Security Policy Review: Credible Event Management

Summary of Findings

December 2009

SYSTEM OPERATOR

Keeping the energy flowing

TRANSPOWER

Transpower New Zealand Ltd The National Grid

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Version	Date	Change
1	October 2009	Draft for Consultation
2	December 2009	Final Version

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1 Executive Summary

During 2009, the System Operator has undertaken a review of its credible event policy as described in its Policy Statement. This review focussed on the identification, classification and management of credible events.

The assessment of historical data and the international planning and operational standards undertaken as part of this review identified a set of credible events, and determined that additional analysis was required to assess optimal means of managing the loss of a busbar section or interconnecting transformer. The consequence and relative costs associated with the management of these events, as directed by the classifications of Contingent Event, Extended Contingent Event and Stability Event, were assessed to determine the optimal method of event management available to the System Operator.

The assessment used steady state studies to analyse the potential consequences and identify measures that could minimise event consequences and associated costs. The loss of a busbar section or transformer may result in dynamic/stability issues. The Security Policy makes provision for the management of stability issues following a Contingent, Extended Contingent, or Stability Event by allowing unplanned load shedding.

The studies found the loss of an interconnecting transformer or busbar section, with the subsequent overload and tripping of additional assets, will result in unplanned load shedding in a significant number of cases. The introduction of planned load shedding, where reasonable and possible, would allow post event parallel transformer overloads to be managed and thus avoid unplanned load shedding associated with subsequent asset trippings. Re-classification of the event as an Extended Contingent Event, along with other key wording changes in the policy, would oblige the System Operator to plan for these events and employ planned post event load shedding, as appropriate, to manage the risk of unplanned load shedding. Analysis shows that there are cost benefits associated with managing the loss of a 220kV, 110kV and 66kV busbar sections (connected to the core grid), and 220kV interconnecting transformers, as Extended Contingent Events.

Based on the results of this credible event review, the System Operator recommends:

- there are no credible events specifically classified as Stability Events, although the concept and definition of a stability event should remain;
- the principles applied for Extended Contingent Events are amended to specify planned post event load shedding as a key mitigation measure;
- the loss of a 220kV interconnecting transformer is classified as an Extended Contingent Event;
- the loss of a 220kV or 110kV or 66kV (connected to a core grid asset) busbar section is classified as an Extended Contingent Event;
- the loss of Reactive Support/SVC fault is classified as a Contingent Event;
- the loss of multiple power system components in close succession is classified as an Other Event;

- the loss of two transmission circuits on the same tower is classified as an Other Event. When a change to environmental or operating conditions indicates there is a high likelihood of occurrence, the event (the loss of a two transmission circuits on the same tower) is re-classified as a Contingent Event in line with international practice;

- the loss of a 110kV interconnecting transformer is considered an Other Event;

- the loss of a 66kV busbar section not connected to core grid assets is considered an Other Event.

This report concludes that the portfolio of management measures available to the System Operator is in line with international practice. With the removal of the Stability Event category, all credible events that are not classified as Contingent Events or Extended Contingent Events should be classified as Other Events. The management measures associated with the Other Event classification should be modified to reflect the change in classification system.

For single feeder circuits, line spurs and/or single transformers, there is an inherent lack of security. This review was unable to recommend changes that would improve the security of supply. The System Operator assumes that distribution companies and direct connect customers are aware of potential security risks and will discuss investment options to improve security with the Grid Owner.

Ongoing improvements to the power system, such as busbar segregation and protection upgrades, will limit the impact of an event by either limiting the extent of the equipment affected or reducing the duration of an event. Major investment projects may nullify the impact of the event by introducing additional asset redundancy. Therefore, the management of credible events should be reviewed on a regular basis to ensure that events continue to be optimally managed. The next credible event management review is scheduled for delivery on or before December 2014.

This review proposes updates to the event management clause(s) within the Credible Event Management Policy (which is set out at clause 12 of the current Policy Statement). Following industry consultation, the updates, with any additional changes, will be incorporated in the draft annual Policy Statement review and submitted to the Electricity Commission.

2 Introduction

2.1 Background

The Policy Statement[1] sets out the policies and means that are considered appropriate for the System Operator to observe in attaining the Principal Performance Obligations[2] (PPOs), subject to the obligation of the System Operator to act as a reasonable and prudent system operator.

The second section of the Security Policy, entitled Credible Event Management[3], identifies events that could occur within the power system that, if not appropriately managed, could subsequently result in wide spread, or cascade, failure within the power system.

The last substantive review of the events included in Credible Event Management occurred in 2003, just prior to inclusion of the Policy Statement in the Electricity Governance Rules (EGRs). In 2009, the System Operator undertook to review credible events, their categorisation and the operational measures to manage credible events to ensure the System Operator continues to comply with the Principle Performance Obligations. The System Operator has completed a review of the credible events that could occur and how these events are categorised. A description of the policy, the review objective, the methodology used to undertake the review and any assumptions made are set out in the document "Security Policy Review: Credible Event Management - Scope and Methodology".

2.2 Document Overview

This report sets out a summary of the credible event identification task, including the outcomes of the literature reviews and historical analysis of previous events.

From the above investigation, two types of event were identified for further analysis in terms of their categorisation and the management plans for their occurrence. This paper provides a summary of that analysis and the resulting recommendations for changes to the Policy Statement.

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[1] Schedule C4 of Part C of the Electricity Governance Rules (EGRs)
[2] Section II of Part C of the EGRs
[3] Formally titled Risk Management Policies

3 Credible Event Identification

3.1 Literature Review: New Zealand Planning and Operational Standards

Reviewing the New Zealand planning criteria, as part of the credible event review, ensures that credible events considered by the Grid Owner for planning purposes are also considered by the System Operator. To this end, the Security Policy in the Policy Statement has a definitive list of “credible events” that includes all “single credible contingency events” defined within Part F Grid Reliability Standards (GRS).

Whilst a similar list of events exists in both Part C and Part F, there are differences in the manner in which the Grid Owner and the System Operator treats these defined events. For the most part, those differences are attributable to the different post-event objectives each party has; that is, the steps each party takes to mitigate those events will be directed by the outcomes they are required to achieve. For example, one of the objectives of the GRS is to maintain supply to GXPs following a single credible contingency event on the core grid, whereas the System Operator has an objective of taking measures to avoid cascade failure and maintain frequency and quality standards.

However, there were a couple of areas that highlighted the need for further investigation.

(i) Part F (GRS) includes the loss of a transformer or busbar section in the category of events that it plans to avoid through network development. The System Operator categorises a loss of these same assets as Stability Events, which allow unplanned load shedding as a post event management measure. Given the potential consequences of some of these events and some identifiable pre-event mitigation measures available, it may be possible and appropriate for the System Operator to reconsider its own classification of these events.

(ii) Part F clearly delineates between what assets belong to the core grid and which are non-core grid assets. This delineation means the GRS only requires supply to be maintained to GXPs following the loss of a core grid asset[4]. This enables the Grid Owner to apply its assessment and mitigation measures to individual assets. On the other hand, the System Operator applies a techno-economic approach to the management of the loss of a particular class of assets, irrespective of their location on the grid or any individual risk factors. Taking into account the definition of core grid in its assessment and categorisation of the above events would allow the System Operator to focus on events that could affect its PPOs.

To summarise, the review of planning and operational standards found that the credible event management review:

- should take into account the definition of the core grid and the level of operational security to which this translates.

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[4] For the non-core grid, there is no minimum N-1 standard

- should consider the appropriateness of classification of transformer and busbar section events as Stability Events.

The full literature review of New Zealand Planning and Operational standards is available on request.

3.2 Literature Review: International Planning and Operational Standards

International planning and operational standards were reviewed to ensure that the System Operator has considered the criteria adopted by other countries in defining and categorising credible events.

The International literature review found that it is not uncommon for transmission owners and operators to have different planning and operational standards as we do in New Zealand. Although operating criteria is inherently aligned with planning criteria, it is not necessary or appropriate for them to be the same. The adoption of a planning criteria and an operational standard serves to clearly illustrate the differences between the two criteria.

Most transmission system owners adopt an N-1 criterion as a benchmark for network planning purposes. Development plans are then subjected to a regulatory or economic test to ensure there is economic justification for the investment.

All the credible events considered by the System Operator are also considered by international transmission system operators, with many planning for the management of all single credible events. Events are classified according to risk (based on event consequences and likelihood of occurrence). Allowances are made for the re-classification of events following the identification of abnormal conditions that give rise to an increased likelihood of the event occurring.

No international operating standards reviewed have an event that is similar to the System Operator “Stability Event”. All international operating standards reviewed consider and manage the loss of a transformer or bus section as a single contingent event.

The review of international planning and operational standards found that:

- The New Zealand approach of having separate Planning and Operational standards is in line with international practice.

- The existing list of credible events is in accordance with requirements of international system operators.

- The majority of international system operators plan for the loss of an interconnecting transformer or busbar section rather than relying on unplanned load shedding post event.

- The portfolio of management measures available to the System Operator is in line with international practice.

The full literature review of International Planning and Operational standards is available on request.

3.3 Review of Historical Event Data

A review of asset failure information from 2004 to 2008 was undertaken as a part of the assessment to determine the likelihood and duration of credible events. The data was compared with data for 1990 – 1999 to determine if there have been significant changes that could conclude a potential increase (or decrease) in the likelihood of an event occurring.

The following table ranks all Credible Events with respect to an Event Risk Factor. This factor considers the number of power system components within the fault set. All existing credible event classifications have been indicated as below:

▒	Contingent event	🟦	Extended contingent event	🟩	Stability event	⬜	Other event

Table 3-1: Risk Factor Ranking of Credible Events considering number of power system component in set

Credible Event **Loss of …**	No in Set	*No. of Events per year*	*Event Risk Factor*
a HVDC Half Pole	2	*20*	*10*
a HVDC Pole	2	*7*	*3.5*
a single generating unit *	<234	*132*	*0.56*
reactive plant	<134	*49*	*0.37*
HVDC bipole	1	*<0.5*	*<0.5*
a single 220kV transmission circuit (no A/R)	142	*25*	*0.18*
a 220kV interconnecting transformer	105	*10*	*0.095*
multiple generating units *	<117	*11*	*0.094*
110kV interconnecting transformer	10	<0.5	0.05
a 66kV, 50kV or 33kV busbar section	151	*5*	*0.033*
a 220kV or 110kV busbar section	282	*6*	*0.021*
a double 220kV transmission circuit (no A/R)	<71	*1*	*0.014*
multiple 220 or 110kV interconnecting transformers	<53	*<0.5*	*0.009*
multiple 220kV transmission circuits	<71	*<0.5*	*0.007*
Connection or disconnection of large load(s)	*Not studied*		

Notes
* The System Operator can not guarantee that all trippings associated with smaller units are recorded. Therefore it should not be assumed that all generator trippings are represented in historical data set.
A/R = Auto-reclose.

Following analysis of historical data the System Operator proposes:

- No change to the classification and management measures associated with the loss of :
    - single transmission circuit
    - single generator unit
    - HVDC pole
    - HVDC bipole
    - multiple transmission circuits
    - multiple generator units
- The following additional credible events should be classified as a contingent event. The loss of a:
    - reactive device (condenser, capacitor, reactor, SVC, RPC)
    - large load / load block
- The loss of multiple transmission circuits/power system components should be classified as an Other Event.
- A review should be undertaken to re-assess the existing classification and management of the loss of a single:
    - 220kV or 110kV interconnecting transformer;
    - 220kV or 110kV busbar section;
    - 66kV busbar section.
- Consideration should be given to the ability to manage the loss of a transformer or busbar section during a planned outage.

A detailed analysis of historical data is provided in "Appendix 1: Identification and historical analysis of credible events".

3.4 Findings from Credible Event Identification

The review of historical event data and international standards indicated that the management of the following N-1 events should be further assessed:

- Loss of a 220kV or 110kV interconnecting transformer;
- Loss of a 220kV or 110kV busbar section;
- Loss of a 66kV busbar section.

In addition, the existing management measures during a commissioning and maintenance outage of one of three transformers in parallel have been reviewed.

All of these events are currently considered as Stability Events within the existing Security Policy. Therefore, the System Operator is not obligated to plan for these events and unplanned load shedding may take place following the event. This approach does not follow international practice where the loss of an interconnecting transformer or busbar requires operational planning to be undertaken to identify potential issues, ascertain the amount of load that may be affected following the event and implement measures to manage the consequences of the event.

The frequency of occurrence, coupled with the potential impact of the event, indicates that these events are likely to pose significant risks to New Zealand’s security of supply. It is reasonable to expect that the System Operator, in acting as a reasonable and prudent system operator, should quantify the risk associated with these events and plan to manage that risk.

This assessment considers the consequences of applying the management measures associated with Stability Event classification and investigates whether re-classification and the application of alternative management measures would result in improved security of supply and cost savings.

4 Further studies – Study Methodology

4.1 Study List

The consequence of the loss of an interconnecting transformer or the loss of a 220kV, 110kV or 66kV busbar section is considered in this section.

The System Operator has determined the following with respect to 66kV busbars:

- The loss of a non-grid connected 66kV busbar section is likely to result in a loss of regional load and may, in some cases, have an impact on the PPOs; these events are therefore considered credible. However as there are no practicable pre-event actions the System Operator can take to manage the loss of the section these are not studied further and will be classified as 'other events' for the purposes of the Security Policy;

- The loss of 66kV busbar sections connected to the core grid has the potential to result in a large loss of demand for a considerable period of time. The size of the impact, the potential impact on the PPOs and the alternative management means available has resulted in further studies to determine whether re-classification of these events is appropriate and what practicable pre-event actions can be taken.

A number of 220kV interconnecting transformers and associated circuits connect to the network via a "T connection" or "point connection". Such connection is made without the use of a solid busbar. Therefore, the loss of a 220kV "point connection" and associated circuits is not considered a busbar event.

The System Operator has determined the following with respect to interconnecting transformers.

- The loss of a 110kV interconnecting transformer is likely to result in a loss of regional load and may, in some cases, have an impact on the PPOs; these events are therefore considered credible. However, there are no practicable pre-event actions the System Operator can take to manage the loss of the section; therefore these are not studied further and will be classified as 'other events' for the purposes of the Security Policy.

- The loss of a 220kV interconnecting transformer has the potential to result in a large loss of demand for a considerable period of time. The size of the impact, the potential impact on the PPOs and the alternative management means available has resulted in further studies to determine whether re-classification of these events is appropriate and what practicable pre-event actions can be taken.

- The pre-event management of the loss of an interconnecting transformer is only achievable during transformer outage periods[5] at sites where there are at least three transformers in connected in parallel. Where there are only two transformers in parallel, the loss of a transformer while the other is out for

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[5] Studies assume that planned outages are undertaken during the summer months

maintenance is likely to result in unavoidable loss of supply to a region. The studies performed are summarised in Table 4-1.

