2018-22
POWERLINK QUEENSLAND REVENUE PROPOSAL

APPENDIX 5.11 - PUBLIC

Powerlink Queensland
Asset Planning Criteria - Framework

Delivering better value

Powerlink – Asset Planning Criteria - Framework

Policy stream	Asset Management	
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Version history

Version	Date	Section(s)	Summary of amendment
1.0	29/03/2006	All	Original version
1.1	22/06/2010	All	Review and update of document
2.0	10/02/2015	Initial	Update document to reflect amended Transmission Authority No T01/98 - Amended 30 June 2014 (Queensland Government)
2.1	26/08/2015	All	Review and update of document
3.0	13/10/2015	All	Review and updated to level 2 framework format

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1. Introduction

1.1 Purpose

The purpose of this document is to provide an overview of the asset planning criteria framework adopted by Powerlink Queensland (Powerlink).

Powerlink is a Transmission Network Service Provider (TNSP) in the Australian National Electricity Market (NEM) that owns, develops, operates and maintains Queensland's high voltage electricity transmission network.

As a TNSP, Powerlink has specific mandatory obligations under its Transmission Authority, the National Electricity Rules and the Electricity Act 1994 (Qld). In addition, Powerlink is committed to delivering electricity transmission services that are valued by our shareholders, consumers, customers and the market.

The Queensland Government has appointed Powerlink as the Jurisdictional Planning Body (JPB) to assess the capability of the State's transmission network to meet forecast electricity demand, in accordance with the reliability standards for electricity transmission. In order to effectively discharge these obligations, Powerlink has implemented the asset planning criteria framework to align development and re-investment decisions in the high voltage network assets in accordance with its obligations.

1.2 Scope

The legislative and NER obligations must be met for forecast demand and as Powerlink invests and reinvests in its network to manage the condition of existing assets. Powerlink must integrate asset condition and demand based limitations to deliver cost effective solutions that manage both reliability of supply obligations and the condition of existing assets.

The asset planning criteria framework is to be applied consistently for all Powerlink's network development and re-investment decisions. This ensures that decisions are aligned with obligations as a TNSP and consistent with the Queensland Government's expectations.

1.3 References

Document code	Document title
TA N0 T01/98 - Amended 30 June 2014	Transmission Authority No T01/98 - Amended 30 June 2014 (Queensland Government)
ASM-I&P-FRA-A2338088	Powerlink – Joint Planning Framework

1.4 Defined terms

Terms	Definition
NER	National Electricity Rules
RIT-T	Regulatory Investment Test for Transmission
RIT-D	Regulatory Investment Test for Distribution
TAPR	Transmission Annual Planning Report
DAPR	Distribution Annual Planning Report
TNSP	Transmission Network Service Provider
DNSP	Distribution Network Service Provider
NSP	Network Service Provider
AER	Australian Energy Regulator
AEMC	Australian Energy Market Commission
AEMO	Australian Energy Market Operator
NEM	National Electricity Market
NTNDP	National Transmission Network Development Plan
PSCR	Project Specification Consultation Report
PADR	Project Assessment Draft Report
PACR	Project Assessment Conclusion Report
JPB	Jurisdictional Planning Body

1.5 Roles and responsibilities

Who	What
Main Grid and Controls Manager	Ensuring that the Asset Planning Criteria - Framework is aligned with Powerlink's Transmission Authority, the National Electricity Rules and the Electricity Act 1994 (Qld).
Main Grid and Controls Manager and Regional Grid Controls Manager	Ensure the Asset Planning Criteria is applied consistently to all of Powerlink's network developments.

2. Powerlink's Statutory Obligations

Powerlink Queensland (Powerlink) is a transmission entity in Queensland, which authorises it under the Queensland Electricity Act, to operate the high voltage transmission grid in the east coast part of Queensland. Powerlink is also a registered Transmission Network Service Provider (TNSP) in the NEM, and must comply with the National Electricity Rules (NER).

