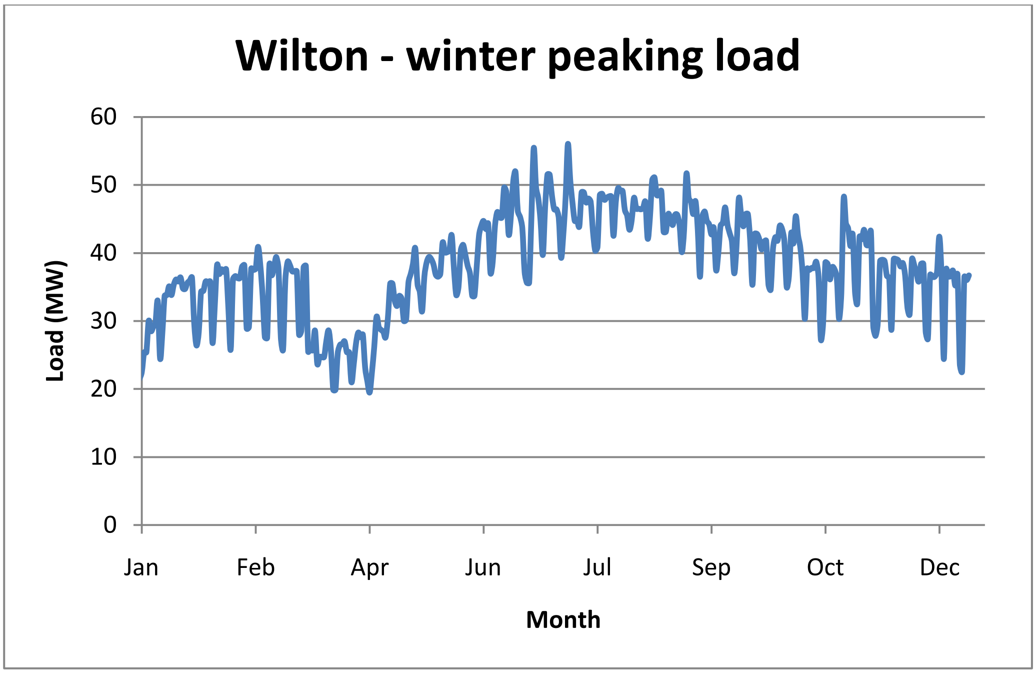

Figure 1: Load at Wilton substation

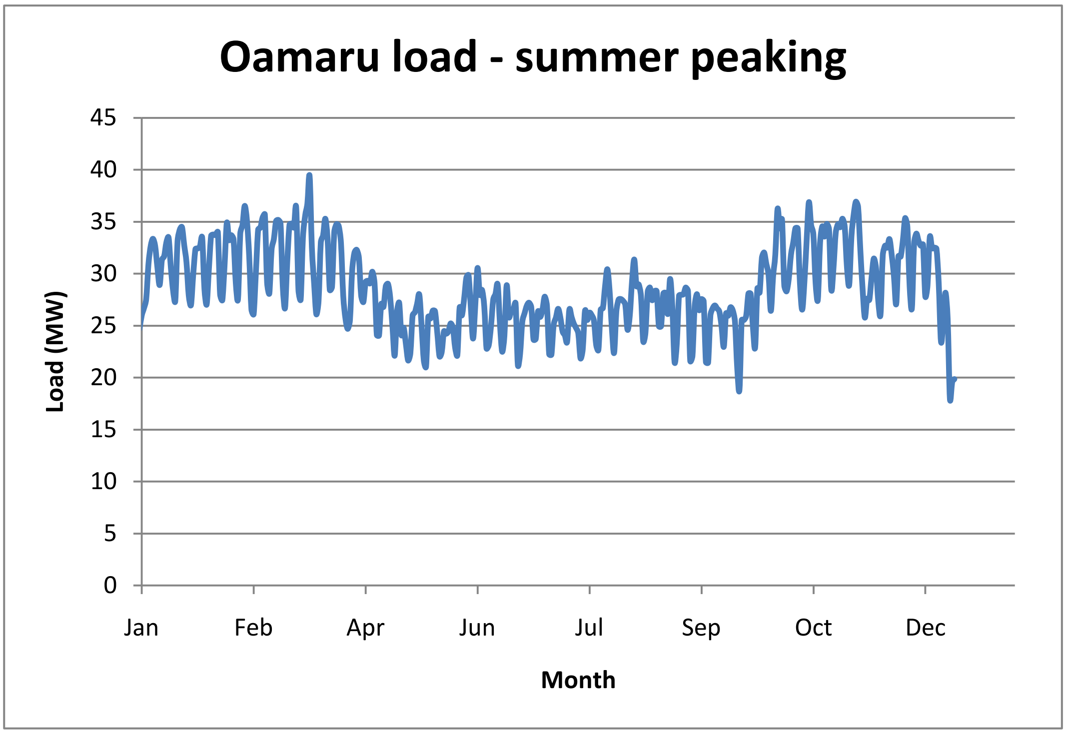

Figure 2: Load at Oamaru substation

5.3.2 System security considerations

The System Operator determines in real time whether a planned outage may proceed or not and can require the cancellation of a planned outage if the risks to the system during the outage are deemed to be unacceptable. The system operator's prime concerns are that:

- Primary transmission assets are not unacceptably overloaded;
- Voltage is within limits;
- The system is stable (no risk to synchronisation); and
- Security of supply is maintained whenever possible

Mitigation measures may be applied during the outage to ensure the system remains secure. These measures include:

- Grid reconfiguration. This includes implementing system splits, potentially reducing **security**, to manage pre and post contingency power flows and voltages during the outage;
- Wider voltage agreements. These are agreements with affected parties which allow local voltages to be operated outside the regulatory limits during outages;
- Market constraints. Market constraints can be applied during the outage. These constraints will restrict power flows on certain circuits which will result in generation in the constrained area being dispatched;
- Load agreement. These are agreements with distributors to manage load at grid exit points during the outage;
- Generation agreements. These are agreements with generators to make plant available for dispatch during the outage;
- Special protection schemes. These are schemes that could be used during planned outages to manage system **security**. Various system states and conditions are monitored and actions taken (e.g. demand shedding, generator runback etc.) in the event of unsatisfactory situation; and
- Emergency return to service. The maximum recall time to achieve this should be specified. This must be considered in project planning, work practices, and contingency planning.

These mitigation measures have associated costs and these costs may be sufficiently high for some outages to warrant **transmission** investment to alleviate the outage issue.

5.3.3 Outage Windows

Outage windows for any asset can be assessed. This is the period of time when outages can be taken without needing to manage load or constrain generation on. Where **outage window**s are insufficient to allow outages to proceed, it will be necessary to apply mitigation measures during the outage (e.g. load management, temporary generation).

The costs of these mitigation measures can be incorporated in investment decision making. The process is straight forward for assets in radial parts of the grid but is harder for assets in the meshed part of the grid. The assessment process has the following steps:

1. Identify the group of loads and generation that are constrained for the particular outage. The System Security Forecast (SSF) is a good source of information.
2. Determine annual load patterns for the group of loads. This is available from historic records. In some cases demand forecasts may be used to determine **outage window**s in future years. The Annual Planning Report provides load forecasts.
3. Determine the load limit applying during the outages. The SSF has indicative load limits for some outages.
4. Superimpose the load limit on the annual load pattern for the group of loads and identify the times of the year where the outage can occur without the need for load shedding. Identify those times when mitigation measures need to be in place (e.g. load management, grid reconfiguration resulting in reduced **security**)
5. Determine the outage requirements for the asset in question (i.e. date and duration).
6. Determine **the costs** of mitigation measures required for each outage:
    - Temporary generation;
    - Load shedding;
    - Expected energy not served due to reduced **security** for outage duration.
7. These costs can then be used in investment decision making. The costs may justify the installation of a special protection scheme or the bringing forward of investment to increase **capacity**.

Outage windows for radial assets

Calculation of outage costs in the radial parts of the grid can be carried out. A load limit group can be identified, historic load data is available and the outage will be independent of

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what else is going on in the power system. Load limit groups and indicative load limits can be found in the System Security Forecast.

If the radial part of the grid has N-1 **security** then outages can be scheduled at any time without a need to manage load albeit with a reduction of **security** during the outage. The load will likely be supplied through a single circuit for the duration of the outage. A forced outage at this time will result in a loss of supply.

The maintenance costs of having N **security** can be calculated simply. This is the energy not served during **maintenance outages** multiplied by a value of lost load **(VoLL)** figure. The **VoLL** may be different for the load during planned outages than the default figure of $20,000 per MWh. The default figure reflects the Value of expected unserved energy that applies under Clause 4 of Schedule 12.2 of the Electricity Industry Participation Code.

Outage windows for meshed grid assets

It is more difficult to calculate **outage window**s for assets in the meshed part of the grid. Load limits applying during certain outages are affected by the presence of concurrent outages in other parts of the grid. The load limits will be affected by generation dispatch. Generation dispatch depends on generation offers amongst other things and it can be difficult to accurately predict what generation dispatch will be present during the outage. Mitigation measures which allow one outage to proceed (e.g. load shifting from one grid exit point to another) may be detrimental to other outages.

Indicative load or transfer limits applying during certain outages are given in the System Security Forecast. These limits do not take into account the effects of any concurrent outages. Hence assessing **outage window**s for assets in meshed parts of the grid becomes a very complicated exercise.

5.3.4 Outage Duration

Figure 3 shows the number of outages by duration for the 2011-2012 Annual Outage Plan. The vast majority of outages have duration of two days or less.

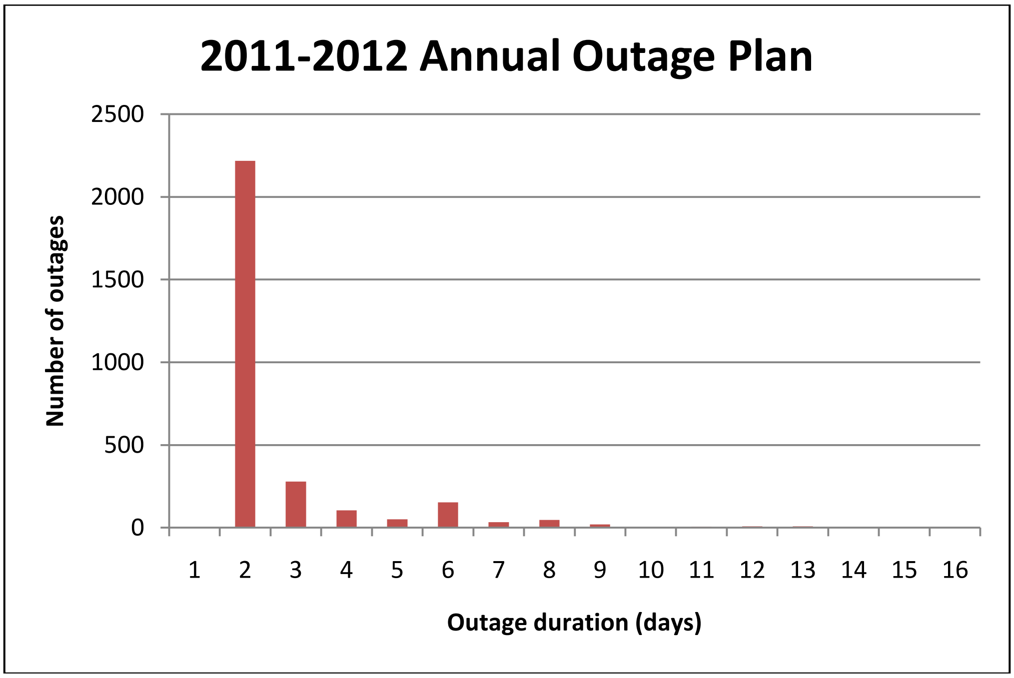

Figure 3: 2011-2012 Annual Outage Plan

If connection assets meet the N-1 **security** criterion under peak demand, then the scheduling of **maintenance outages** can occur at any time of the year. Core grid and non-core grid correspond to the definitions in the Electricity Industry Participation Code. There are 23 outages of duration five days or greater of assets in the meshed part of the grid. There should be no difficulty in scheduling these outages provided such outages have **outage window**s of a month or two each year available.

Figure 4 shows how many outages (maintenance and project) are planned for each month in the 2011-2012 period. Many outages are scheduled for the summer months although a significant number occur during times of higher demand in the winter months.

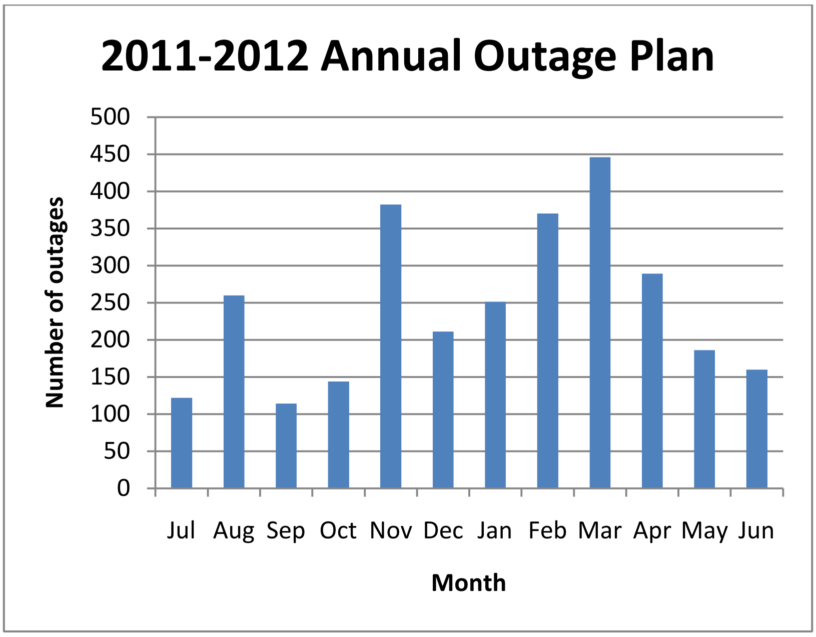

Figure 4: 2011-2012 Annual Outage Plan

Table 1 shows statistics around planned outages in 2011-2012. Around 11 % of outages are planned for the weekend. Around 24 % of outages are for greater than 1 day. Of these, the majority are on a daily basis (the assets are returned to service overnight).

Table 1: Outage statistics

Total planned outages in 2011-2012	**2935**	
Outages scheduled in weekend	312	11 %
Outages longer than one day	714	24 %
Outages five days or longer	126	4 %
Outages five days or longer (Continuous)	62	2 %
Outages longer than one day (Daily)	496	69 %
Outages longer than one day (Continuous)	218	31 %

Around 4 % of outages are for five days or longer. Of these outages, around half (2% of total **outages)** are continuous**.**

Table 2 shows a breakdown of continuous outages five days or longer in duration into the nature of the asset. Of the 62 outages, 39 related to connection assets (e.g. supply transformers, feeders and spur lines), 12 related to outage of assets in the non-core grid and 11 were related to assets on the core grid.

Table 2: Continuous outages greater than five days in duration

Asset Type	Number of outages
Connection	39
Non-core grid	12 (0.4 % of total outages)
Core grid	11 (0.4 % of total outages)

If connection assets meet the N-1 **security** criterion under peak demand, then the scheduling of **maintenance outages** can occur at any time of the year. Core grid and non-core grid correspond to the definitions in the Electricity Industry Participation Code. There are 23 outages of duration five days or greater of assets in the meshed part of the grid. There should be no difficulty in scheduling these outages provided such outages have **outage window**s of a month or two each year available.

5.3.5 Indicative tests for outage window insufficiency

Analysis of planned outages based on the length of continuous duration of an outage suggests some **outage window** sufficiency tests can be applied to determine whether maintenance issues may be relevant to investment decision making.

The majority of outages (85 %) are of two days duration or less. This includes outages for both maintenance and project work. It is usually possible to schedule a two day outage at the weekend when loads are typically lower than during the week. If it is not possible for the two day outage to proceed in any weekend during the year then the cost of mitigation measures warrants further consideration. The requirement in the test for the outage to be taken over the weekend should not be construed to advocate all outages should occur in the weekend (or all in the same weekend). It merely provides an indication of whether the two day outage can be carried out with little cost.

Around 2 % of outages have durations of five continuous days or longer. Most of these outages relate to connection assets such as supply transformers or feeders. Around 0.8 % of all outages which are for continuous outages of five days or more relate to assets on the meshed grid.

Some outages are hard to schedule for reasons other than restricted outage windows. Access to some assets may be difficult at some times of the year due to ground conditions. Connected parties and land owners may have certain preferences as to when outages are planned. For example, connected parties may prefer that outages reducing security are carried out at times when dairy factories are not at peak production. Land owners may prefer that assets on their land are not accessed during lambing season.

5.4 New Zealand Examples

The following sections illustrate how costs incurred in maintenance can be incorporated in **transmission** investment decision making.

5.4.1 Outage of Cobb-Stoke circuit

Figure 5 shows the combined Motupipi and Motueka load. This combined load reaches its peak around April. This load needs to be managed when there is an outage of the Cobb-Stoke circuit. The load limit depends on the thermal rating of the remaining circuit and the amount of generation at Cobb. The load limit is at its lowest during the period when summer ratings apply (December through March). The limit is higher in the periods when spring, autumn and winter ratings apply. **Maintenance outages** can be taken in the period July to November with no need for Cobb generation or load management.

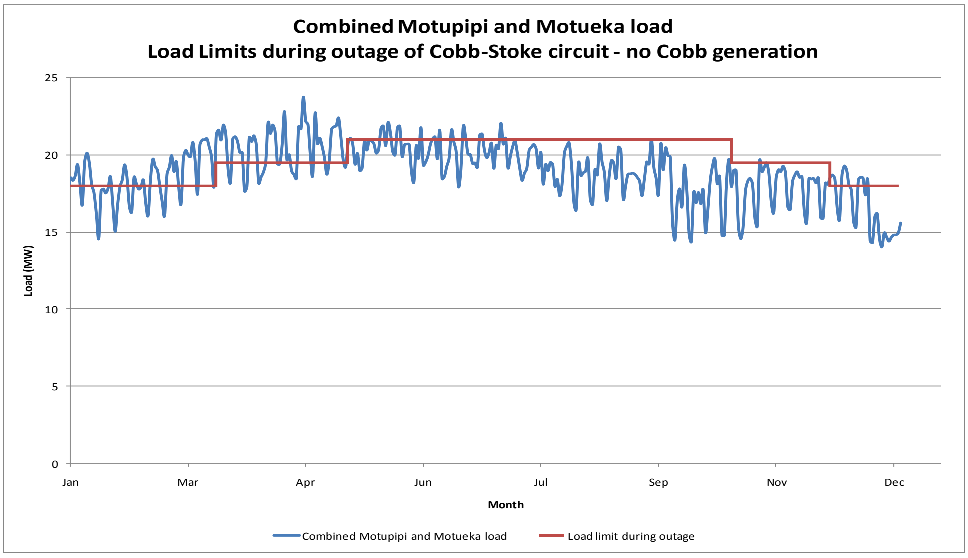

Figure 5: Load limits for outage of Cobb-Stoke circuit

Figure 6 shows the costs of carrying out a 5 day continuous outage throughout the year. The blue trace shows the cost of energy not served. This cost is obtained using a value of lost load of 20,000 per MWh and assuming that 5 % of the load can be managed by the lines company. The red trace shows the cost of hiring and running temporary generation for the duration of the outage. There is a period from September to November where there are no mitigation costs in carrying out the outage.

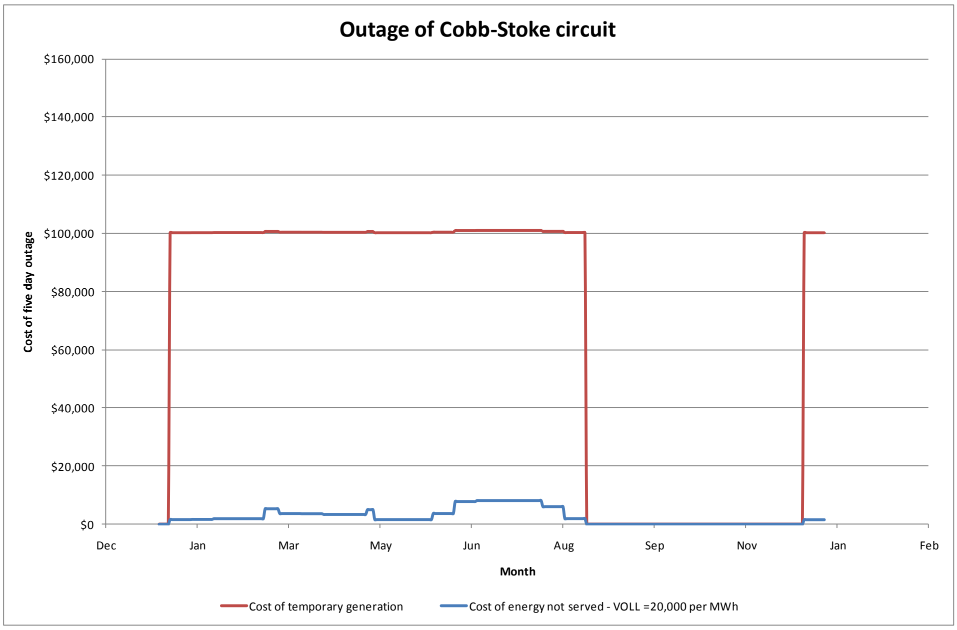

Figure 6: Costs of meeting load during Cobb-Stoke circuit outage (5 % load management)

Figure 7 shows the costs in the case where no load management is possible. There is still a window when the outage can be carried out without incurring mitigation costs. The cost of energy not served is markedly increased than in the figure above.