Table 4-1: Summary of Studies Performed

Busbar Studies	***Transformer Studies***	
N-1	N-1[6]	N-1-1[7]
220kV busbars 110kV busbars 66kV busbars connected to core grid	220/110kV interconnecting Transformers 220/66kV interconnecting Transformers	220/110kV Bunnythorpe Transformers 220/110kV Haywards Transformers 220/110kV Otahuhu Transformers 220/66kV Islington Transformers

4.2 Study Assumptions

To ensure system models adequately represent the power system, Grid Owner network data and Asset Capability Statement (ACS) data is incorporated in the model.

Power system studies are performed on the basis of the following assumptions:

- asset capability statements fairly reflect asset capability and performance;
- assets remain connected and contribute to maintaining or restoring power quality while power quality remains within Asset Owner Performance Obligations (AOPO) limits specified in the EGRs or in any exemption or dispensation issued;
- the Automatic Under-Frequency Load Shedding (AUFLS) scheme operates as anticipated, i.e. 2x16% demand blocks exist at all times and load is shed within the prescribed timeframe;
- the power system remains stable after the operation of the AUFLS scheme, including the possibility that more than 32% of demand is shed;
- there is co-ordination between asset owner protection schemes;
- offered transmission, generation, ancillary services and special protection schemes are physically available;
- asset owners and ancillary service providers comply with dispatch instructions;
- short term 15 minute off-load thermal ratings are available for transmission circuits;
- 24 hour post-contingency ratings are available for transmission circuits;

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[6] The loss of a single transmission element

[7] Sites where there are three interconnecting transformers.

- 24 hour post contingency ratings and continuous ratings are available for transformers;
- automatic post-contingency control measures (SPS schemes) will operate fast enough to avoid voltage collapse;
- protection devices/protection modules will be in service and will operate to clear circuits, transformers and busbar section faults as intended ;
- interruption of the HVDC link is available to maintain security.

4.3 Network Model Assumptions

The study is performed using the following parameters:

- peak winter load values are used to simulate the loss of an interconnecting transformer or busbar;
- peak summer load values are used to simulate the loss of a transformer during a planned outage of a parallel-connected transformer (where there are three interconnecting transformers);
- The output of core grid-connected generation is determined by system load. Unless stated otherwise, all core grid connected generation is assumed to be in service;
- Local generation in the region is minimised to increase transmission circuit and interconnecting transformer loadings. The output of local generation assumed for contingency studies are given in Appendix 2. Where the direction of the HVDC transfer influences the loadings in the region, both North and South transfer are investigated.

Assumptions related to the status of network assets, Special Protection Schemes and the upgrades that are represented in the network model are also given in Appendix 2.

4.4 Power System Study Methodology

Power system studies are performed by firstly assessing the consequence and outcome of the event after applying management measures for Stability Events (as set out in the Policy Statement). To ascertain if the existing measures are optimal, the consequence of the event is then re-assessed after applying the management measures associated with a Contingent Event and an Extended Contingent Event.

A costing methodology has also been developed to compare relative costs of event outcomes and the application of existing and alternative measures. This costing methodology (described in section 4.5) is then applied to compare the economic effectiveness of any re-classification and the revised event management strategy. The flow diagram in Figure 4-1 illustrates the methodology behind the power system studies.

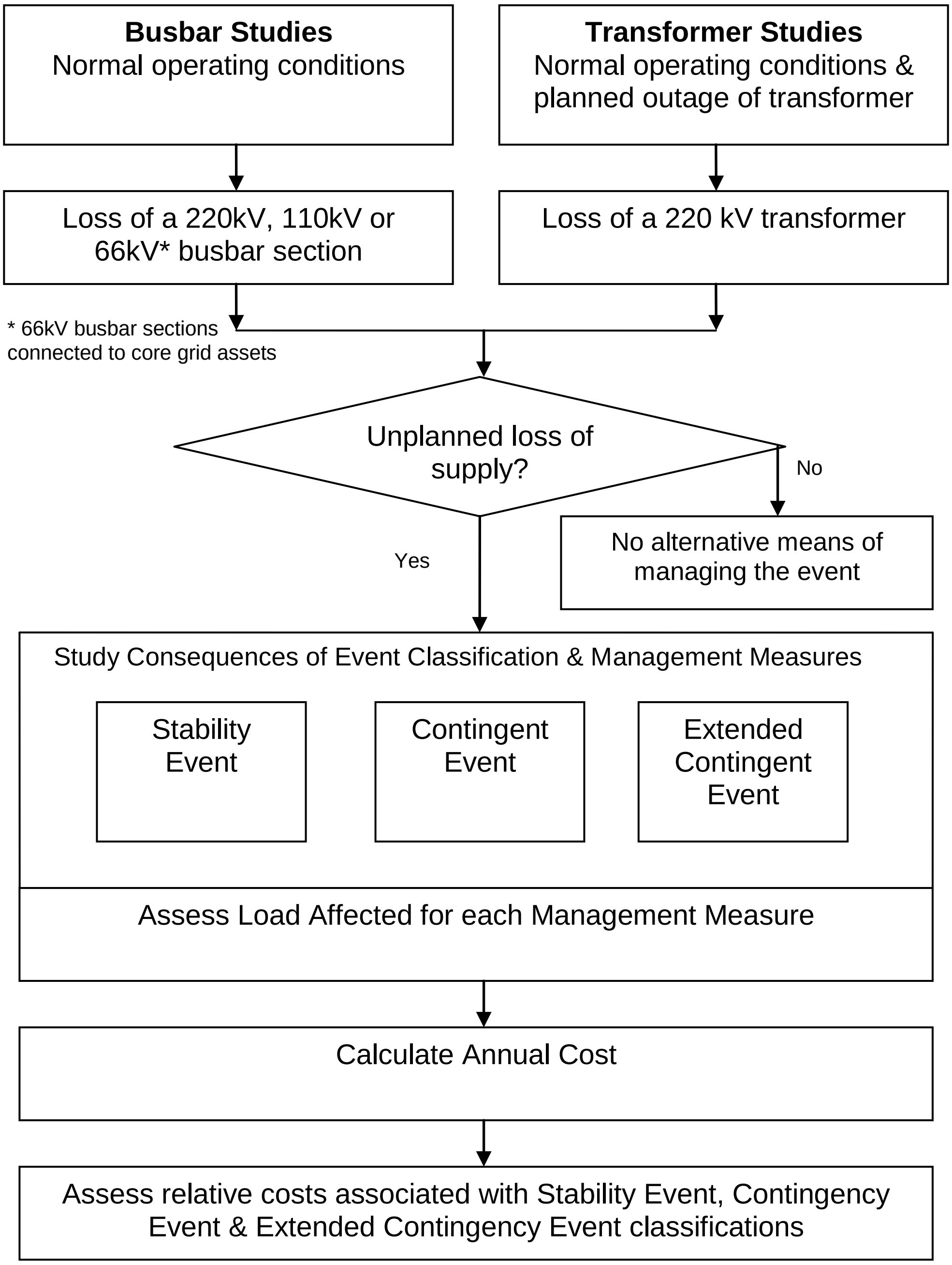

Figure 4-1 Study flow diagram

For this review, the System Operator applied the actual post event measures employed by system operations to the study case[8]. Steady state studies are performed to ascertain whether thermal and/or voltage violations occur after the event that initiate the action of enabled Special Protection Schemes and the removal from service (subsequent tripping) of elements loaded above their 24 hour post-contingency rating.

Such actions allow the amount of post-event load shedding (unavoidable, planned and unplanned) to be calculated, noting that:

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[8] Information regarding the appropriate measures is obtained from System Operator contingency plans and relevant personnel

- unavoidable load shedding is associated with the loss of the element;
- planned load shedding is associated with Special Protection Schemes;
- unplanned load shedding is associated with subsequent tripping(s) and voltage violations.

It is assumed that within two hours of any event, manual measures are employed, (where available) to restore supply to a proportion of the affected load, while maintaining the forced outage of the power system element associated with the event.

Post event feeder connections have not been changed apart from those directly affected by the event or those that will automatically occur as a result of an enabled Special Protection Scheme (i.e. a temporary split or busbar splitting scheme).

The power system studies performed also do not consider the closure of a permanent split as a post-event measure to manage the loss of a transformer or busbar. In the majority of cases, the decision to close a permanent split is taken following on-site inspection of the affected network asset. An operator is then required to travel to the point of closure to initiate the change in circuit breaker and disconnector status. Once the decision is taken to reverse the status of the split, an operator is required to return to site to re-open connections. Due to the man-hours associated with initiating the closure and re-opening of a permanent network split and the additional studies that are needed to confirm that further issues do not arise with the adoption of abnormal network operating conditions, the closure of a permanent split is rarely undertaken.

The operation of busbar section circuit breakers is assumed where bus zone protection is operational. In these cases, circuit breakers isolate the affected busbar section rather than the whole busbar. A single busbar, sectionalised with disconnector, switches the entire busbar and all connected feeders are affected for the duration of the event.

Some double busbar schemes offer the capability to change circuit connections from one busbar to another. Where affected feeders can be re-connected to a healthy busbar, with the operation of circuit breakers, this action is applied two hours after the start of the event. This two hour time period reflects the delay associated with an operator inspecting the busbars before initiating the circuit switching. However, at the majority of double busbar sites, the connection of affected circuits to an alternative busbar requires the closure of disconnectors, rather than circuit breakers. The closure of disconnectors necessitates the isolation of the healthy busbar prior to circuit switching. The busbar would need to be isolated to make the new connections and again, to restore original connections when the event was resolved, resulting in additional loss of load. Therefore, in the majority of cases, the System Operator has not considered the switching of load to the alternative busbar as a practicable post event action.

Transformers, overhead lines and cables have time dependent post-contingency ratings. For transmission circuits, the System Operator may use asset owners’ 15 minute short term ratings post-event. For transformers, the System Operator is required to manage transformer loading within advised 24 hour post-contingency ratings (‘short term rating’).

Generation output in a region is assumed to be minimal, so that security risks are identified whilst providing a level of generation that meets demand and reflects a realistic pre-event operating condition. The assumption that generators in a region operate at a high dispatch level may lead to over optimistic study outcomes.

The ability to dispatch generation post-event is also not assumed in the study. The dispatch of generation and/or "black start" generation (where available) to supply load post-event is not considered to be a planned post-event management measure. Assuming generators are available to provide power post-event may falsely negate potential security risks and underestimate the amount of load that could be affected. Generation may be unavailable for dispatch due to planned maintenance. In addition to influencing the potential load affected following the event, the cost of post-event generation dispatch would be a significant input into the costing methodology. The cost of dispatch is variable and dependent on many factors. The amount of load affected and the cost of generation dispatch may potentially compromise the methodological approach of comparing the relative costs of event management.

Investment in additional circuit breakers, transformers, or busbar sections at substation sites is likely to improve security and minimise unplanned loss of supply. Investment in system upgrades to maintain post-event security is not an option available to the System Operator. The identification and cost assessment of investment options to improve security are outside the scope of this review.

The management measures associated with each type of event classification are described in the following sub-sections:

4.4.1 Consideration as a Stability Event

The Security Policy requires that following a Stability Event, system stability should be maintained. To ensure system stability, the System Operator relies on **unplanned involuntary** load shedding.

All the events studied in this review are currently managed as Stability Events. The studies will simulate the switching of circuit breakers, initiated by bus zone protection, transformer protection and Special Protection Schemes. The amount of unplanned load shedding post-event will be recorded.

Post-event consequences following the loss of a busbar section or transformer in the Otago, Bunnythorpe and Wellington regions depend on the direction of HVDC transfer. Studies in these regions will consider the pre-contingent conditions of both HVDC North transfer and South transfer. Some events may lead directly to the loss of the HVDC or the interruption of the HVDC as a post-event measure applied to maintain stability. This action is referred to as "HVDC Interruption".

4.4.2 Consideration as a Contingent Event

The Security Policy requires that following a Contingent Event, levels of quality are maintained and unplanned load shedding is avoided. To ensure that these requirements are met, the System Operator endeavours to secure sufficient reserves and apply necessary security constraints. Where these measures are not sufficient to ensure post-event security, the System Operator will take alternative action to maintain quality levels such as pre-event load reduction to reduce the potential security risk.

For study purposes, rather than state the security constraints applied to transmission circuits, the studies will assess the pre-event load limit (or load constraint) required at certain GXPs and/or GXPs within a region to allow management of the event as a Contingent Event. Cross referencing the load constraint with the associated Annual Load Duration Curve (LDC) for the GXPs will return an average amount of load that would need to be constrained and the period of time during the year that the load constraint would need to be in place. The use of Load Duration Curves to determine the average load to be constrained and risk period for which the constraint is in place is discussed in Section 4.5.5.

The application of a pre-event security constraint on the HVDC pole for the management of the loss of a busbar or transformer is not considered to be an economically viable management option and will not be costed. The transfer on a HVDC pole is only constrained if the loss of the HVDC pole is the single largest Contingent Event risk on the network and there is not enough reserve available to maintain supply following the loss of the pole.

4.4.3 Consideration as an Extended Contingent Event

The Security Policy requires that following an Extended Contingent Event levels of quality are maintained. To ensure this requirement is met, the System Operator may action planned **involuntary** load shedding schemes such as Automatic Under Frequency Load Shedding (AUFLS) in addition to planned **voluntary** load shedding schemes used to manage Contingent Events.

The loss of the HVDC bipole is considered an Extended Contingent Event. The consequence of this event may result in a system frequency change that is sufficient for AUFLS relays to trip feeder circuits. The loss of a busbar or transformer may not result in system frequency dropping to a level that would initiate the action of AUFLS. To manage the loss of a busbar or transformer as an Extended Contingent Event, an additional backstop mechanism to facilitate post event planned involuntary load shedding would need to be established.

Planned load shedding schemes are facilitated by the use of Special Protection Schemes to enable the immediate disconnection of load post event. The use of a Special Protection Scheme to automatically reduce load to an acceptable level would be one mechanism that could be employed to manage post-event asset loadings and voltage levels. The management of an event as an Extended Contingent Event by such a scheme would enable a pre-determined amount of load to be shed post-event in order to maintain quality levels.

For management as an Extended Contingent Event, HVDC transfer may need to be reduced post event. With the present HVDC arrangement, this is not possible and, as in the case of Stability Event management, the only action available to the System Operator is to interrupt HVDC transfer. From 2012, the introduction of the new HVDC pole 2/3 configuration will provide additional operational flexibility that will allow post-event reduction in HVDC transfer. Studies will consider the cost benefits of pre-2012 ECE management measures (HVDC Interruption) and post-2012 management measures (HVDC Reduction).