Under Queensland legislation, Powerlink has the responsibility to plan for the future Queensland transmission needs, including the interconnection with other networks. These planning obligations are prescribed by Queensland's Electricity Act 1994 (the Act), the National Electricity Rules (NER) and Powerlink's Transmission Authority, issued by the Queensland Government

Section 34 (2) of the Act, provides that Powerlink has a responsibility to:

> *"...ensure, as far as technically and economically practicable, that the transmission grid is operated with enough capacity (and, if necessary, augmented or extended to provide enough capacity) to provide network services to persons authorised to connect to the grid or take electricity from the grid…."*

As a TNSP, Powerlink must also comply with the NER relating to technical performance standards during intact and contingency conditions. The NER sets out minimum performance requirements of the network and connections and requires that reliability standards at each connection point be included in the relevant connection agreement. Schedule S5.1.2.1 of the NER specifies that Powerlink:

> *"… must plan, design, maintain and operate the transmission network to allow the transfer of power from generating units to Customers with all facilities or equipment associated with the power system in service and may be required by a Registered Participant under a connection agreement to continue to allow the transfer of power with certain facilities or plant associated with the power system out of service, whether or not accompanied by the occurrence of certain faults (called "credible contingency events").*

The Transmission Authority requires that Powerlink plans and develops the transmission grid in accordance with good electricity practice, having regard to the value that end users of electricity place on the quality and reliability of electricity services.

These legislative and NER obligations must be met for forecast demand and as Powerlink invests and reinvests in its network to manage the condition of existing assets. Powerlink must integrate asset condition and demand based limitations to deliver cost effective solutions that manage both reliability of supply obligations and the condition of existing assets.

The NER sets out the planning process and requires Powerlink apply the Regulatory Investment Test for Transmission (RIT-T) promulgated by the Australian Energy Regulator (AER) to transmission investment proposals.

3. Variation to Powerlink's Asset Planning Standard

Powerlink's Transmission Authority mandates reliability obligations which formed the basis for decisions on non-discretionary investment in grid augmentations due to load growth or network re-investment up until 1 July 2014. The Transmission Authority required that the network be planned and developed to an N-1 criterion, unless varied by a connection or other agreement. N-1 meant that the network must be able to meet forecast maximum demand during an outage of the most critical single network element.

In April 2014, the Queensland Government advised Powerlink that reforms to Powerlink's electricity network reliability standards would be implemented by removing the obligation to deliver on the N-1 planning standard in preference of a more flexible planning approach. This revised approach officially came into effect on 1 July 2014 and Powerlink's Transmission Authority was amended accordingly (reference 1).

This revised approach is referred to within this document as the Revised Flexible Planning Standard.

4. Powerlink's Transmission Authority – 30 June 2014

On the 30 June 2014, the Queensland State Government reissued the "Transmission Authority – No. T01/98". Clause 6.2 of the Transmission Authority requires that Powerlink:

> *"…plan and develop its transmission grid in accordance with good electricity practice, having regard to the value that end users of electricity place on the quality and reliability of electricity services, such that:*
>
> *(a) If the power quality standards specify different obligations during normal and other operating conditions – the power quality standards will be met by the transmission entity;*
>
> *(b) If the power quality standards do not specify different obligations during normal and other operating conditions – the power quality standards will also be met by the transmission entity even during the most critical single network element outage; and*
>
> *(c) The power transfer available through the power system will be such that the forecast of electricity that is not able to be supplied during the most critical single network element outage will not exceed:*
>
> *I. 50 megawatts at any one time; or*
>
> *II. 600 megawatt-hours in aggregate.*
>
> *6.3 The obligations imposed on the transmission entity by clause 6.2 will apply unless otherwise varied by*
>
> *(a) a connection or other agreement made by the transmission entity with a person who receives or wishes to receive transmission services, in relation to those services; or*
>
> *(b) agreement with the Regulator."*

Clause 6.2 of the Transmission Authority requires Powerlink to plan and develop its transmission grid in accordance with good electricity practice. The requirement to apply "good electricity practice" requires a range of supporting technical standards to be defined.

Whilst the components of the flexible planning standard are not specifically defined by the NER or in the State Government legislation, the flexible planning standard must be defined for the required statutory outcomes to be achieved. This framework documents the elements of Powerlink's Revised Flexible Planning Standard.