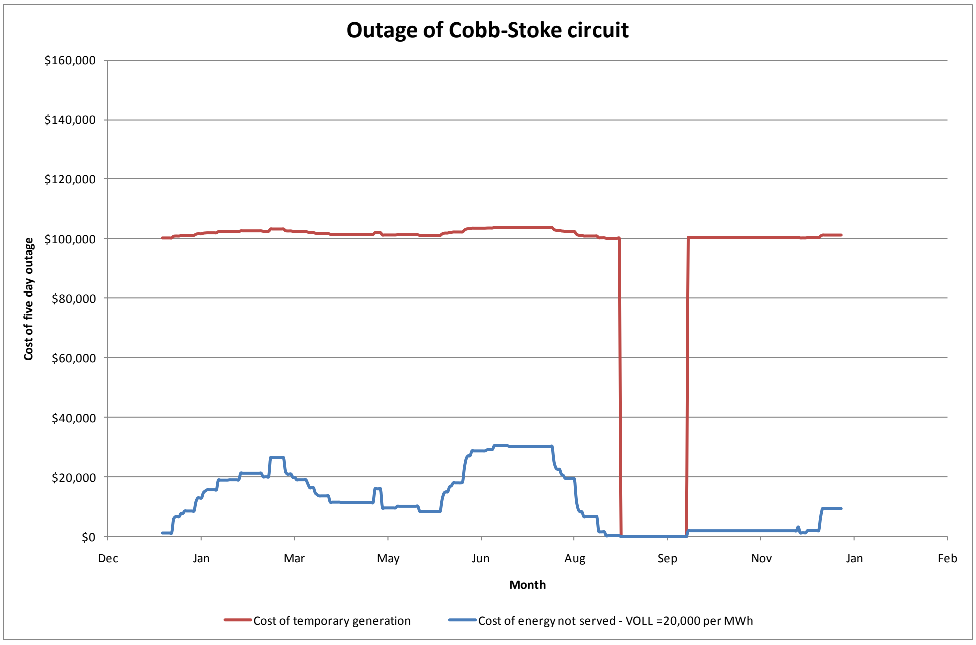

Figure 7: Costs of meeting load during Cobb-Stoke circuit outage (0 % load management)

Figure 8 shows the cost of the outage when demand has increased 10 %. There is no now time when the mitigation costs are zero. Outages will require load shedding or Cobb generation constrained on during the outage. The cost of providing temporary generation is around $100,000. If a five day outage is required each year then the net present value of providing temporary generation during the outage is around $1.3 M (assuming a 7 % discount rate over a 20 year period).

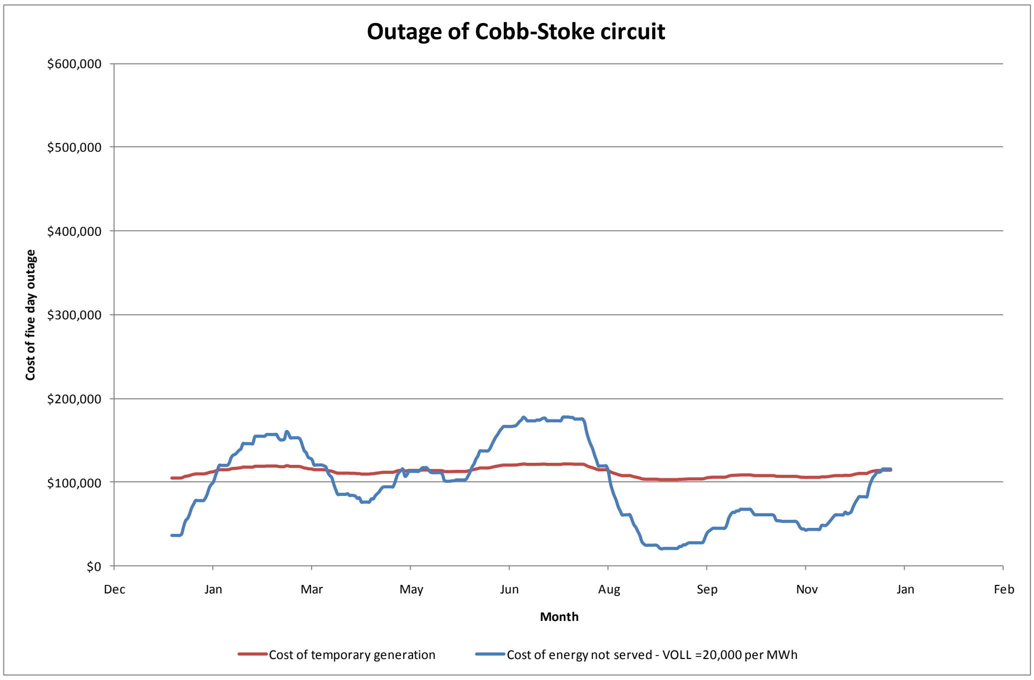

Figure 8: Costs of meeting load during Cobb-Stoke circuit outage (demand increased by 10 %)

The **outage windows** for the Cobb-Stoke circuit are in spring. Outages at other times will require load management or Cobb generation constrained off. **Outage windows** for the Cobb-Stoke circuit will shrink as demand increases at Motupipi and Motueka.

Figure 9 shows load limits applying during a five day outage of the Cobb-Stoke circuit where the circuit is returned to service between 17:30 and 07:30 each night. The return of the circuit provides greater **security** during the times of evening and morning peak demand.

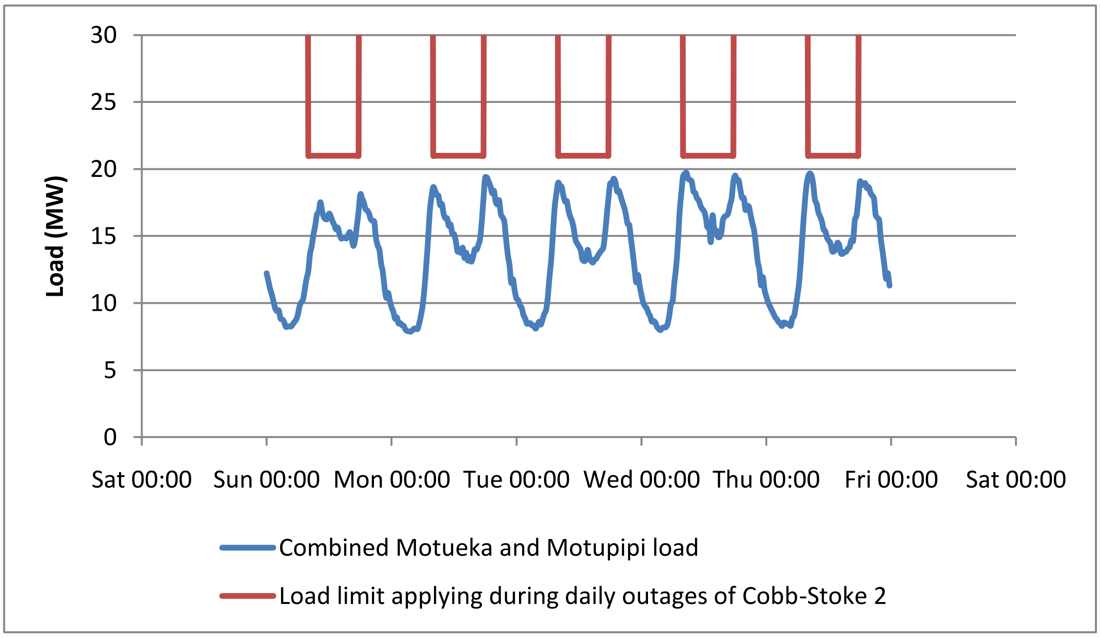

Figure 9: Daily outages of Cobb-Stoke 2 circuit

5.4.2 Maintenance Costs

A load is supplied through two supply banks. Load management is required during a planned outage of one of the banks for five days continuous. **Figure 10** below shows the load during the outage and the load limit (32 MW in this case). The load above the load limit is assumed not to be served during the outage.

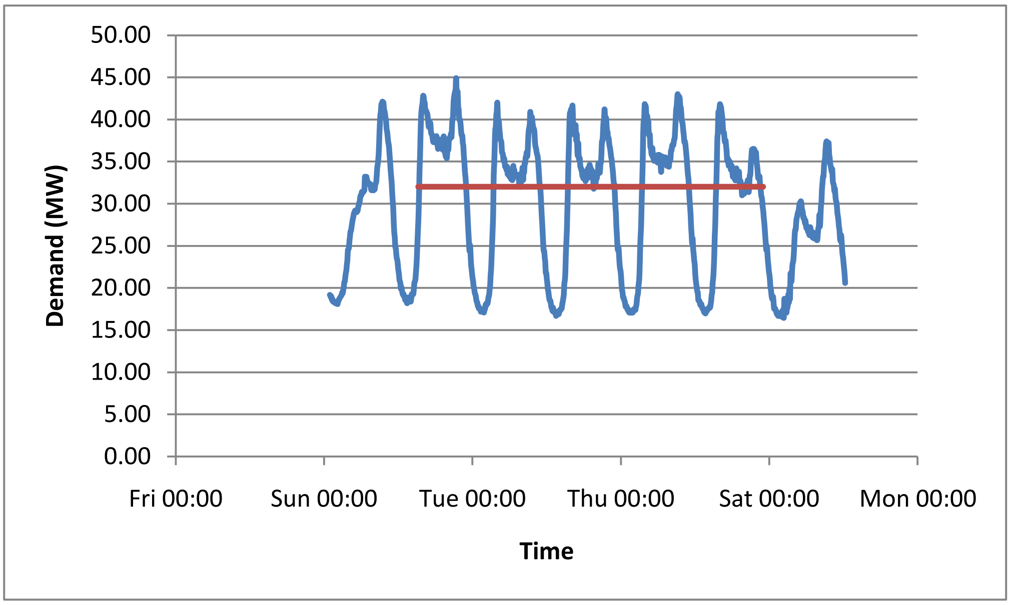

Figure 10: Energy not served during transformer maintenance

Figure 11 below shows the cost of load not served during the outage (based on load in **Figure 10**) as a function of load limit. The figure also shows the percentage of time that load management is required. The VOLL is assumed to be $20,000 per MWh.

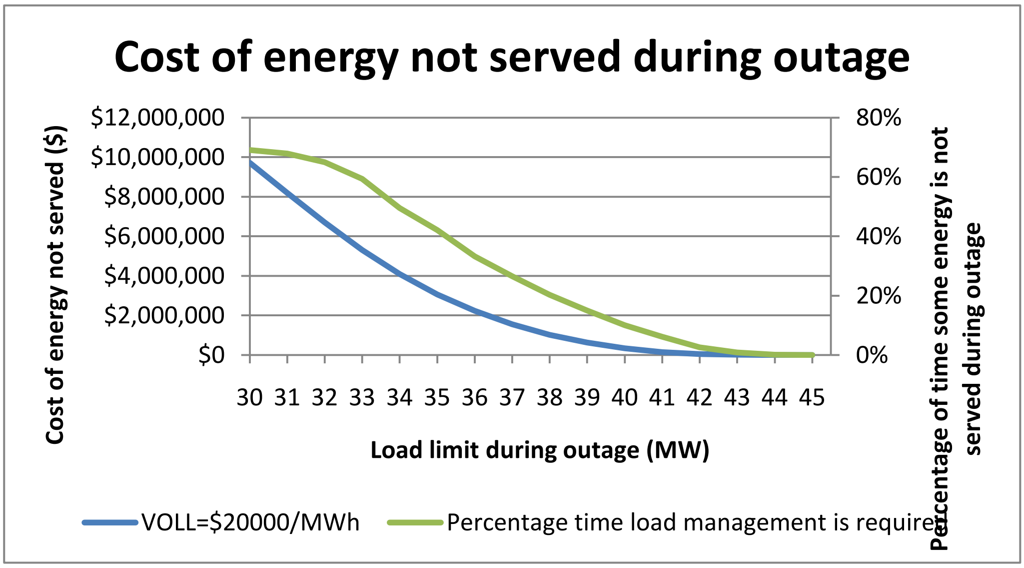

Figure 11: Cost of energy not served during supply transformer outage

On the assumption that the supply banks will need to be replaced in 5 years time (for either peak **capacity** or condition reasons) then there may be some benefit in bringing the replacement forward to avoid load management costs during planned outages in the next five years.

The cost of replacing the supply banks is $6M in year 5. One continuous outage of five days is required in year 4. The cost of bringing forward the replacement to year 3 (avoiding the need for load management during the five day outage in year 4) is around $620,000 (discount rate of 7 %). From the figure above, bringing forward the replacement of the supply banks is justifiable when the load limit applying during the outage is 38 MW or lower.

5.4.3 Two supply bank maintenance reliability cost calculation

The forced outage of a supply bank during planned outage of the parallel supply bank will result in a loss of supply. The expected cost of this occurrence can be calculated as follows.

Transformer faults on the supply banks occur roughly once every 5 years

The probability of a transformer fault during a 5 day continuous outage

P= 5/365/5 =0.00274

Cost of outage of 100 MW for 4 hours

Cost = 100 MW x 4 h x $20000/MWh = $8M.

Expected cost of energy not served

E = 100 MW x 4 h x $20000 x 0.00274 = $21,918.

The expected cost is quite low and would not justify much in the way of investment to mitigate this risk.

5.4.4 Meshed Grid Maintenance

The configuration of Southland 110 kV network is shown in **Figure 12**.

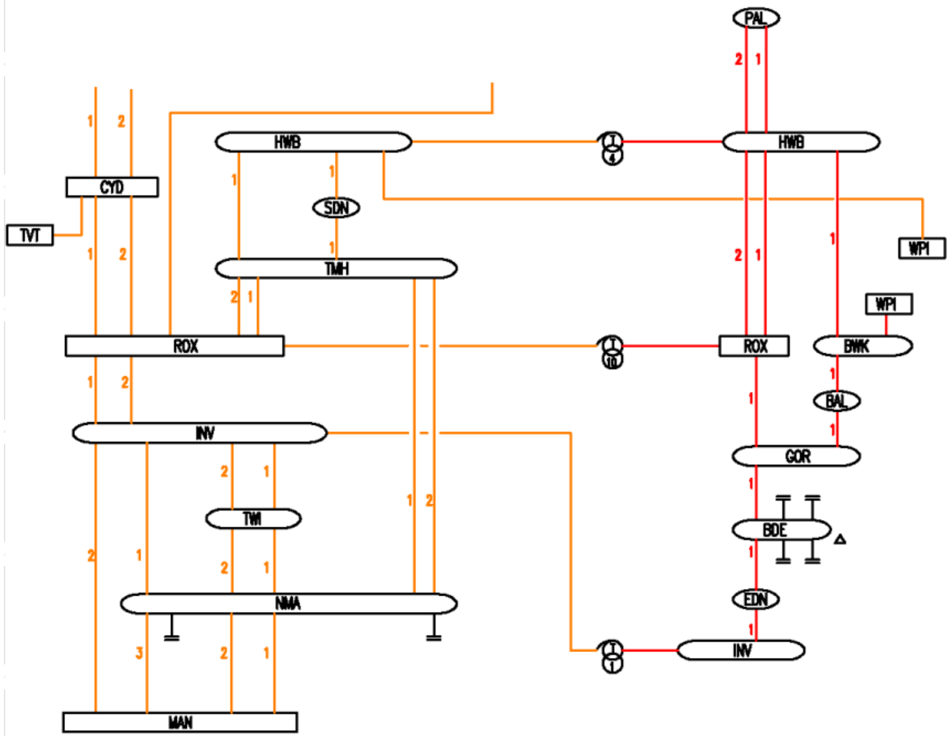

Figure 12: Southland 110 kV network

In recent years, load growth in the Southland 110 kV network has made certain **maintenance outages** problematic. In many cases a system split on the 110 kV network is required which places a number of grid exit points on reduced **security**.

Balclutha grid exit point is connected and fed by the Balclutha-Gore and Balclutha-Berwick circuits. Therefore, customers supplied through Balclutha might expect to be on reduced **security** during outages of the Balclutha-Gore or Balclutha-Berwick circuits. However, more often than not, Balclutha is placed on reduced **security** during the following additional outages:

- Gore-Roxburgh circuit;
- Brydone-Gore circuit;
- Brydone-Edendale circuit;
- Edendale-Invercargill circuit;

- Invercargill T1 interconnecting transformer; and
- Invercargill bus-section.

All the above outages necessitate that a system split is put in place at Gore end of Balclutha-Gore circuit to avoid voltage collapse on the 110 kV network post-contingency.

Table 3 below shows the number of days that Balclutha was placed on reduced **security** in 2006 and 2007 during any of the outages mentioned above. A comparison is made with three other grid exit points of similar peak load in the grid serviced by two circuits.

	No. of days on reduced security	
	2006	2007
Balclutha (Southland)	50	45
Oamaru (Otago)	26 [3]	13
Kaiwharawhara (Wellington)	5	4
Kaikohe (Northland)	6	3

Table 3: The extent of reduced security on four similar grid exit points

Table 4 shows a list of circuit outages in the 110 kV network, which would require system splits to be put in place in order to maintain system **security** pre-contingency, but in doing so putting numerous grid exit points on reduced **security**.

Outages	Mitigations required	Grid exit points on reduced security
220 kV Halfway Bush-South Dunedin circuit	Remove Halfway Bush T4 interconnecting transformer to avoid voltage instability in the 110 kV network post-contingency	Halfway Bush, South Dunedin
220 kV South Dunedin-Three Mile Hill circuit	Remove Halfway Bush T4 interconnecting transformer to avoid voltage instability in the 110 kV network post-contingency	Halfway Bush, South Dunedin
Brydone-Gore circuit	Remove Balclutha-Gore circuit to avoid voltage collapse on the 110 kV network post-contingency	Balclutha, Edendale, Brydone, Gore
Brydone-Edendale circuit	Remove Balclutha-Gore circuit to avoid voltage collapse on the 110 kV network post-contingency	Balclutha, Edendale, Brydone, Gore
Edendale-Invercargill circuit	Remove Balclutha-Gore circuit to avoid voltage collapse on the 110 kV network post-contingency	Balclutha, Edendale, Brydone, Gore
Invercargill T1 interconnecting transformer	Remove Balclutha-Gore circuit to avoid voltage collapse on the 110 kV network post-contingency	Balclutha, Edendale, Brydone, Gore
Gore-Roxburgh circuit	Remove Balclutha-Gore circuit to avoid voltage collapse on the 110 kV network post-contingency Pre-contingency load management may be required	Balclutha, Edendale, Brydone, Gore

Table 4: Outages which require multiple grid exit points be placed on reduced security

[3] The high number at Oamaru grid exit point was due to the commissioning of the new Black Point grid exit point, which tees off Oamaru-Waitaki 1 circuit

The extent of the loss of supply post-contingency varies, ranging from 10 MW to 84 MW at each grid exit point. Certain outages have significant impacts on **security** and **reliability** for a number of grid exit points. The effect of placing grid exit points on reduced **security** during outages is to increase the risk of a loss of supply at the grid exit point.

As demonstrated previously, certain planned outages in the Southland 110 kV network require that load be managed pre-contingency or result in more frequent reductions in **security** to one or more grid exit points. Losses of supply are therefore more likely during these times. One way to determine the extent of the risk is to estimate the expected unserved energy resulting from circuit trippings at times of reduced **security** during outages.

Balclutha grid exit point spends around 50 days a year on reduced **security** (see Table 3). Balclutha is supplied through the Balclutha-Gore and the Balclutha-Berwick-Halfway Bush circuits. These circuits have experienced 113 forced outages in the last 20 years. Each circuit might expect to have around 3 forced outages each year. The average probability of a circuit being forced out in a certain hour is 0.322 × 10-4.

The expected number of losses of supply at Balclutha over a year during a planned outage of one of the two circuits is 50/365 × 3 = 0.39 losses per year. Assuming that the average load interrupted is 17 MW, the time to restore is 2 hours and value of lost load is $20,000 per MWh, the estimated value of unserved energy occurring while Balclutha is on reduced **security** during planned outages is about $270,000 per year.

The value of this unserved energy from Balclutha (and other grid exit points) provides a strong case for bring forward investment in **transmission capacity** to avoid the need to split the Southland 110 kV network during **maintenance outages**. The issues in this network were a clear indicator for the need for investment. This need for investment has subsequently been approved, and will be completed by 2015.