4.4.4 Summary of available and back-stop management measures

To ensure a consistent approach, “backstop measures” are applied to manage the event when classified as a Stability Event, Contingency Event, or Extended Contingent Event. The back stop measures indicated in Table 4-2 are assumed for each event classification.

Table 4-2: Summary of available and back stop measures

Event Classification	**Available Measures**	**Backstop Measure**
Contingent Events	Purchase of instantaneous reserves, pre-contingency security constraints, planned voluntary load shedding, demand inter-trips, run-back schemes and Automatic Under Voltage Load Shedding (AUVLS).	Pre-contingency security constraints
Extended Contingent Events	All of the measures available for Contingent Events plus: Planned involuntary load shedding, Automatic Under Frequency Load Shedding (AUFLS)	Planned involuntary load shedding “*pre-arranged post event load shedding*”
Stability Events	All of the measures available for Contingent Events and Extended Contingent Events (except the purchase of instantaneous reserves) plus: Unplanned involuntary load shedding as necessary to avoid system instability	Unplanned load shedding
Other Events	All of the measures available for Contingent Events, Extended Contingent Events and Stability Events (except the purchase of instantaneous reserves) plus: Emergency load shedding & restoration	Emergency load shedding & restoration

4.5 Costing Methodology

4.5.1 Introduction

The costing methodology developed calculates an indicative cost of the immediate consequence of the event and the pre- and post-event measures applied to manage or mitigate event consequences. The purpose of the cost value is to allow an assessment of the **relative costs** of an event when managed as directed by the different event classifications rather than necessarily determining actual event costs. Assessing the relative cost of managing an event by different means will allow identification of potential cost-benefits associated with an alternative event classification and the application of back-stop management measures.

An “Annual Cost” associated with the consequence of the event, the cost of arranging pre-event measures and the application of post event measures is evaluated. Annual costs will be re-calculated for an event when managed by measures associated with the existing Stability Event (SE) classification and alternative measures associated with Contingent Event (CE) management and Extended Contingent Event (ECE) management. The calculation of Event Cost and Annual Cost for each event management approach and the associated input parameters, are described in the following sections.

4.5.2 Annual Cost & Event Cost

Each event will have a **Total Annual Cost** associated with the consequences and management approach that result from the application of measures applicable to the different event classifications. All post event consequences and applied pre-and post-event measures will have an associated Annual Cost as shown below:

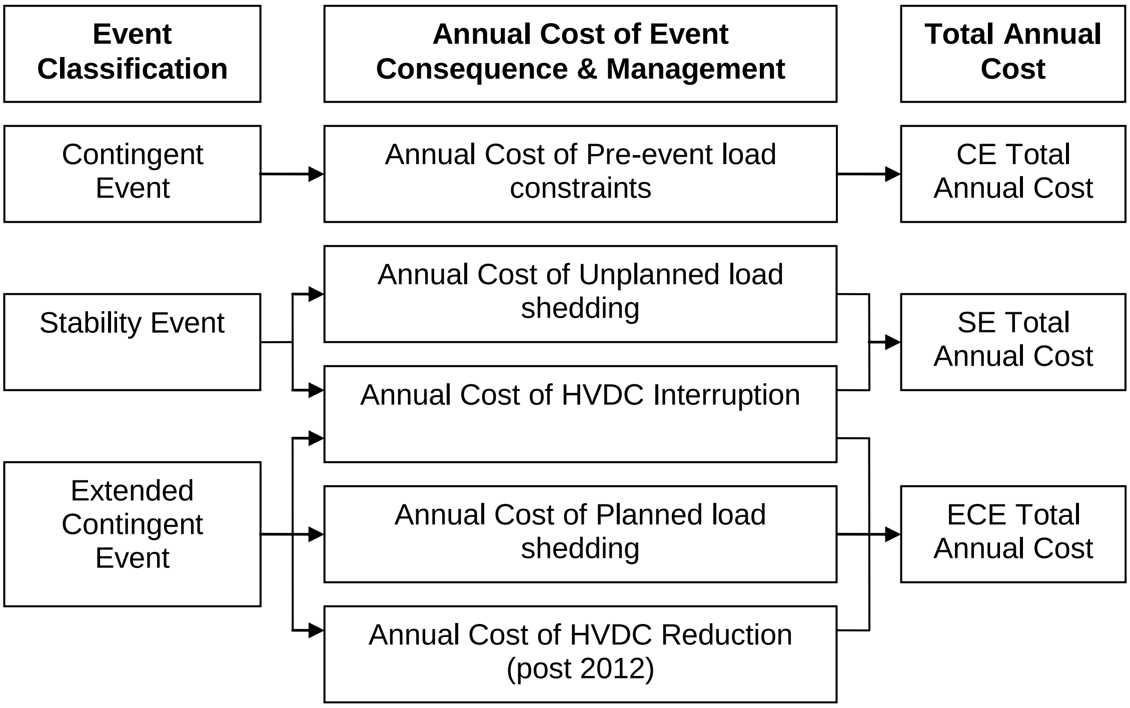

Figure 4-2 Total Annual Cost by Event Classification

Table 4-3: Total Annual Cost by Event Classification

Classification	***Total Annual Cost (management measure) =***
If CE	Annual Cost (Pre-event Load Constraints)
If SE	+ Annual Cost (Unplanned Load Shedding)
If SE or ECE	+ Annual Cost (HVDC Interruption)
If ECE	+ Annual Cost (Planned Load Shedding)
If ECE	+ Annual Cost (HVDC Reduction) post 2012

An Annual Cost is calculated from an Event Cost that is representative of the event consequence(s) or the cost of pre-and post event measures to mitigate the consequence(s) of the event. The Event Cost is multiplied by risk factors to reflect the likelihood of the event occurring (“Event Risk Factor”) and the risk of the consequences arising as a result of the event (“Load Risk Factor”).

Annual Cost = Event Cost x Event Risk Factor x Load Risk Factor ... (1)

The cost associated with the application of load constraints for Contingent Event management is independent of the number of events that occur, thus the Event Risk Factor for CE management is set to 1.0. A Load Risk Factor will be applied to reflect the period of time the constraint is required.

The Event Cost for each measure are based on the following equation

Event Cost = Average Load Affected x Duration x Unit Cost ... (2)

The Annual Cost calculation is illustrated in Figure 4-3. A summary of all costing assumptions and examples of the application of the costing methodology are given in Appendix 3.

Detailed descriptions of the parameters used in the costing equations are provided in the following sections.

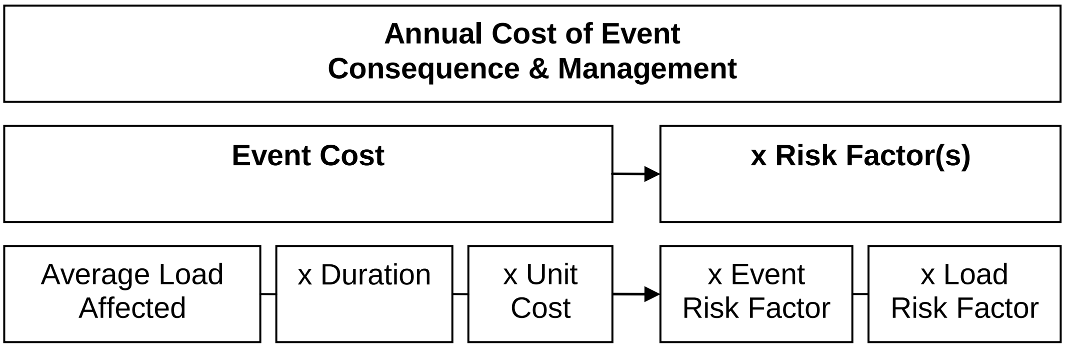

Figure 4-3 Annual Cost Calculation

4.5.3 Event Risk Factor & Number of Events per year

An Event Risk Factor is associated with the loss of either a transformer or busbar is calculated from the average number of events experienced in a year and the number of elements at risk, as described in equation 3.

$$\textbf{Event Risk Factor} = \frac{\textbf{N}^{\textbf{o}}\textbf{ of events per year assoc. with element set}}{\textbf{N}^{\textbf{o}}\textbf{ of elements in set}} \qquad \textbf{…(3)}$$

The average number of events per year associated with a set of elements can be derived from historical data. Analysis of five year event data (2000-2005) indicates that there are, on average, six 220kV and 110kV busbar section events in any one year. Given that there are 282 220kV and 110kV busbar sections on the Transpower network, the Event Risk Factor associated with the loss of a single 220kV or 110kV busbar section is calculated to be 0.021. Event Risk Factors can be calculated in a similar manner for 66kV busbar sections and 220kV interconnecting transformers.

Event Risk Factors for the events under review are indicated in Table 4-4.

Table 4-4: Summary of Event Risk Factors

Event **Loss of a**	**Number of events per year**	**Event Risk Factor** **N-1 Studies**	**Event Risk Factor** **N-1-1 Studies**
220kV Interconnecting Transformer	10	0.095	0.0475
220kV or 110kV Busbar Section	6	0.021	N/A
66kV Busbar Section	5	0.033	N/A

4.5.4 Duration

When calculating the Event Cost associated with planned and unplanned load shedding, the duration parameter is the average time associated with the event.

Analysis of five year historical event data (2000-2005) provides the average event durations given in Table 4-5.

Table 4-5: Summary of Event Durations

Event **Loss of a**	**Duration (hours)**
220kV Interconnecting Transformer	16.7
220kV or 110kV Busbar Section	7.5
66kV Busbar Section	6.3

Average event durations are derived from historical data with the duration of any single event capped at 120 hours.

Where a voltage collapse event is likely, a duration of 72 hours is applied to represent the time required to restore supply to GXPs within the affected regions.

When calculating the cost associated with the application of a pre-event load constraint, the duration is the maximum number of hours that the load constraint may be applied. For all N-1 studies, duration is equal to the number of hours in a year, 8760 hours. For all N-1-1 studies, duration is taken as the summer months only, 4380 hours.

4.5.5 Load Risk Factor & Average Load Affected

Power system studies will indicate the GXPs affected following the loss of a busbar section or transformer and any subsequent trippings that may occur as a result of asset thermal overloads and voltage violations. The post event load loss may result directly from the loss of the contingent element or indirectly from the subsequent tripping of an overloaded asset or voltages moving outside acceptable ranges. The methodology for determining the Load Risk Factor and the Average Load Affected is described below. Examples are provided to aid understanding.

For the **direct** loss of load the following criteria applies:

- The loss of load is unavoidable following the loss of the contingent element.
- There are no other means of maintaining or restoring supply to the load.
- The loss of supply to the load is not dependent upon the pre-event load level.
- The Load Risk Factor = 1.0
- The Average Load Affected is obtained from Load Duration Curves (LDCs)

For the **indirect** loss of load the following criteria applies:

- The loss of load occurs due to the secondary asset tripping; or.
- The loss of load occurs due to the voltage violation (voltages at a load connection point move outside range and result in the loss of load).
- The loss of load is avoidable.
- The loss of supply to the load is dependent upon the pre-event load level.
- The Load Risk Factor ≠1.0
- The Load Risk Factor is obtained from Load Duration Curves
- The Average load affected is obtained from Load Duration Curves

4.5.5.1. Load Risk Factor

A load risk factor of 1.0 indicates that the load is always lost post event irrespective of the pre-event load level. A load risk factor that is not equal to 1 indicates that the load will only be lost if the pre-event load level is above a critical “Load Constraint Limit”.

Power system studies will identify the Load Constraint Limit(s) associated with indirect load loss. The Load Risk Factor is the period of the Load Duration Curve when the load is above the “Load Constraint Limit”.

4.5.5.2. Average Load

For direct loss of load, an average load value calculated for the entire LDC is used as the value of Average Load Affected in the costing formula.

For indirect loss of load, the average load value calculated over the risk period identified from the Load Duration Curve is used as the Average Load Affected in the costing formula.

Example: Direct Loss of Load

The example Load Duration Curve shown in Figure 4-4 indicates the annual spread of load values at a GXP or group of GXPs. The peak load is 170MW and the minimum load is approximately 45MW. If this load is lost on all occasions following the loss of the contingent element, the load is at risk 100% percent of the time. The Load risk factor will be equal to 1.0. As the event may occur at any time of the year, it would be inappropriate to use the peak load value as the value of load affected for event costing purposes. Therefore, an average load is derived from the load duration curve. This is used in conjunction with the load risk factor of 1.0 in the costing formula. For the direct loss of load shown in this example, Load Risk factor = 1.0 and Average Direct Load Affected = 99MW.

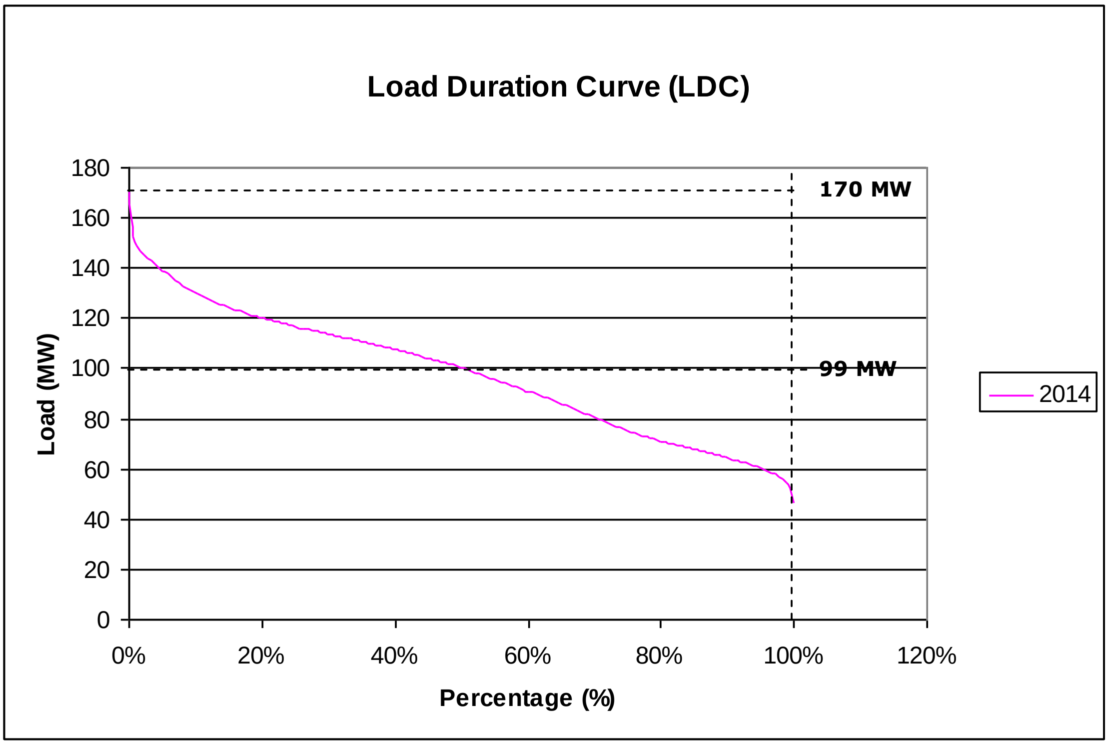

Figure 4-4 Load Duration Curve: Direct loss of load

Example: Indirect Loss of Load

The example Load Duration Curve shown in Figure 4-4 indicates the annual spread of load values at a GXP or group of GXPs. The peak load is 170MW and the minimum load is approximately 45MW. In this example, the load at this GXP, or group of GXPs, is only lost when the load is above the Load Constraint Limit of 120MW. If the pre-event load is above this limit, all load is lost.

