

1 Electricity transmission reliability standards – optimisation model inputs and assumptions

This document describes the inputs and assumptions used in the optimisation model.

The model finds the 'least total cost' set of planning criteria (see 1.1) for each BSP, where *total cost* = *cost of supply arrangements* + *cost of expected unserved energy*.

Where two or more sets of planning criteria produce the same total cost, the model selects the set which involves the least load at risk and the quickest restoration time.

In calculating total costs, the model includes the following scenarios:

- ▼ system normal
- ▼ a single transformer failure
- ▼ a single line failure
- ▼ a double transformer failure, and
- ▼ a double line failure.

1.1 Planning criteria

The model uses **planning criteria** to inform both the cost of expected unserved energy and the cost of supply arrangements.

The planning criteria include the required level of redundancy at each BSP. The model is able to find the optimal level of redundancy at each BSP. However, we have recommended that the level of redundancy at each BSP remains the same as that which is required by the current electricity transmission reliability standard.

The values for other planning criteria are determined through the optimisation process. For each of these criteria, the model defines a range of discrete options. The criteria cover:

- ▼ **Load at risk** - load supplied from the BSP which is at risk of being interrupted, **after** allowing for any available backup capacity but **before** repair of the asset/s.

- ▼ **Restoration strategy** - the strategy to bring any available backup capacity into service following an asset failure or failures. An integer parameter from 0 to 5 is defined to select different forms and timescales of switching to the backup supply capacity, from no switching allowed (ie, no backup capacity), to automatic switching, remote switching and manual switching. This criterion imposes design requirements on switching arrangements.
- ▼ **Repair strategy** - the strategy to repair the failed asset(s) to their normal service levels (or to replace failed asset(s)). An integer parameter from 1 to 4 is defined to reflect the length of repair time, with longer repair times requiring less costly actions to achieve. This criterion imposes requirements on the management of spares, asset procurement and repair and replacement protocols.

The model assumes an upper bound for repair of transformers of 15,351 hours, repair of overhead lines of 120 hours, and repair of underground cables of 2,016 hours. These values were based on consultant advice to IPART, and correspond to the least-cost repair options.

Table 1.1 Planning criteria (0 level of redundancy required, ie, N standard)

Planning criteria	Range of possible values		
	System normal (no failures)	Single failure	Double failure ^a
Load at risk for transformers	0%, 10%, 20%, ..., 80% 90%	n/a	n/a
Load at risk for lines	0%, 10%, 20%, ..., 80% 90%	n/a	n/a
Restoration strategy (same for transformers, lines and cables)	n/a	n/a	n/a
Repair strategy for transformers ^b	n/a	1 = 24 hrs 2 = 720 hrs 3 = 6,579 hrs 4 = 8,772 hrs	Equal to repair strategy for single failure
Repair strategy for overhead lines	n/a	1 = 8 hrs 2 = 24 hrs 3 = 48 hrs 4 = 120 hrs	Equal to repair strategy for single failure
Repair strategy for underground cables	n/a	1 = 168 hrs 2 = 672 hrs 3 = 1,344 hrs 4 = 2,016 hrs	Equal to repair strategy for single failure

^a Many BSPs with 0 level of required redundancy (N standard) may only have one transformer or line. For these BSPs the planning criteria for a double failure are not relevant. However, some BSPs with 0 level of required redundancy (N standard) may have multiple transformers or lines. For example, three transformers might supply a load and a failure of any one of the three transformers would mean that the required supply cannot be met. In this situation, the repair strategy for transformers becomes relevant.

^b The repair times for transformers have been updated since IPART's Draft Report, based on advice from TransGrid.

Data source: IPART based on consultant advice and advice by TransGrid.

Table 1.2 Planning criteria (1 level of redundancy required, ie, N-1 standard)

Planning criteria	Range of possible values		
	System normal (no failures)	Single failure	Double failure
Load at risk for transformers	0%	0%, 10%, 20%, ..., 80% 90%	n/a
Load at risk for lines	0%	0%, 10%, 20%, ..., 80% 90%	n/a
Restoration strategy (same for transformers, lines and cables) ^a	n/a	0 = 0 1 = 0-5 mins 2 = 5 to 30 mins 3 = 0.5 to 1 hr 4 = 1 to 4 hrs 5 > 4 hrs	n/a
Repair strategy for transformers ^b	n/a	1 = 24 hrs 2 = 720 hrs 3 = 6,579 hrs 4 = 8,772 hrs	Equal to repair strategy for single failure
Repair strategy for overhead lines	n/a	1 = 8 hrs 2 = 24 hrs 3 = 48 hrs 4 = 120 hrs	Equal to repair strategy for single failure
Repair strategy for underground cables	n/a	1 = 168 hrs 2 = 672 hrs 3 = 1,344 hrs 4 = 2,016 hrs	Equal to repair strategy for single failure

^a A restoration time of 0 means that no backup is available. The model assumes a restoration time of 8 hours for strategy option 5.