Two day **outage window**s for 220 kV circuits supplying the Upper South Island

The load in Christchurch and northwards is supplied via four 220 kV circuits from Waitaki. This section provides an example of calculating whether a two day outage over the weekend of one of the 220 kV circuits is possible.

Historic data from the 2006 and 2007 calendar years was used to analyse peak demand on weekend days over the winter period. The weekend peak data can be represented with good accuracy as a normal distribution. The normal distributions for 2006 and 2007 were scaled using the SOO demand forecast increases figures to determine distribution functions for winter weekend day peak demand for the period 2008 to 2050.

The probability of a weekend day peak demand being less than a certain value was calculated. **Figure 13** shows probability of the winter weekend day peak demand being less than a certain amount for each year from 2008 to 2050. From **Figure 13**, the probability of a winter weekend day peak demand in 2008 being less than 850 MW (the limit applying during certain 220 kV circuit outages) is around 35 %. The probability of a winter weekend day peak demand in 2008 being less than 950 MW (the approximate upper limit applying during other 220 kV circuit outages) is around 75 %.

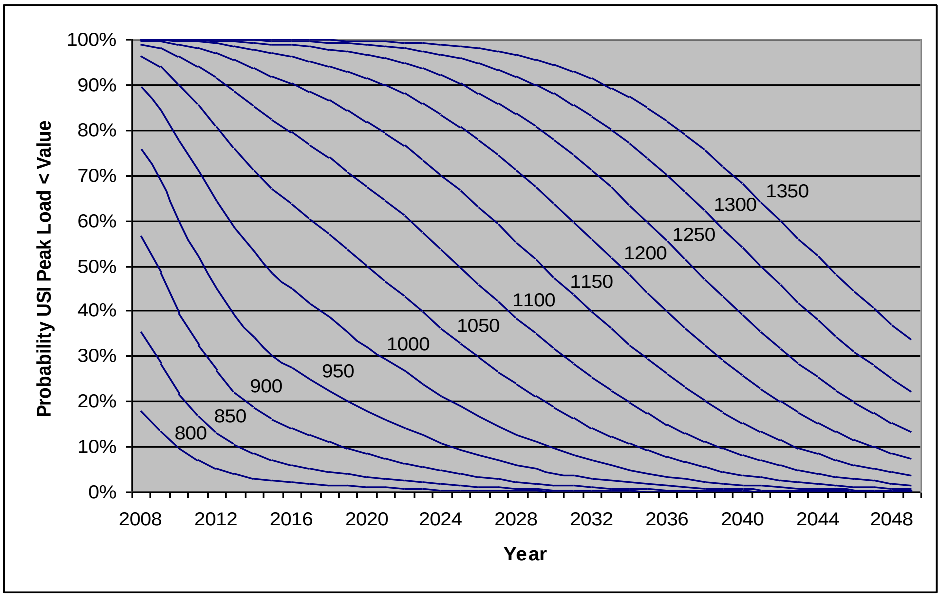

Figure 13: Probability of daily peak load in winter (weekends only) being less than a specified value (in MW), using a normal distribution

In 2008, 75 % of weekend days had a peak demand of 950 MW or lower. An urgent outage to repair equipment on one of the 220 kV circuits supplying the USI carried out over a weekend peak in winter will has a 25 % chance that some load management may be required. In 2012, this figure rises to 50 %.

5.5 Outcomes

5.5.1 Outage types

There are two sorts of planned outages:

- **Planned maintenance** outages are outages that have been scheduled with at least 24 hours notice to carry out maintenance work on an out-of-service asset. Such work includes inspection, repairs, replacement and refurbishment of existing assets and would normally require an outage duration of 5 days or less.
- **Major project** outages are for non-maintenance work and for work of a significant nature. Such work normally requires an outage of more than 5 continuous days and tends to involve procedures that cannot be terminated quickly in an emergency.

Maintenance **outage window**s must not be assumed to be sacrificed for **major project**s outages.

Transmission investment decision making can and does take account maintenance needs. This commentary has shown how maintenance issues are identified and how the costs of the mitigations can be quantified and incorporated into investment decision making.

The commentary proposes a simple test to indicate whether maintenance issues should be considered further:

- Whether a two day continuous outage for each asset can be scheduled over any weekend of the year.
- Whether a five day continuous outage for each asset can be scheduled for at least 50 % of the year.

If a maintenance outage for an asset fails this test, the costs of the outage and its mitigations may materially affect investment decision making. If these criteria are not satisfied further investigation of options takes place.

6. REACTIVE COMPENSATION COMMENTARY

6.1 Introduction

Reactive Compensation may be required on a **transmission** system to provide voltage control and, more particularly, to provide voltage support in heavily loaded systems. High levels of reactive compensation tend to lead to brittle or ill-conditioned systems.

Transpower is applying increasing quantities of reactive compensation to the grid in order to maximise the utilisation of assets and is currently at the forefront of internationally accepted levels. Moving into the future the following is becoming increasingly apparent:

- Operation is starting to be beyond international experience and is likely to be increasingly so in the future;
- There are real-time operational management issues and system risks; and
- Traditional key operational parameters are being eroded in that busbar voltage is no longer a reliable indicator of system health and voltage instability is becoming an increasing risk, even at voltages within operational limits.

Operating in this way requires that the risks be fully recognised, are measurable, and managed; it is essential that reactive control facilities be suitably developed and validated, potentially requiring an area control capability (which must be on a system specific basis).

To alleviate these concerns, Transpower is formalising the application of reactive compensation to the grid.

Studies have confirmed that absolute technical limits for either static or dynamic reactive compensation levels are difficult to define, as, in practice, there are no rigid boundaries or prescriptive limits. Therefore, the approach adopted combines **GEIP** and findings from generic studies.

This approach combines:

- Assessing system performance at different levels of compensation, based on a comparison with other utilities and generic (two-port-model) analysis;
- Assessing the acceptable ratio of dynamic and static compensation, based on WECC standards and a comparison with other utilities;
- Avoiding unacceptable risks resulting from over complex automatic control systems;
- Static modelling, using PV and VQ curves, based on the need to operate at the lower voltage limit and with stability margins defined in Western Electricity Coordinating Council (WECC) standards;
- Dynamic modelling as currently performed by Transpower; and
- Use of real-time reactive tools such as VSAT in the control room.

6.2 Planning Principles

Extensive study is required to determine the levels of compensation required on a **transmission** system and the optimum mix of static and dynamic compensation.

Automatic control requires detailed engineering analysis. Automatic control between more than two physically separated substations within an **importing group** is unacceptable.

Compensation is controlled at three levels:

- Primary control is automatic control of individual reactive power resources; control is based upon local measurements; the timescale is up to one minute;
- Secondary control is automatic or manual control of reactive power resources in a specific area of the system; its aim is to minimise interaction between primary controllers; the timescale is between one and a few minutes;
- Secondary controllers mainly fix or alter the reference point of the primary voltage controller, adjust the slope of the reactive power resource output characteristic, or trip or limit the output of the reactive power resource so that system **security** is maintained; or
- Tertiary control is secondary control actions to optimise the voltage performance in a post contingency period; the timescale is around ten minutes.

Interaction

Having three levels of control can result in adverse interactions, and decoupling mechanisms are needed. Decoupling, in most cases, is achieved using partially-automatic or totally-automatic, secondary voltage control, in a timescale of not less than one minute, and computer-assisted, manual, tertiary voltage control.

Automating secondary voltage control reduces the operational burden considerably and facilitates the coordination of voltage controller actions. However, automation requires an appreciable investment in control facilities, as reactive power resources are usually geographically dispersed, causing increased risk, reducing **reliability** and requiring implementation of bespoke systems and networks. International experience shows that secondary and tertiary control systems can take years to develop, and that staged developments are needed to minimise risks both in terms of successful operation and successful implementation.

Approach

Because of the risks and impacts associated with automatic control, Transpower requires that all automatic control is subject to detailed engineering and economic analysis and operational proving. RPC schemes are complex, bespoke, and not to be undertaken lightly without experience of planning and operating

The requirement for reactive support is dependent on the evolving nature of the load. Increasing proportions of motor loads and heat pumps influence how the power system responds to major faults

6.2.1 Power system analysis − static

Systems deemed marginal i.e. between 40 % and 85 % **compensation factor**) require static (both PV and VQ) analysis. If this indicates an ill-conditioned system further dynamic analysis will be required.

The analysis assumes Transpower's modelling criteria and generally follows the procedure adopted by WECC (www.wecc.biz)

It should be noted that Transpower limits the use of PV analysis to operations. In the longer term, Transpower considers VQ analysis a more appropriate methodology for static power system analysis.

PV analysis

The voltage characteristic (PV curve) of a typical, uncompensated **transmission line** is shown in **Figure 14**. This characteristic is calculated from a two-port, single-transmission-line model. In this case, the maximum real power that can be transferred is 100 MW before the voltage falls below 0.9 pu.

The 'nose point' of the curve is the limit of system stability. For the curve shown, the nose is safely below the voltage limit (the voltage limit is encountered first). For **line**s longer than 100 km, these voltage and instability limits are usually reached before the **line**'s thermal limit.

As compensation is added, the PV curve rises and the real power transfer increases. The curves in **Figure 15** show a system with different amounts of variable compensation (e.g. supplied by a SVC). The compensation output increases as the load increases, so the voltage declines only slightly over the range of the compensation. The rate at which the voltage declines depends upon the setting of the SVC, which typically has a 3-5 % negative slope.

At the limit of variable compensation (when the SVC runs out of its range), a 'knee point' forms in the voltage curve, as shown. The system can be operated beyond the knee point, but at high levels of compensation the margin between the flat, normal-operating portion of the voltage curve and the nose point (instability) is small (i.e. the system is brittle). See the discussion on WECC standards, below.

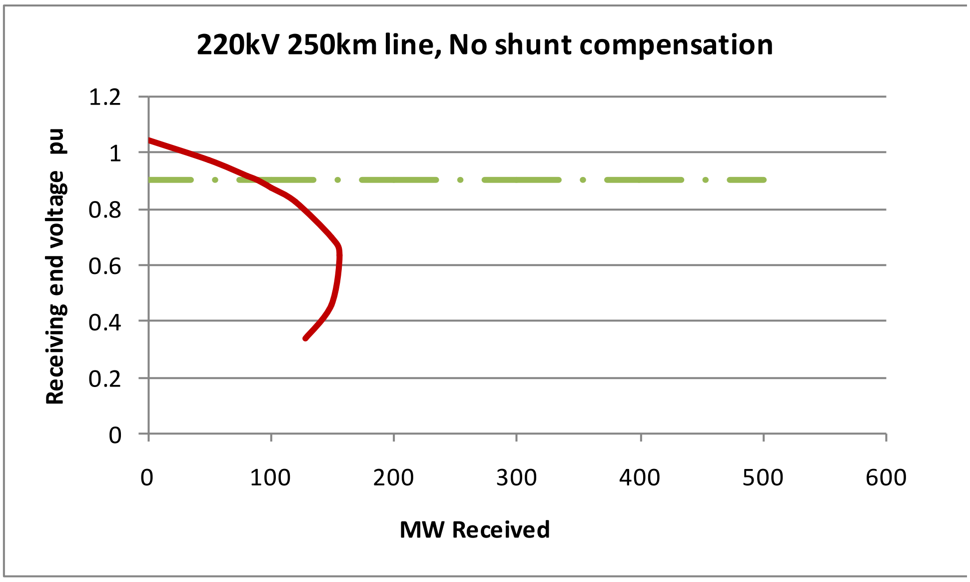

Figure 14: 220kV 250km line without compensation

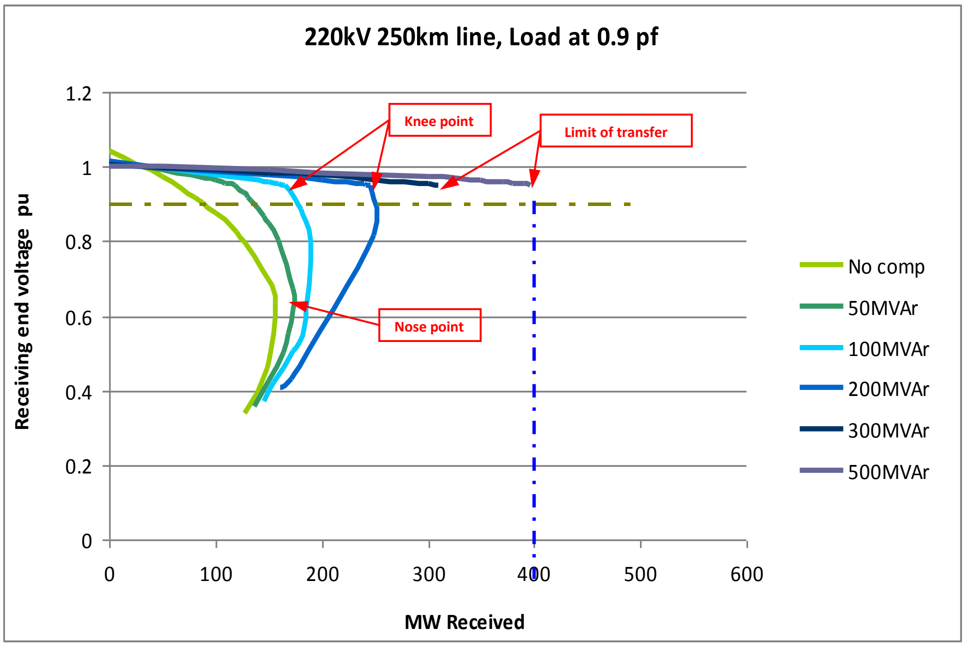

Figure 15: 220kV 250km line with compensation

At still higher levels of compensation, the **stable** operating range ends abruptly before the voltage falls to 0.9 pu, and the model can calculate no **stable** operating point for higher loads or lower voltages. Such operating characteristics are specifically excluded from the code.

Voltage instability point

Figure 16 shows a typical VQ characteristic. It is the quadrature equivalent of the PV curves in **6.2.1**.

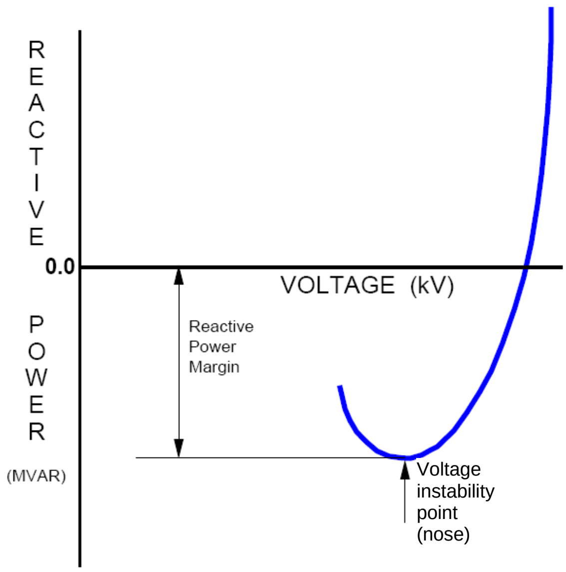

Figure 16: Typical VQ characteristic

The minimum point of the VQ curve (where dQ/dV = 0) is the critical "nose" point. To the right of this point, an increase in MVAr requirements causes a drop in voltage, and a decrease in MVAr requirements causes a rise in voltage, so it is therefore a **stable** system. Conversely, points to the left of the critical point minimum are unstable.

If the nose point of the VQ curve is above the horizontal axis, the system is reactive power deficient, and additional reactive power is required to prevent a voltage collapse.

Reactive power margin

Figure 17 shows VQ curves for three different conditions:

(a) N-0, base load conditions

(b) Worst-case N-1 contingency

(c) Worst-case N-1 contingency and a 5 % increase in load.

The second Curve (N-1 worst-case contingency) is near the lower operating voltage limit of (in this example) 0.95 pu. Thus the system has sufficient reactive compensation to just handle an N-1 contingency.

The third Curve shows that for the worst-case N-1 contingency and a 5 % increase in load, the reactive power is 300 MVAr short of that needed to maintain the voltage at 0.95 pu. Thus, if the **security** criterion is the ability to maintain stability at 5 % above the expected load, then an additional 300 MVAr is required.

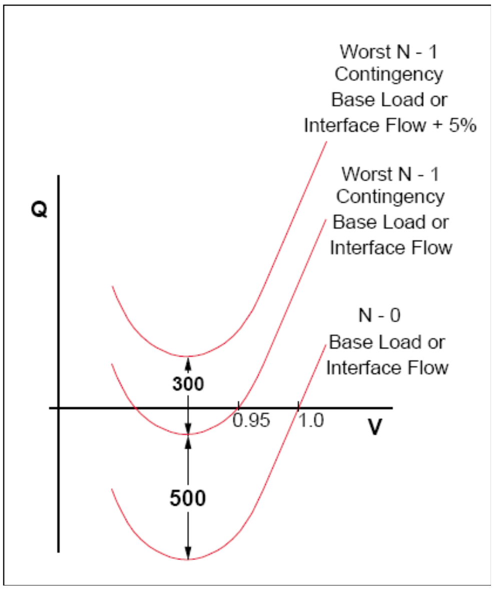

Figure 17: VQ curves for different system conditions

VQ procedure

As with the PV curves in **6.2.1**, the above curves simply demonstrate the concept of stability and can be constructed from a simple two-port model. In practice, the procedure for similar analysis of a real power system is more complicated.

The following procedure is recommended by WECC.

A power flow is set up for a post-disturbance condition (N-1, N-1-1, etc, depending on the **security** criteria) and the critical busbar is identified (usually the most reactive deficient). A reactive power source or sink is applied to that busbar (WECC describes this as a "fictitious synchronous condenser"), the voltage at that busbar (V) is altered by a small amount, and the output or absorption of the reactive source or sink (Q) to achieve this is calculated. This is repeated for different excursions in voltage until a VQ curve can be drawn.

VQ curve interpretation

The VQ curve for a single, uncompensated **transmission line** is shown in **Figure 18**. This is for the same model as used in the PV analysis in **6.2.1**.

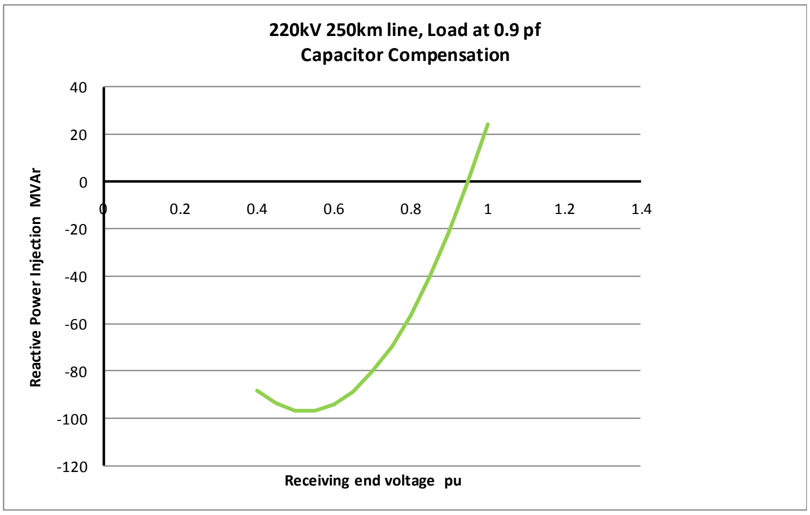

Figure 18: VQ curve for single uncompensated line

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Figure 18 represents a "base case" (zero-compensation). VQ curves for different levels of non-dynamic compensation are shown in **Table 5** and **Figure 19**.

Non-dynamic compensation levels				
Case	Compensation MVAr	Load MW	Load MVAr	Compensation factor
Base case	0	63.5	31.75	0 %
Case 1	50	118	59	42 %
Case 2	100	166	83	60 %
Case 3	200	247	123.5	81 %
Case 4	300	310	155	97 %
Case 5	500	397	198.5	126 %

Table 5: Non-dynamic compensation levels

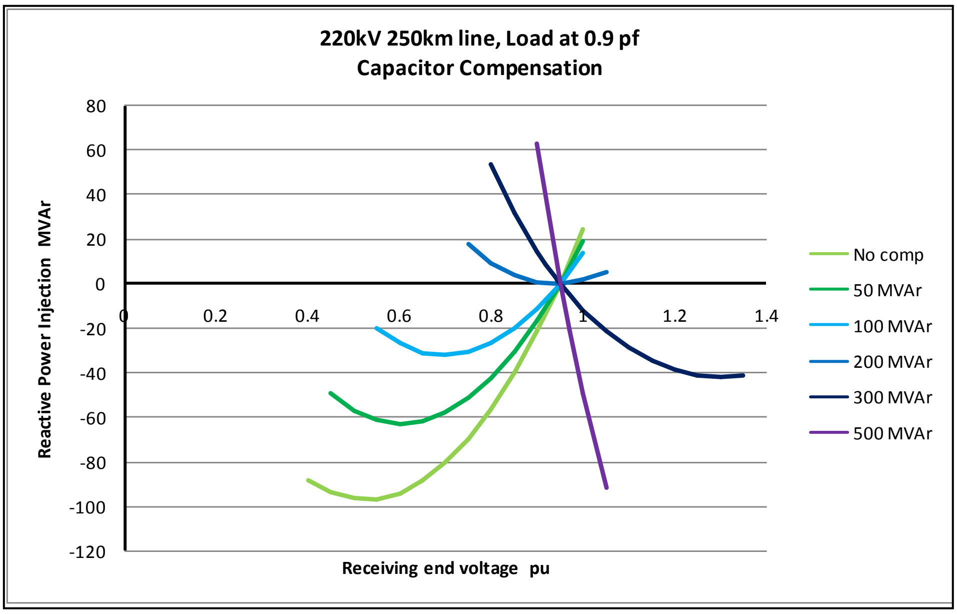

Figure 19: VQ curves for 220kV 250km line with capacitor compensation

The nose point of the 0, 50 MVAr, and 100 MVAr curves are significantly below 0.95 pu voltage, so for these levels of compensation, the system is **stable**.