The Load Risk Factor is equivalent to the percentage of the Load Duration Curve where load is above the load Constraint limit; therefore, the Load Risk Factor = 0.2.

The load will only be affected during the 20% period when it is above the load constraint limit. As in the previous case, it is inappropriate to use the peak load value as representative of the load affected following the event. Neither is it appropriate to use the load constraint value of 120MW to indicate load affected. Therefore, an average load value of 140MW is used.

The Average Load Affected is calculated over the 20% risk period and used in conjunction with the load risk factor of 0.2 in the costing formula.

For the indirect loss of load, subject to a load constraint limit of 120MW, the Load Risk factor = 0.2 and the Average Load Indirectly Affected during the risk period = 140MW.

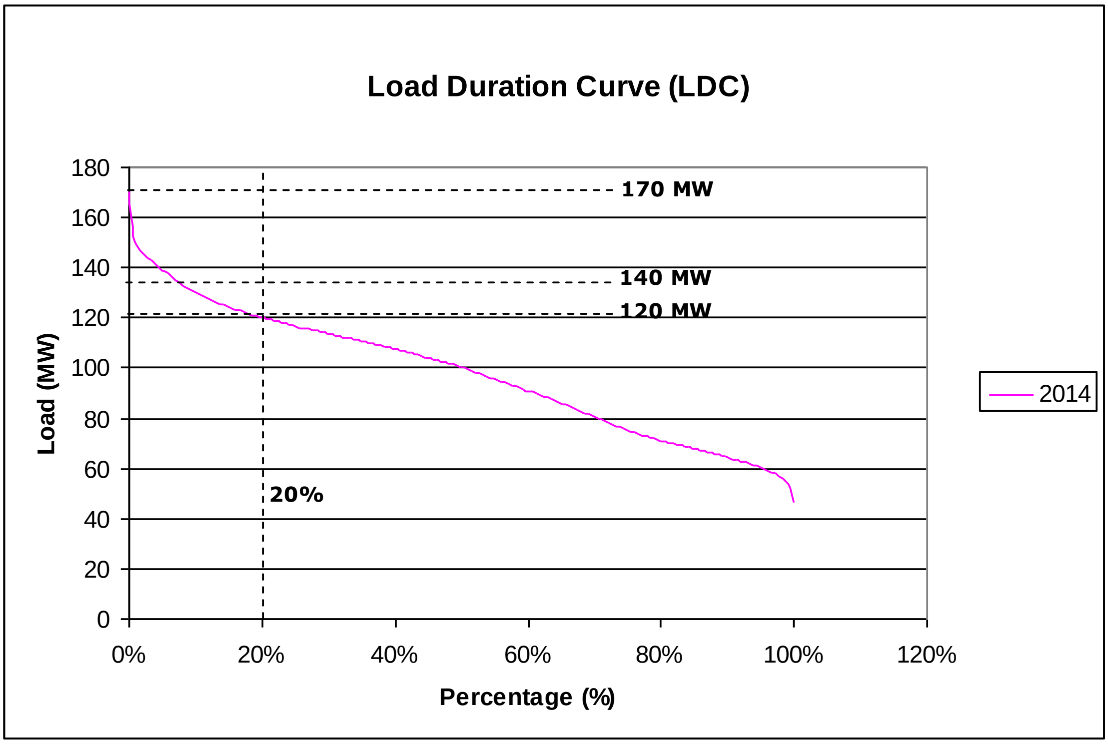

Figure 4-5 Load Duration Curve: Indirect loss of load

4.5.6 Load Management by Event Classification

Studies have recorded the amount of directly lost load and indirectly lost load associated with an event.

Direct load loss is unavoidable and the cost of this loss is the same in all three event management approaches. The cost assessment considers the **relative costs** of alternative management measures; therefore, it is not necessary to include the cost of direct load loss in the Annual Cost associated with the event. Only load associated with indirect loss of load is considered in the event cost.

Average Load Affected = Indirect Loss of Load ...(4)

For the different event classifications, loss of load is managed in different ways; hence the Average Load Affected will be different. But in all cases, load affected can be derived from Load Duration Curves and the application of the above methodology.

4.5.6.1. Stability Event –Unplanned Load Shedding

Stability Events may result in unplanned load loss. This risk is currently accepted and no measures are put in place to manage indirect unplanned loss of load.

Average Load Affected = Unplanned Load Shed ...(5)

where

Unplanned Load Shed = Average load Indirectly affected during risk period

Calculation of the Average Load Affected during a risk period are described in the previous methodology

4.5.6.2. Contingent Event – Pre-event Security Constraints

Management of an event as a Contingent Event requires the risk of indirect load shedding to be eliminated by applying pre-event security constraints to manage load to within acceptable levels during the risk period. The load at GXPs at risk from indirect loss of supply would need to be constrained to levels below the Load Constraint Limit. Therefore, the load affected would comprise the amount of load constrained pre-event.

Average Load Affected = Pre-Constrained Load ...(6)

Where

Pre-Constrained Load = Average Load Indirectly affected during risk period – Load Constraint Limit

Calculation of the Average Load Affected during a risk period is described in the previous methodology.

4.5.6.3. Extended Contingent Event – Planned Load Shedding

Management of the event as an Extended Contingent event would minimise the amount of load shedding. The use of a Special Protection Scheme would initiate planned post event load reduction at the GXPs at risk to a level below the load constraint limits and prevent subsequent trippings and voltage violations.

Average Load Affected = Planned Load Shed ...(7)

Where

Planned Load Shed = Average Load Indirectly affected during risk period – Load Constraint Limit

Calculation of the Average Load Affected during a risk period is described in the previous methodology.

4.5.6.4. Management Measures Free of Charge

It is assumed that the following measures are free of additional cost:

- Wider Voltage Agreements
- Manual system re-configuration pre-event and/or post event
- Reduced security by agreement
- Off-load time or 24 hour emergency ratings
- Special Protection Schemes (armed pre-event)
    - Application of system re-configuration: No cost
    - Application of generation runback: No cost
- Switching of capacitor banks and condensers

A complete summary of costing assumptions can be found in Appendix 3.

4.5.7 Calculation of Event Costs

For each measure, an Event Cost is calculated as defined in equation 8.

Event Cost = Average Load Affected x Duration x Unit Cost … (8)

4.5.7.1. Planned and Unplanned load shedding

Management as a Stability Event will employ the use of unplanned post event load shedding. The amount of unplanned load shedding required is the amount of load lost following the loss of elements directly associated with the event, in addition to those that subsequently trip as a result of thermal loading and voltage violations. System studies identify the GXPs affected; average load at the GXPs affected is obtained from Load Duration Curves.

Management as an Extended Contingent Event will employ the use of planned post event load shedding. The amount of planned post-event load shedding is the difference between a pre-determined load constraint limit and the average load value when above this limit.

For the costing of planned and unplanned load shedding, equation 8 is used with appropriate values of average load shed, the duration of the load shedding and the Value of Lost Load (VoLL). In December 2004, the Electricity Commission set VoLL at $20,000/MWh dollars for the Grid Investment Test. This value represents the value of unplanned involuntary load shedding. Planned load shedding can be expected to have a lower value. For the purposes of this review, Event Costs associated with planned load shedding are calculated using values of $10,000/MWh, $5,000/MWh and $2,000 /MWh for VoLL.

Event Cost Parameters are as follows:

Average Load Affected = Average amount of load shed obtained from studies and load duration curves

Duration = Event Duration in hours based on historical event data

Unit Cost (Unplanned load shedding) = VoLL (Unplanned load shedding) = $20,000 /MWh

Unit Cost (Planned load shedding) = VoLL (Planned load shedding) = $10,000 to $2,000 /MWh

4.5.7.2. Pre-event load constraints

Management as a Contingent Event may require pre-event security constraints to be applied to avoid unplanned post-event load shedding. As discussed in section 4.4.2, this study uses a pre-event load constraint for costing purposes. The average amount of load that would need to be constrained is calculated from power flow studies and load duration curves. The average amount of load that would be constrained is the difference between a load constraint limit and the average load value when above this limit.

To cost load constraints, the event cost duration is the maximum number of hours in a year that the event may occur. The multiplication by an appropriate Load Risk Factor will give an Annual Cost based on the period of time during the year when the constraint is applied.

Event Cost Parameters are as follows:

Average Load Affected = Average amount of load to be constrained calculated from studies and load duration curves

Duration = The maximum number of hours when the constraint may be applied

= 8760 hours in 1 year used in N-1 studies

= 4380 hours in summer used in N-1-1 studies

Unit Cost (constraint) = 10, 000 $/MWh

4.5.7.3. HVDC interruption

Where HVDC transfer is interrupted as a post event measure, an Event Charge ($/MW) is applied to the HVDC MW transfer interrupted rather than a Value of Lost Load (VoLL). The cost of interrupting the HVDC is independent of event duration.

Event Cost parameters are as follows:

Average Load Affected = Average amount of HVDC transfer

Duration = Not applicable (set to 1.0 in calculation)

Unit Cost (HVDC Interruption) = Event Charge (HVDC Interruption) = $1250/MW

4.5.7.4. *Automatic reduction of HVDC transfer (post 2012)*

Post-2012, the new HVDC configuration will allow the post-event reduction in HVDC transfer to be used as a measure to manage Extended Contingent Events. Where HVDC transfer is reduced as a post event measure, an Event Charge ($/MW) is applied. The cost of reducing the HVDC transfer is independent of event duration.

Event Cost parameters are as follows:

Average Load Affected = Average amount of HVDC transfer reduction obtained from studies and load duration curves

Duration = Not applicable (set to 1.0 in calculation)

Unit Cost (HVDC reduction) = Event Charge (HVDC Reduction) = $1250/MW

4.5.8 *Summary of Costing Methodology*

The calculation of the Annual Cost associated with event consequences and management and Total Annual Cost is summarised in Figure 4-6 and Figure 4-7