^b The repair times for transformers have been updated since IPART's Draft Report, based on advice from TransGrid.

Data source: IPART based on consultant advice, and advice from TransGrid.

Table 1.3 Planning criteria (2 levels of redundancy required, ie, N-2 standard)

Planning criteria	Range of possible values		
	System normal (no failures)	Single failure	Double failure
Load at risk for transformers	0%	0%	0%, 10%, 20%, ..., 80% 90%
Load at risk for lines	0%	0%	0%, 10%, 20%, ..., 80% 90%
Restoration strategy (same for transformers, lines and cables) ^a	n/a	0 = 0 1 = 0-5 mins 2 = 5 to 30 mins 3 = 0.5 to 1 hr 4 = 1 to 4 hrs 5 > 4 hrs	0 = 0 1 = 0-5 mins 2 = 5 to 30 mins 3 = 0.5 to 1 hr 4 = 1 to 4 hrs 5 > 4 hrs But such that it is longer than or the restoration time for a single failure.
Repair strategy for transformers ^b	n/a	1 = 24 hrs 2 = 720 hrs 3 = 6,579 hrs 4 = 8,772 hrs	1 = 24 hrs 2 = 168 hrs 3 = 2,190 hrs 4 = 4,380 hrs But such that it is longer than or equal to the repair time for a single failure.
Repair strategy for overhead lines	n/a	1 = 8 hrs 2 = 24 hrs 3 = 48 hrs 4 = 120 hrs	1 = 8 hrs 2 = 24 hrs 3 = 48 hrs 4 = 120 hrs But such that it is longer than or equal to the repair time for a single failure.
Repair strategy for underground cables	n/a	1 = 168 hrs 2 = 672 hrs 3 = 1,344 hrs 4 = 2,016 hrs	1 = 168 hrs 2 = 672 hrs 3 = 1,344 hrs 4 = 2,016 hrs But such that it is longer than or equal to the repair time for a single failure.

^a A restoration time of 0 means that no backup is available. The model assumes a restoration time of 8 hours for strategy option 5.

^b The repair times for transformers have been updated since IPART's Draft Report, based on advice from TransGrid.

Data source: IPART based on consultant advice, and advice from TransGrid.

1.2 Existing network inputs and assumptions

The model also uses input data and assumptions about the existing network and demand for electricity to inform both the cost of expected unserved energy and the cost of supply arrangements.

It uses the following input data, supplied by TransGrid, which is specific to each BSP:

- ▼ estimated maximum demand for 2018-19 (50% Probability of Exceedance (POE) forecast)¹
- ▼ actual number of transformers, and
- ▼ actual number of lines.

For simplicity it assumes that:

- ▼ each transformer at each BSP is of equivalent capacity
- ▼ each line at each BSP is of equivalent capacity, and
- ▼ lines at each BSP are all either overhead or underground.

Where necessary to meet required level of redundancy, the model will increase the number of transformers or lines at a BSP. For example, if an N-2 BSP has only two transformers and no ability to switch to backup capacity, the model will add one transformer to allow the N-2 requirement to be met.

While the number of transformers and lines is based on the actual configuration at the BSP (subject to the caveat in the prior paragraph), the sizing of these assets is done dynamically by the model. Normally the assets are sized so that the maximum demand can just be met. For example, at a BSP with four transformers and a maximum load of 100 MW, each transformer would be sized to 25 MW capacity. However, if the transformer load at risk criterion is set to 40%, then the model will “shrink” the transformers so that each would be sized to 15 MW capacity.

IPART estimated line lengths based upon the location type for each BSP (ie, whether it is CBD, suburban, regional, or remote).

¹ Probability of Exceedance (POE) refers to the likelihood that a maximum demand forecast will be met or exceeded. A 50% POE maximum demand projection is expected to be exceeded, on average, five years in 10.

Table 1.4 Estimated line lengths

Location type	Estimated line length (km)
CBD	15
Suburban	30
Regional	150
Remote	300

Data source: IPART estimates.

1.3 Cost of supply arrangements

The supply arrangement costs cover the capital and operating costs for the following elements:

- ▼ transformer and line capacity
- ▼ backup capacity and restoration obligations, and
- ▼ repair obligations.