The nose point for 200 MVAr is actually at 0.95 pu, which means the system is **stable** at that voltage, but unstable for lower voltages (the limiting case).

For 300 MVAr or 500 MVAr of compensation, the system operating point (0.95 pu) is well into the unstable region; the nose points for these curves (not shown for 500 MVAr) are well to the right of the operating point.

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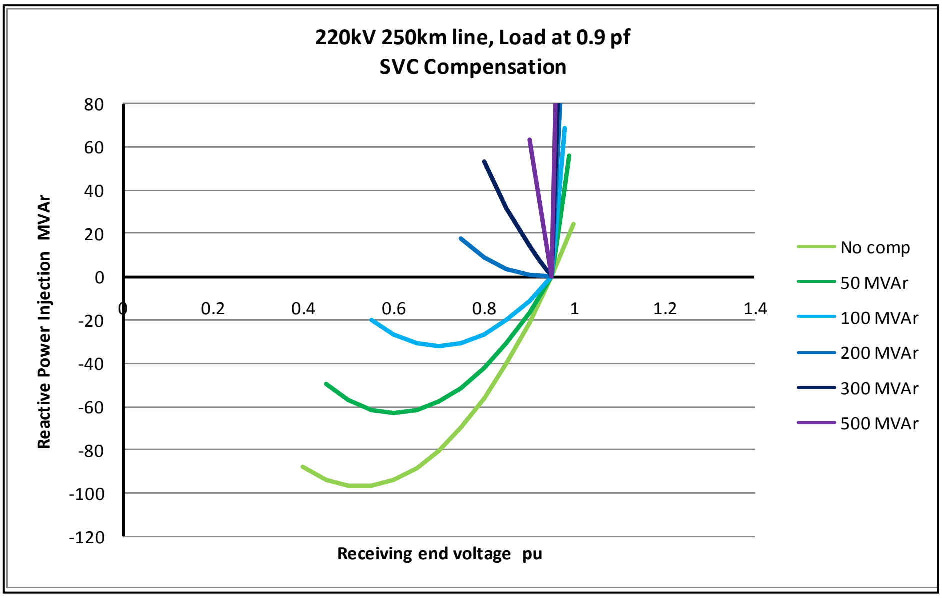

Figure 20: VQ curves for 220kV 250km line with SVC compensation

If the compensation in the model is provided by an SVC rather than a capacitor, voltages above 0.95 pu reflect the SVC's characteristic (and are near straight **line**s at slopes corresponding to the control slope of the SVC); below 0.95 pu the SVC acts as a capacitor, and the curves are identical to those shown in **Figure 19**. Curves passing through operating point thus have a non-linearity at that point, equivalent to the "knee point" in the PV curves. This is shown in **Figure 20**.

Of particular note is that, unlike as in **Figure 19**, the curves for more than 200 MVAr compensation are now **stable** for voltages above 0.95 pu (but below this voltage have a steeply negative slope, so are highly unstable).

Reactive reserve

Figure 21 illustrates the concept of reactive reserve.

Figure 21 is the same as **Figure 20**, except that acceptable (green), marginal (yellow), and undesirable (red) zones have been highlighted. The x-axis scale has been expanded for clarity.

The green zone is bounded by the locus of nose points. The yellow zone is somewhat arbitrary, but necessary to separate the green and red zones.

Points below the x-axis are not within the normal operating region (they are below 0.95 pu), but they are points to which the system would move in the event that the reactive load increases (and no action is taken). For example, consider the system with 50 MVAr of compensation. If the system is operating at 0.95 pu and the reactive load is increased by about 60 MVArs, the system voltage falls to about 0.68 pu, but remains **stable** (this point is in the green zone).

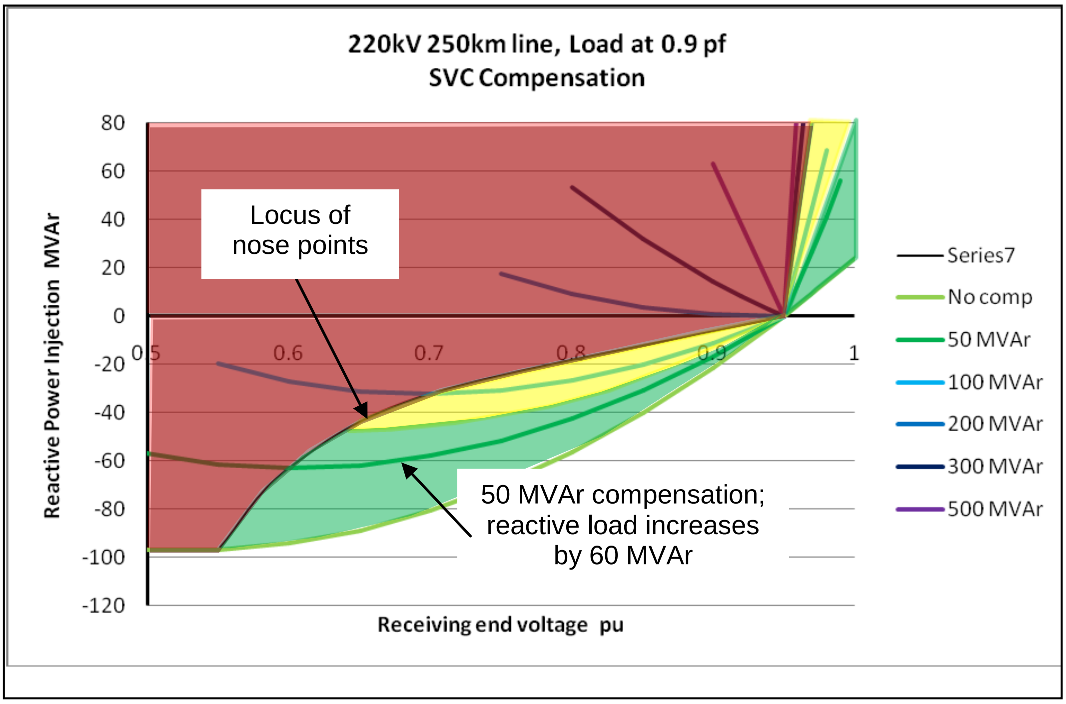

Figure 21: VQ curves showing acceptable, marginal and undesirable zones

6.2.2 Compensation factor

Compensation factor is a generalised parameter for the purposes of broad comparisons between different **transmission** systems and assumes (at this stage) a representative power factor of 0.9. It provides a measure of the degree of compensation in an importing system against the peak demand of that system, and hence can give indications of:

- Whether the system is being planned in a manner that creates an ill-conditioned system and, therefore, one that is likely to lead to voltage instability without warning; or
- Design beyond international norms and therefore inconsistent with **GEIP**.

It should be appreciated that it provides a measure of system robustness in comparison with what other utilities do and is not an absolute figure based on particular demand characteristics.

For the purpose of being able to carry out a comparison on an international basis, compensation is measured in terms of installed **capacity**.

Compensation factor is the capacitive reactive compensation connected to a **transmission** system divided by the maximum power demand of that system. This factor is calculated for a basically importing demand group within that system.

Capacitive reactive compensation includes:

- All shunt fixed capacitors connected at **transmission** voltages;
- All variable capacitive reactive compensation (including continuously-variable and block-switched units) connected at **transmission** voltages. The value of output used for the calculation is the maximum nominal capacitive reactive output; and
- All capacitive compensation connected at the low voltage side of all grid supply points that is used in support of the **transmission** system.

The capacitive reactive compensation does NOT include the reactive compensation embedded within local networks or the reactive output of generating units (unless these are the subject of long term service contracts).

It might be argued that tap changer action on distribution networks keeps approximately constant voltage on the demand. Therefore, in the steady state, the demand along with its capacitors remains at a constant PQ. However, any large aggregation of distribution capacitors that do not have constant voltage applied should not be ignored in the calculation of the **compensation factor**.

However, Transpower considers that while including all shunt capacitive compensation might have some merits in the development of an absolute measure, the **compensation factor** is a relative measure enabling a comparison between utilities (i.e. assessment of **GEIP**). As such, **transmission** systems are dealt with rather than distribution systems, and it would be difficult, if not impossible, to obtain the appropriate data on distribution systems from other **transmission** utilities.

Compensation directly affects system stability, and it is convenient to define the boundaries between the three zones of the three zone model, for a demand **importing group**, in terms of **compensation factor** in the first instance.

Further analysis

Following satisfactory assessments of the static analysis, additional specific evidence must be considered to guard against:

- Overloading of equipment
- Damage to equipment
- Cascade failures
- Blackouts or brownouts over a wide area
- Protection co-ordination and stability
- Defence measures and SPS interaction

6.2.3 Power system analysis − dynamic

In addition to static analysis, marginal cases are subjected to dynamic (transient) analysis.

Transpower has a dynamic analysis procedure. The procedure assumes an initially intact network operating under certain conditions, including a load with a specified inductive component. Then, an outage is assumed of a single item of **transmission** equipment (with and without a fault), followed by a recovery phase. During the outage and the recovery phase the system voltage must adhere to recovery criteria specified in the Grid Planning Guidelines.

The requirement for reactive support is dependent on the evolving nature of the load. Increasing proportions of motor loads and heat pumps influence how the power system responds to major faults. Transpower will use data from fault monitoring systems to refine the load models

6.2.4 Balance of dynamic and static compensation

Having established that a given level of compensation is acceptable (or marginal and requires further analysis), the next step is to assess the necessary mix of dynamic and static compensation.

The mix is expressed as a percentage of dynamic to total compensation.

6.3 International Experience

6.3.1 WECC stability criteria

WECC uses the above principles to define stability criteria, as shown in **Figure 22**. Note that this diagram is stylised to illustrate the stability margin concepts and differs in detail from the curves above, which are calculated from actual models.

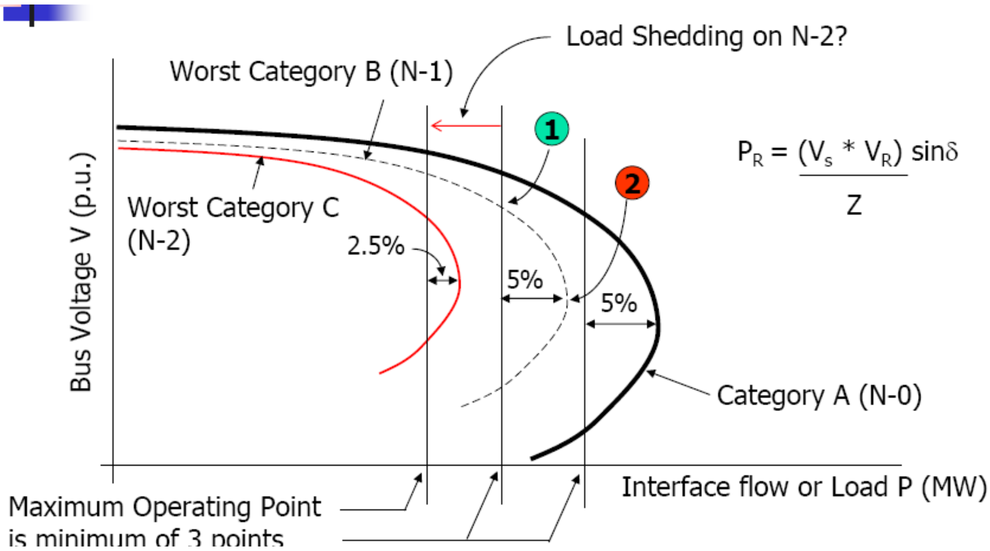

Figure 22: WECC stability criteria

WECC defines three stability margins:

(a) Under normal operating conditions (category A), there is a minimum 5 % margin between the operating point and the nose point.

(b) Under the worst-case, single-outage conditions (category B), there is a minimum 5 % margin between the operating point and the nose point.

(c) Under the worst-case, double-outage conditions (category C), there is a minimum 2.5 % margin between the operating point and the nose point.

(d) The operating point is the maximum established planned load limit for the area under study. The WECC criteria are illustrated by smooth curves that are typical of a well conditioned and, in their case, a highly meshed system. In an ill conditioned system, where voltage instability can take place suddenly, single and double contingency criteria are much more difficult to define.

In order to provide a succinct Code, and because the standard contingency criterion in N-1, the 5 % margin has been described in terms expected system states; this covers both the intact network and N-1 conditions.

VQ analysis

The WECC have established a procedure for voltage-collapse analysis based on using VQ curves. The procedure uses a normal load-flow program, and the VQ curves are produced by running a series of load flow cases.

Both PV curves and VQ curves illustrate the effect of adding compensation. They differ in that PV curves are drawn for constant load power factor and variable demand, while VQ curves are drawn for constant power demand and variable power factor. VQ curves are considered as a more effective method of determining reactive reserve requirements.

6.3.2 International norms for levels of compensation

In the absence of clear technical limits, international norms provide a guide to the generally accepted limits of compensation. Going beyond such norms demands a controlled and monitored progression, e.g. confirming automatic reactive control behaviour; confirming post-disturbance dynamic responses of automatically-controlled equipment; monitoring operational control; reviewing demand forecasting; and real-time assessment and management of a highly brittle network.

Transpower distributed a questionnaire to other major **Transmission** System Operators (TSO) worldwide seeking information on maximum levels of compensation and the mix of static and dynamic compensation. The aim was to further refine the boundaries between these three zones in terms of **compensation factor**.

From the survey results, **Table 6** below gives an indication of the level of compensation in terms of the **Compensation factor** and the ratio of total compensation to maximum demand.

TSO compensation factors			
	Max demand (GW)	Compensation (GVAr)	Ratio of Total Compensation of Maximum Demand
Belgium	13.7	1.89	14 %
England & Wales	61.2	19.59	32 %
Ireland	4.88	0.77	17 %
Italy	56.8	3.944	7 %
Portugal	8.95	2.04	23 %
Queensland[4]	8.71	7.938	91 %
Queensland (10 % POE)[5]	9.54	7.938	83 %
Victoria	9.82	4.31	44 %
New Zealand (North Island)	4.46	1.989	44 %
New Zealand (South Island)	2.23	1.122	50 %

Table 6: TSO compensation factors

The demand figures for New Zealand, in the above table, are taken from Part C of the System Security Forecast 2008. The compensation figures for New Zealand, in the above table, are taken from Part G of the System Security Forecast 2008.

It will be noted that the level of compensation in Australia, based on the two states considered, is significantly higher than in Europe. This is due to the long **lines** and consequent distance over which power needs to be transferred. Compensation in New Zealand is generally higher than Europe but low compared to Queensland. The New Zealand **transmission** system is less interconnected than Europe, but does not cover such long distances as the **transmission** system in Queensland. Hence the level of compensation lies between the two.

Transpower accepts that utilities, in general, do not set limits on the levels of reactive compensation. However, an examination of the compensation used by several utilities shows that the level installed rarely approaches that seen and being contemplated in New Zealand. Hence, there has been little practical requirement for other utilities to consider setting such limits. Further, a number of generic studies, described below, demonstrate the difficulties of operating a **transmission** system with high levels of compensation. Such levels could result in **transmission** systems in which the transition to instability can be rapid and unpredictable. The Code provides a practical set of limits to safeguard the New Zealand system against such an outcome.

6.3.3 WECC recommendations – Voltage Stability and Reactive Power Reserve

The WECC, Voltage Stability Criteria and Reactive Power Reserve Monitoring Methodology, state:

> "*Sufficient reactive resources must be located throughout the electric systems, with a balance between static and dynamic characteristics. Both static and dynamic reactive power resources are needed to supply the reactive power requirements of customer demands and the reactive power losses in the transmission and distribution systems, and provide adequate system voltage support and control*."

Further, it provides a principle:

[4] Includes substations demand and supply to Terranora in New South Wales.
[5] Includes substations demand, transmission losses and supply to Terranora in New South Wales, based on 10% probability of exceedance.

> "*Reactive power resources, with a balance between static and dynamic characteristics, shall be planned and distributed throughout the interconnected transmission systems...*"

Thus WECC acknowledges that both static and dynamic compensation are needed for satisfactory **transmission** performance.

The WECC recommend that:

> "*The best method for determining the proper mixture of static and dynamic reactive power is to conduct dynamic simulations using the current ...... programs. Member systems which already have the capability to conduct long-term dynamic /simulations should use dynamic simulations to determine the required mixture of static and dynamic reactive power support*."

Transpower is able to perform such studies, and the use of authenticated programs, other than those suggested by WECC, is acceptable. WECC notes that the simulation time depends on the system studied and could vary from a few minutes up to about 15 minutes following a contingency. The WECC does not recommend an absolute mix of static and dynamic reactive compensation.

From the international survey results, there is limited information on **importing groups** from the respondents, because either demand data is unavailable or there do not appear to be significant **importing groups** in some areas. For those where information is available, information has been summarised on the following table which shows the proportion of dynamic compensation plotted against **Compensation factor**. This enables the absolute level **Compensation factor** levels to be seen as well as the proportion of dynamic compensation at various levels of **compensation factor**.

Zone	Peak Demand MW	Shunt Capacitors MVAr	SVC MVAr	Total MVAr	Compensation Factor %	Dynamic ratio %
England and Wales, Z16	4275	1071	300	1371	32.0	21.8
England and Wales, Z17	2802	1247	780	2027	72.3	38.5
England and Wales, Z16 + Z17	7077	2318	1080	3398	48.0	31.8
Ireland, NW	358	90	45	135	37.7	33.3
Ireland, SW	144	30	0	30	20.9	0
Australia, Queensland, Far North[6]	367	285	150	435	118.5	34.5
Australia, Queensland Moreton + Gold Coast[7]	5669	3650	950	4600	81.1	20.7
New Zealand UNI	2070	1045	371	1416	68.4	26.2
New Zealand USI	1079	616	310	926	85.8	33.5

Table 7: Proportion of dynamic compensation vs. compensation factor

[6] 10% Probability of Exceedance (POE) demand

[7] Includes supply to demand at Terranora in New South Wales, 10% probability of exceedance (POE) demand

The last two columns in the table above are plotted in **Figure 23** below and demonstrate the high magnitude of **compensation factor** for both New Zealand Upper North Island (UNI) and Upper South Island (USI) when compared with **importing groups** in other utilities. Although the Far North of Queensland does have a higher **compensation factor**, this is due to the extreme distance over which the power must be transmitted.

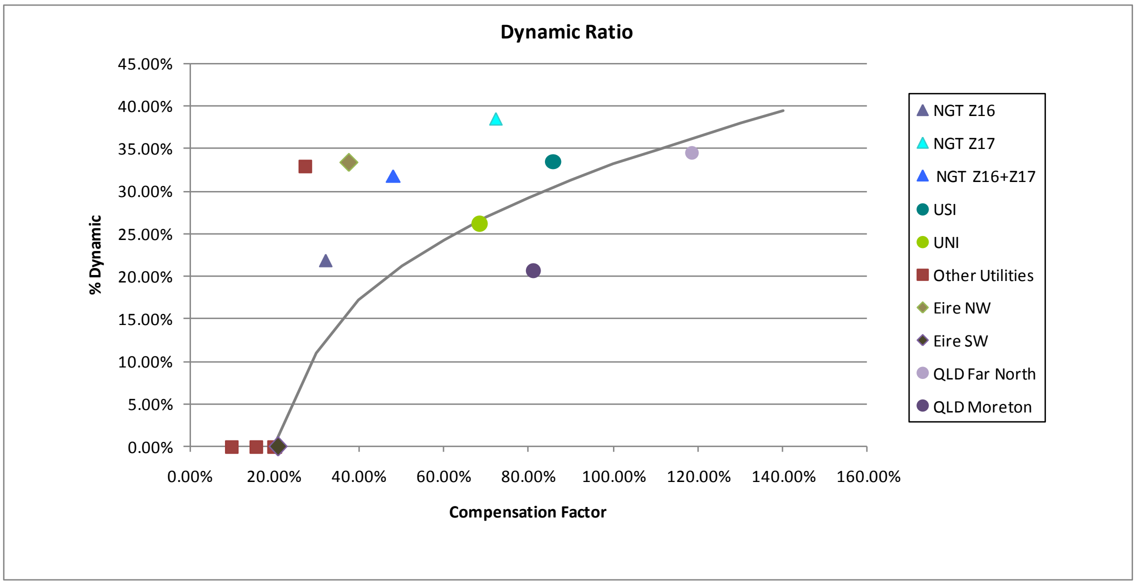

Figure 23: Ratio of dynamic compensation to Compensation Factor for various importing groups

From the overseas utilities data, it may be noted that the **compensation factors** are generally 80 % or below with only one instance, Queensland, above. It can also be seen that most ratios fall above the **dynamic ratio line** rather than below. This indicates that Transpower is already in the upper range of compensation deployment compared with other utilities and that extreme caution should be exercised where **compensation factors** higher than 80 % considered. It is also considered good practice internationally, concurring with Transpower practice, that the **dynamic ratio** for any particular area should be above the **line** unless it can be proved that less dynamic compensation will be satisfactory for all operating conditions.

