North-East Tasmania Power System Security Upgrade

Final Report
Submission to the
Reliability and Network Planning Panel

21 February 2003

ABN 57 082 586 892
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1 EXECUTIVE SUMMARY

The North-East region of Tasmania is supplied from Norwood Substation by the last remaining 88 kV transmission line in Tasmania. This remaining portion of the 88 kV transmission system has been in service since 1936. The main problems related to this 88 kV supply system are:

- security of supply,
- reliability of supply,
- compliance to the Tasmanian Electricity Code, Technical Standards, Transmission Licence, and Connection Agreement with Aurora Energy,
- operational issues,
- safety and environmental issues.

To resolve these problems Transend has developed a Strategy for North-East Tasmania electricity supply. In addition Transend has undertaken an open consultation process and invited non-network development proposal that could resolve above issues. The approach for the Regulatory Test application for this project justification was agreed with the Reliability and Network Planning Panel in November 2002.

Five development options were considered over eight market development scenarios for replacement of the current assets (which are at the end of their physical operational life) and provision of the long term supply need for Aurora Energy, to determine the most robust option. The main outcome of the Regulatory Test application is the following recommendation.

1.1 Recommendation

This is the final report for the North-East Tasmania power system security upgrade project. The project satisfies all aspects of the Regulatory Test, and used a detailed Risk Analysis model (written in Decision Programming Language, DPL) for assessment of net market benefit to determine the preferred option. The recommended option provides the highest net market benefit for seven of the eight market development scenarios considered. Accordingly:

Transend recommends:

The establishment of a double circuit 110kV line between Norwood and Scottsdale, with a single circuit 110 kV line between Derby and the Scottsdale “tee” to satisfy Aurora Energy’s long term supply need. This project estimated cost is $17.5 million.
2 INTRODUCTION & BACKGROUND

2.1 Introduction

The purpose of this paper is to describe the proposed options, scenarios, and assumptions and submit the results of the market benefit analysis to the Reliability and Network Planning Panel (RNPP) for consideration, together with a recommendation to proceed with implementation of the preferred option. This paper:

- Provides background information relating to the North-East region power security upgrade,
- Defines development options for improving the electricity supply,
- Defines the framework of market development scenarios for evaluating these options,
- Defines the methodology for evaluating the options for each scenario,
- Present the results of the market benefit analysis, and
- Recommends the preferred option.

2.2 Background

The scope of the study is the existing 88 kV supply from Norwood to Scottsdale and Derby (as shown on the location diagram below). The 88 kV transmission line supplying the region is 67 km in length from Norwood to Derby, with a 6 km tee section to Scottsdale.

![Location Map](image.png)

Figure 1 – Location Map
A simplified diagram of the existing supply arrangement is shown in Figure 2.

The region is supplied by two, 67-year-old, 110/88 kV autotransformers via a single circuit 88 kV transmission line from Norwood Substation. There is a very limited back-up supply to the region via Aurora’s 22 kV distribution network from remote Trevallyn, George Town and St Marys substations. An outage of the single circuit 88 kV line can cause interruption of supply to all customers supplied from both Scottsdale and Derby substations. Aurora has requested Transend to consider establishing a second circuit to provide secure supply to the region and meet Aurora’s long-term load growth projection.

The main problems associated with the existing 88 kV transmission line include:
- Inadequate conductor rating;
- Substandard conductor to ground clearances;
- Suitability of the existing towers to meet future requirements;
- Security of electricity supply;
- High conductor losses, and;
- Non-compliant communications system.
Substation issues related to the 88 kV supply include:

- Reliability of the two 110/88 kV auto-transformers supplying the North-East region
- Operational issues at Norwood and Scottsdale substations
- Condition of the 88 kV switchgear at Scottsdale and Derby substations.

The latest report on the reliability of the non-firm distribution system connection points in Tasmania for 2001-2002\(^1\) showed that of 25 forced outages, Scottsdale (5) and Derby (7) accounted for 12 of those outages (or 48%). The average number of forced outages per connection point per annum across the whole system was 1.19 against a target of <0.50. With Derby and Scottsdale taken out the average becomes 0.63. The total forced outage duration for both substations was 132 minutes for the 2001-2002 year, against a target of <25.0 per connection point. The main causes for outages have been adverse weather conditions.

These statistics do not include the most recent outages of 47 minutes in August 2002 and more than 388 minutes on 16 September 2002 (388 minutes outage of supply to Scottsdale plus additional 164 minutes outage of supply to Derby). This most recent outage was caused by a large tree falling across the existing single 88kV line.

### 2.2.1 Load characteristics and load growth

The peak load for the line in 2002 was 24.0 MVA\(^2\), which occurred on 16 December with 16.0 MVA load at Scottsdale and 6.0 MVA load at Derby plus 2.0 MW (or about 9%) power losses. The main reason for the summer peak appears to be the increase in irrigation in the summer months. Also, the town of Bridport increases population from 1,800 people in winter to more than 8,000 in the summer holiday season. In winter the approximate population of the whole Dorset municipal area is around 7,000.