5. Asset Planning Criteria Framework

The planning standard permits load to be interrupted following a *credible contingency event*. However, limits have been placed on the maximum load and energy that may be at risk of not being supplied following a *credible contingency*. The maximum load at risk must not exceed 50MW and no more than 600MWh of energy is to be lost at any one time.

For convenience the planning standard will be referred to as “N-1-50MW”.

Credible contingency events that are to be taken into account when assessing whether the N-1-50MW criterion is met are defined in Schedule 5.1.2.1 of the NER.

Credible contingency events include the disconnection of any single generating unit (or large individual customer load), transmission circuit or transmission plant (e.g. transformer, reactive power device, but not limited to) with or without the application of a single circuit two-phase-to-ground solid fault at 110kV or above.

When considering the application of a fault, Schedule 5.1.2.1 of the NER allows the fault to be cleared in primary protection time by the faster of the duplicate protection schemes with installed intertrips available.

Satisfying the “N-1-50MW” criterion means that following the credible contingency event, the power system settles to a “*satisfactory*” operating state without requiring more than 50MW of non-interruptible load (and 600MWh) to be shed immediately following the contingency.

The network should have sufficient capacity to accommodate AEMO’s operating obligations which include the re-dispatch of generation and ancillary services following a first contingency, such that within 30 minutes, the power system can again be returned to a “*secure*” state (NER 4.2.6(b)(1)). *Satisfactory* and *secure* operating states are defined in sections 5.2 and 5.3 respectively.

5.1 Load at Risk

The maximum load at risk must not exceed 50MW and 600MWh at any one time following a *credible contingency event.* These risk limits are “planning” standards. That is, the limits are assessed relative to the forecast maximum demand and energy (refer to Section 8.1).

By their very nature forecasts are uncertain. As too are the daily load profiles that aggregate to the energy forecast. As such, the load and energy at risk are quantified by scaling load (within the relevant area, zone or connection point) until the *satisfactory* and *secure* operating states are achieved.

It is acknowledged that there may be differences between the “planning level” load at risk and the actual load at risk once operational constraints are taken into account (i.e. the discrete load blocks that are shed at the TNSP and DNSP substations). However, extra complexity could be considered if the load blocks to shed are very coarse and the risk would exceed the 50MW limit. This could be the case when the nature of the network limitation requires automated load shedding but the controllable load that can be disconnected is disproportionate to the violation of the limitation. As a consequence, exceptions to the “scaling” approach can be considered.

The 50MW load shed limit is also assumed to apply at all times following a *credible contingency event* with no allowance for greater load to be shed before auto changeovers restore the load shed within the 50MW limit.

However, it should also be noted that for both these examples the Transmission Authority allows for a flexible approach. The risk can be varied by:

(a) a connection or other agreement made by the transmission entity with a person who receives or wishes to receive transmission services, in relation to those services; or

(b) agreement with the Regulator.

In all cases Powerlink will implement contingency plans, manual procedures and automatic schemes as required to ensure that the reliability of supply to consumers and customers is maximised.

5.2 Satisfactory Operating State

A *satisfactory* operating state is described in Chapter 4.2.2 of the NER.

"The power system is defined as being in a satisfactory operating state when:

(a) the frequency at all energised busbars of the power system is within the normal operating frequency band, except for brief excursions outside the normal operating frequency band but within the normal operating frequency excursion band;
(b) the voltage magnitudes at all energised busbars at any switchyard or substation of the power system are within the relevant limits set by the relevant Network Service Providers in accordance with clause S5.1.4 of schedule 5.1;
(c) the current flows on all transmission lines of the power system are within the ratings (accounting for time dependency in the case of emergency ratings) as defined by the relevant Network Service Providers in accordance with schedule 5.1;
(d) all other plant forming part of or impacting on the power system is being operated within the relevant operating ratings (accounting for time dependency in the case of emergency ratings) as defined by the relevant Network Service Providers in accordance with schedule 5.1;
(e) the configuration of the power system is such that the severity of any potential fault is within the capability of circuit breakers to disconnect the faulted circuit or equipment; and
(f) the conditions of the power system are stable in accordance with requirements designated in or under clause S5.1.8 of schedule 5.1"

Schedule S5.1.8 of the NER requires:

(a) the power system to remain in synchronism;
(b) power system oscillations to be adequately damped; and
(c) voltage stability criteria to be satisfied.

following any *credible contingency event*.