On the basis of the data points in **Figure 23**, it is difficult to assess a universal level for the balance of static and dynamic compensation, but the curve in **Figure 23** illustrates the principle.

The curve in **Figure 25** shows that even at the lowest levels of compensation some dynamic compensation is required, i.e. even if the **compensation factor** is acceptable. As the **compensation factor** increases, higher levels of dynamic compensation are required.

6.3.4 Acceptable levels of compensation

Utilities have generally adopted a lower operating voltage limit of 10 % below nominal value (0.9 pu), in order to keep the system within its **stable** operating range and to ensure correct co-ordination of automatically-controlled equipment, e.g. transformer tap changers and generator AVRs. Most utilities have voltage limits of ±10 % of nominal specified within their governance documents (e.g. Grid Code, Planning and Operational Standards), as shown in

Table 8 below.

Keeping equipment within its control ranges ensures that the **transmission** system is not required to operate outside its design parameters. In many cases utilities set planning voltage limits within operating limits (e.g. a lowest planned voltage of 0.95 pu) to allow for system conditions that are not exactly as planned (e.g. higher load levels, different generation patterns, alternative **maintenance outages**).

Voltage limits		
Country	Voltage	
	Normal **i.e. steady state**	**Abnormal** **i.e. post-contingency**
Abu Dhabi	±5 %	±10 %
Britain	±5 %	±10 %
Ireland	370-410 kV 210-240 kV 105-120 kV	350-420 kV 200-245 kV 99-123 kV
Malaysia	±5 %	±10 %
Pakistan	±5 %	±10 %
Philippines	±5 %	Not defined
NZ (Rules & Regs)	±10 %	±10 %

Table 8: Voltage limits

6.4 New Zealand Experience

6.4.1 Independent review- compensation factor

Transpower commissioned a review of its Auckland 400 kV plans. This review stated that a **compensation factor** is "a matter of concern once it exceeds 25 %" and that "a 50 % level is generally considered unacceptable" (p. 28). These figures are considerably lower than the proposed acceptable zone boundaries (40 %, 85 %). However, the report goes on to say "there are no studies to prove this rule". Nor is there any information on the power systems from which these concerns originated.

Analysis indicates that **line** length is a critical determinant of real power transfer capability. Substantial reactive compensation is required to achieve a real power transfer over a long **line** (say 250 km) that would require relatively little compensation on a short **line** (< 100 km). Thus, dense, heavily meshed systems, as encountered in many countries, particularly in Europe, require substantially lower **compensation factors** than sparse, largely linear systems, as is New Zealand's. The 25 % and 50 % figures given in the review need to be considered in this light.

6.4.2 Independent reviews – reactive compensation limits

Internationally, debate continues over the best method of determining reactive compensation limits. Utility standards, in describing PV and VQ analysis, invariable show smooth curves (often stylised) for well-conditioned systems, and the means of analysing ill-conditioned systems is unresolved, apart from recommending dynamic studies that are inherently limited by the inaccuracies of demand modelling, load forecasting, generation locations, etc.

Standards often propose resolving these difficulties in terms of reactive margin, but this does not address the planning and operating of ill-conditioned systems in which voltage instability can occur rapidly and without warning.

In contrast, Transpower has based its analysis on real models, rather than just generic principles and has sought critical independent assessment of its analysis procedures.

To verify its PV and VQ analysis procedure, Transpower commissioned two separate, independent reviews of its modelling of the Upper South Island. These reviews were conducted by Pterra and EPRI.

The reviews confirmed Transpower's analysis and largely agreed with each other in terms of how much the **transmission capacity** into Christchurch could be augmented using reactive compensation. Pterra described Transpower's analysis as "thorough and technically correct and consistent with international planning practice" (p.32).

Pterra noted that (in the USI analysis) the PV/VQ and dynamic analyses produced similar maximum possible power transfer results (the PV/VQ analysis being more conservative), but that the dynamic analysis better differentiated between compensation options.

Both reviews commented on the system operator's ability to monitor and control the system, particularly at high levels of compensation, when the system stability becomes increasingly sensitive to small changes in demand. Pterra warned that a high nose point on the PV curve limits the "observability" of the system; it noted that reactive reserve is the most commonly used indicator of system status, and recommended that this be determined not from VQ curves but from dynamic simulation.

6.4.3 Model

Transpower distributed a questionnaire to major TSOs worldwide seeking information on maximum levels of compensation and the mix of static and dynamic compensation. This survey would assist in further refining the percentage of dynamic compensation planned for Transpower's system.

Figure 24 below shows some available data, plotted against **compensation factor**. The curve is fitted to New Zealand data for Upper South Island and derived from planning study work on the development of the associated grid for the years 2010-25; three data points from Britain have been added for comparison.

Plotting percentage against **compensation factor** incorporates demand into the model, and indeed provides a better fit to the data than when plotted against just compensation (MVAr).

The proposed code, therefore, is that the percentage of dynamic compensation should always lie above the illustrated curve.

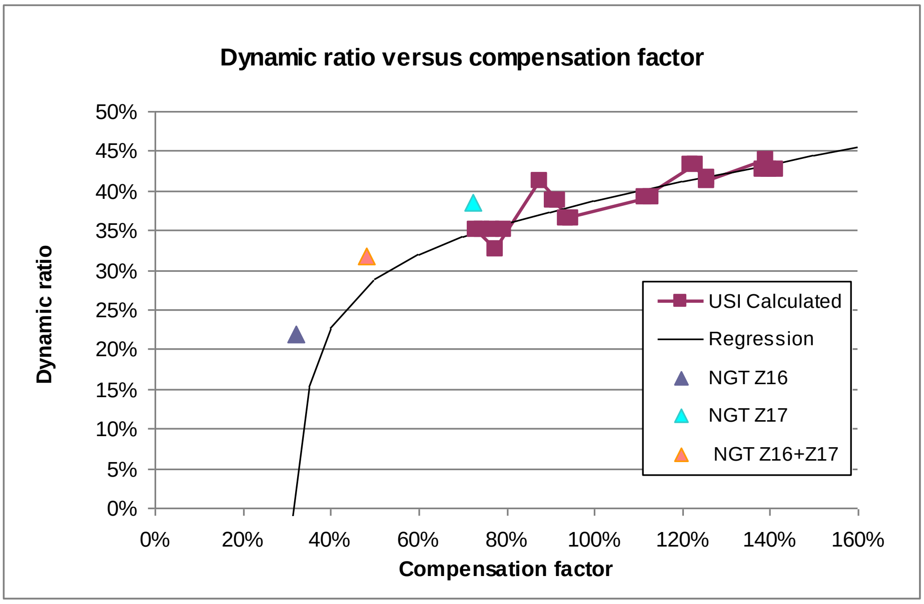

Figure 24: Dynamic ratio vs. compensation factor

6.5 Outcomes

The analysis from previous sections, leads to the code requirements that a system's VQ curve must have a portion below the x-axis and that at 0.9 pu the curve must have a positive slope.

To be consistent with the criteria for the PQ analysis, a 5 % demand increase is applied.

There will be parts of the grid that are inconsistent with these criteria for historical and other reasons. These will be examined as part of grid planning, taking into account the requirements of this **Transmission** Code.

6.5.1 Acceptable levels of compensation

Transpower's approach to assessing performance at different levels of compensation has been to conduct generic (two-port) modelling and to reconcile the results with international norms.

Clear technical limits to compensation are hard to quantify, as evidenced by lack of clear-cut standards internationally in this respect, but generic modelling indicates operating conditions that must be avoided if system stability is to be maintained.

In particular, compensation should not prevent the system reaching its lower operating voltage limit, i.e. there should be a smooth, progressive decline in voltage as load increases. Being unable to reach the lower operating voltage limit implies a brittle and ill-conditioned system that could suffer voltage instability very quickly should reactive compensation reserves be depleted. Monitoring of reactive reserves is essential if the decline in voltage reaches a sudden limit at which voltage instability takes place without warning.

A brittle system is one that can move from being well-conditioned, linear, and operating normally to one that is unstable, non-linear, and uncontrolled, with little or no transition phase. Such a shift can arise from (say) a **line** trip that creates a step change in the loading of other lines. In this condition, reactive compensation runs out of its control range, which leads to a sudden decrease in output, immediate voltage instability, relay mal-operation, break up of the system, generation disconnection, and black-out conditions. This occurs in a matter of seconds, so operators are unable to take manual corrective action. System black out events internationally have confirmed the rapid **failure** that can be experienced under voltage instability conditions.

Highly compensated demand **importing group**s are particularly susceptible to this phenomenon.

Acceptable compensation levels have been designated by three zones:

- Acceptable zone – Generic models indicate a robust system in which it is possible to operate at the lower end of the operating voltage range (10 % below nominal) and there is operational visibility provided by real time voltage measurements of system performance even below this voltage level;

  Operating in this zone is consistent with international norms. See below.
- Marginal zone – The generic model shows a small inherent stability margin allowing operation down to 10 % below nominal, but further, albeit minimal, voltage deterioration would move the system into instability; or
- Unacceptable zone – The system operates in a stable manner until critical reactive reserves are depleted causing the system to collapse without warning. The system, under stable conditions, cannot be operated down to a voltage of 10 % below nominal.

Unacceptable conditions are at or beyond the limits of international **GEIP**. Adoption of such conditions would present significantly elevated risk. They may become acceptable with advance control and automation facilities in the longer term.

Systems in the marginal zone must be analysed in more detail.

6.5.2 TCOP boundaries

The boundaries of acceptability for incorporation in the **TCOP** are:

Compensation factor		
Acceptable	Marginal	Unacceptable
CF < 40 %	40 % ≤ CF ≤ 85 %	CF > 85 %

Table 9: Compensation factor

The figures of 40 % and 85 % are based on the generic model, in which up to 40 % compensation results in a reasonable nose point. A **compensation factor** of 40 % to 85 % enables 0.9 pu voltage to be attained, but with a sharp nose point. If the **compensation factor** is above 85 %, it is not possible to attain 0.9 pu voltage before voltage collapse occurs.

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Transpower acknowledges that in the analysis of compensation requirements there can be some doubt on the representation of load characteristics. For this reason, Transpower recommends both static and dynamic analyses (see **6.2.1 & 6.2.3**,), particularly the latter at high levels of compensation. This approach is cautious and limits the amount of compensation being implemented.

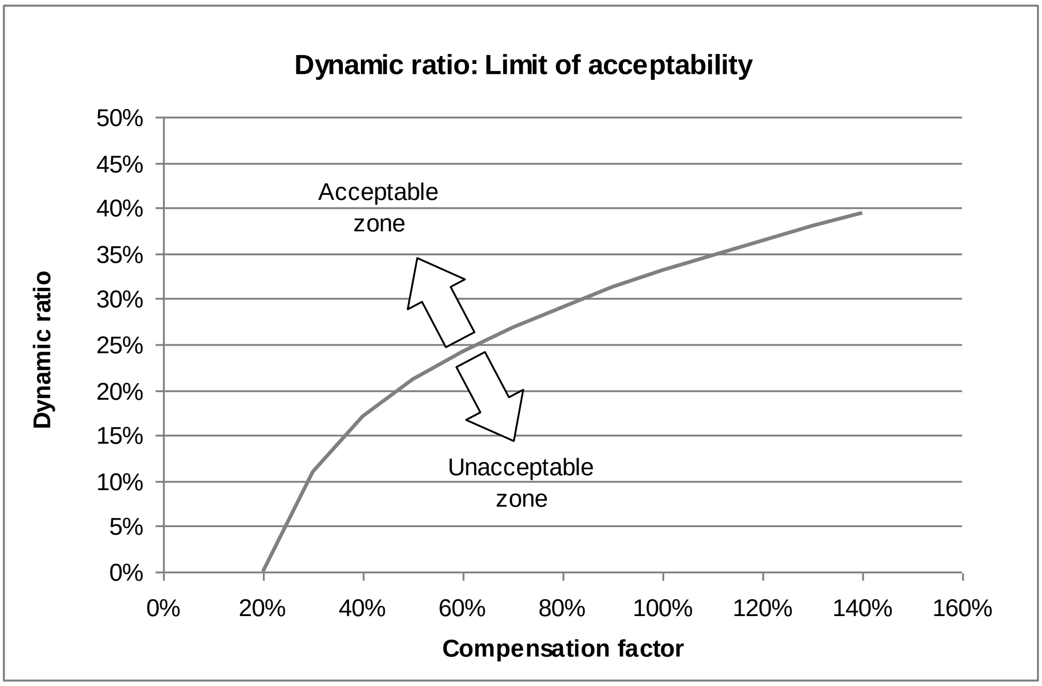


Figure 25: Acceptable levels of compensation

For the purpose of assessing capacitive dynamic reactive compensation, synchronous condensers, SVCs, STATCOMs, and TSCs should be included.

It should be noted that the above diagram applies to important groups and not individual grid exit points. Thus, there is no requirement to provide dynamic compensation to small load points on the **transmission** system where levels of compensation are below 20 %.

7. GRID CONNECTION COMMENTARY

A Grid Connection is the manner in which physical assets are arranged for a customer to inject power into (Grid Injection Point - GIP) or abstracts power from (Grid Exit Point - GXP) the **transmission** system.

The decision of the configuration of a proposed new connection is based on an assessment of technical, operational, commercial and legal requirements, as well as an economic assessment. The outcome of the process will determine feasibility (including engineering requirements) of the new connection and identify ownership boundaries.

7.1 Standard Configurations

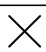
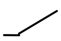
In line with the principles specified in the **TCOP**, the following connection options to the grid are considered to be in accordance with Good Electricity Industry Practice (**GEIP**), meets the Grid Reliability Standard (GRS) and are the initial standard connection offerings that Transpower would offer to any Generator, Network Company or other party wishing to connect the national grid. Other connection options are possible and following more detailed analysis may be proven to meet minimum performance criteria.

The simplified Single Line Diagrams (SLDs) that follow should be used as a guide. They are generic, commonly used configurations for Grid Exit Point (GXP) or Grid Switching station applications and are those most likely to be approved by Transpower without significant engineering input. These configurations could also be used for Grid Injection Points (GIPs), however it is recognised that the level of service that they provide may be in excess of what a typical generation customer may require.

Transpower standard configurations provide generic or default connection options which are currently accepted. For each type of connection a simplified pictorial Single Line Diagram (SLD) and some guidance notes are given to aid in the understanding of why such an arrangement has been proposed. Although generally a single circuit representation is shown, these arrangements can be used for either a Single (N) or Double (N-1) connections.

A DCB (Disconnecting Circuit Breaker), or Compact Integrated Switchgear (CIS) is an item of switchgear that incorporates the functions of a Circuit Breaker, Disconnector, Earth Switch and in some circumstances instrument transformers. DCBs/CIS are normally of the Air Insulated Switchgear (AIS) configuration. The use of Transpower approved CIS in place of conventional switchgear is allowed provided in the medium term (5 years to 2016) the layout of the substation allows for the retrofit of conventional Disconnector and Earth Switches. This additional space is to allow for the retrofit of conventional AIS disconenctors and earth switches should the performance of the CIS be less than satisfactory.

When installing CIS a QDC (Quick Disconnect Clamp) that can be applied or removed using a hotstick is required to minimise the switching, earthing, isolation, and equipment potential bonding requirements and time should a CIS ever need to be isolated from the system.
The symbols used in these simplified SLDs are

	Busbar		QDS Disconnection Point/Clamp
	Conventional AIS CB		AIS CIS/DCB
	Conventional AIS DIS		CT
	Connection Point		Transpower Protection Zone

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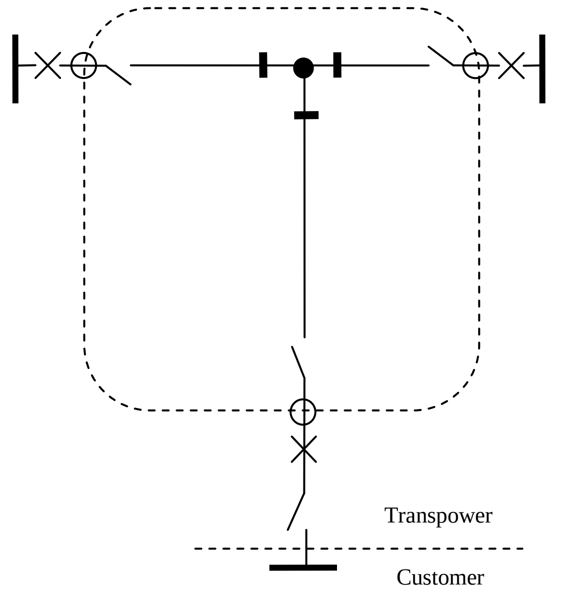
7.2 Multi Terminal Connections

With reference to the Technical Code of Practice the following outline the different Multi Terminal Connections "T" type connection service offerings Transpower offer.

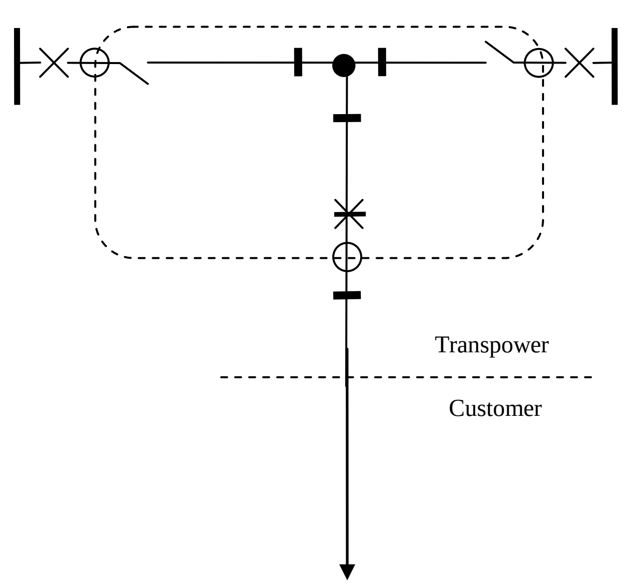
7.2.1 Type 1 T Maintenance Isolation Point



- Incorporates some form of Quick Disconnecting Clamp/Link
- Clamp is zero maintenance
- Transpower preference to own spur line
- First & Only T on circuit
- CIS can be used

Figure 26: Type 1 Transpower Owned Spur Line

Should the customer wish to own the **line** the following variation where the CB is located at the T point, would apply. The requirement for this is to manage the impact on through transmission caused by the development of the spur circuit.