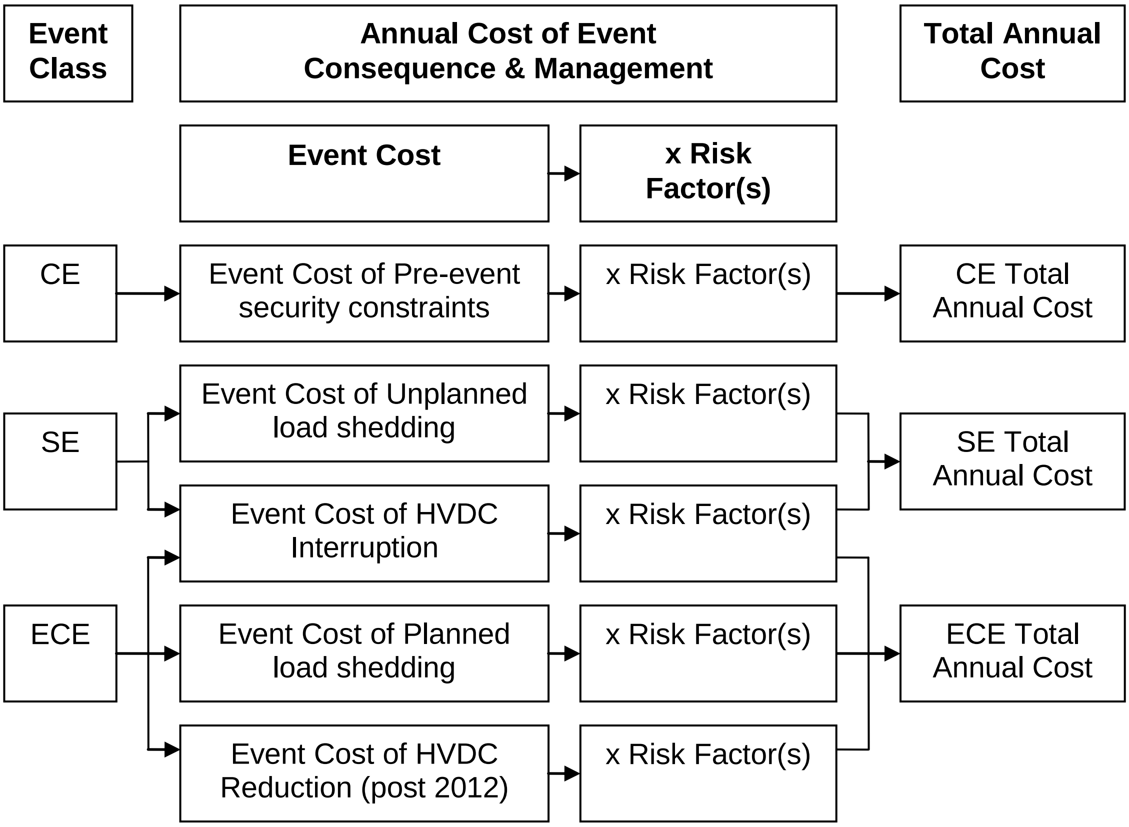

Figure 4-6 Total Annual Cost

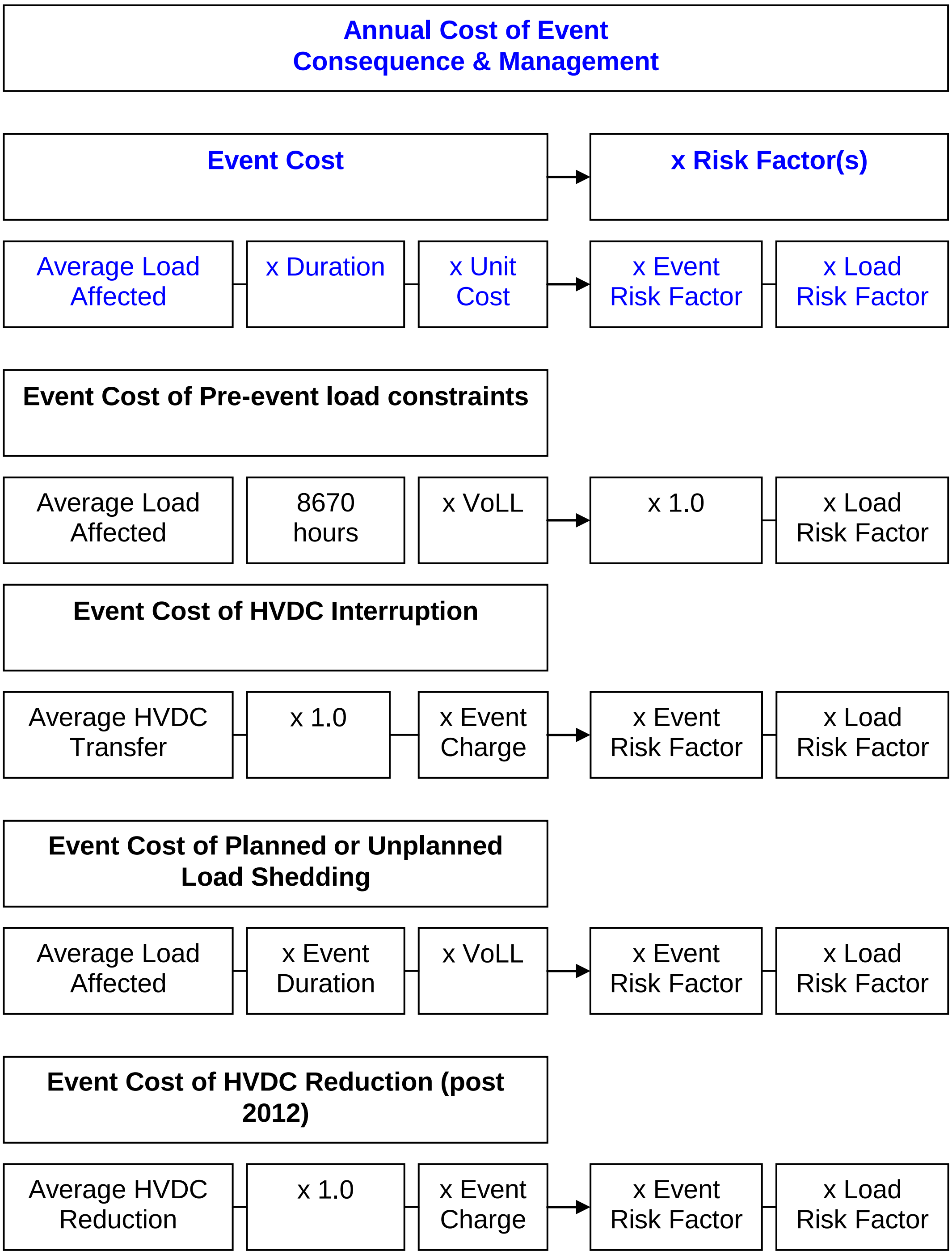

Figure 4-7 Annual Cost of Event Consequence and Management

5 Busbar Studies

5.1 Introduction

This section summarises the consequences associated with the loss of a 220kV, 110kV or 66kV busbar section following the application of management measures in accordance with Event classification criteria (Contingent Event, Extended Contingent Event and Stability Event).

The loss of a busbar section is currently classed as a Stability Event.

To assess the different event management approaches it is necessary to present the potential cost benefits. The cost assessment undertaken indicates the **relative costs** of each event management approach.

The consequence of a loss of a busbar section is dependent upon the number and type of asset(s) connected to the busbar section, the substation configuration and the protection systems and switching schemes available.

5.2 Direct Loss of Load/Generation

5.2.1 Loss of Directly Connected Load

The loss of single section busbars may result in the unavoidable loss of the load with no pre-or post event measures available to avoid or minimise the load lost, or restore supply to the load. For all three event classifications, the cost associated with the loss of directly connected load is the same. As the objective of the cost assessment is to consider the **relative costs** of alternative management measures, the annual cost of direct load loss is not included in the total annual cost.

For busbar events that result in the indirect loss of load, a consequence/cost assessment is undertaken. A complete list of 220kV, 110kV and 66kV busbar sections considered, with links to the individual cost assessments, can be found in Appendix 5. For busbar events that result solely in direct loss of supply, an indication of the amount of lost load or generation is given.

For the loss of a busbar section in the Otago, Bunnythorpe and Wellington regions studies consider the direction of power transfer on the HVDC. The costs associated with the loss of a busbar section during North transfer and South transfer may be added, as the cost calculation applies Load Risk Factors that represent the risk periods associated with each operating condition.

5.2.2 Loss of Directly Connected Generation

The loss of a busbar may result in the direct loss of more than one generating unit. The System Operator currently manages the loss of a single generator unit as a Contingent Event (CE) and secures reserves to manage the loss of the largest “CE risk” on the network. Currently, the risk of more than one generator unit tripping is only managed upon receipt of a “risk of trip” indication from the generator. Following notification, the System Operator may instruct the generator to reduce the power output of the plant.

Reserves are secured in the North Island and in the South Island to cover either:

- the AC CE risk of the loss of a generator unit; or
- the DC CE risk of the loss of a HVDC pole;

depending upon which is the greater of the two. At present, the largest single generating unit on the North Island is Huntly e3P, with a maximum output of 390MW. The largest unit on the South Island is a Manapouri 120MW generator.

While the current level of reserve may manage the generation loss associated with some busbar sections, it is not enough to cover the potential generation that may be lost at all sites. There are a number of single busbar sections that provide connection to generating units with a combined output that is greater than the current maximum CE risk. Table 5-1 summaries the number of generator units connected to a single busbar section and the total generation that could potentially be lost following the loss of a busbar section.

Table 5-1: Summary of potential generation loss following the loss of a busbar section

Loss of a Busbar Section at		**Number of generating units**	**Max. Output**
North Island	Huntly	1	390
	Otahuhu	1	380
	Stratford	1	385
South Island	Aviemore	4	220
	Benmore Busbar A	2	180
	Benmore Busbar B	3	230
	Clyde Busbar B	2	216
	Manapouri Busbar A	3	360
	Manapouri Busbar C	3	360
	Ohau A	4	264
	Tekapo B	2	160

To manage the loss of a busbar section as a Contingent Event, additional reserve would need to be procured to manage the potential loss of more than one generating unit.

Management of the loss of a busbar section and the direct loss of connected generation plant as an Extended Contingent Event would avoid unplanned load shedding without the requirement to procure additional reserve. If reserves are insufficient to manage the generation loss, an under frequency event would occur and initiate Automatic Under frequency Load Shedding (AUFLS).

5.3 Busbar Configuration & Protection

Substation configuration and the protection systems and switching schemes available will have a significant influence on the consequence of the loss of a substation busbar. Different busbar arrangements lead to different levels of busbar security.

5.3.1 Busbar Configuration

The following busbar configurations are identified on the Transpower network; configurations are illustrated and described in Appendix 4.

- Single Busbar & 2x Single Busbar(s)
- Sectionalised Single Busbar
- Meshed System
- Breaker and a Half
- Double Busbar

220kV Busbar Configurations

Figure 5-1 and Figure 5-2 indicate busbar configurations and the consequences of a busbar section event at 220kV substation sites.

From the graphs it can be seen that 32% of 220kV busbars are single busbar sections (including 2x single section busbars), 34% are sectionalised busbars and the remaining 34% comprise double busbar, breaker and a half, and meshed configurations. The sectionalised busbar configuration may not have the capability to automatically isolate busbar sections. Busbar section isolation may require the off-load switching of disconnectors.

The loss of a 220kV busbar section will result in:

- No issues in 32% of cases;
- Direct loss of supply (load and/or generation) in 36% of cases;
- Indirect unplanned loss of supply in 32% of cases.

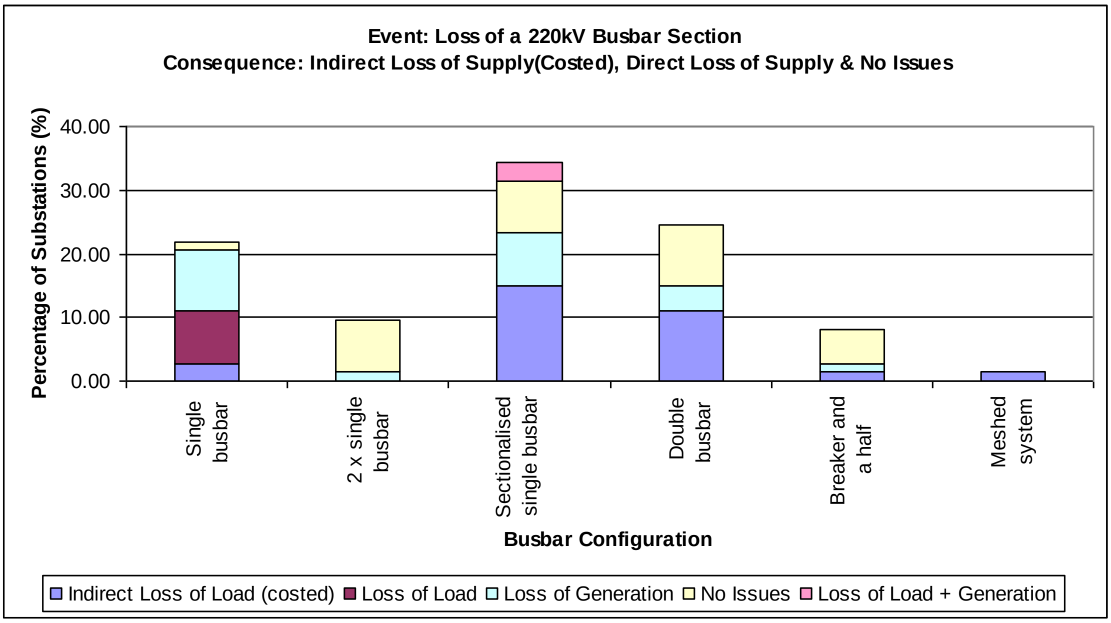

Figure 5-1 220kV Busbar Configurations and Consequence (Direct/Indirect loss of supply & no Issues)

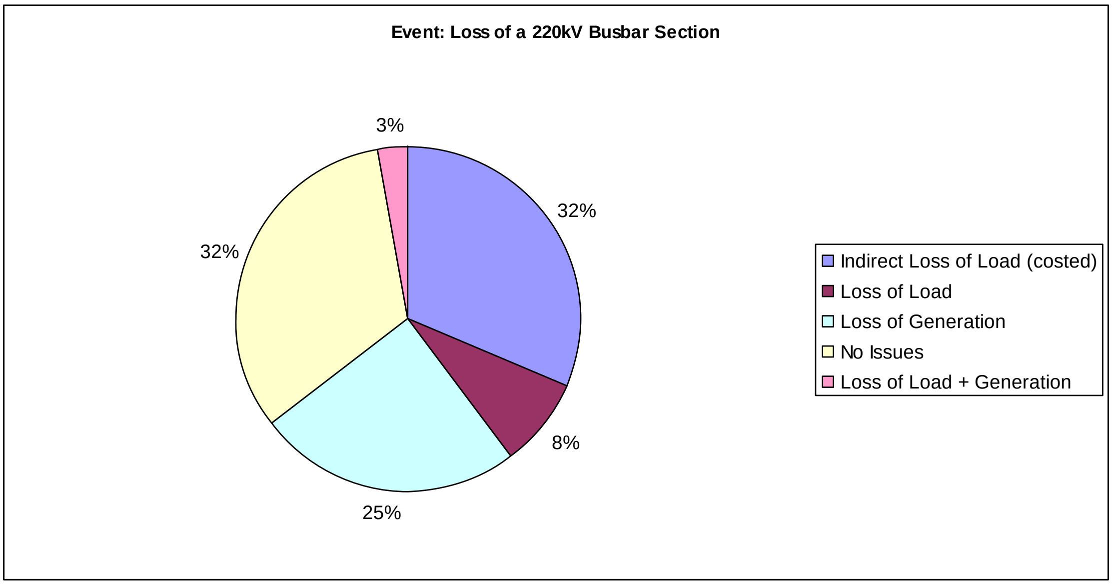

Figure 5-2 Loss of a 220kV Busbar Section: Indirect loss of supply, direct loss of supply & no Issues

Only the loss of 220kV busbar sections where there is indirect loss of load and alternative means of managing the consequences of the event are considered in the cost assessment.

110kV Busbar Configurations

Figure 5-3 and Figure 5-4 indicate busbar configurations and the consequences of a busbar section event at 110kV substation sites.

From the graphs it can be seen that 70% of 110kV busbars are single busbar sections, 23% are sectionalised busbars and the remaining 7% comprise of double busbar, breaker and a half, and meshed configurations.

The loss of a 110kV busbar section will result in:

- No issues in 26% of cases;
- Direct Loss of supply (load and/or generation) in 59% of cases;
- Indirect unplanned loss of supply in 15% of cases.