Transformer and line capacity costs provide the cost of system capacity in its normal state, ie, no asset failures. The cost of backup capacity, restoration obligations and repair obligations drive the cost of system capacity to deal with a single or double asset failure.

The model only includes costs that vary when the planning criteria change. This means, for example, that it excludes the cost of substation land, fencing and other site costs as they are the same across all the possible planning criteria.

1.3.1 Capital cost of transformer and line capacity

Life time capital costs

The model uses a power law to calculate the capacity cost of transformers and lines of a given MW rating.² It then multiplies the cost per transformer/ line circuit for each BSP by the number of transformers/ lines at each BSP.

Transformer unit costs are calculated using the following equation:

$$\text{Cost} = c.MW^b$$

where:

$$c = 0.094214$$

$$b = 0.640401$$

² It assumes that transformers (and circuits) of any capacity can be purchased at a price given by the power law function. In practice, organisations like TransGrid tend to buy transformers of standard types and sizes to minimise purchase prices and inventory costs.

IPART derived the values for 'c' and 'b' by fitting a power law function to transformer purchase price data provided by TransGrid.

For **lines**, the capacity cost is multiplied by the line length to give a per circuit cost. An underground scaling factor is applied if the circuit is defined as an underground (UG) cable. Line circuit costs are calculated using the following equation:

$$\text{Cost} = (\text{UG scaling factor if UG cable}) \cdot \text{km} \cdot c \cdot \text{MW}^b$$

where:

$$c = 0.024784$$

$$b = 0.640401$$

$$\text{UG scaling factor} = 15$$

IPART assumed the value for 'b' in the line equation is the same that is used in the transformer equation. The value for 'c' and the underground scaling factor were based on consultant advice to IPART. The assumed line lengths are shown in Table 1.4.

Cost multipliers are applied to the unit costs for transformers and circuit costs for lines to allow for installation. The multipliers vary by location type and the values used are shown in Table 1.5.

Table 1.5 Transformer and line cost multipliers

Location type	Transformer cost multipliers	Overhead line cost multipliers	Underground cable cost multipliers
CBD	2	2	1
Suburban	1.5	1.5	1
Regional	1	1	1
Remote	1.5	1.5	1

Data source: IPART based on consultant advice.

Annualising capital costs

Transformer and line capacity capital costs are transformed to an average annual basis using the following formula:

$$\text{Annualised capital cost} = d \cdot \text{capital cost} / [(1 - (1 + d)^{-L}) \cdot (1 + d)];$$

where d = discount rate

L = life of asset

Discount rate

The model assumes a discount rate of 5.6% (real pre-tax).³

Life of asset

The model assumes the following asset lives, based on TransGrid's Regulatory Information Notice submitted to the AER:

- ▼ Transformer average life = 40 years.
- ▼ Overhead line average life = 50 years.
- ▼ Underground cable average life = 45 years.⁴

1.3.2 Backup capacity and restoration obligation costs

The total cost per MW of transformer and line capacity at each BSP is used as a proxy to cost backup capacity.⁵ There are two further assumptions that scale these costs down:

- ▼ it is assumed backup capacity is shared between two BSPs, and therefore, only 50% of the cost is assigned to the BSP being assessed, and
- ▼ an additional efficiency factor of 50% is included to allow for backup capacity primarily being installed to service other requirements (For example, backup capacity may be provided by the distribution network, but it is likely that this distribution capability will also be being used for its own supply purposes. Therefore, only part of the distribution network costs are assigned to backup for the transmission system).

The costs of equipment or labour associated with having and using backup capacity include:

- ▼ the capital costs associated with any facilities or services necessary to achieve the required restoration times (eg, automatic control schemes), and
- ▼ the operating costs associated with using these facilities or services, when an asset failure occurs.

³ Using IPART's WACC methodology sampled to 22 July 2016 for inflation and interest rates, and to the end of June 2016 for market risk premium and debt margin.

⁴ The asset lives have been updated since the Draft Report.

⁵ Note: backup capacity could be provided by various forms that are not explicitly modelled.

Table 1.6 Backup capacity and restoration strategy costs

Restoration time	Form of switching	Fixed capital cost (\$m)	per MW capital costs (\$m)	Fixed operating cost (per use) (\$m)	per MW operating cost (per use) (\$m)
0	firm - no requirement for switching	-	-	-	-
0 to 5 mins	fast-automatic	1.000	0.002	-	-
5 to 30 mins	slow-automatic	0.500	0.001	-	-
0.5 to 1 hr	fast-remote	0.100	0.0002	-	-
1 to 4 hrs	slow-remote / manual	-	-	0.050	0.0002
> 4 hrs	manual	-	-	0.100	0.0004

Data source: IPART based on consultant advice.