These power system stability criteria are further defined in Section 8.4.

5.3 AEMO's Obligation to return the Power System to a Secure State

Section 4.2.4(a) of the NER defines a *secure* operating state as:

"The power system is defined to be in a secure operating state if, in AEMO's reasonable opinion, taking into consideration the appropriate power system security principles described in clause 4.2.6:

(1) the power system is in a satisfactory operating state; and
(2) the power system will return to a satisfactory operating state following the occurrence of a single credible contingency event in accordance with the power system security and reliability standards."

Section 4.2.6 of the NER (General principles for maintaining power system security) defines AEMO's obligations with regard to operating the interconnected power system in a *secure* state.

"The *power system security* principles are as follows:

(a) To the extent practicable, the power system should be operated such that it is and will remain in a secure operating state.
(b) Following a contingency event (whether or not a credible contingency event) or a significant change in power system conditions, AEMO should take all reasonable actions:
  (1) to adjust, wherever possible, the operating conditions with a view to returning the power system to a secure operating state as soon as it is practical to do so, and, in any event, within thirty minutes;"

Actions considered reasonable by AEMO to return the power system to a *secure* operating state include:

- re-rate transmission plant as agreed
- implement agreed network switching solution
- re-dispatch generation and dispatchable load
- re-distribute ancillary services, and
- where there is no other alternative, shed load.

Following any operational rating adjustment allowed by prevailing weather conditions and network switching, AEMO will redispatch available generation and/or dispatchable load to return the system to a new secure state. As such, the generation assumptions used to assess whether or not this can be achieved may be quite different from those assumptions used to assess the reliability standard for the initial single contingency event (N-1-50MW). The most notable difference may be the maximum dispatch of any available energy limited plant following the initial contingency. These generation assumptions are dealt with in more detail in Section 8.2.

If AEMO can only return the power system to a secure operating state following an initial contingency by shedding non-interruptible load in excess of 50MW (before the second contingency), then the power system fails to meet the planning standard.

However, if further tripping of non-interruptible load, even beyond the first 50MW, can be shed following the second contingency such that the system then falls to a satisfactory operating state, then the power system still satisfies the revised flexible planning standard.

For convenience, this requirement will be referred to as meeting the (N-1-50MW Secure) criterion throughout the rest of this document.

The requirement to shed load either immediately following the first contingency or following the second contingency depends on the failure mode of the system when subjected to the second contingency. If the power system is dynamically unstable (transient or oscillatory) following the second contingency, then load must be shed pre-contingent. However, if the limitation is the thermal rating of plant, then the response to place the system at a satisfactory operating point may be post-contingent. If the failure mode is voltage instability then the required timeframe for the load-shed response must be carefully considered.

Before additional non-interruptible load is shed prior to the second contingency (therefore violating the revised planning standard), consideration must be given to the technical and economic viability of implementing system integrity protection schemes (SIPS) to mitigate system security and plant overload risks. Successful implementation of SIPS may mitigate the need for more expensive investment options.

6. Regulatory Investment Test for Transmission

The NER sets out the planning process and requires Powerlink to apply the RIT-T, promulgated by the AER, to transmission investment proposals.

The RIT-T specifies that Powerlink must identify the commercially and technically feasible option that maximises the present value of the net economic benefit to all those who produce, consume and transport electricity in the market. This requires the market benefit of each credible option (network and/or non-network) to be considered and, if material, quantified.

The materiality threshold is if classes of market benefits impact the ranking and timing of credible network and/or non-network options. The RIT-T prescribes the use of “market dispatch modelling methodology” to quantify these market benefits, unless this analysis methodology is not proportional to the scale and likely impact on each credible option.

The various classes of market benefits that may need to be considered are:

(a) changes in fuel consumption
(b) changes in voluntary load curtailment
(c) changes in involuntary load shedding
(d) changes in costs for parties, other than the TNSP, due to:
    I. differences in the timing of new plant
    II. differences in capital costs, and
    III. differences in the operational and maintenance costs
(e) differences in the timing of transmission investment
(f) changes in network losses
(g) changes in ancillary services costs
(h) competition benefits arising from the impact on participant bidding behaviour
(i) option value, and
(j) negative of any penalty paid or payable for not meeting the renewable energy target,

In the case of network and/or non-network investments, whose primary focus is to improve the efficient operation of the NEM, it is essential that the relevant classes of market benefit are rigorously assessed. However, for reliability based investment decisions this requirement may be less onerous. The appropriate analysis methodology must still be assessed on a case by case basis.