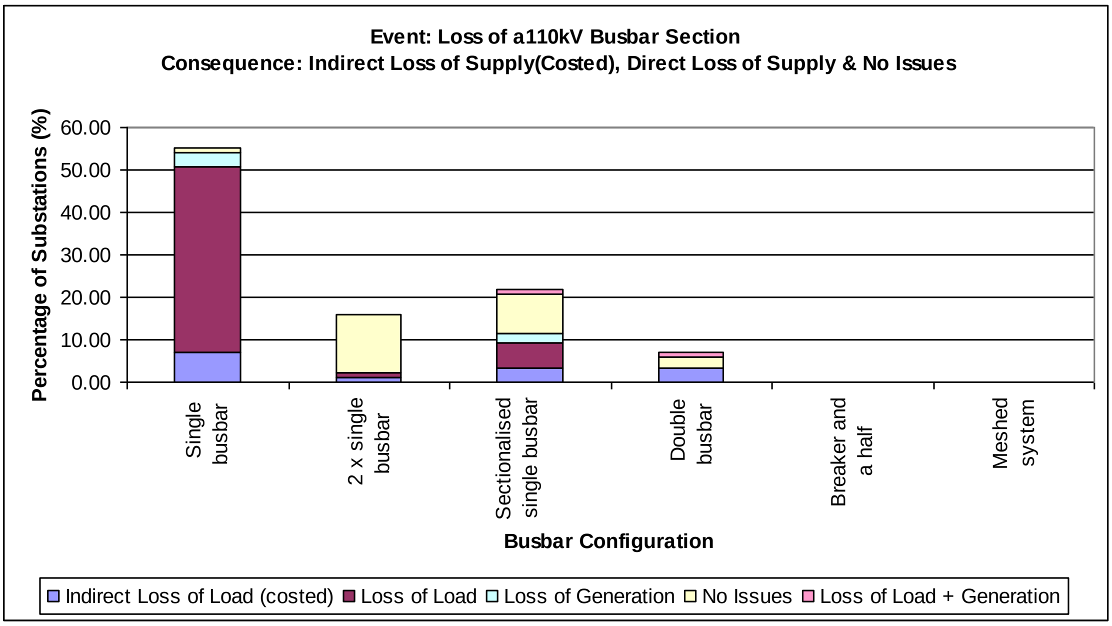

Figure 5-3 110kV Busbar Configurations and Consequence (Direct/Indirect loss of supply & no issues)

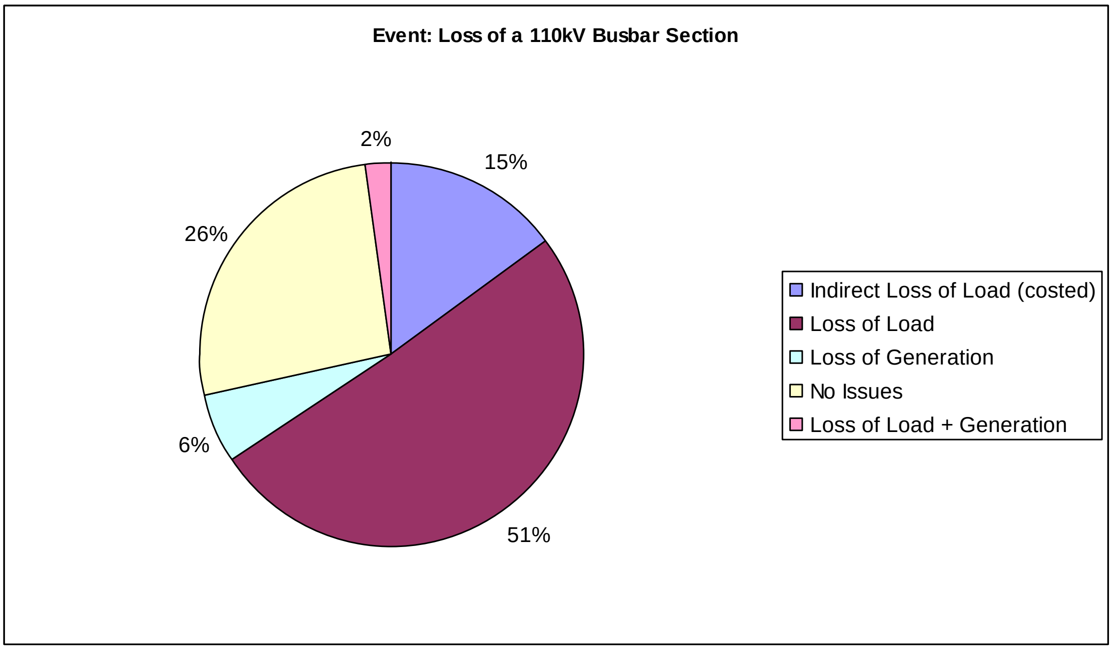

Figure 5-4 Loss of a 110kV Busbar Section: Indirect loss of supply, direct loss of supply & no Issues

Only the loss of 110kV busbar sections where there is indirect loss of load and alternative means of managing the consequences of the event are considered in the cost assessment.

66kV Busbar Configurations

Figure 5-5 and Figure 5-6 indicate busbar configurations and the consequences of a busbar section event at 66kV substation sites.

The majority of 66kV substations are of single busbar-single section configuration the loss of a 66kV busbar section will result in:

- No issues in 8% of cases;
- Direct and/or Indirect Loss of supply (load and/or generation) in 92% of cases.

There are few alternative means for managing the loss of a 66kV busbar section. The System Operator performed further studies on 3% of busbars that resulted in an indirect and unplanned loss of supply. This review considers options for managing the loss of a 66kV busbar section at Islington and Addington (busbars that are connected to core grid).

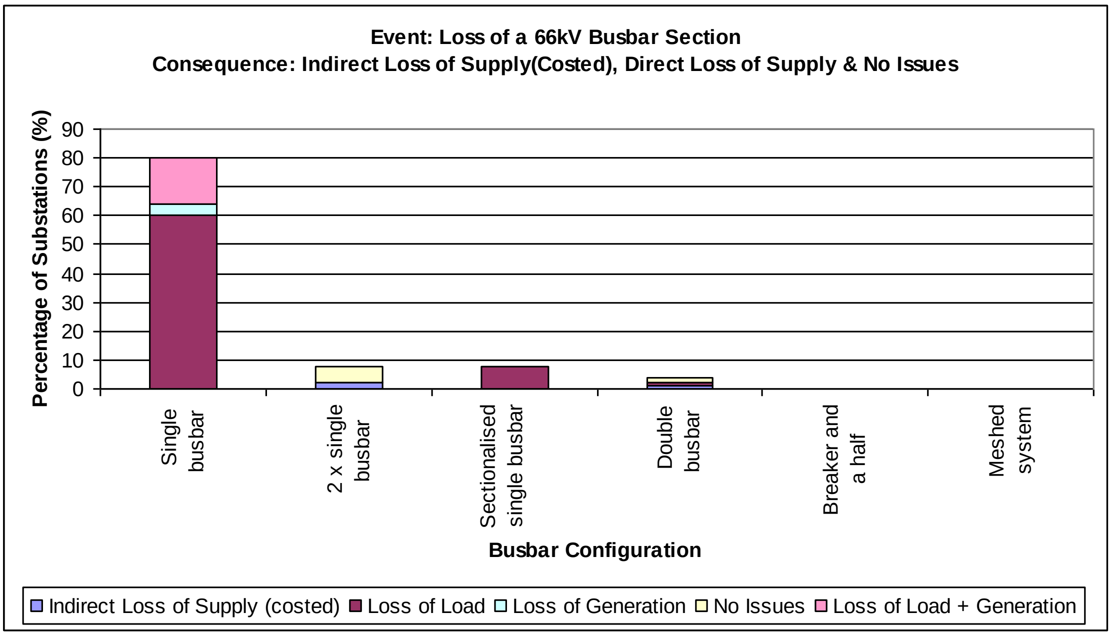

Figure 5-5 66 kV Busbar Configurations and Consequence (Direct/Indirect loss of supply & no issues)

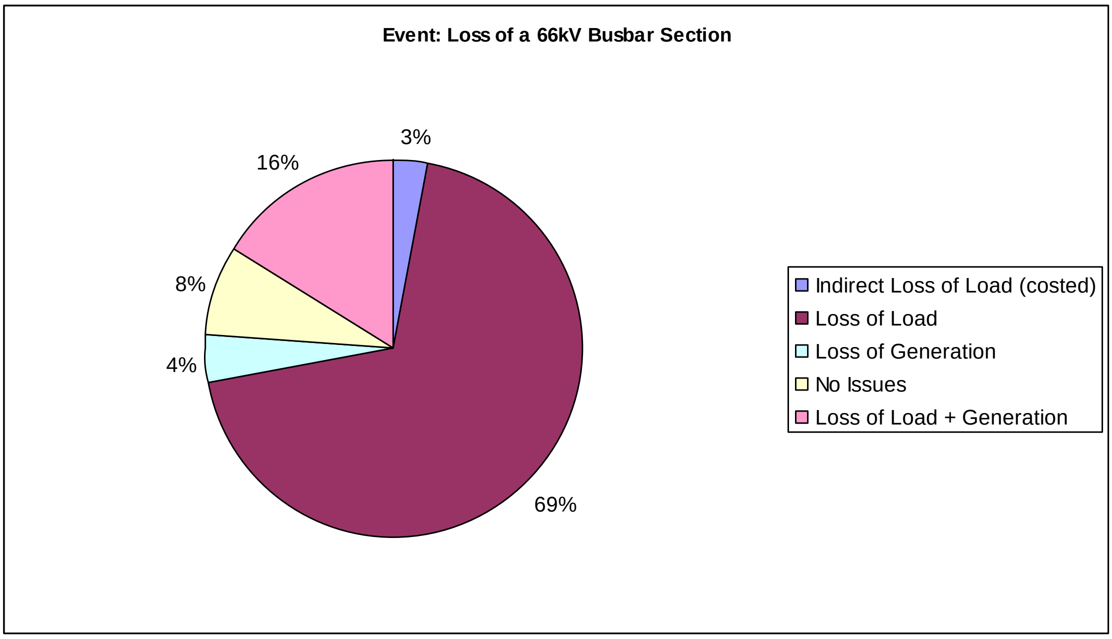

Figure 5-6 Loss of a 66kV Busbar Section: Indirect loss of supply, direct loss of supply & no issues

5.3.2 Bus Zone Protection

If a fault occurs on a busbar with no bus zone protection (including where the Bus Zone protection is switched off), busbar fault clearance will be initiated from the remote ends of the circuit(s) feeding into that bus. The studies assume that where bus zone protection is installed, it is available and will operate as expected.

A procedure will be written by the System Operator and agreed before September 2010 detailing the actions to be taken prior to an outage of bus zone protection, to mitigate the risks of a fault during the period of the outage. Due to the number of outages of bus zone protection taken annually it is recommended that even during the depletion of bus zone protection a fault on that busbar will still be covered as an Extended Contingent Event.

5.4 Busbar Study Commentary

The summary of busbar events is set out in the commentary below. The events in box form are those to which the System Operator would like to draw the reader’s attention.

5.4.1 North Island Overview

Due to the interconnectivity and loading of assets within the Auckland region, the loss of a busbar section that directly affects and removes from service a 220kV interconnecting transformer may result in other assets overloading. Special Protection Schemes and overload protection on circuits and transformers may result in subsequent trippings, leading to loss of supply.

The loss of a 220kV busbar section at Otahuhu may result in the direct loss of an interconnecting transformer and at least two circuits that supply the Auckland region. Similar consequences may arise from the loss of a 110kV busbar section at Otahuhu.

Studies have identified alternative management measures that can be applied to minimise the amount of indirect load loss.

Loss of either 220kV busbar section at Hamilton does not result in the subsequent overload of the remaining interconnecting transformer.

There is a significant amount of generation connected to the 220kV or 110kV busbar sections within the Bay of Plenty region. The majority of generation is connected to the 220kV network. Load in the Bay of Plenty region is supplied via the Tarukenga and Kawerau substations. The loss of a busbar section at either of these substations and the direct loss of an interconnecting transformer, will result in the overload and subsequent tripping of the remaining interconnecting transformer and 220kV transmission circuit supplying the region. This event will lead to loss of supply and/or low voltages in the region. The potential for the event to be coupled with the loss of generation presents a significant risk of voltage collapse.

The Hawkes Bay 110kV network is supplied by two interconnecting transformers. The loss of a 220kV busbar section and the direct loss of an interconnecting transformer may lead to the remaining transformer overloading and subsequently being tripped out of service, resulting in loss of supply to the 110kV network. The loss of the 110kV busbar section results in the loss of **both** interconnecting transformers.

The Taranaki region is supplied by two interconnecting transformers; one at New Plymouth and another at Stratford. The loss of the New Plymouth interconnecting transformer will cause the loading of the transformer at Stratford to approach its 24hour post contingency rating.

The consequence of a loss of a 220kV or 110kV busbar section within the Bunnythorpe and Wellington regions is significantly influenced by the pre-contingency operating conditions of the HVDC link. During HVDC North transfer, the loss of a 220kV or busbar section within the Bunnythorpe region that directly causes the loss of an interconnecting transformer and two or more major circuits, will overload and subsequently trip the remaining interconnecting transformers. This event will result in loss of supply and voltage collapse affecting the Bunnythorpe and Taranaki regions

During HVDC South transfer, the loss of a 220kV or 110kV busbar section will, again, give rise to subsequent tripping of interconnecting transformers with the additional loss of the HVDC link. These events will result in the loss of supply to the Bunnythorpe and Wellington regions.

The loss of a 110kV busbar section within the Bunnythorpe region may present low voltage issues that may, in turn, result in loss of supply and voltage collapse.

The loss of a 220kV busbar section at Tokaanu will result in the loss of two 220kV circuits and the loss of generation. During south transfer, such an event will result in loss of generation, loss of supply to the Bunnythorpe and Wellington regions and the loss of the HVDC link.

Bunnythorpe – 220kV Tokaanu busbar section– HVDC South transfer

A fault on a 220kV busbar at Tokaanu under HVDC south transfer conditions will result in loss of two of the four generator transformers, a Tokaanu-Bunnythorpe 220kV circuit and a Tokaanu-Whakamaru 220kV circuit. The consequence of this fault would be voltage collapse and loss of supply to the Bunnythorpe and Wellington regions as well as tripping HVDC pole 2.

As in the case of busbar events in the Bunnythorpe region, the loss of a 220kV busbar section in the Wellington region during HVDC North transfer that results in the direct loss of an interconnecting transformer will cause the subsequent tripping of another interconnecting transformer via overload protection. The event will lead to loss of supply and possible low voltages, leading to voltage collapse within the region.

Wellington – 220kV Haywards busbar section A, B or C– HVDC North transfer

A fault on a 220kV busbar at Haywards under HVDC North transfer conditions results in the loss of one of the three interconnecting transformers at Haywards, the loss of reactive support and consequently, the overload of the remaining transformer. Low voltages on the 110 kV busbars will arise and possibly lead to voltage collapse. A loss of the busbar where Pole 2 is connected will result in loss of 660MW generation. Such an event is covered by the reserves in the North Island.

In general, the loss of a 110kV busbar section in the Wellington region will not lead to regional loss of supply, with the exception of Haywards section A and a Tekapo Road busbar section.

A busbar event at 110kV Haywards busbar section A results in the loss of two of the three interconnecting transformers. This may cause immediate overload of the remaining transformer and the 110kV Woodville-Mangamaire-Masterton circuit leading to voltage collapse in the region. The loss of a Tekapo Road busbar section, when Wilton T8 is out of service, will result in loss of supply to a significant number of GXPs within the Wellington region.

During HVDC South transfer, the loss of a 220kV busbar may result in the loss of one or more interconnecting transformers and reactive support, resulting in low voltages and loss of supply. Low voltages will trip the HVDC link and overload the remaining interconnection transformer and 110kV circuits. This event will lead to loss of supply to the Wellington region.

Wellington – 220kV Haywards busbar section A, B or C – HVDC South transfer

The loss of a 220kV busbar section at Haywards during South transfer will result in the loss of an interconnecting transformer and loss of reactive support. It is highly likely that the HVDC will trip due to low voltages or that HVDC will be manually tripped. Wellington regional load is then supplied via two interconnecting transformers and the 110kV Woodville-Mangamaire circuit, all of which may overload.