1.3.3 Repair obligation costs

The costs of equipment or labour associated with repairing (or replacing) assets include:

- ▼ the capital costs associated with any facilities or services necessary to achieve the required repair times (eg, spares, network arrangements, etc), and
- ▼ the operating costs associated with implementing the repair (or replacement), when an asset failure occurs.

Table 1.7 Transformer repair strategy costs

Repair time ^a	Comment	Fixed capital cost (\$m)	per MW capital costs (\$m)	Fixed operating cost (per repair) (\$m)	per MW operating cost (per repair) (\$m)
24 hours	Requires on-site bay spare and fast change over	-	0.0144	0.050	0.001
720 hours	Requires spares and fast installation	-	0.0036	0.100	0.003
6,579hours	Fast procurement, delivery and normal installation	-	-	-	0.0018
8,772 hours	Normal procurement, delivery and installation	-	-	-	-

^a The repair times for transformers have been updated since IPART's Draft Report, based on advice from TransGrid.

Data source: IPART based on consultant advice and advice from TransGrid.

Table 1.8 Overhead line repair strategy costs

Repair time	Comment	Fixed capital cost (\$m)	per MW capital costs (\$m)	Fixed operating cost (per repair) (\$m)	per MW operating cost (per repair) (\$m)
8 hours	Requires special equipment and fast response	0.100	0.001	0.050	0.002
24 hours	Requires fast response	-	-	0.050	0.002
48 hours	Enhanced response	-	-	0.050	0.0015
120 hours	Normal response	-	-	0.050	0.0005

Data source: IPART based on consultant advice.

Table 1.9 Underground cable repair strategy costs

Repair time	Comment	Fixed capital cost (\$m)	per MW capital costs (\$m)	Fixed operating cost (per repair) (\$m)	per MW operating cost (per repair) (\$m)
168	requires special equipment, spares and fast response	0.2000	0.0020	0.1000	0.0070
672	requires spares and fast response	-	0.0020	0.1000	0.0070
1,344	enhanced response and repair	-	-	0.0500	0.0025
2,016	normal response and repair	-	-	0.0500	0.0010

Data source: IPART based on consultant advice.

1.3.4 Operating costs

The long-term average annual operating costs associated with capital costs (eg, to cover maintenance activities)⁶ are assumed to be linearly proportional to the calculated capital cost, with a single constant input in the model to define this relationship. The constant used in the model is 2%. That is, the annual operating cost of equipment is 2% of the annual capital cost of the equipment.

The average annual operating costs are separate to the operating costs associated with particular repair or restoration strategies which are only incurred when there is an asset failure.

1.4 Cost of expected unserved energy

1.4.1 Expected amount of unserved energy

The expected unserved energy at each BSP is the sum of the expected amount of unserved energy for each scenario⁷ at that BSP.

The expected amount of unserved energy for each scenario=

expected number of asset failures (forced outages) per year *

duration of supply outage associated with the asset failure(s) *

proportion of annual energy required that cannot be supplied while the asset is in a failed state *

annual energy required (MWh)

Where backup capacity is available, the model calculates:

- 1) the expected unserved energy before switching has occurred, and
- 2) the expected unserved energy after switching has occurred but before repair of the asset.⁸

⁶ These are in addition to operating costs associated with the use of specific restoration or repair strategies as described in sections 1.3.2 and 1.3.3.

⁷ The scenarios are: system normal, a single transformer failure, a single line failure, a double transformer failure and a double line failure.

⁸ For double contingency events (double transformer failures or double line failures) the model performs an equivalent four-stage process as it steps through the two restorations and two repair stages.

Expected number of asset failures (forced outages)

The expected number of asset failures (forced outages) is the probability of asset failure multiplied by the number of assets, for each asset type at each BSP.

The probabilities of asset failure used in the model are summarised in Table 1.10. They are reflective of the average life-cycle failure rates for each asset type. For transformers and overhead lines, IPART derived these values using TransGrid’s historic failure data, weighted by asset subcategory. For underground cables, IPART derived the values from Ausgrid failure data for Inner Sydney, provided by TransGrid. TransGrid provided separate rates for catastrophic transformer failure (requiring replacement) and non-catastrophic transformer failure (not-requiring replacement).