As the planning standard (N-1-50MW) permits some load to be interrupted following a credible *contingency event*, changes in the cost of losses and involuntary load shedding must be at least considered in assessing the timing and ranking of options for investment.

7. Joint Planning

Powerlink's transmission network planning and development responsibilities include developing recommendations to address emerging network limitations through joint planning. Joint planning while mainly focused on the DNSPs and TransGrid, can also include consultation with AEMO, other Registered Participants, load aggregators and other interested parties.

Solutions may include network upgrades or non-network options such as local generation and demand side management initiatives. The objective of joint planning is to identify the most cost effective solution, regardless of asset boundaries, including potential non-network solutions.

Energex and Ergon Energy have been issued amended Distribution Authorities in July 2014. The service levels defined in their respective Distribution Authority differ to that of Powerlink's.

Joint Planning accommodates these different planning standards by applying the planning standard consistent with the owner of the asset which places load at risk following a *credible contingency event*.

The joint planning framework adopted by Powerlink in relation to its interactions with other network service providers (NSPs) in accordance with the requirements set out in the National Electricity Rules (Rules) is defined in Powerlink – Joint Planning Framework document.

8. Technical Standards

The following section defines the technical standards under which Powerlink will meet its statutory obligations.

8.1 Load Forecast

The NER requires that investment decisions be based on a cost benefit analysis which includes an assessment of reasonable scenarios of future supply and demand growth. The central, or highest probability, scenario will be based on the medium growth load forecast published in Powerlink's most recent Transmission Annual Planning Report. If planning for a local supply area or zone adjustments will be made to the load forecast to reflect the coincident peak of that area or zone.

For each relevant future supply and demand scenario, planning of the main transmission system to meet the revised flexible planning standard will be based on the 10% Probability of Exceedance (PoE) load forecast (zonal or multiple zone coincident peak). This standard is broadly adopted across the Electricity Supply Industry and is consistent with good industry practice. The main transmission system is defined as transmission lines, transformers and assets connected to Powerlink's high voltage interconnected network at 275kV or above. Therefore, this extends to the provision of adequate transformation capacity at Powerlink's major substations that supply bulk power to each zone (i.e. 275/132kV and 275/110kV).

Consistent with DNSPs, the 50% PoE load forecast is to be used to identify the limitations within the zones. Allowance is made to consider the most onerous of the 50% PoE zone or local peak forecast. However, Powerlink's transmission system must be capable of meeting the forecast 10% PoE peak load (zonal or multiple zones) with all network elements in service and the power system within a satisfactory and secure operating state.

8.1.1 Load Power Factor

The load power factor to be applied is obtained for the DNSPs and major customers connected to the Powerlink network during the load forecasting process. Powerlink prepares reactive forecasts in consultation with DNSPs and major customers. The resultant power factor is then used to determine the reactive load at other demand levels (e.g. 10% PoE) with adjustments as appropriate.

8.2 Generation

In planning to meet the revised flexible planning standard assumptions relating to generation availability, dispatch and capability are important. The generation assumptions take account of:

- number of generating units of influence in the area or zone
- age, technology and reliability
- energy limitations of any plant
- external factors (e.g. water availability, fuel supply, environmental restrictions etc.) that may impact on the generation capacity (both short and long term) and availability, and
- linkages that may exist between different generation sources within a zone or region with respect to critical resource availability (e.g. water, fuel). Such linkages may mean that if one of the power stations is experiencing constraints, there is a high likelihood that several of the other power stations may also be constrained for similar reasons or be constrained as an operating consequence from the constraint on the first power station.

8.2.1 Coincident Generator Outage

Generator outages are an inevitable occurrence. Notwithstanding good operating and maintenance practices, full availability of generation can never be guaranteed. In addition, hot weather places additional stress on plant and may increase the likelihood of failure.