- CB located at T point
- Type of CB/DIS/CIS/QDS confirmed during detailed design

Figure 27: Type 1 Customer Owned Spur Line

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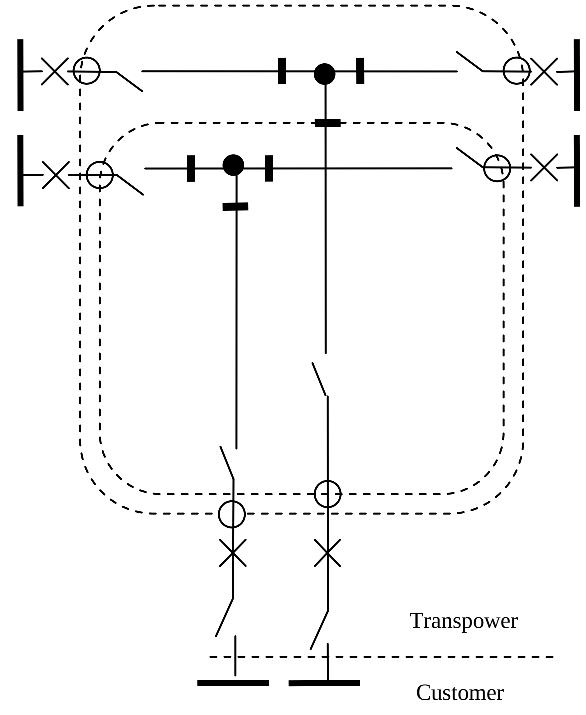
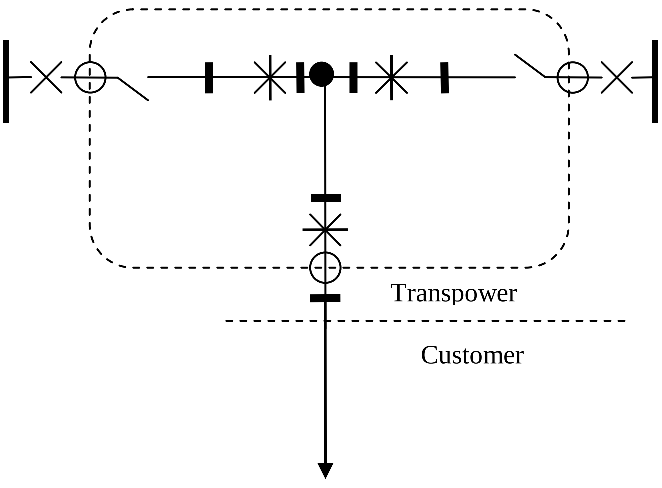


- Incorporates some form of Quick Disconnecting Clamp/Link
- Clamp is zero maintenance
- Transpower preference to own spur line
- CIS can be used

Figure 28: Type 1 Example of a Double T Transpower Owned Spur Line

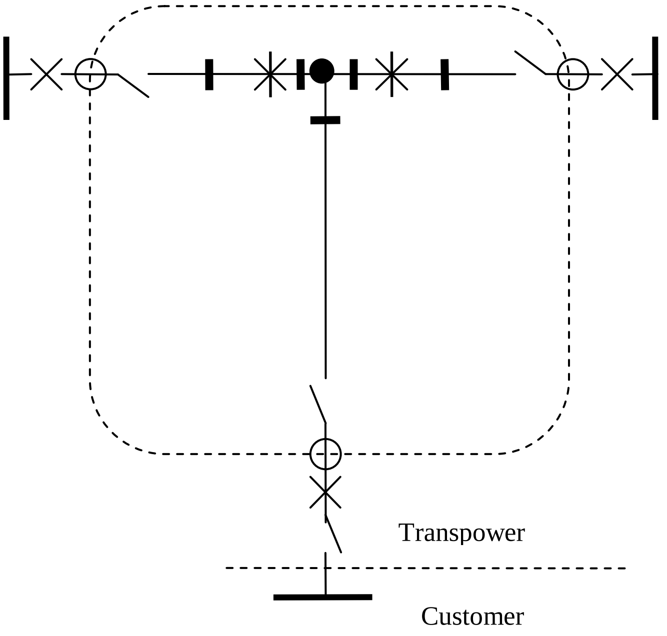
7.2.2 Type 2 T Dumb Sectionaliser

Should technical or operational reasons such as line charging current, load current, time to travel to remote ends or customer need for a minimum of supply disruption be present then the use of a dumb sectionaliser enables the isolation of any given circuit branch.



- Sectionalisers on the through line are dumb devices with no protection functionality.
- Manual & SCADA open/close control at the "T" point to isolate line section for works.
- Generally only load breaking, not fault breaking

Figure 29: Type 2 Customer Owned Spur Line

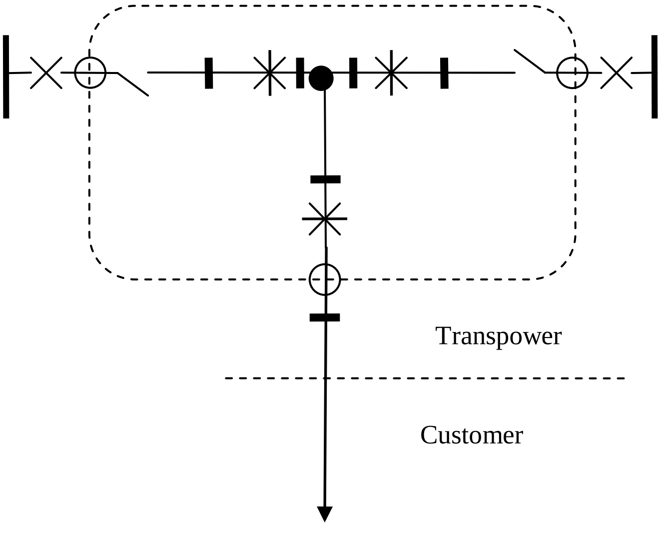


- Sectionalisers on the through line are dumb devices with no protection functionality.
- Manual & SCADA open/close control at the "T" point to isolate line section for works.
- Generally only load breaking, not fault breaking
- No Protection of sectionalisers

Figure 30: Type 2 Transpower Owned Spur Line

7.2.3 Type 3 T Smart Sectionaliser

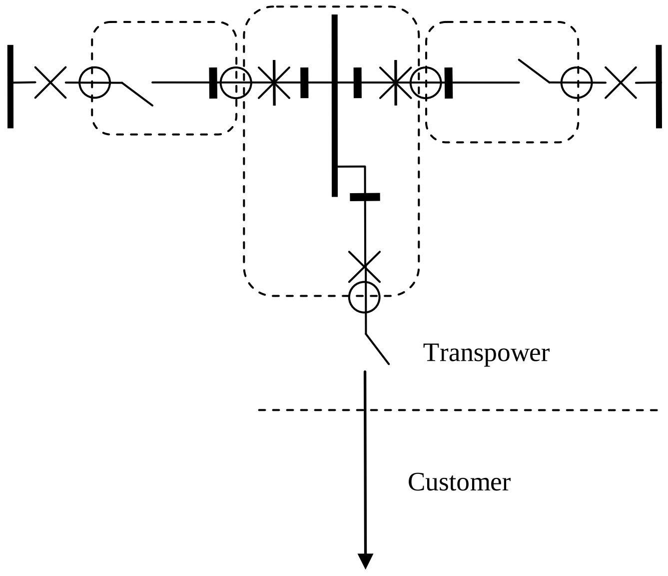
Smart sectionalisers enable the remote opening and closing of the sectionalising circuit breaker.



- Sectionalisers on the through line are smart devices which trip on CB(Fail) of "T" located CB.
- Manual & SCADA open/close control at the "T" point to isolate line section for works.
- Is both load and fault breaking capable
- Note "T" CB could be a CIS without DIS

Figure 31: Type 3 Customer Owned Spur Line

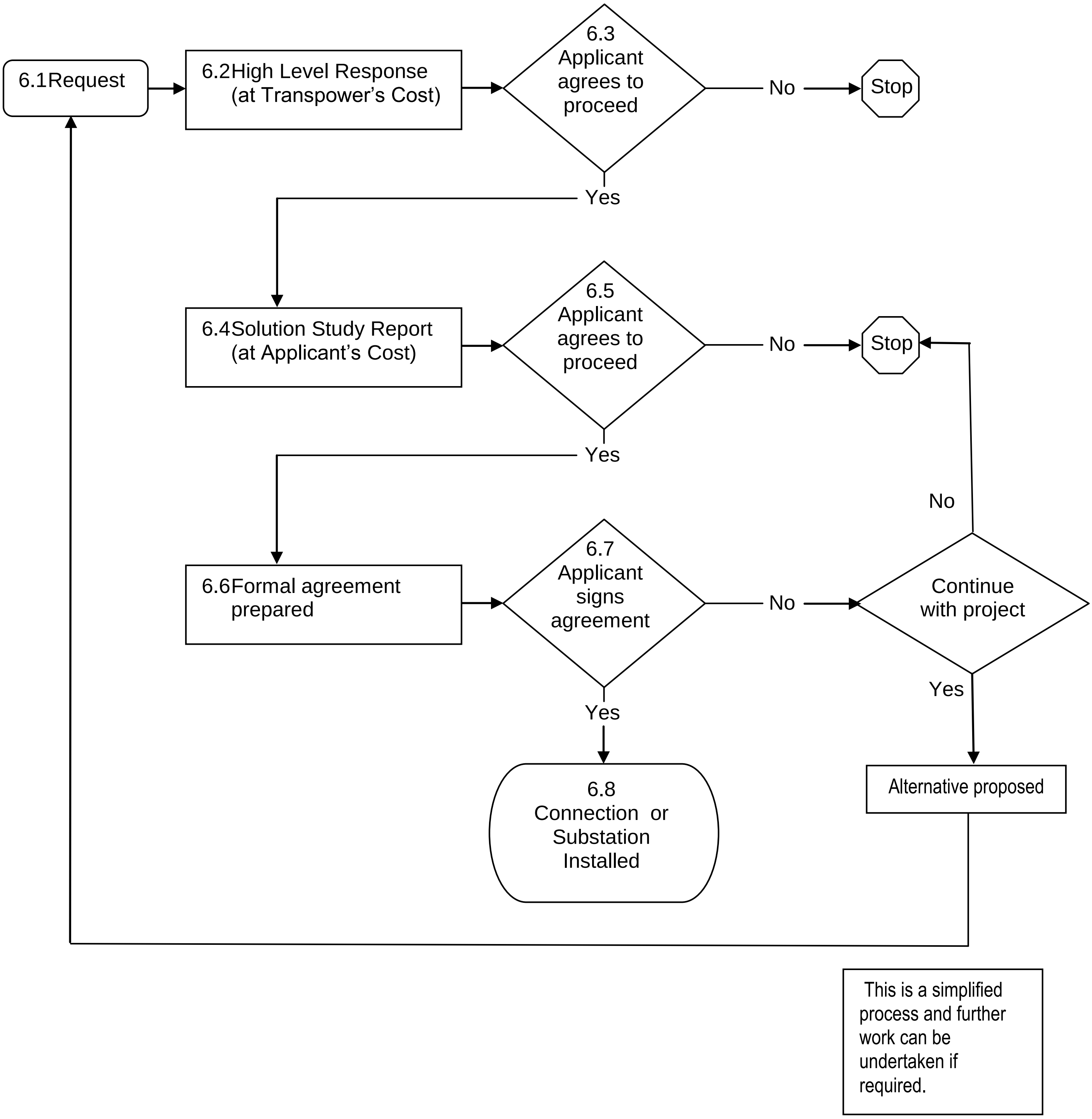
7.2.4 5 Type 4 T Full Substation



- Through Line complete with full line protection and may be a CIS
- Note "T" CB could be a CIS without DIS or Normal CB with bus & line DIS

Figure 32: Type 4 Customer Owned Spur Line

7.3 Connection & Substation Configuration Process



7.4 Selection Matrices

To assist in the decision making process the following selection matrices are used to assess the impact of the various decision making criteria and based on the results act as a general guide as to what would be generally acceptable without detailed analysis.. They are not intended to provide a definitive answer but is an option evaluation tool to assist in the identification of a solution that tries to balance the various competing inputs.

The tables that follow are to be used as a guide as to the type of connection that is most likely to be approved by Transpower without significant engineering investigation. The table tries to highlight that creating a new conenction needs to be carefully considered and that there are many and varied criteria that need to be considered and balanced when selecting a given connection. Once all items have been considered and ticks placed in each relevant box, it is the weighted balance that is imporatnt. Just because one tick may appear in the Type 4 column and the rest appear in Type 1 or 2 it does not mean a type 4 solution is required.

7.4.1 Single "T" N Security

Criteria	Type 1	Type 2	Type 3	Type 4	Comment
Through Line Capacity (MVA) (GXP/GIP)	<10	<45	<75	>75	
Spur Capacity (MVA)(GXP/GIP)	<5/20	<25/40	<50/75	>50/75	
Spur Length (km)	0 – 0.5	0.5 – 1	1-5	>5	
Total Length of all Spurs as % of Through Line	<5%	<10%	<20%	>20%	
Spur Earthwire	100%	2km	1km	0km	
Spur Required Protection	None	Single	Backup	Duplicate	
Conversion of Terminals from/to	2-3	3-4	4-5	5 or more	
# Other Customers Affected	0	1	2	>2	
Size Other Customer Loads (MVA)	<5	<10	<25	>25	
Reliability Required of Other Loads GXP (GIP) (hrs/daysweek/daysyear)	12/6/200 (8/5/200)	12/6/365 (8/5/365)	24/7/200 (12/7/365)	24/7/365 (18/7/365)	
Need for Comms to operate system	None	SCADA	Prot & SCADA	Dup Prot & SCADA	
Outages Though Line (ease of obtaining % of time)	100%	75%	50%	5%	
Outages Spur Line (ease of obtaining % of time)	100%	75%	50%	5%	
Operator time to isolate cct	0-1hr	1-2hrs	2-3hrs	3-4hrs	

Table 10: Single "T" N Security

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7.4.2 Double "T" N-1 Security

Criteria	Type 1	Type 2	Type 3	Type 4	Comment
Through Line Capacity (MVA) (GXP/GIP)	<75	<100	<150	>150	
Spur Capacity (MVA) (GXP/GIP)	<15/50	<25/75	<50/100	>50/<150	
Spur Length (km)	0 – 5	5 – 10	10-15	>15	
Total Length of Spur as % of Through Line	<20%	<25%	<30%	>30%	
Spur Earthwire	100%	2km	1km	0km	
Spur Required Protection	None	Single	Backup	Duplicate	
Conversion of Terminals from/to	2-3	2-3	3-4	5 or more	
# Other Customers Affected	0	0	1	2 or more	
Size Other Customer Loads (MVA)	<10	<20	<30	>30	
Reliability Required of Other Loads GXP (GIP)(hrs/daysweek/daysyear)	12/6/200 (8/5/200)	12/6/365 (8/5/365)	24/7/365 (12/7/365)	24/7/365 (18/7/365)	
Need for Comms to operate system	None	SCADA	Prot & SCADA	Dup Prot & SCADA	
Outages Though Line (ease of obtaining % of time)	60%	50%	20%	5%	
Outages Spur Line (ease of obtaining % of time)	50%	40%	30%	5%	
Switching Time to isolate cct	0-3hr	3-4hrs	4-5hrs	>5hrs	

Table 11: Double "T" N-1 Security

8. SUBSTATION CONFIGURATION COMMENTARY

A substations configuration is the manner in which physical assets are arranged to enable the required system performance and customer performance expectations to be meet.

8.1 Standard Configurations

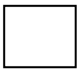
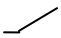
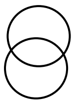
The standard substation configurations in **Table 12** are considered to be in accordance with Good Electricity Industry Practice (**GEIP**), meets the Grid Reliability Standard (GRS) and are the initial substation offerings that Transpower would offer to any Generator, Network Company or other party wishing a substation connection. Other station options are possible and following more detailed analysis may be proven to meet all specified performance criteria.

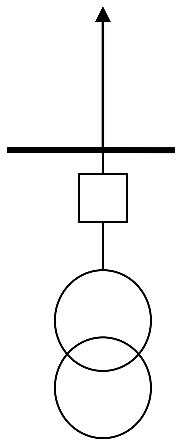
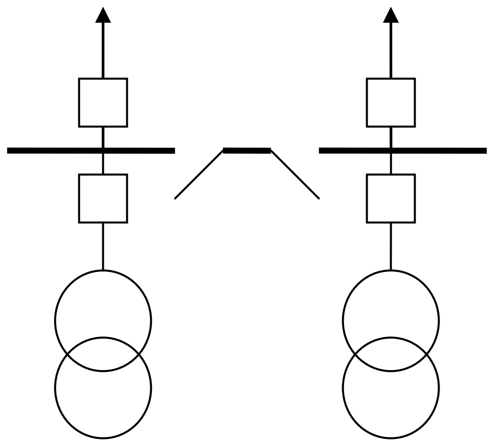
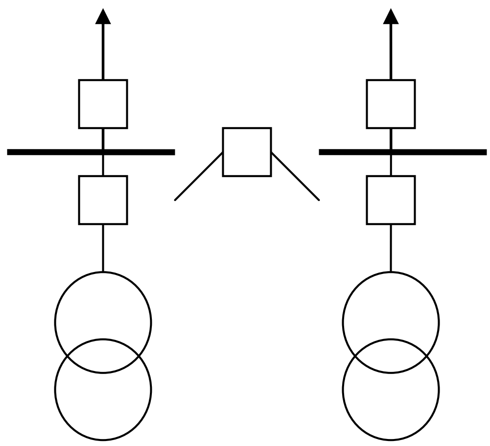
For each type of station a simplified pictorial Single Line Diagram (SLD) and some guidance notes are given to aid in the understanding of why such an arrangement has been proposed.

Due to the differing design drivers for Generators the type GIP station configuration can be quite different as it is based on different capital cost and reliability calculations, that include the cost of lost production, cost of instantaneous reserves, impact on frequency if the station/unit trips, security and availability requirements, and the transformer contingency management policy of the customer. In addition the range given for GIP compared to connection could differ markedly for North Island and South Island connections dependant on fuel, security and availability charges.

A DCB or CIS (Disconnecting Circuit Breaker, or Compact Integrated Switchgear) is a circuit breaker that incorporates the functions of a Circuit Breaker, Disconnector, Earth Switch and in some circumstances instrument transformers. The use of Transpower approved CIS in place of conventional switchgear is allowed provided in the medium term (5 years) the layout of the substation allows for the retrofit of conventional Disconnector and Earth Switches if the performance of the CIS is not satisfactory.

The symbols used in these simplified SLDs are

	Conventional AIS CB & DIS switchgear group or DCB switchgear group or switch board		Busbar
	Conventional AIS DIS		Transformer

Capacity		Connection	Comments
GIP	**GXP**		
<100 - 160MVA	<10MVA		• Single Bus • Single Transformer • Single Line 100MVA • Through transmission capacity <100MVA
>25 - 60MVA <75 - 400MVA	>10MVA <40MVA		• Single Bus Sectionalised • Duplicate Bus DIS • Duplicate Transformer • Through transmission capacity <60MVA cct
>75- 160MVA <120- 400MVA	>40MVA <120MVA		• Single Bus Sectionalised • Bus Coupler • Duplicate Transformer • Through transmission capacity > 60MV <120MVA

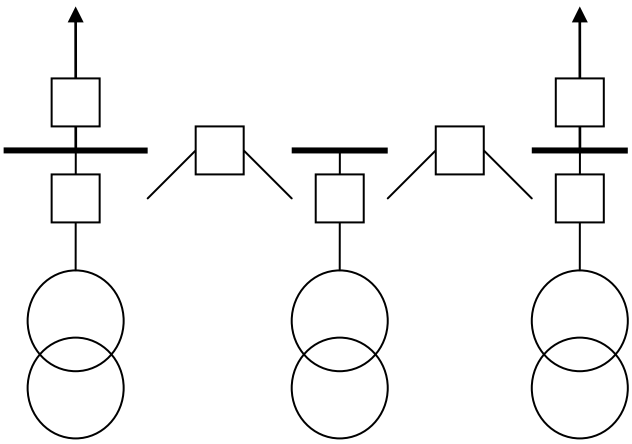
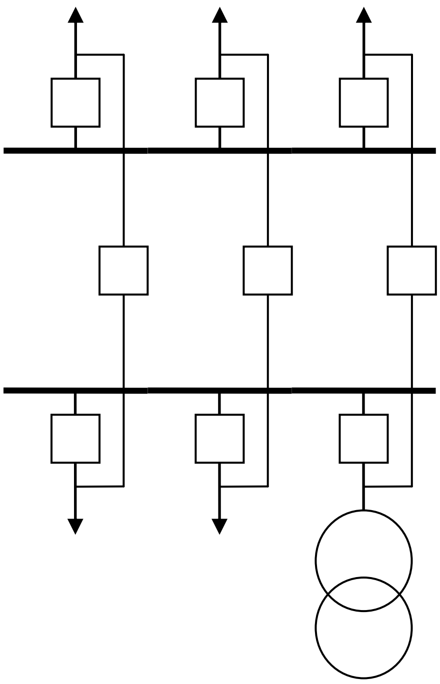
Capacity		Connection	Comments
GIP	GXP		
>120MVA <360-600MVA	>120MVA <240MVA		• Single Bus Sectionalised • Duplicate Bus Coupler • Triplex Transformer 120MVA • Through transmission capacity >120MVA <240MVA
>120MVA	>240MVA		• 1 & 1/2CB • Through transmission capacity >120MVA

Table 12: Standard Substation configurations

8.2 Economic Assessment Process

Proposed to run each bus configuration with SLD through SubRel then using this data to complete economic analysis of the value of load not served at the default Value of Loss Load (**VoLL)** of $20,000/MWh with sensitivity of +/- $10,000/MWh

Should the **VoLL** change from $20,000/MWh a review of bus configurations and expected bus capacities would be completed.

At this stage the default value of **VoLL** is $20,000/MWh for the purpose of reliability calculations or outage planning (reflecting the Value of expected unserved energy that applies under Clause 4 of Schedule 12.2 of the Electricity Industry Participation Code). However, customers may propose alternate values of **VoLL** if this can be demonstrated, which may be higher or lower than the $20,000/MWh. The example in Figure 33 illustrates the results of an economic reliability calculation where a customer has nominated a **VoLL** of $3,500/MWh

8.3 Discussion

The expected fault levels that each station would be designed for would be in accordance with Section 9.0 Fault Level Commentary.

When fault levels are predicted to be approaching fault level limits of the existing equipment, an in-depth fault level study is carried out. Unless there are very large motors connected near the GXP grid busbar, the contribution to fault levels from the motors is unlikely to be significant. Should an in-depth study be required, knowledge of the size and location of presently "unmodelled" embedded generators may also need to be investigated and accounted for. In reality for many GXP's this level of detailed modelling is likely to be unnecessary.