Table 1.10 Asset failure frequency

Asset type	Failure frequency
Transformers (catastrophic failures per year per transformer)	0.557%
Transformers (non-catastrophic failures per year per transformer)	17.0%
Overhead lines (failures per year per 100km)	29.01%
Underground cables (failures per year per 100km)	5.95 %

Data source: IPART based on TransGrid historic performance data and Ausgrid underground failure rates provided by TransGrid.

The model assumes the primary and secondary buses of the transformers are effectively solid and fully switched (ie, a fault on any transformer or line will not automatically result in the outage of other transformers or lines).⁹

Duration of supply outage

The duration of supply outages associated with a particular scenario is determined by the restoration and repair strategies (see section 1.1).

Proportion of annual energy required that cannot be supplied

The model uses a normalised integral of a load duration curve to determine the proportion of annual energy required that cannot be supplied while an asset remains in a failed state. The curve relates the proportion of annual energy required that cannot be served to the proportion of maximum demand that can still be served following a failure event.

The proportion of maximum demand that can be served following a failure event is equal to (1- %load at risk) for the relevant scenario (see section 1.1).

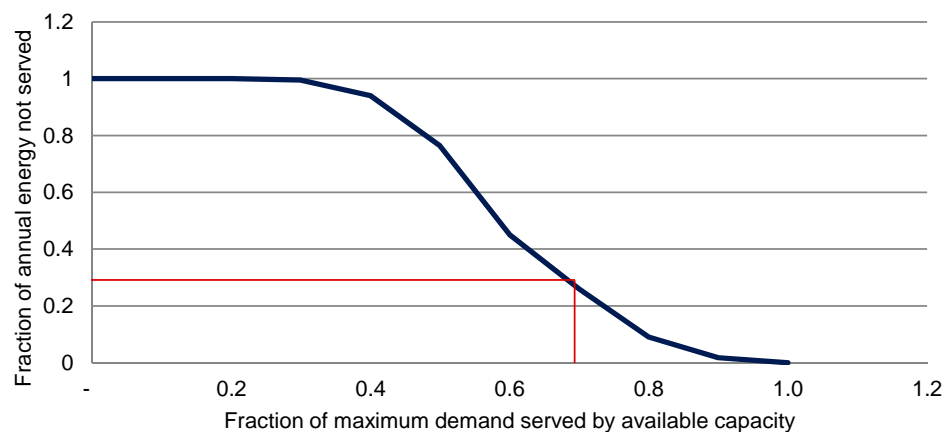
⁹ An underlying assumption is that for actual circumstances where this is not the case, operating arrangements would be such that any “good” assets would be rapidly switched back into service following the fault, such that the resulting actual reliability is approximately equal to these assumed arrangements.

A hypothetical example is provided in Box 1.1.

The model uses curves which are specific to each BSP.¹⁰ IPART derived the curves using TransGrid data (load at 15 minute intervals for the 2011 calendar year).

Box 1.1 Proportion of annual energy required that cannot be supplied if a single transformer fails

Normalised integral of the load duration curve for a hypothetical BSP



In this example, the load at risk if a transformer fails is 30% of maximum demand at the BSP (as set by the planning criteria). Therefore 70% of maximum demand can be served following a transformer failure (ie, capacity is reduced to 70% of maximum demand).

If the transformer failure occurs during a period of low demand then it is likely that the required supply at that point in time could be met. However, if the failure occurs during a period of high demand, then it is possible that none of the required supply could be met.

Because we do not know when a transformer failure will occur, we consider what proportion of energy would be lost if the failure lasts for an entire year (which includes periods of low and high demand). The curve tells us that, on average across all possible moments of failure, around 30% of energy required at this BSP would not be served if capacity of the BSP was reduced to 70% of maximum demand.

Note: If there are load shedding protocols in place, some supply may still be met even if the failure occurs during a period of high demand.

¹⁰ The model used for IPART's Draft Report used TransGrid's state-wide load duration curve.

Annual energy required

The **annual energy required** (MWh) at each BSP is the maximum demand (MW) multiplied by the load factor (%) multiplied by the number of hours in a year.

IPART estimated a load factor for each BSP using TransGrid data (load at 15 minute intervals for the 2011 calendar year).¹¹ Maximum demand assumptions are discussed in section 1.2.

1.4.2 Cost of expected unserved energy

The cost of unserved energy (ie, annual reliability cost) is the total amount of expected unserved energy for each BSP multiplied by the value of customer reliability (VCR) for that BSP.

The model uses the most recent VCRs published by AEMO¹², weighted by customer type at each bulk supply point.