As generators have significantly lower availabilities than transmission network elements, reliance on any individual generating unit cannot be made when considering network reliability obligations.

As a result, Powerlink plans and develops its transmission grid in accordance with good electricity practice such that power quality and the reliability standards, defined in the NER and in Powerlink's Transmission Authority, are met under a number of generation dispatch patterns including consideration of the most critical generation unit outage affecting the area or zone of study.

The risk limit of 50MW will be assessed with the most critical generating unit affecting the area or zone of study out of service.

However, for the energy risk limit (600MWh) the outage duration should be taken into account. For example, if the critical contingency is an outage of a transmission line, with a typical restoration time in the hours, then it is conceivable that there may be a coincident generator unit outage for the entire duration of the transmission line outage. However, if the critical contingency is a transformer, with a replacement time in weeks, then it may not be reasonable to assume that the critical generator unit is also out of service for the entire duration of the transformer outage. In assessing the energy at risk the following should be taken into account:

- major generator unit overhauls and planned outages. These are assumed not to coincide with peak load conditions when supply reliability limitations may emerge.
- unplanned/forced generator outages. Unplanned or forced generation outages could coincide with the most onerous period of network loading.
- constraints on generation. When the generating unit is available load should not be placed at risk in lieu of constraining generation. If generation is an alternative to managing the network limitation then changes in the cost of fuel consumption need to be considered as a class of market benefits. This may require use of "market dispatch modelling methodology".

8.2.2 Generator Reactive Power Capability

Unless otherwise contracted, the reactive power capability of all generators is assumed to conform to their registered performance standards.

Additional reactive capability may be procured to maintain power system security, meet the required flexible reliability standard, and/or to maintain or increase the power transfer capability of the transmission network. In all cases the cost of procuring this service must be included in the RIT-T analysis.

8.3 Rating of Transmission Equipment

The NER prescribes that the current flows on all transmission lines and plant of the power system are within the ratings (accounting for time dependency in the case of emergency ratings) defined by the relevant Network Service Providers in accordance with schedule 5.1.

8.3.1 Transmission Lines

For planning the network, Powerlink uses fixed ratings for both system normal operation and following a contingency event, which will prevent line conductors violating statutory clearances under a range of expected ambient conditions.

For system normal operation, the sustained flow on a transmission line must not exceed the normal continuous rating.

The maximum sustained flow on a transmission line following a contingency event is based on not exceeding the contingency rating. The contingency rating is based over a shorter time span than the normal continuous rating and therefore presents opportunity for a slightly higher rating without increasing risk.

The transmission lines are normally loaded more heavily relative to their rating in summer compared to other times of the year. As a result, the line ratings coincident with hot summer day ambient conditions are usually most relevant when assessing supply reliability. However, line ratings coincident with other periods of the day or year may be critical when:

- assessing the market benefits of options where time sequential analysis is required across the year,

- peak forecast demand occurs outside the normal summer daytime period, or
- long term network outages are required to implement options and these outages are taken during non-peak load periods.

Where appropriate, consideration can also be given to loading a transmission line beyond its relevant contingency rating following a contingency event but prior to implementing network switching and/or load curtailment. In this instance the dynamic temperature response of the conductor must be modelled to determine the time delay before the conductor reaches its design temperature. This analysis requires consideration of the pre and post contingent loading and the applicable ambient conditions. If the temperature of the conductor is assessed to reach its design temperature within 10 minutes then network switching and/or load curtailment must be automated by implementing system integrity protection schemes (SIPS). SIPS should be graded with protection and other relevant control schemes (e.g. auto reclose) to maximise supply reliability but also manage the risk of overloading plant.

8.3.2 Transformers

For system operation, Powerlink has assigned normal cyclic, emergency cyclic, short term emergency (2-hour) and short term maximum ratings (10-minute) for each transformer. For planning the network, the same ratings are applied with the following guidelines:

Powerlink’s transformer rating policy is based on not exceeding the emergency cyclic rating following a contingency event and any subsequent mitigating action to curtail the loading (e.g. load transfer between connection points, network switching, voluntary load shedding and/or involuntary load shedding within the planning standard).

Under no circumstances is the immediate post contingent loading of the transformer to exceed the short term maximum rating.