5.4.2 South Island Overview

The loss of a 220kV or 110kV busbar section in the Upper South Island (Canterbury, Christchurch, West Coast and Nelson), with direct loss of either an interconnecting transformer or two or more circuits, will result in loss of transfer capability and low voltages, particularly in the West Coast and Nelson regions. Low levels of local generation and limited core grid connected generation in the Upper South Island exacerbates the low voltage issue and presents an increased risk of voltage collapse.

High consequence busbar section events in the Upper South Island are the loss of a 220kV or 66kV busbar section at Islington, or a 220kV busbar section at Tekapo B. Following these events, there is a significant risk of voltage collapse in one or more regions.

Christchurch – Islington

The loss of an Islington 220kV or 66kV busbar section may result in the loss of an Islington interconnecting transformer, leading to the subsequent overload and tripping of the remaining Islington interconnecting transformers. This event results in loss of supply to the Christchurch region and potential voltage collapse within the West Coast and Nelson regions.

Canterbury – Tekapo B

The loss of the Tekapo B busbar results in the loss of two generators and two 220kV circuits. Due to the potential lack of reactive support in the upper south Island, there is a significant risk of voltage collapse.

The loss of a 220kV busbar within the Otago or Southland region may lead to the loss of more than one generating unit and/or one or more transmission circuit. Faults in and around Benmore may result in the loss of the HVDC pole. The loss of more than one generating unit may result in insufficient reserves being available to manage the loss of generation associated with the event.

The System Operator procures reserves in the South Island to manage the loss of the single largest Contingent Event risk – either the loss of a generating unit (Manapouri 120MW) or the loss of the HVDC Pole 2 when operating in south transfer.

The loss of a busbar section at either Manapouri or Benmore presents the largest potential loss of generation in the South Island. The loss of the 220kV Manapouri busbar section may result in up to 360MW of lost generation. The loss of the 220kV Benmore section during south transfer may lead to the loss of up to 230MW of Benmore generation, in addition to the transfer on the HVDC.

Otago – Benmore busbar section B

The loss of the 220kV Benmore busbar section B results in the loss of three Benmore generators and HVDC Pole 2. Assuming pre-contingency generation at Benmore and HVDC south transfer, there may not be enough reserves to manage the event. This may result in an under frequency event and the initiation of Automatic Under Frequency Load Shedding (AUFLS).

If the Benmore busbar section B loss is considered a Contingent Event, additional reserves would need to be procured to cover the loss of the HVDC and Benmore generation units. If reserves are not available to cover the event, the output of the Benmore units would need to be constrained back during HVDC South transfer to ensure enough reserves are available to avoid AUFLS following the loss of the busbar section.

If considered as an Extended Contingent Event, the event would be managed by AUFLS operation.

Within Southland, there are three interconnecting transformers supplying the 110kV network. The loss of one transformer or associated busbar section may result in the overloading and tripping of the remaining transformers. Low voltage issues are prevalent in the Southland 110kV network. This loss of a busbar section or interconnecting transformer and subsequent transformer tripping(s), will result in loss of supply and voltage collapse within the Southland 110kV network.

5.5 Busbar Cost Analysis

At 32% of 220kV substation sites, the loss of one busbar section will result in the overload and subsequent tripping of further transformers and/or circuits, or result in voltages moving outside allowable range. In all cases where load is indirectly lost as a result of subsequent asset tripping(s) and voltage violations, consideration as an Extended Contingent Event and the introduction of a Special Protection Scheme to manage the event will minimise the amount of unplanned load shedding. The management of the event as a Contingent Event and application of pre-contingency security constraints, would mitigate against post-event load shedding by constraining load to avoid post-event load shedding.

A complete list of annual costs associated with the loss of a 220kV, 110kV, or 66kV busbar and management of indirect loss of supply for Stability Event, Contingent Event or Extended Contingent Event classification can be found in Appendix 6.

Busbar events (20) that have the highest annual costs are listed in Table 5-2. The Annual Cost is calculated taking into consideration, the amount of load at risk, the risk of the event occurring, the period of risk and the duration of an event. Annual Cost does not consider cost(s) associated with the loss of generation or directly connected load.

From the table, the loss of a busbar section at Islington, Ashburton, Bunnythorpe, Tokaanu and Tekapo B rank within the ten highest cost events on the network. Busbar section events at Islington or Ashburton have high associated costs due to the risk of voltage collapse in up to three regions. During HVDC south transfer, the loss of a 220kV section at Bunnythorpe or Tokaanu result in voltage collapse within the Bunnythorpe and Wellington regions. The loss of a 110kV section at Haywards or Bunnythorpe results in voltage collapse within either the Bunnythorpe or Wellington region.

Table 5-2: Busbar events with the highest annual costs

Busbar Section	*Annual cost associated with event classification ($m)*				
	Stability Event	*Contingent Event*	*Extended Contingent Event*		
			$10k	*$5k*	*$2k*
ASB 220_C	3.245	1102.01	0.0198	0.00991	0.00396
ISL 220_A	2.087	490.56	0.0088	0.004	0.002
ISL 220_B	1.82	409.97	0.0074	0.004	0.001
BPE 220_A1 HVDC South *	1.6582		0.00055	0.00055	0.00055
BPE 220_A2 HVDC South *	1.6582		0.00009	0.00009	0.00009
BPE 220_B HVDC South *	1.6582		0.00009	0.00009	0.00009
TKU_220_1 HVDC South *	1.6582		0.00004	0.00004	0.00004
TKU_220_2 HVDC South *	1.6582		0.00004	0.00004	0.00004
TKB 220	1.639	210.24	0.0038	0.00189	0.00076
KIK 110	1.207	848.84	0.0153	0.008	0.0031
HAY_110_A HVDC North	1.005	10798.44	0.194	0.0097	0.039
HAY_110_A HVDC South *	0.91		0.14	0.009	0.003
ISL 66_C	0.748	59.57	0.0014	0.00071	0.00028
IGH 110	0.687	364.42	0.0066	0.003	0.0013
ISL 220_C	0.638	70.08	0.0013	0.00063	0.00025
KIK 220_A	0.5504	87.6	0.0016	0.001	0.0003
STK 220_A	0.55	91.98	0.0017	0.001	0.0003
BPE 110_A HVDC South *	0.444		0.00073	0.0005	0.00036
BPE 110_B HVDC South *	0.444		0.00004	0.00004	0.00004
ATU 110	0.266	57.82	0.001	0.00052	0.00021

*post 2012
Note: Total number of events resulting in indirect loss of load =75.

Annual Costs are summed to allow comparison of the relative costs associated with the loss of a busbar section and application of alternative management measures in accordance with event classification, see Table 5-3.

Table 5-3: Summary of Busbar Cost Analysis

		Annual cost associated with event classification ($m)				
	Busbar Voltage	*Stability Event*	*Contingent Event*	*Extended Contingent Event*		
				$10k	*$5k*	*$2k*
North Island	220kV	9.85	3874.39	0.07	0.04	0.02
	110kV	4.30	16574.69	0.45	0.08	0.07
South Island	220kV	11.25	7024.64	0.13	0.06	0.02
	110kV	2.31	2130.43	0.04	0.02	0.01
	66kV	0.76	90.23	0.00	0.00	0.00
TOTAL Annual Cost ($m)		28.47	29694.38	0.69	0.20	0.12
Δ Annual Cost (%)			104209	-98	-99	-100

At present, the loss of a busbar section is managed as a Stability Event. Post event, the current management approach will lead to indirect unplanned load shedding at 23% of 220kV and 110kV substation sites. The loss of a busbar section will result in unavoidable loss of load at 28% of 220kV and 110kV sites, as shown in Figure 5-7.

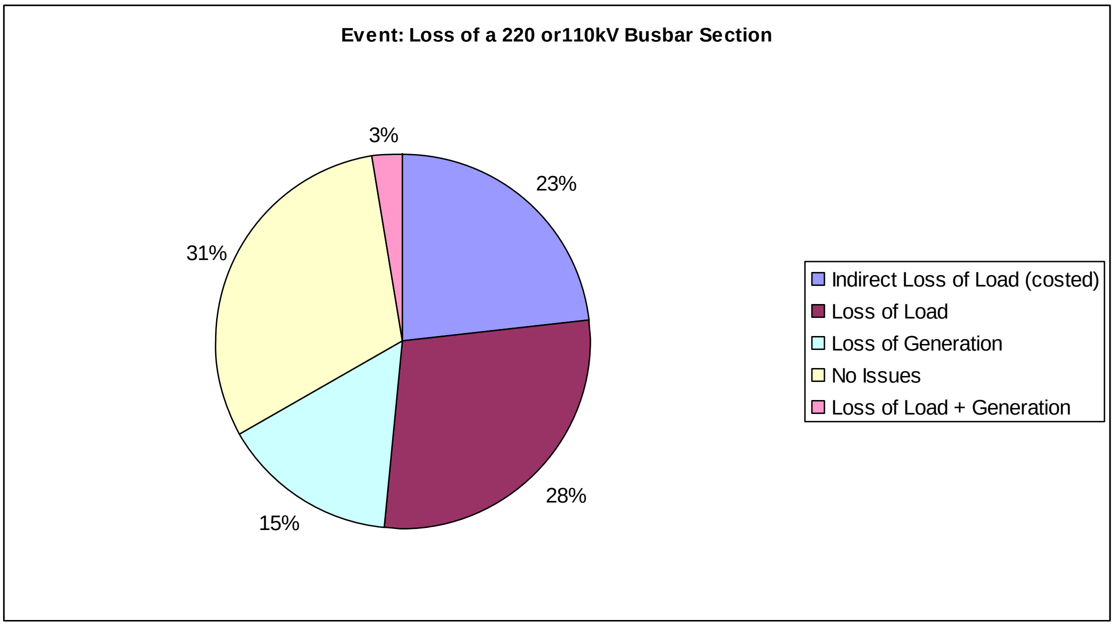

Figure 5-7 Loss of a 220kV or 110kV Busbar Section: Indirect loss of supply, direct loss of supply & no issues

The cost analysis shows that considering this event as an Extended Contingent Event would lead to a substantial reduction in the annual cost associated with indirect unplanned load loss.

Considering all busbar sections in the study set as Extended Contingent Events with the adoption of a Value of Lost Load of $10,000/MWh will result in a 98% saving in costs associated with indirect unplanned load shedding. Considering the twenty highest cost busbar events listed in Table 5-2 as Extended Contingent Event would result in an 85% saving in annual cost.

The re-classification and management of the event as a Contingent Event requires the application of security constraints to ensure that post event load shedding is avoided. The cost associated with increased reserve requirements to cover the potential risk of loss of multiple generation units connected to a single busbar is not included in the above cost figures. It is clear that this management approach is significantly more expensive and brings no security or operational benefits to network connected parties.

6 Transformer Studies

6.1 Introduction

This section summarises the consequences associated with the loss of a 220kV interconnecting transformer following the application of management measures in accordance with Event Classification criteria (Contingent Event, Extended Contingent Event and Stability Event). The loss of a 220kV interconnecting transformer is currently classed as a “Stability Event”.

To assess the different event management approaches, it is necessary to present the potential cost benefits. The cost assessment undertaken indicates the **relative costs** of each event management approach.

Transformer studies consider the loss of a single transformer when all assets are in service and when one interconnecting transformer is out of service for planned maintenance. The majority of 220kV substations that facilitate interconnection between the 220kV and 110kV power systems provide connection via one or two interconnecting transformers. Substations at Otahuhu, Bunnythorpe, Haywards and Islington provide connection via three or more interconnecting transformers.

6.2 Direct Loss of Load

Loss of Directly Connected Load

The loss of a 220kV interconnecting transformer may result in the unavoidable loss of the load with no pre-or post event measures available to avoid or minimise the load lost, or restore supply to the load. For all three event classifications, the cost associated with the loss of directly connected load is the same. As the objective of the cost assessment is to consider the **relative costs** of alternative management measures, the annual cost of direct load loss is not included in the total annual cost.

For transformer events that result in the indirect loss of load, a consequence/cost assessment is undertaken. A complete list of 220kV interconnecting transformers, with reference to the relevant cost assessments, or an indication of any direct loss of load can be found in Appendix 7.

For the loss of an interconnecting transformer in the Benmore, Bunnythorpe and Wellington regions, studies considered the direction of power transfer on the HVDC. The costs associated with the loss of an interconnecting transformer during North transfer and South transfer may be added, as a load duration curve developed to reflect HVDC transfer during a year allows a representative load risk factor to be used in the cost calculation.

Figure 6-1 shows the consequences of the loss of a 220kV interconnecting transformer.

The loss of a 220kV interconnecting transformer will result in:

- No issues in 42% of cases;
- Direct loss of supply (load and/or generation) in 4% of cases;
- Indirect unplanned loss of supply in 50% of cases;

- 4% of transformers are normally out of service.

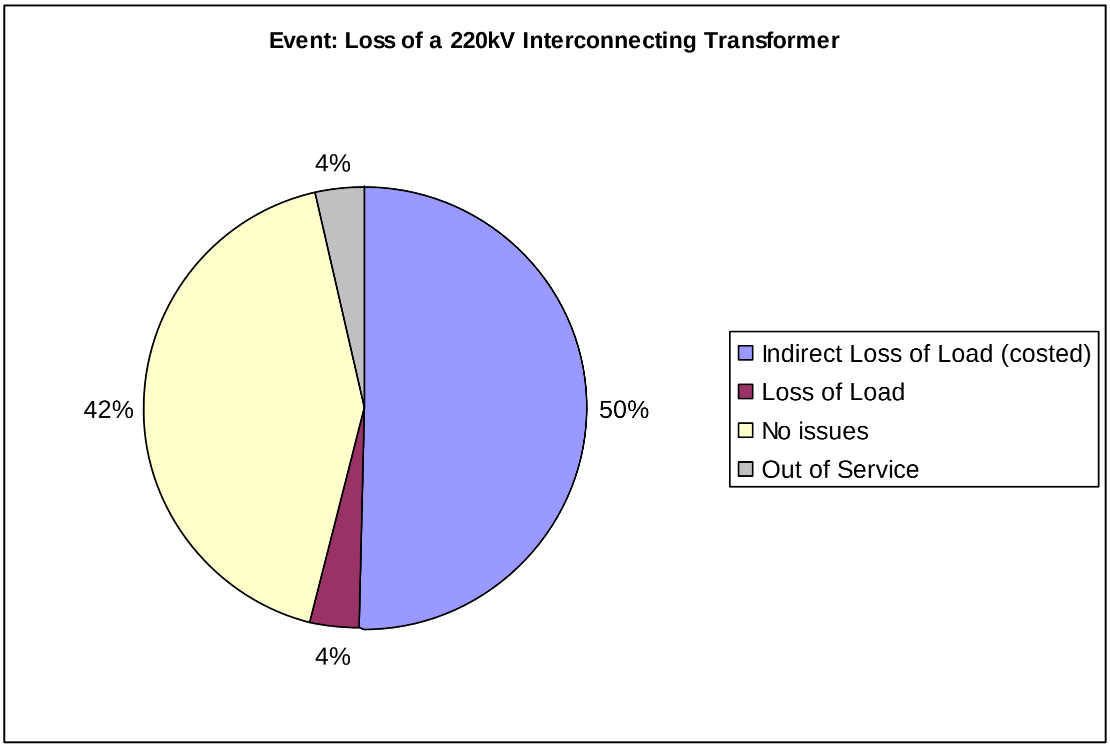

Figure 6-1 Loss of a 220kV Interconnecting Transformer: Indirect loss of supply, direct loss of supply & no issues

Only the loss of 220kV interconnecting transformers, where there is indirect loss of load and alternative means of managing the consequences of the event, are considered in the cost assessment.