IPART engaged WSP Parsons Brinckerhoff (PB) to recommend VCRs for each bulk supply point, based on the values published by AEMO, weighted by customer type. For bulk supply points that were based on Ausgrid data, PB developed a non-weighted VCR using the straight average of the customer type splits. This is because there was no consumption data provided to undertake a weighted average. Additionally, no weighting was required for direct connect customers as there is only one customer type at each bulk supply point.

Since publishing our Draft Report we have updated the VCRs for some BSPs based on advice from TransGrid, Ausgrid and Essential Energy.

1.5 Unserved energy allowance

The unserved energy allowance for each BSP that IPART has adopted for our recommended reliability standards takes the expected unserved energy associated with the 'least total cost' set of the following planning criteria, given the required level of redundancy:

- ▼ load at risk
- ▼ restoration strategy
- ▼ repair strategy.

¹¹ The model used for IPART's Draft Report had an average load factor of 51% for all BSPs, based on TransGrid's state-wide load duration curve.

¹² AEMO, *Value of Customer Reliability Review - Final Report*, September 2014, pp 2, 18.

To this value we add an allowance for non-catastrophic transformer failure. While the optimisation model only takes into account catastrophic failures (that is, where the transformer needs to be replaced following failure),¹³ the rate of non-catastrophic transformer failure (failures that can be repaired) is significant and this adds to the expected unserved energy for the network.

To estimate the allowance for non-catastrophic transformer failures we used information on the rate of these failures (provided by TransGrid) as well as information on the average repair time (also from TransGrid) and the speed of switching available at the BSP (based on our modelled optimum). Where backup capacity is available, we assumed that a non-catastrophic failure would lead to an outage lasting only as long as it takes to switch to backup capacity. Where no backup capacity is available, then we assumed that the non-catastrophic outage would last for the repair time (TransGrid's average is approximately 35 hours).

While the model identifies the optimal level of redundancy, we have recommended that the level of redundancy at each BSP remains the same as that which is required by the current electricity transmission reliability standard.

The expected unserved energy in MWh is then used to calculate the allowance for expected unserved energy in minutes per annum by dividing it by estimated average annual demand at that BSP (in MW) and converting it to minutes (by multiplying it by 60).

We have estimated annual demand at each bulk supply point using forecast maximum demand (in MW) and the estimated load factor.

¹³ Because this rate and the cost of minor repairs are largely independent of the planning criteria adopted, the presence of non-catastrophic transformer failures would not affect the optimisation calculation.

1.6 Bulk Supply Point (BSP) data

Table 1.11 BSP data

Bulk Supply Point/s	Level of redundancy (category) ^a	Maximum demand (MW)	Number of transformers	Number of lines/ cables	Location type	Line/ cable length (km)	Overhead line or underground cable	Load factor	VCR (\$/MWh)
Albury 132 kV	2	112	0	3	Regional	150	o'head line-s	0.49	36,119
ANM 132 kV	2	100	0	3	Regional	150	o'head line-s	0.73	6,050
Armidale 66 kV	2	26	2	4	Regional	150	o'head line-s	0.57	34,827
Balranald 22 kV	1	4	1	1	Remote	300	o'head line-s	0.45	33,793
Beryl 66 kV	2	67	2	2	Regional	150	o'head line-s	0.55	34,024
Boambee South 132 kV	2	22	0	2	Regional	150	o'head line-s	0.54	33,835
Broken Hill 22 kV	1	38	2	1	Remote	300	o'head line-s	0.48	34,676
Broken Hill 220 kV	1	22	0	1	Remote	300	o'head line-s	0.75	34,150
Canberra 132 kV and Williamsdale 132 kV	2	Canberra 132 kV =435 Williamsdale 132 kV =180	Canberra 132 kV = 4 Williamsdale 132 kV = 2	Canberra 132 kV = 5 Williamsdale 132 kV = 4	Regional	150	o'head line-s	0.55	37,279
Coffs Harbour 66 kV	2	48	3	6	Regional	150	o'head line-s	0.54	36,373
Coleambally 132 kV	2	11	0	2	Regional	150	o'head line-s	0.38	38,166
Cooma 66 kV	2	17	3	3	Regional	150	o'head line-s	0.24	34,357
Cooma 132 kV	2	40	0	2	Regional	150	o'head line-s	0.52	34,357
Cowra 66 kV	2	30	2	3	Regional	150	o'head line-s	0.43	33,831
Dapto 132 kV	2	571	4	3	Regional	150	o'head line-s	0.65	39,575