The decision to choose one substation configuration over another is based on an economic assessment of capital costs versus improved **reliability**. At the design stage of any substation modification or new build, the substation is modelled in a program called SUBREL to ascertain **reliability** differences and likely outage implications. SUBREL also makes provision for **maintenance outages** and the possibility of faults during this period. It then provides overall Mean Time Between Failure (MTBF) and Mean Time To Repair (MTTR) statistics for each configuration.

Once the results from SUBREL are obtained and capital cost differences between the different substation configurations estimated, **reliability** benefit analysis is carried out. While **reliability** differences between some configurations are generally small, sometimes the investment to improve **reliability** can also be small. Over an extended analysis period however, exposure to the reduced **reliability** can be used to justify the additional capital expenditure to mitigate the potential outage risk identified in the SUBREL analysis.

An example of the economic application of SUBREL results is shown in **Figure 33** below where two H-bus substation configurations were compared. The first was a standard configuration with circuit breakers, disconnectors and a single bus section breaker. The second involved the use of disconnecting circuit breakers and in this case two bus section breakers in series.

The economic analysis determined that for a **VoLL** of $3,500/MWh at the supply point in question, at approximately 22 MW peak demand at that GXP, the option with two bus section breakers and DCB's was economically justified. This MW break point occurs when the capital cost difference between the two configurations is exceeded by the cost of the **reliability** difference.

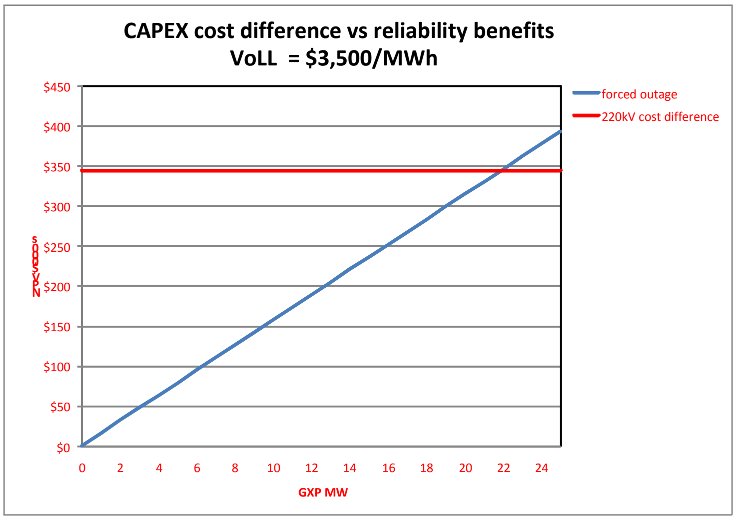


Figure 33: SUBREL economic analysis results

This is the general philosophical approach that is taken for the economic justification of any substation configuration modifications and new builds and underpins the selection of the specified MW ranges between these substation types.

9. FAULT LEVELS COMMENTARY

9.1 Introduction

The monitoring and management of fault levels on the transmission system is important for all parties connected to the grid, including lines companies, Generators, direct connect customers and Transpower, as any of these can be impacted by any change to fault levels.

Therefore adequate information is required to ensure assets are appropriately designed to withstand faults on the power system.

9.2 Discussion

Under existing fault levels at each transmission network point of connection (GXP or GIP) is an important consideration in Transpower's grid development process and to the planning processes of any connected parties. Similarly, the ongoing connection of new generation assets or significant network (Transpower or connected networks) reconfigurations also impact on fault levels.

Transpower is required under the Electricity Industry Participation Code 2010 to provide a 10 year forecast of the maximum fault levels at each point of connection. This requirement is to provide both Transpower and connected parties a possible forecast view of potential fault level increases beyond existing equipment ratings.

Prior to the commencement of the Electricity Industry Participation Code, Transpower published specified maximum fault level limits (at nominal voltage levels) in its historical Planning Guidelines.

This historical maximum fault level information is presently included within the Connection Code, and is reproduced in **Table 13** below. However, circuit breaker fault level capabilities have increased in recent times beyond the fault levels stated in **Table 13**. If it transpires that fault levels exceed existing equipment ratings for any reason then the means by which this can be mitigated must be made on an economic basis, which will include both Transpower and the connected party costs. Should this issue arise then it will need to be dealt with on a case by case basis.

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

Table 13: Maximum fault levels

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

9.2.1 Calculation method

In determining fault levels, Transpower bases its maximum fault level calculation on the IEC standard 60909 method. The IEC method uses a pre-defined voltage level for the calculation of both maximum and minimum fault levels and provides a worst case scenario result within the boundaries of acceptable steady state operational voltage limits.

For the maximum fault levels, which are more concerned about circuit breaker fault interrupt design, all generation is assumed to be operating to feed into the fault. Minimum fault levels are more concerned with protection design, and more in depth protection studies may be necessary on a case by case basis.

When analysis concludes that maximum fault levels are nearing existing equipment ratings, a more thorough assessment of fault conditions may be necessary, such as basing the calculation on a network load flow solution, as opposed to the IEC method where 1.1pu voltage at the faulted bus is the worst case assumed voltage. Also a more in depth assessment of connected party load and embedded generation may be necessary in these cases.

9.2.2 Generation scenarios

For the 10 year fault level forecast grid configuration changes and potential new-build generation assumptions are important. Under the previous regulatory regime, Transpower had 5 generation development scenarios from the Statement of Opportunities (SOO) it could use in its analysis.

As the requirement to publish a SOO has been removed from the most recent regulatory environment, Transpower will be developing its own view of generation scenarios for the purpose of assessing grid investment. It is envisaged that these will also be utilised for fault level analysis. Until new scenarios are developed, Transpower will continue to use the 2010 SOO as a basis for its fault level predictions.

9.2.3 Management of Fault levels

Transpower has nominated design capability ratings which it applies both to new assets procured, and to design requirements for new and existing points of connection.

Transpower reviews existing asset ratings against the 10 year forecast. When Transpower replaces existing assets or installs new assets, the assets will be rated with the nominated design capability ratings at each point of connection on the grid unless there is good reason to do otherwise.

Transpower recommends that customers seeking new connections at existing or new grid exit points should approach Transpower as early as possible so that implications for future fault levels can be assessed. Transpower will then provide the customer with the required design capabilities ratings for their connection.

The 10 year forecast of fault levels is based on information known to Transpower at the time. Some information, especially regarding rotating plant embedded within a GXP or lines company operational splits, may be inaccurate or out of date. These factors may affect the connected party fault levels.

In cases where fault levels are known to be approaching asset design limits it will be necessary for Transpower to have a more detailed understanding of connected party load (primarily motor load), network configuration, and the proximity and size of unknown embedded generation.

9.2.4 Future considerations

Issues to be considered as part of future reviews of the Fault level chapter include:-

- How asset owners are to specify equipment in downstream networks where the asset life is materially longer than the 10 year forecast fault levels at the GIP/GXPs.
- Management of connected parties ability to inject fault current into the grid, or how the available capacity might be allocated between connected parties, or what provision should be made for future connections in terms of allocation kept in reserve
- Approach to setting an operating limit below the actual equipment rating, to allow for such things as modelling inaccuracies, aging equipment and the like, that in combination may mean that on the day a safe maximum fault level may be less than the theoretical calculated value.

Appendix 1: Fault level contribution from the grid for each point of connection

Grid exit point	Point of service	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	Nominated design capability[8]
NORTHLAND													
Albany	ALB0331	20.3	20.5	20.5	21.6	21.6	21.6	21.6	21.6	21.6	21.6	21.6	25
Albany	ALB1101	16.4	16.8	16.9	19.1	19.1	19.1	19.1	19.1	19.1	19.1	19.1	31.5
Bream Bay	BRB0331	10.5	10.5	10.6	10.7	10.7	10.7	10.7	10.7	10.7	10.7	10.7	25
Dargaville	DAR0111	4.8	4.8	4.8	4.8	4.8	4.8	4.8	4.8	4.8	4.8	4.8	25
Henderson	HEN0331	19.4	19.6	19.6	19.9	19.9	19.9	19.9	19.9	19.9	19.9	19.9	25
Hepburn Road	HEP0331	22.6	22.8	22.8	23.1	23.1	23.1	23.1	23.1	23.1	23.1	23.1	25
Kaikohe	KOE0331	7.9	7.9	7.9	7.9	7.9	7.9	7.9	7.9	7.9	7.9	7.9	25
Kaitaia	KTA0331	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	25
Kensington	KEN0331	9.3	9.4	9.4	9.5	9.5	9.5	9.5	9.5	9.5	9.5	9.5	25
Marsden	MDN1101	7.9	7.9	7.9	8.2	8.2	8.2	8.2	8.2	8.2	8.2	8.2	31.5
Maungatapere	MPE0331	8.3	8.4	8.4	8.4	8.4	8.4	8.4	8.4	8.4	8.4	8.4	25
Maungaturoto	MTO0331	4.5	4.5	4.5	4.5	4.5	4.5	4.5	4.5	4.5	4.5	4.5	25
Silverdale	SVL0331	18.5	18.7	18.7	19.5	19.5	19.5	19.5	19.5	19.5	19.5	19.5	25
Wellsford	WEL0331	7.4	7.4	7.5	7.5	7.5	7.5	7.5	7.5	7.5	7.5	7.5	25
AUCKLAND													
Bombay	BOB0331	9.1	9.1	9.1	9.1	9.1	9.1	9.1	9.1	9.1	9.1	9.1	25
Bombay	BOB1102	11.4	11.5	11.5	11.6	11.6	11.6	11.6	11.6	11.6	11.6	11.6	31.5
Glenbrook	GLN0331	16.3	16.4	16.4	16.4	16.4	16.4	16.4	16.4	16.4	16.4	16.4	25
Glenbrook	GLN0332	16.7	16.8	16.8	16.8	16.8	16.8	16.8	16.8	16.8	16.8	16.8	25
Mangere	MNG0331	16.3	16.4	16.4	16.4	16.4	16.4	16.4	16.4	16.4	16.4	16.4	25
Mangere	MNG1101	22.1	22.8	22.9	23.2	23.2	23.2	23.2	23.2	23.2	23.2	23.2	31.5
Meremere	MER0331	9.1	9.1	9.1	9.1	9.1	9.1	9.1	9.1	9.1	9.1	9.1	25
Mt Roskill	ROS0221	23.0	23.1	23.1	23.3	23.3	23.3	23.3	23.3	23.3	23.3	23.3	25
Mt Roskill	ROS1101	22.1	22.8	22.9	23.6	23.6	23.6	23.6	23.6	23.6	23.6	23.6	31.5
Otahuhu A	OTA0221	28.2	28.4	28.5	28.5	28.5	28.5	28.5	28.5	28.5	28.5	28.5	31.5
Otahuhu A	OTA1101	24.1	24.9	25.0	25.3	25.3	25.3	25.3	25.3	25.3	25.3	25.3	40[9]
Otahuhu B	OTC2201	24.8	27.2	27.5	27.4	27.4	27.5	27.5	27.5	27.5	27.5	27.5	40[10]
Pakuranga	PAK0331	16.7	25.8	25.9	24.6	24.7	24.7	24.7	24.7	24.7	24.7	24.7	25
Penrose	PEN0221	20.0	20.1	20.1	20.3	20.3	20.3	20.3	20.3	20.3	20.3	20.3	25
Penrose	PEN0331	27.4	27.7	27.8	28.2	28.2	28.2	28.2	28.2	28.2	28.2	28.2	31.5
Penrose	PEN1101	26.7	25.6	25.7	29.4	29.5	29.5	29.5	29.5	29.5	29.5	29.5	31.5
Southdown	SWN2201	20.4	21.9	22.1	22.1	22.2	22.2	22.2	22.2	22.2	22.2	22.2	31.5
Takanini	TAK0331	18.3	18.4	18.4	18.4	18.4	18.4	18.4	18.4	18.4	18.4	18.4	25
Wiri	WIR0331	20.0	20.1	20.1	20.2	20.2	20.2	20.2	20.2	20.2	20.2	20.2	25

[8] This figure is based on the higher of the maximum power and short circuit levels as specified in Table B2 of Appendix B of the Connection Code or the ten year forecast fault levels indicated in this table.
[9] Higher than standard 110 kV fault rating
[10] Higher than standard 110 kV fault rating

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Grid exit point	Point of service	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	Nominated design capability[8]
WAIKATO													
Arapuni	ARI1101	11.6	11.6	11.6	11.6	11.6	11.6	11.6	11.6	11.6	11.6	11.6	31.5
Atiamuri	ATI2201	18.0	18.6	18.6	19.2	19.4	19.5	19.5	19.5	19.5	19.5	19.5	31.5
Cambridge	CBG0111	21.7	21.7	21.7	21.7	21.7	21.7	21.7	21.7	21.7	21.7	21.7	25
Hamilton	HAM0111	15.3	15.3	15.3	15.3	15.3	15.3	15.3	15.3	15.3	15.3	15.3	25
Hamilton	HAM0331	21.3	21.3	21.4	21.4	21.4	21.4	21.4	21.4	21.4	21.4	21.4	31.5[11]
Hamilton	HAM0551	13.4	13.4	13.6	13.6	13.7	13.7	13.7	13.7	13.7	13.7	13.7	25
Hamilton	HAM0552	13.4	13.4	13.6	13.6	13.7	13.7	13.7	13.7	13.7	13.7	13.7	25
Hangatiki	HTI0331	4.9	4.9	4.9	4.9	4.9	4.9	4.9	4.9	4.9	4.9	4.9	25
Hinuera	HIN0331	6.7	6.7	6.7	6.7	6.7	6.7	6.7	6.7	6.7	6.7	6.7	25
Huntly	HLY0331	15.1	15.1	15.1	15.1	15.1	15.1	15.1	15.1	15.1	15.1	15.1	25
Huntly	HLY0332	15.1	15.1	15.1	15.1	15.1	15.1	15.1	15.1	15.1	15.1	15.1	25
Huntly	HLY2201	29.6	30.1	30.4	30.5	30.5	30.5	30.5	30.5	30.5	30.5	30.5	40
Karapiro	KPO1101	7.1	7.1	7.1	7.1	7.1	7.1	7.1	7.1	7.1	7.1	7.1	31.5
Kopu	KPU0661	2.6	2.6	2.6	2.6	2.6	2.6	2.6	2.6	2.6	2.6	2.6	16
Maraetai	MTI2201	21.2	22.6	23.9	24.7	24.9	25.1	25.1	25.1	25.1	25.1	25.1	31.5
Ohakuri	OHK2201	17.5	17.9	18.0	18.7	18.9	19.1	19.1	19.1	19.1	19.1	19.1	31.5
Te Awamutu	TMU0111	17.0	17.0	17.0	17.0	17.0	17.0	17.0	17.0	17.0	17.0	17.0	25
Te Awamutu	TMU0112	17.0	17.0	17.0	17.0	17.0	17.0	17.0	17.0	17.0	17.0	17.0	25
Te Awamutu	TMU1101	3.6	3.6	3.6	3.6	3.6	3.6	3.6	3.6	3.6	3.6	3.6	31.5
Te Kowhai	TWH0331	22.5	22.6	22.6	22.6	22.6	22.6	22.6	22.6	22.6	22.6	22.6	31.5[12]
Waihou	WHU0331	6.7	6.7	6.7	6.7	6.7	6.7	6.7	6.7	6.7	6.7	6.7	25
Waikino	WKO0331	6.0	6.0	6.0	6.0	6.0	6.0	6.0	6.0	6.0	6.0	6.0	25
Waipapa	WPA2201	13.2	13.8	14.2	14.5	14.6	14.6	14.6	14.6	14.6	14.6	14.6	31.5
Whakamaru[1]	WKM2201	26.2	28.6	31.1	32.6	33.1	33.4	33.4	33.4	33.4	33.4	33.4	40
BAY OF PLENTY													
Edgecumbe	EDG0331	14.8	14.8	14.8	14.9	14.9	14.9	14.9	14.9	14.9	14.9	14.9	25
Kaitimako	KMO0331	7.1	7.5	7.5	7.5	7.5	7.5	7.5	7.5	7.5	7.5	7.5	25
Kawerau	KAW0111	19.3	19.4	19.4	19.4	19.4	19.4	19.4	19.4	19.4	19.4	19.4	25
Kawerau	KAW0114	35.3	35.4	35.4	35.4	35.4	35.5	35.5	35.5	35.5	35.5	35.5	50[13]
Kawerau	KAW0116	17.2	17.2	17.2	17.2	17.3	17.3	17.3	17.3	17.3	17.3	17.3	25
Kawerau	KAW0117	24.6	24.6	24.6	24.6	24.6	24.6	24.6	24.6	24.6	24.6	24.6	31.5
Kawerau	KAW0118	20.6	20.6	20.6	20.6	20.6	20.6	20.6	20.6	20.6	20.6	20.6	31.5
Kawerau	KAW0119	17.9	17.9	17.9	17.9	17.9	17.9	17.9	17.9	17.9	17.9	17.9	25
Kawerau	KAW1101	11.5	11.5	11.5	11.5	11.5	11.5	11.5	11.5	11.5	11.5	11.5	31.5
Kinleith	KIN0111	14.2	14.2	14.2	14.2	14.2	14.2	14.2	14.2	14.2	14.2	14.2	25
Kinleith	KIN0112	35.5	35.5	35.5	35.5	35.5	35.5	35.5	35.5	35.5	35.5	35.5	50[14]
Kinleith	KIN0331	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	25

[11] Higher than standard 33 kV fault rating
[12] Higher than standard 33 kV fault rating
[13] Higher than standard 11 kV fault rating
[14] Higher than standard 11 kV fault rating

Grid exit point	Point of service	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	Nominated design capability[8]
Lichfield	LFD1101	6.8	6.8	6.8	6.8	6.8	6.8	6.8	6.8	6.8	6.8	6.8	31.5
Matahina	MAT1101	9.7	9.7	9.7	9.7	9.7	9.7	9.7	9.7	9.7	9.7	9.7	31.5
Mt Maunganui	MTM0331	10.6	11.4	11.4	11.5	11.5	11.5	11.5	11.5	11.5	11.5	11.5	25
Owhata	OWH0111	9.8	9.8	9.8	9.8	9.8	9.8	9.8	9.8	9.8	9.8	9.8	25
Rotorua	ROT0111	19.0	19.0	19.0	19.0	19.0	19.0	19.0	19.0	19.0	19.0	19.0	25
Rotorua	ROT0331	9.5	9.4	9.4	9.5	9.5	9.5	9.5	9.5	9.5	9.5	9.5	25
Rotorua	ROT1101	8.3	8.3	8.3	8.3	8.4	8.4	8.4	8.4	8.4	8.4	8.4	31.5
Tarukenga	TRK0111	10.7	10.7	10.7	10.7	10.7	10.7	10.7	10.7	10.7	10.7	10.7	25
Tauranga	TGA0111	13.7	14.1	14.1	14.1	14.1	14.1	14.1	14.1	14.1	14.1	14.1	25
Tauranga	TGA0331	12.2	13.2	13.2	13.2	13.2	13.2	13.2	13.2	13.2	13.2	13.2	25
Te Kaha	TKH0111	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	25
Te Matai	TMI0331	7.2	7.4	7.4	7.4	7.4	7.4	7.4	7.4	7.4	7.4	7.4	25
Waiotahi	WAI0111	8.4	8.4	8.4	8.4	8.4	8.4	8.4	8.4	8.4	8.4	8.4	25
CENTRAL NORTH ISLAND													
Aratiatia	ARA2201	17.6	18.1	20.4	22.4	23.1	23.5	23.5	23.5	23.5	23.5	23.5	31.5
Bunnythorpe	BPE0331	18.2	18.1	18.1	18.1	18.1	18.1	18.1	18.1	18.1	18.1	18.1	25
Bunnythorpe	BPE0551	15.7	14.9	14.9	14.9	14.9	14.9	14.9	14.9	14.9	14.9	14.9	25
Bunnythorpe	BPE0552	15.7	14.9	14.9	14.9	14.9	14.9	14.9	14.9	14.9	14.9	14.9	25
Dannevirke	DVK0111	16.7	16.7	16.7	16.7	16.7	16.7	16.7	16.7	16.7	16.7	16.7	25
Linton	LTN0331	18.5	18.3	18.3	18.3	18.3	18.3	18.3	18.3	18.3	18.3	18.3	25[15]
Mangahao	MHO0331	9.2	9.0	9.1	9.1	9.1	9.1	9.1	9.1	9.1	9.1	9.1	25
Mangamaire	MGM0331	4.6	4.6	4.6	4.6	4.6	4.6	4.6	4.6	4.6	4.6	4.6	25
Marton	MTN0331	6.6	6.6	6.6	6.6	6.6	6.6	6.6	6.6	6.6	6.6	6.6	25
Mataroa	MTR0331	3.5	3.5	3.5	3.5	3.5	3.5	3.5	3.5	3.5	3.5	3.5	25
National Park	NPK0331	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	25
Nga Awa Purua[1]	NAP2201	16.9	17.9	19.9	21.6	22.2	22.5	22.5	22.5	22.5	22.5	22.5	31.5
Ohaaki	OKI0111	3.4	3.4	3.4	3.4	3.4	3.4	3.4	3.4	3.4	3.4	3.4	25
Ohaaki	OKI2201	14.1	14.6	15.9	17.0	17.3	17.6	17.6	17.6	17.6	17.6	17.6	31.5
Ohakune	OKN0111	4.7	4.7	4.7	4.7	4.7	4.7	4.7	4.7	4.7	4.7	4.7	25
Ongarue	ONG0331	3.6	3.6	3.6	3.6	3.6	3.6	3.6	3.6	3.6	3.6	3.6	25
Poihipi[1]	PPI2201	17.3	18.2	20.9	22.7	23.5	24.2	24.2	24.2	24.2	24.2	24.2	31.5
Rangipo	RPO2201	6.9	6.9	7.0	7.1	7.1	7.1	7.1	7.1	7.1	7.1	7.1	31.5
Tangiwai	TNG0111	19.9	19.9	19.9	19.9	19.9	20.0	20.0	20.0	20.0	20.0	20.0	25
Tangiwai	TNG0551	5.2	5.1	5.2	5.2	5.2	5.2	5.2	5.2	5.2	5.2	5.2	25
Tangiwai	TNG0552	5.2	5.1	5.2	5.2	5.2	5.2	5.2	5.2	5.2	5.2	5.2	25
Tararua Wind Central	TWC2201	11.0	10.5	10.6	10.6	10.6	10.6	10.6	10.6	10.6	10.6	10.6	31.5
Tokaanu	TKU0331	7.5	7.5	7.5	7.5	7.5	7.5	7.5	7.5	7.5	7.5	7.5	25
Tokaanu	TKU2201	12.1	12.2	12.4	12.5	12.5	12.5	12.5	12.5	12.5	12.5	12.5	31.5
Waipawa	WPW0111	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	25