If the initial post contingent flow through the transformer exceeds the short term emergency (2-hour) rating, then any mitigating action to curtail the loading must be automated.

8.4 Power System Stability

Schedule S5.1.8 of the NER requires the power system to be stable following any credible single contingency event. Instability can manifest itself as transient, oscillatory of voltage instability.

8.4.1 Transient Stability

Transient stability is assessed on the basis of rotor angle swings following credible contingency events. These contingencies can include the trip of a generating unit or customer load, or an outage of a transmission element. In accordance with the NER, if the critical contingency is an outage of a transmission element then this may be preceded by the application of a solid two phase-to-ground fault on one circuit at the most critical location. The fault is assumed to be cleared by the faster of the primary protection systems with the full availability of intertrips.

8.4.2 Oscillatory Stability

The requirements for controlling oscillatory stability are defined in schedule 5.1.8 of the NER. For planning purposes, oscillatory stability (or system damping) is considered to be adequate under any given operating condition if, after the most critical contingency event, predictions indicate that the halving time of the least damped electromechanical mode of oscillation is not more than 5 seconds.

The prediction of the oscillatory stability performance of the system is to be undertaken using software and models that have been calibrated against system tests.

8.4.3 Voltage Stability

Schedule 5.1.8 of the NER defines the general requirement for voltage stability:

> *"The voltage control criterion is that stable voltage control must be maintained following the most severe credible contingency event. This requires that an adequate reactive power margin must be maintained at every connection point in a network with respect to the voltage stability limit as determined from the voltage/reactive load characteristic at that connection point. Selection of the appropriate margin at each connection point must be at the discretion of the relevant Network Service Provider, subject only to the requirement that the margin (expressed as a capacitive reactive power (in MVAr)) must not be less than one percent of the maximum fault level (in MVA) at the connection point."*

The voltage stability limits for various parts of the transmission system are to be assessed by determining the maximum power transfer (or load level) above which the reactive power margins are no longer preserved at key buses following a critical *credible contingency event*.

The assessment methodology does not allow for the determination of the reactive power (MVAr) margins at every connection point in the network. Rather, Powerlink recognises the existence of "coherent bus groups" and therefore selects key buses that will be reasonably representative of buses in the neighbourhood. In general, different MVAr margin observation buses will be selected to determine different transmission limits for different contingencies. The appropriate MVAr margins of these key buses will be reassessed from time to time, but are not less than 1% of the maximum fault level at that bus.

In making this assessment Powerlink is also cognisant of the effect high levels of reactive power compensation have on the characteristics and operability of a heavily loaded network. Therefore, maintaining reactive power margins by adding ever increasing amounts of reactive power compensation is not sustainable. High levels of compensation erode key operational measures such that bus voltage is no longer a reliable indicator of system health or proximity to voltage instability. In fact voltage instability may occur at voltages within operational limits. Such system characteristics must be avoided.

The assessment of system performance must also comply with the power quality system standards as defined in schedule 5.1.4 to schedule 5.1.7 of the NER

The voltage stability limits of the power system are very dependent on the location and capability (both real and reactive power) of generators. The generation assumptions to be applied have previously been discussed in Section 7.2. Of great significance also are the power factor of the load and the availability of static capacitor banks, both at the transmission and distribution voltage levels.

8.5 Fault Levels

The network must be operated within the fault breaking capability of circuit breakers to ensure that faulted plant can be removed from the system quickly and safely.

At no time should the contribution that the circuit breaker must interrupt of the total fault current, or the through current exceed the plant capability.

These short circuit currents are calculated assuming:

- All scheduled and significant embedded non-scheduled generators are in-service;
- Fault level contributions from significant embedded non-scheduled generators are included in the analysis;
- Generators are modelled as 110% of nominal voltage behind sub-transient reactance;
- Classical network model is used where all transformer taps set to nominal and system loads and all shunt admittances not represented;
- Maximum fault contribution from inter-regional interconnections; and
- Normally open connections are treated as open.

9. Distribution list

Internal	Contact details
☒ Investment and Planning	Group Manager Strategy and Planning Group
☒ Operations and Field Services	Group Manager Network Operation Services

Appendix A – Powerlink's Transmission Grid