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Bulk Supply Point/s	Level of redundancy (category) ^a	Maximum demand (MW)	Number of transformers	Number of lines/ cables	Location type	Line/ cable length (km)	Overhead line or underground cable	Load factor	VCR (\$/MWh)
Darlington Point 132 kV	2	18	2	1	Regional	150	o'head line-s	0.9	37,691
Deniliquin 66 kV	2	45	2	2	Regional	150	o'head line-s	0.53	35,547
Dorrigo 132 kV	1	2	0	1	Regional	150	o'head line-s	0.62	34,513
Finley 66 kV	2	18	2	2	Regional	150	o'head line-s	0.49	35,460
Forbes 66 kV	2	31	2	2	Regional	150	o'head line-s	0.54	34,721
Gadara 132 kV and 11 kV	2	60	2	2	Regional	150	o'head line-s	0.61	6,050
Glen Innes 66 kV	2	8	2	3	Regional	150	o'head line-s	0.54	34,432
Griffith 33 kV	2	80	3	2	Regional	150	o'head line-s	0.47	36,683
Gunnedah 66 kV	2	25	2	2	Regional	150	o'head line-s	0.52	36,353
Hawks Nest 132 kV	1	8	0	1	Regional	150	o'head line-s	0.37	32,849
Herons Creek	1	9	0	1	Regional	150	o'head line-s	0.53	38,350
Holroyd 132 kV	2	313	2	4	Suburban	30	u'ground cable-s	0.46	40,650
Ilford 132 kV	1	8	0	1	Regional	150	o'head line-s	0.47	38,350
Ingleburn 66 kV	2	142	2	2	Suburban	30	o'head line-s	0.47	39,149
Inner Sydney	3	Bea = 362 Hay = 446 Roo = 280 SydN = 835 SydS = 1033	Beaconsfield 3 Haymarket 3 Rookwood R 3 Sydney N 5 Sydney S 6	Beaconsf 1 Haymarket 1 Rookwood 2 Sydney N 6 Sydney S 6	CBD	15	u'ground cable-s	Bea = 0.55 Hay = 0.48 Roo = 0.48 SyN = 0.52 SyS = 0.53	90,000
Inverell 66 kV	2	35	2	3	Regional	150	o'head line-s	0.49	34,248
Kempsey 33 kV	2	24	2	5	Regional	150	o'head line-s	0.56	34,693
Koolkhan 66 kV	2	48	3	3	Regional	150	o'head line-s	0.5	35,143

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Bulk Supply Point/s	Level of redundancy (category) ^a	Maximum demand (MW)	Number of transformers	Number of lines/ cables	Location type	Line/ cable length (km)	Overhead line or underground cable	Load factor	VCR (\$/MWh)
Liddell 330 kV (33 kV supply via Mac Gen)	2	25	0	6	Regional	150	o'head line-s	0.65	40,211
Lismore 132 kV	2	116	2	2	Regional	150	o'head line-s	0.48	36,003
Liverpool 132 kV	2	373	3	2	Suburban	30	o'head line-s	0.42	36,330
Macksville 132 kV	2	8	0	2	Regional	150	o'head line-s	0.57	35,223
Macarthur 132 kV and 66 kV	2	Macarthur 132 kV =162 Macarthur 66 kV =162	Macarthur 132 kV = 1 Macarthur 66 kV = 1	Macarthur 132 kV = 2 Macarthur 66 kV = 1	Suburban	30	o'head line-s	0.47	37,364
Marulan 132 kV	1	104	1	6	Regional	150	o'head line-s	0.61	36,865
Molong 66 kV	1	4	1	3	Regional	150	o'head line-s	0.51	32,176
Moree 66 kV	2	27	2	2	Regional	150	o'head line-s	0.54	37,147
Morven 132 kV	1	7	0	1	Regional	150	o'head line-s	0.49	38,350
Mount Piper 66 kV	2	41	2	3	Regional	150	o'head line-s	0.5	38,401
Mudgee 132 kV	1	21	0	1	Regional	150	o'head line-s	0.48	34,311
Munmorah 33 kV and 132 kV	2	113	1	2	Regional	150	o'head line-s	0.41	35,530
Munyang 33 kV	1	2	2	1	Regional	150	o'head line-s	0.18	39,965
Murrumbateman 132 kV	1	5	0	1	Regional	150	o'head line-s	0.44	29,314
Murrumburrah 66 kV	2	36	2	2	Regional	150	o'head line-s	0.53	34,661
Muswellbrook 132 kV	2	227	2	2	Regional	150	o'head line-s	0.51	40,211
Nambucca 66 kV	2	6	2	2	Regional	150	o'head line-s	0.49	33,775