6.2.1 N-1 Transformer Studies

In 50% of cases (indicated in Figure 6-1) the loss of one interconnecting transformer may result in the overload and subsequent tripping of a parallel connected transformer. In all cases where load is lost as a result of subsequent trippings, consideration as an Extended Contingent Event will minimise the amount of load lost. Management as an Extended Contingent Event will require the application of a Special Protection Scheme to manage the event by reducing area load.

The loss of an interconnecting transformer at Haywards or Benmore will give rise to significant load shedding; these events are described in detail below.

Haywards Interconnecting Transformer

During HVDC North transfer, the loss of an interconnecting transformer at Haywards may lead to the remaining two interconnecting transformers exceeding their 24h-post contingency ratings and/or low voltages at the 110kV busbars, resulting in loss of supply to GXPs within the Wellington region.

During HVDC South transfer, the loss of a transformer at Haywards may lead to the remaining two transformers exceeding their 24h-post contingency ratings and/or cause low voltages at the 110kV busbars. The loss of an interconnecting transformer at Haywards will also remove reactive support devices and result in a trip of the HVDC link (pre-2012) or require a reduction in HVDC transfer (post-2012).

In both cases, load constraint limits will be raised and voltage levels supported with the availability West Wind generation.

Benmore Interconnecting Transformer

The loss of a Benmore transformer T2 or T5 will result in the loss of generation at Benmore. The management of the loss of the Benmore transformer as a Contingent Event would require the procurement of additional reserves. Managing the loss of a Benmore interconnecting transformer as an Extended Contingent Event would allow reliance on the operation of AUFLS if there are insufficient reserves in the South Island to manage the generation loss.

As the network is developed it may be possible, in a future review, to re-classify the loss of an interconnecting transformer as a Contingent Event. Although the management of the loss of a Benmore 220kV transformer as a Contingent Event will require sufficient reserves to be available to cover the loss of three generator units at Benmore, it is possible that by the time a re-classification as a Contingent Event is a viable option, the North and South Islands will have a unified reserves market. Hence the reserve requirement for the loss of the Benmore 220kV interconnecting transformer may be less than the Contingent Event Risk reserve requirements associated with the loss of a single large generator such as Huntly e3p.

6.2.2 N-1-1 Transformer Studies

At stations where there are two interconnecting transformers on site, the loss of a single transformer when the other is out of service will result in the direct loss of supply to a region, with limited measures available to restore supply post-event. The loss of supply resulting from the loss of one transformer, while the only remaining parallel connected transformer is out of service is unavoidable and is not subject to cost analysis.

At stations where there are more than two interconnecting transformers the loss of a single transformer when another is out of service for maintenance will result in the overloading and subsequent tripping of the remaining transformer and the loss of supply to a region. Therefore, in these circumstances, there are no security benefits associated with the presence of the third transformer. In all cases where load is lost as a result of subsequent tripping of the remaining transformer, consideration as an Extended Contingent Event will minimise the amount of load lost.

There are four substations, with three or more interconnecting transformers: Otahuhu, Bunnythorpe, Haywards and Islington. The System Operator has assessed the cost of the indirect load loss associated with the tripping of transformers following the loss of a transformer, during a planned outage of another.

6.3 Transformer Cost Analysis

A complete list of annual costs associated with the loss of a 220kV interconnecting transformer and management of indirect loss of supply for Stability Event, Contingent Event, or Extended Contingent Event classification can be found in Appendix 7.

The Annual Cost is calculated taking into consideration the amount of load at risk, the risk of the event occurring, the period of risk and the duration of an event. Annual Cost does not consider the cost(s) associated with the loss of generation or directly connected load.

6.3.1 N-1 Transformer Studies

Transformer events (10) that have the highest annual costs are listed in Table 6-1. From the table, the loss of an interconnecting transformer at Haywards, Islington, Stoke, or Kikiwa rank within the ten highest cost events on the network.

The loss of the interconnecting transformer at Halfway Bush and the associated event cost arises from the assumption that generation at Roxburgh 110kV is unavailable.

Table 6-1: 220kV Transformer events with the highest annual costs

Transformer	*Annual cost associated with event classification ($m)*				
	Stability Event	*Contingent Event*	*Extended Contingent Event*		
			$10k	*$5k*	*$2k*
HWB 220/110 T 4	2.51	1676.66	0.303	0.1515	0.0606
STK 220/110/11 T7	2.4898	78.84	0.0143	0.0071	0.0029
HAY 220/110/11 T1 - North	2.17	740.22	0.134	0.067	0.027
HAY 220/110/11 T2 - North	2.17	740.22	0.134	0.067	0.027
HAY 220/110/11 T5 - North	2.17	740.22	0.134	0.067	0.027
ISL 220/66/11 T6	2.0164	50.81	0.0092	0.0046	0.0018
ISL 220/66/11 T3	1.0397	5.26	0.001	0.0005	0.0002
ISL 220/66/11 T7	1.0397	5.26	0.001	0.0005	0.0002
KIK 220/110/11 T2	0.948	39.42	0.0071	0.0036	0.0014
HAY 220/110/11 T1 - South	0.905	183.96	0.034	0.0175	0.0076

Note: Total number of events resulting in indirect loss of load =27.

Annual Costs are summed to allow comparison of the relative costs associated with the loss of a 220kV interconnecting transformer and application of alternative management measures in accordance with event classification, see Table 6-2.

Table 6-2: Summary of 220kV Interconnecting Transformer Cost Analysis

		Annual cost associated with event classification ($m)				
	Voltage	*Stability Event*	*Contingent Event*	*Extended Contingent Event*		
				$10k	*$5k*	*$2k*
North Island	220/110	12.45	3514.52	0.64	0.32	0.13
South Island	220/110	6.94	2031.43	0.37	0.18	0.07
	220/66	4.10	61.33	0.01	0.01	0.00
TOTAL Annual Cost ($m)		23.49	5607.28	1.02	0.51	0.21
Δ Annual Cost (%)			23772	-96	-98	-99

At present the loss of an interconnecting transformer is managed as a Stability Event. Following an event, the current management approach will lead to indirect unplanned load shedding for 50% (as indicated in Figure 6-1) of interconnecting transformers. The cost analysis shows that considering this event as an Extended Contingent Event would lead to a substantial reduction in the annual cost associated with indirect unplanned load loss.

Considering all 220kV interconnecting transformers as an Extended Contingent Event, with the adoption of a Value of Lost Load of $10,000/MWh, will result in a 96% saving in costs associated with indirect unplanned load shedding. Treating the ten highest-cost transformer events listed in Table 6-1 as Extended Contingent Events would result in a 71% saving in Annual Costs.

The re-classification and management of the event as a Contingent Event requires the application of security constraints to ensure that post event load shedding is avoided. The cost associated with increased reserve requirements to cover the potential risk of loss of multiple generation units connected to the network via a single interconnecting transformer is not included in the above cost figures. It is clear that this management approach is significantly more expensive and brings no security or operational benefits to parties connected to the grid.

6.3.2 N-1-1 Transformer Studies

Annual costs are calculated for the N-1-1 event of the loss of a transformer while another is out of service for planned maintenance at substations where there are at least three transformers.

Annual Costs are summed to allow comparison of the relative costs associated with the management of the loss of a 220kV interconnecting transformer while another transformer is out of service (see Table 6-3). The risk period associated with an outage is assumed to be six months. As the aim is to assess the relative costs of each management approach, the total costs calculated may not be a true representation of actual event cost.

Table 6-3: Summary of N-1-1 220kV Interconnecting Transformer Cost Analysis

		Annual cost associated with event classification ($m)				
	Voltage	*Stability Event*	*Contingent Event*	*Extended Contingent Event*		
				$10k	*$5k*	*$2k*
North Island						
OTA T4 & PEN T10	220/110	2.01	1555	0.282	0.141	0.056
BPE T1 & T2 North Transfer	220/110	2.79	1167.27	0.211	0.106	0.042
HAY T1 & T2 North Transfer	220/110	2.99	1544.39	0.28	0.14	0.056
HAY T1 & T2 South Transfer	220/110	1.976	-	0.115	0.077	0.023
NI TOTAL		9.77	4266.66	0.89	0.46	0.18
South Island						
ISL T3 & T6	220/66	15.887	1330.64	0.241	0.1205	0.048
ISL T6 & T7	220/66	16.142	1379.7	0.250	0.1249	0.050
ISL T3 & T7	220/66	10.581	488.81	0.089	0.0443	0.018
SI TOTAL		42.61	3199.15	0.58	0.29	0.12
TOTAL$^{\textbf{6 month outage period}}$		52.38	7465.81	1.47	0.75	0.29
TOTAL$^{\textbf{1 month outage period}}$		8.73	1244.30	0.245	0.125	0.0483
Δ Annual Cost (%)			14154	-97	-99	-99

At present, the loss of an interconnecting transformer is managed as a Stability Event. The loss of a transformer during a planned outage of a transformer connected in parallel will lead to indirect unplanned load shedding. The cost analysis shows that considering this event as an Extended Contingent Event would lead to a substantial reduction in the annual cost associated with indirect unplanned load loss.

7 Credible Event Policy Changes

7.1 List of Credible Events

Following a review of historical event data and international planning / operational standards the System Operator proposes the following set of possible Credible Events.

Loss of a single power system component

- Generator unit
- 220kV or 110kV Transmission circuit
- HVDC Pole (valve group, overhead dc line or undersea cable)
- Interconnecting Transformer (and all directly connected elements, i.e reactive devices connected to transformer tertiary)
- 220kV or 110kV Busbar section
- 66kV Busbar section
- Reactive device (condenser, capacitor, reactor, SVC, RPC)
- Large load / load block
- Protection Communication, Special Protection Scheme

Simultaneous loss of multiple power system components

- Any combination of 2 or more single power system components listed above
- 1+ Transmission circuits (on the same transmission tower on the same transmission corridor/ common right of way) **
- 1+ generator units (generating station)
- 1+ busbar sections (switching station busbar, substation busbar)
- HVDC Bipole (both overhead dc circuits, multiple undersea cables)

** when a change to environmental or operating conditions indicate there is a high likelihood of occurrence the loss of a two transmission circuits on the same tower should be re-classified as a Contingent Event.

7.2 Classification of Credible Events

The security policy allows for Contingent Event and Stability Events to be considered Stability Events to allow unplanned load shedding to manage post-event network stability issues. The System Operator recommends that the Stability Event classification is removed and replaced with a clause that states that unplanned load shedding can be relied upon to manage network instability following any credible event.

7.3 Categorisation of Credible Events

The System Operator recommends the following changes to the categorisation of credible events.

- There are no credible events specifically classified as Stability Events, although the concept and definition of a stability event should remain.
- The principles applied for Extended Contingent Events (clause 12.5) are amended to include planned post event load shedding as a key mitigation measure.
- The loss of a 220kV interconnecting transformer is classified as an Extended Contingent Event.
- The loss of a 220kV or 110kV or 66kV (connected to a core grid asset) busbar section is classified as an Extended Contingent Event.
- The loss of Reactive Support/SVC fault is classified as a Contingent Event.
- The loss of multiple power system components in close succession is classified as an Other Event.
- The loss of two transmission circuits on the same tower is classified as an Other Event. When a change to environmental or operating conditions indicates there is a high likelihood of occurrence, the event (the loss of a two transmission circuits on the same tower) is re-classified as a Contingent Event in line with international practice.
- The loss of a 110kV interconnecting transformer are considered Other Events.
- The loss of a 66kV busbar section not connected to core grid assets is considered an Other Event.

7.4 Management of Credible Events

The portfolio of management measures available to the system operator are in line with international practice.

With the removal of the Stability Event category, all credible events that are not classed as Contingent Events or Extended Contingent Events should be classed as Other Events. The management measures associated with the Other Event classification should be modified to reflect the change in classification system.

7.5 Summary of Proposed Changes to the Security Policy

Specific credible events in clause 12 should be removed from the Stability Event category. Stability Events should therefore be defined as any credible event the System Operator believes is likely to result in dynamic or transient instability.

A summary of the proposed classification of credible events and the associated measures that may be applied is given in Table 7-1. In addition to the changes required in clause 12, changes may also be required to the demand shedding table in clause 74 of the Policy Statement.

A list of proposed policy statement changes is set out in Appendix 8.

Table 7-1: Summary of Proposed Credible Event Classification and Management

SO Classification	Credible Events	Post-Event Measures
a) Contingent Event	Loss of a single: • Transmission circuit • Generator unit • HVDC Pole • Reactive device (condenser, capacitor, reactor, SVC, RPC) • Large load / load block	24 hour post-contingency ratings or 15 minute off-load ratings Under-frequency reserve & over-frequency reserve Automatic control measures or Special Protection Schemes : • Inter-trips, overload protection • Automatic Under Voltage Load Shedding (AUVLS) • Generation runback • Switching of reactive devices
b) Extended Contingent Event	Loss of a: • HVDC Bipole (both overhead dc circuits) • 220kV Interconnecting Transformer • 220kV or 110kV busbar section • 66kV busbar section connected to core grid assets	Measures for event class a) may be employed in addition to: Automatic planned load shedding Automatic under frequency load shedding (AUFLS)

c) Other	Loss of: • two transmission circuits on the same tower** • multiple power system components in close succession • multiple power system components simultaneously • a non-core grid 66kV busbar • a 110kV interconnecting transformer	Measures for event class a) and b) may be employed in addition to: Manual grid re-configuration Black start generation Unplanned load shedding / demand management: • Demand Reduction (via DAN) • Emergency Demand Shedding & Restoration

** when a change to environmental or operating conditions indicate there is a high likelihood of occurrence the loss of a two transmission circuits on the same tower should be re-classified as a Contingent Event.