[15] Has significant embedded generation

Grid exit point	Point of service	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	Nominated design capability[8]
Waipawa	WPW0331	4.9	4.9	4.9	4.9	4.9	4.9	4.9	4.9	4.9	4.9	4.9	25
Wairakei	WRK0331	22.2	22.3	22.6	22.8	21.3	21.3	21.3	21.3	21.3	21.3	21.3	25[16]
Wairakei	WRK2201	21.9	22.7	26.6	30.3	31.6	32.4	32.4	32.4	32.4	32.4	32.4	40[17]
Woodville	WDV0111	7.8	7.8	7.8	7.8	7.8	7.8	7.8	7.8	7.8	7.8	7.8	25
Woodville	WDV1101	9.5	9.4	9.4	9.4	9.4	9.4	9.4	9.4	9.4	9.4	9.4	31.5
TARANAKI													
Brunswick	BRK0331	9.1	9.1	9.1	9.1	9.1	9.1	9.1	9.1	9.1	9.1	9.1	25
Carrington Street	CST0331	13.1	13.7	13.7	13.7	13.7	13.7	13.7	13.7	13.7	13.7	13.7	25
Hawera	HWA0331	7.9	8.0	8.2	8.2	8.2	8.2	8.2	8.2	8.2	8.2	8.2	25
Hawera	HWA0332	4.6	4.6	4.7	4.7	4.7	4.7	4.7	4.7	4.7	4.7	4.7	25
Hawera	HWA1101	6.9	7.0	7.6	7.6	7.6	7.6	7.6	7.6	7.6	7.6	7.6	31.5
Hawera	HWA1102	6.9	7.0	7.6	7.6	7.6	7.6	7.6	7.6	7.6	7.6	7.6	31.5
Huirangi	HUI0331	6.9	7.1	7.1	7.1	7.1	7.1	7.1	7.1	7.1	7.1	7.1	25
Kaponga	KPA1101	4.1	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	31.5
Motunui	MNI0111	15.0	15.7	15.8	15.8	15.8	15.8	15.8	15.8	15.8	15.8	15.8	31.5[18]
Motunui	MNI0112	15.2	15.9	15.9	15.9	15.9	15.9	15.9	15.9	15.9	15.9	15.9	31.5[19]
Moturoa	MRA0111	10.6	10.7	10.7	10.7	10.7	10.7	10.7	10.7	10.7	10.7	10.7	25
New Plymouth	NPL0331	10.0	10.3	10.3	10.3	10.3	10.3	10.3	10.3	10.3	10.3	10.3	25
New Plymouth	NPL2201	8.9	9.5	9.6	9.6	9.6	9.6	9.6	9.6	9.6	9.6	9.6	31.5
Opunake	OPK0331	4.2	4.3	4.3	4.3	4.3	4.3	4.3	4.3	4.3	4.3	4.3	25
Stratford	SFD0331	7.2	7.3	7.3	7.3	7.3	7.3	7.3	7.3	7.3	7.3	7.3	25
Taumarunui	TMN0551	4.3	4.3	4.3	4.3	4.3	4.3	4.3	4.3	4.3	4.3	4.3	25
Taumarunui	TMN0552	4.3	4.3	4.3	4.3	4.3	4.3	4.3	4.3	4.3	4.3	4.3	25
Wanganui	WGN0331	6.3	6.3	6.4	6.4	6.4	6.4	6.4	6.4	6.4	6.4	6.4	25
Waverley	WVY0111	2.7	2.7	2.7	2.7	2.7	2.7	2.7	2.7	2.7	2.7	2.7	25
HAWKE'S BAY													
Fernhill	FHL0331	9.6	9.4	9.4	9.4	9.5	9.5	9.5	9.5	9.5	9.5	9.5	25
Gisborne	GIS0501	4.0	3.9	4.0	4.0	4.0	4.0	4.0	4.0	4.0	4.0	4.0	16
Redclyffe	RDF0331	10.5	10.2	10.3	10.3	10.3	10.3	10.3	10.3	10.3	10.3	10.3	25
Tuai	TUI0111	1.1	1.1	1.1	1.1	1.1	1.1	1.1	1.1	1.1	1.1	1.1	25
Tuai	TUI1101	6.4	6.2	6.2	6.3	6.3	6.3	6.3	6.3	6.3	6.3	6.3	31.5
Wairoa	WRA0111	11.4	11.3	11.3	11.3	11.3	11.3	11.3	11.3	11.3	11.3	11.3	25
Whakatu	WTU0331	13.2	12.5	12.6	12.7	12.8	12.8	12.8	12.8	12.8	12.8	12.8	25
Whirinaki	WHI0111	24.6	23.6	23.8	23.8	23.9	23.9	23.9	23.9	23.9	23.9	23.9	50[20]
Whirinaki	WHI0112	24.5	23.5	23.6	23.7	23.8	23.8	23.8	23.8	23.8	23.8	23.8	50[21]

[16] Significant embedded generation
[17] Higher than standard fault rating due to significant embedded generation
[18] Higher than standard fault rating
[19] Higher than standard fault rating
[20] Higher than standard fault rating due to significant embedded generation
[21] Higher than standard fault rating due to significant embedded generation

Grid exit point	Point of service	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	Nominated design capability[8]
Whirinaki	WHI0113	25.0	24.0	24.1	24.2	24.2	24.2	24.2	24.2	24.2	24.2	24.2	50[22]
Whirinaki	WHI2201	8.5	6.4	6.6	6.8	6.8	6.9	6.9	6.9	6.9	6.9	6.9	31.5
WELLINGTON													
Central Park	CPK0111	7.2	7.2	7.2	7.2	7.2	7.2	7.2	7.2	7.2	7.2	7.2	25
Central Park	CPK0331	20.3	19.7	19.7	19.7	19.7	19.7	19.7	19.7	19.7	19.7	19.7	31.5
Gracefield	GFD0331	13.7	13.4	13.4	13.4	13.4	13.4	13.4	13.4	13.4	13.4	13.4	25
Greytown	GYT0331	4.5	4.5	4.5	4.5	4.5	4.5	4.5	4.5	4.5	4.5	4.5	25
Haywards	HAY0111	12.7	12.6	12.6	12.6	12.6	12.6	12.6	12.6	12.6	12.6	12.6	25
Haywards	HAY0331	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	25
Kaiwharawhara	KWA0111	22.3	22.0	22.0	22.0	22.0	22.0	22.0	22.0	22.0	22.0	22.0	25
Masterton	MST0331	7.4	7.3	7.3	7.3	7.3	7.3	7.3	7.3	7.3	7.3	7.3	25
Melling	MLG0111	13.7	13.6	13.6	13.6	13.6	13.6	13.6	13.6	13.6	13.6	13.6	25
Melling	MLG0331	9.5	9.4	9.4	9.4	9.4	9.4	9.4	9.4	9.4	9.4	9.4	25
Paraparaumu	PRM0331	8.1	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	25
Pauatahanui	PNI0331	6.3	6.3	6.3	6.3	6.3	6.3	6.3	6.3	6.3	6.3	6.3	25
Takapu Road	TKR0331	15.0	14.6	14.6	14.6	14.6	14.6	14.6	14.6	14.6	14.6	14.6	25
Upper Hutt	UHT0331	9.7	9.6	9.6	9.6	9.6	9.6	9.6	9.6	9.6	9.6	9.6	25
West Wind	WWD1101	11.2	10.6	10.6	10.6	10.6	10.6	10.6	10.6	10.6	10.6	10.6	31.5
West Wind	WWD1102	11.2	10.6	10.6	10.6	10.6	10.6	10.6	10.6	10.6	10.6	10.6	31.5
Wilton	WIL0331	13.9	13.5	13.5	13.5	13.5	13.5	13.5	13.5	13.5	13.5	13.5	25
NELSON-MARLBOROUGH													
Argyle	ARG1101	2.8	2.9	2.9	2.9	2.9	2.9	2.9	2.9	2.9	2.9	2.9	31.5
Blenheim	BLN0331	7.9	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	25
Cobb	COB0661	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	16
Motueka	MOT0111	7.9	7.9	7.9	7.9	7.9	7.9	7.9	7.9	7.9	7.9	7.9	25
Motupipi	MPI0661	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7	16
Stoke	STK0331	11.5	11.6	11.6	11.6	11.6	11.6	11.6	11.6	11.6	11.6	11.6	25
WEST COAST													
Arthurs Pass	APS0111	2.3	2.3	2.3	2.3	2.3	2.3	2.3	2.3	2.3	2.3	2.3	25
Atarau	ATU1101	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	31.5
Castle Hill	CLH0111	2.8	2.8	2.8	2.8	2.8	2.8	2.8	2.8	2.8	2.8	2.8	25
Dobson	DOB0331	2.9	3.2	3.2	3.2	3.2	3.2	3.2	3.2	3.2	3.2	3.2	25
Greymouth	GYM0661	2.3	2.7	2.7	2.7	2.7	2.7	2.7	2.7	2.7	2.7	2.7	16
Hokitika	HKK0661	2.1	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.2	16
Kikiwa	KIK0111	2.9	2.9	2.9	2.9	2.9	2.9	2.9	2.9	2.9	2.9	2.9	25
Kumara	KUM0661	2.5	2.7	2.7	2.7	2.7	2.7	2.7	2.7	2.7	2.7	2.7	16
Murchison	MCH0111	2.7	2.7	2.7	2.7	2.7	2.7	2.7	2.7	2.7	2.7	2.7	25
Orowaiti	ORO1101	1.5	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	31.5

[22] Higher than standard fault rating due to significant embedded generation

Grid exit point	Point of service	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	Nominated design capability[8]
Orowaiti	ORO1102	1.5	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	31.5
Otira	OTI0111	2.1	2.1	2.1	2.1	2.1	2.1	2.1	2.1	2.1	2.1	2.1	25
Reefton	RFN1101	1.7	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	31.5
Reefton	RFN1102	1.9	1.9	1.9	1.9	1.9	1.9	1.9	1.9	1.9	1.9	1.9	31.5
Westport	WPT0111	8.9	9.0	9.0	9.0	9.0	9.0	9.0	9.0	9.0	9.0	9.0	25
CANTERBURY													
Addington	ADD0111	16.3	16.3	16.3	16.3	16.3	16.3	16.3	16.3	16.3	16.3	16.3	25
Addington	ADD0112	15.8	15.8	15.8	15.8	15.8	15.8	15.8	15.8	15.8	15.8	15.8	25
Addington	ADD0661	12.5	12.5	12.5	12.5	12.5	12.5	12.5	12.5	12.5	12.5	12.5	25
Ashburton	ASB0331	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	25
Ashburton	ASB0661	8.8	8.8	8.8	8.8	8.9	8.9	8.9	8.9	8.9	8.9	8.9	16
Ashley	ASY0111	8.7	8.7	8.7	8.7	8.7	8.7	8.7	8.7	8.7	8.7	8.7	25
Bromley	BRY0111	15.9	15.9	15.9	15.9	16.0	16.0	16.0	16.0	16.0	16.0	16.0	25
Bromley	BRY0661	11.2	11.2	11.2	11.2	11.2	11.2	11.2	11.2	11.2	11.2	11.2	16
Coleridge	COL0111	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	25
Coleridge	COL0661	4.3	4.3	4.3	4.3	4.3	4.3	4.3	4.3	4.3	4.3	4.3	16
Culverden	CUL0331	7.2	7.2	7.2	7.2	7.2	7.2	7.2	7.2	7.2	7.2	7.2	25
Hororata	HOR0331	2.8	2.8	2.8	2.8	2.8	2.8	2.8	2.8	2.8	2.8	2.8	25
Hororata	HOR0661	4.6	4.6	4.6	4.6	4.6	4.6	4.6	4.6	4.6	4.6	4.6	16
Islington	ISL0331	15.1	15.1	15.1	15.1	15.1	15.1	15.1	15.1	15.1	15.1	15.1	25
Islington	ISL0661	17.9	17.9	17.9	17.9	18.0	18.0	18.0	18.0	18.0	18.0	18.0	25[23]
Kaiapoi	KAI0111	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	25
Kaikoura	KKA0331	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	25
Middleton	MLN0661	12.9	12.9	12.9	12.9	12.9	12.9	12.9	12.9	12.9	12.9	12.9	16
Middleton	MLN0662	12.9	12.9	12.9	12.9	12.9	12.9	12.9	12.9	12.9	12.9	12.9	16
Papanui	PAP0111	10.8	10.8	10.8	10.8	10.8	10.8	10.8	10.8	10.8	10.8	10.8	25
Papanui	PAP0661	13.7	13.8	13.8	13.8	13.8	13.8	13.8	13.8	13.8	13.8	13.8	16
Southbrook	SBK0331	6.1	6.1	6.1	6.1	6.2	6.2	6.2	6.2	6.2	6.2	6.2	25
Springston	SPN0331	7.1	7.1	7.1	7.1	7.1	7.1	7.1	7.1	7.1	7.1	7.1	25
Springston	SPN0661	8.3	8.3	8.3	8.3	8.4	8.4	8.4	8.4	8.4	8.4	8.4	16
Waipara	WPR0331	1.8	1.8	1.8	1.8	1.8	1.8	1.8	1.8	1.8	1.8	1.8	25
Waipara	WPR0661	8.6	8.6	8.6	8.6	8.6	8.6	8.6	8.6	8.6	8.6	8.6	25
SOUTH CANTERBURY													
Albury	ABY0111	4.4	4.4	4.4	4.4	4.4	4.4	4.4	4.4	4.4	4.4	4.4	25
Aviemore	AVI2201	15.7	15.9	15.9	16.9	17.1	17.1	17.1	17.1	17.1	17.1	17.1	31.5
Bells Pond	BPD1101	2.8	2.8	2.8	2.8	2.8	2.8	2.8	2.8	2.8	2.8	2.8	25
Benmore	BEN2201	19.6	19.7	19.7	19.8	20.1	20.1	20.1	20.1	20.1	20.1	20.1	31.5
Blackpoint	BPT1101	3.5	3.5	3.5	3.5	3.5	3.5	3.5	3.5	3.5	3.5	3.5	31.5
Oamaru	OAM0331	5.4	5.4	5.4	5.4	5.4	5.4	5.4	5.4	5.4	5.4	5.4	25

[23] Higher than normal fault rating

Grid exit point	Point of service	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	Nominated design capability[8]
Ohau A	OHA2201	18.0	18.0	18.0	18.1	18.1	18.1	18.1	18.1	18.1	18.1	18.1	31.5
Ohau B	OHB2201	19.5	19.5	19.6	19.6	19.7	19.7	19.7	19.7	19.7	19.7	19.7	31.5
Ohau C	OHC2201	17.3	17.4	17.4	17.4	17.5	17.5	17.5	17.5	17.5	17.5	17.5	31.5
Studholme	STU0111	7.4	7.4	7.4	7.4	7.4	7.4	7.4	7.4	7.4	7.4	7.4	25
Tekapo A	TKA0111	14.5	14.5	14.5	14.5	14.5	14.5	14.5	14.5	14.5	14.5	14.5	25
Tekapo A	TKA0331	1.3	1.3	1.3	1.3	1.3	1.3	1.3	1.3	1.3	1.3	1.3	25
Tekapo B	TKB2201	12.1	12.1	12.1	12.1	12.1	12.1	12.1	12.1	12.1	12.1	12.1	31.5
Temuka	TMK0331	6.5	6.5	6.5	6.5	6.5	6.5	6.5	6.5	6.5	6.5	6.5	25
Timaru	TIM0111	20.4	20.4	20.4	20.4	20.4	20.4	20.4	20.4	20.4	20.4	20.4	25
Twizel	TWZ0331	9.0	9.0	9.0	9.0	9.0	9.0	9.0	9.0	9.0	9.0	9.0	25
Waitaki	WTK0111	34.7	34.9	34.9	34.9	35.0	35.0	35.0	35.0	35.0	35.0	35.0	40
Waitaki	WTK0331	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	25
OTAGO-SOUTHLAND													
Balclutha	BAL0331	3.8	3.8	3.8	3.6	3.6	3.6	3.6	3.6	3.6	3.6	3.6	25
Berwick	BWK1101	4.9	4.9	4.9	4.7	4.8	4.8	4.8	4.8	4.8	4.8	4.8	31.5
Brydone	BDE0111	12.7	12.7	12.7	14.0	14.1	14.1	14.1	14.1	14.1	14.1	14.1	25
Clyde	CYD0331	11.7	11.7	11.7	11.7	11.8	11.8	11.8	11.8	11.8	11.8	11.8	25
Clyde	CYD2201	15.2	15.2	15.9	15.9	16.1	16.1	16.1	16.1	16.1	16.1	16.1	31.5
Cromwell	CML0331	10.8	10.8	10.8	10.8	10.8	10.8	10.8	10.8	10.8	10.8	10.8	25
Edendale	EDN0331	6.1	6.1	6.1	6.7	6.7	6.7	6.7	6.7	6.7	6.7	6.7	25
Frankton	FKN0331	7.7	7.7	7.8	7.8	7.8	7.8	7.8	7.8	7.8	7.8	7.8	25
Gore	GOR0331	6.2	6.2	6.2	10.2	10.4	10.4	10.4	10.4	10.4	10.4	10.4	25
Halfway Bush	HWB0331	14.5	14.5	14.5	14.5	14.7	14.7	14.7	14.7	14.7	14.7	14.7	31.5[24]
Halfway Bush	HWB0332	16.0	16.0	16.1	16.0	16.2	16.2	16.2	16.2	16.2	16.2	16.2	31.5[25]
Invercargill	INV0331	17.5	17.5	17.6	17.4	17.6	17.6	17.6	17.6	17.6	17.6	17.6	25
Manapouri	MAN2201	11.7	11.7	11.7	11.6	11.8	11.8	11.8	11.8	11.8	11.8	11.8	31.5
Naseby	NSY0331	8.6	8.7	8.7	8.7	8.8	8.8	8.8	8.8	8.8	8.8	8.8	25
North Makarewa	NMA0331	12.0	12.0	12.0	12.0	12.0	12.0	12.0	12.0	12.0	12.0	12.0	25
Palmerston	PAL0331	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7	25
Roxburgh	ROX1101	9.0	9.0	10.5	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2	31.5
Roxburgh	ROX2201	15.3	15.3	16.1	16.1	16.5	16.5	16.5	16.5	16.5	16.5	16.5	31.5
South Dunedin	SDN0331	17.3	17.3	17.4	17.4	17.7	17.7	17.7	17.7	17.7	17.7	17.7	25
Tiwai Point	TWI2201	8.8	8.8	8.9	8.7	9.0	9.0	9.0	9.0	9.0	9.0	9.0	31.5

Notes

1. At this point of service, we have included some probable generation developments that are identified in the report referenced 'Whakamaru/Wairakei Ring Short-Circuit Assessment (Grid Beyond NIGUP and WRK-PPI-WKM Duplexing Project)'. We expect higher fault levels at this and nearby points of service.

[24] Higher than normal rated fault current due to embedded generation
[25] Higher than normal rated fault current due to embedded generation

10. CONCLUSION

The criteria developed by Transpower and set out in this document have drawn on international experience and generic modelling set in the context of the New Zealand power system. They have been developed in conjunction with key New Zealand stakeholders. Transpower believes they provide a sound framework for developing the New Zealand power system

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