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Bulk Supply Point/s	Level of redundancy (category) ^a	Maximum demand (MW)	Number of transformers	Number of lines/ cables	Location type	Line/ cable length (km)	Overhead line or underground cable	Load factor	VCR (\$/MWh)
Narrabri 66 kV	2	44	2	3	Regional	150	o'head line-s	0.56	36,084
Newcastle 132 kV	2	425	3	6	Regional	150	o'head line-s	0.33	39,507
Orange North 132 kV/ Orange 132kV and 66kV	2	Orange North 132 kV/ Orange 132kV =144 Orange 66 kV =49	Orange North 132 kV/ Orange 132kV = 3 Orange 66 kV = 3	Orange North 132 kV/ Orange 132kV = 2 Orange 66 kV =5	Regional	150	o'head line-s	Orange North 132 kV/ Orange 132kV = 0.74 Orange 66 kV = 0.54	34,366
Parkes 132 kV	2	29	0	3	Regional	150	o'head line-s	0.83	6,050
Parkes 66 kV	2	25	2	3	Regional	150	o'head line-s	0.46	34,215
Port Macquarie 33 kV	2	55	3	3	Regional	150	o'head line-s	0.53	35,051
Queanbeyan 66 kV	2	63	2	1	Regional	150	o'head line-s	0.52	32,756
Raleigh 132 kV	2	7	0	2	Regional	150	o'head line-s	0.52	33,951
Regentville 132 kV	2	264	2	2	Regional	150	o'head line-s	0.37	36,346
Snowy Adit 132 kV	1	10	0	1	Regional	150	o'head line-s	0.31	44,549
Stroud 132 kV	2	34	0	3	Regional	150	o'head line-s	0.37	32,960
Sydney East 132 kV	2	533	4	2	Suburban	30	o'head line-s	0.52	36,952
Sydney West 132 kV	2	1,107	5	9	Suburban	30	o'head line-s	0.46	38,534
Taree 66 kV and 33 kV	2	Taree 33 kV =24 Taree 66 kV =47	Taree 33 kV = 2 Taree 66 kV = 2	Taree 33 kV = 3 Taree 66 kV = 3	Regional	150	o'head line-s	Taree 33 kV = 0.47 Taree 66 kV = 0.53	34,906
Tamworth 66 kV	2	101	2	2	Regional	150	o'head line-s	0.52	36,250

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Bulk Supply Point/s	Level of redundancy (category) ^a	Maximum demand (MW)	Number of transformers	Number of lines/ cables	Location type	Line/ cable length (km)	Overhead line or underground cable	Load factor	VCR (\$/MWh)
Tenterfield 22 kV	2	5	2	2	Regional	150	o'head line-s	0.57	33,891
Tomago 132 kV	2	210	3	4	Regional	150	o'head line-s	0.97	39,507
Tomago 330 kV	2	965	4	4	Regional	150	o'head line-s	0.97	6,050
Tuggerah 132 kV	2	182	2	2	Regional	150	o'head line-s	0.43	35,530
Tumut 66 kV	2	32	2	2	Regional	150	o'head line-s	0.59	33,997
Vales Pt 132 kV	2	99	2	4	Regional	150	o'head line-s	0.37	35,530
Vineyard 132 kV	2	474	3	2	Regional	150	o'head line-s	0.32	35,546
Wagga 66 kV	2	73	3	4	Regional	150	o'head line-s	0.38	34,842
Wagga North 132 kV	2	54	0	2	Regional	150	o'head line-s	0.73	34,842
Wagga North 66 kV	1	20	1	3	Regional	150	o'head line-s	0.38	34,842
Wallerawang 132 kV	2	79	2	4	Regional	150	o'head line-s	0.35	34,085
Wallerawang 66 kV	2	4	2	4	Regional	150	o'head line-s	0.47	34,085
Waratah West 132 kV	2	204	2	2	Regional	150	o'head line-s	0.38	39,507
Wellington 132 kV	2	164	2	2	Regional	150	o'head line-s	0.57	34,747
Wellington Town	1	10	0	1	Regional	150	o'head line-s	0.55	34,747
Williamsdale 132 kV	2	180	2	4	Regional	150	o'head line-s	0.55	37,279
Yanco 33 kV	2	38	2	4	Regional	150	o'head line-s	0.53	35,914
Yass 66 kV	1	12	2	6	Regional	150	o'head line-s	0.51	32,581

^a This is the level of redundancy required by the current electricity transmission reliability standard. It is not used an input to the model.

Source: TransGrid; IPART based on TransGrid data; IPART assumptions.