The yearly energy used from the Scottsdale substation is around 80 GWh and Derby is around 15 GWh.

The main uses for energy supplied by the assets in question can be summarised as follows:

- Softwood timber production,
- Vegetable processing,
- Dairy industry (pumps for irrigation, dairy operations),
- Other Rural/Residential,
- Boat Building (Bridport),
- Holiday / Tourist (particularly around Bridport in the summer months).

The most recent forecast at the time of writing this report predicts power consumption to rise by 3.0% for Scottsdale and 2.7% at Derby substations (a weighted average of approximately 2.9% for the region) over 10 years period. A graph of the predicted demand can be seen below.

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\(^1\) Transend Transmission System Performance Report to OTTER (TNM-PR-809-0107 Issue 2.0, September-02).

\(^2\) Source – System SCADA 15 minutes data.
Due to the recently announced closure of the Simplot factory at Scottsdale the current estimate of peak load will be reduced by 2 MW, over all load scenarios.

Transend’s network security and planning criteria, developed by Sinclair Knight Mertz for a revenue reset project indicates a second transmission circuit may be required for loads between 10-25MW if a supply transmission line is longer than 40 kilometres and local backup is not available.

The load forecast profile for Scottsdale Substation (shown in Figure 3 above) is comparable with several key 110 kV Transend substations that already have firm electricity supply. These include George Town, Rokeby, New Norfolk, Sorell, Smithton, Kingston, Bridgewater and Wesley Vale substations, giving an indication that Scottsdale Substation should have firm electricity supply.

### 2.2.2 Connection Obligations

The existing connection agreement between Aurora Energy and Transend (CANS1) specifies only equipment capabilities at a connection point. Transend is obliged under this agreement to provide the following capabilities for Scottsdale and Derby connection points.

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3 Source – Aurora Terminal Substation Forecasts 2001 (AUR-108050 6/2/2002 No Gas Forecast Rev. 2)
Table 1 – Agreed Connection Point Capabilities (CANS)

<table>
<thead>
<tr>
<th>Parameter</th>
<th>Unit</th>
<th>Scottsdale</th>
<th>Derby</th>
</tr>
</thead>
<tbody>
<tr>
<td>Connection Voltage</td>
<td>kV</td>
<td>22</td>
<td>22</td>
</tr>
<tr>
<td>Feeder type</td>
<td>-</td>
<td>Retail</td>
<td>Retail</td>
</tr>
<tr>
<td>Transformers</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Installed capacity (ONAN)</td>
<td>MVA</td>
<td>36</td>
<td>15</td>
</tr>
<tr>
<td>N Capacity</td>
<td>MVA</td>
<td>60</td>
<td>15</td>
</tr>
<tr>
<td>N-1 Capacity</td>
<td>MVA</td>
<td>30</td>
<td>5</td>
</tr>
<tr>
<td>Fault level</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Three phase</td>
<td>MVA</td>
<td>151</td>
<td>62</td>
</tr>
<tr>
<td>Three phase</td>
<td>A</td>
<td>3963</td>
<td>1627</td>
</tr>
</tbody>
</table>

The configuration of Scottsdale Substation does not allow for an N-1 contingency to be in place even though the substation has two transformers. One transformer is completely de-energised. The existing supply arrangement is a single line and as a consequence all customers supplied from the Scottsdale and Derby substations will lose supply if a line outage occurs.

2.3 Tasmanian Electricity Code

Under the Tasmanian Electricity Code (TEC), Chapter 5, Transend is responsible for the planning and development of the transmission network in Tasmania. Transend has developed a strategy to improve reliability and security of supply to the North-East region of Tasmania.

Chapter 8 of the TEC expects that the supply of electricity is safe, efficient and reliable. Specific requirements and standards for the reliability and quality of the electricity supply are listed in this chapter. An adequate and reliable electricity supply to the North-East region of Tasmania is essential to meet the expectations of key stakeholders and customers and to comply with these legislative obligations.

The outage on 16 September 2002 has confirmed the need to increase security and improve reliability of the supply to the North-East region of Tasmania. This outage to the Scottsdale area lasted 6 hours and 28 minutes, and to the Derby area lasted additional 2 hours and 44 minutes.

2.4 Public Consultation Process

A public consultation process was conducted to provide an opportunity for interested parties to review the proposal, and to offer alternative solutions. Transend produced a consultation paper, which was advertised in Tasmania’s three daily newspapers in October 2002.

The only formal response was made by Mr David Male, who suggested the analysis of a dispersed generation option. This option, as agreed by the RNPP in the November 2002 presentation is included in the model.
3 DESCRIPTION OF OPTIONS

3.1 Introduction

The following options were compared against each other:

- **Option 0 - Double circuit 88 kV** – This option evaluated maintaining and bringing the existing 88 kV line up to a Code compliant condition and adding a second circuit to increase security of supply to the region.

- **Option 1 - Hybrid option** – This option evaluated a 110 kV single circuit supply plus embedded generation (25 MW wood-fired) to provide security of supply to the region.

- **Option 2 - Double circuit 110 kV option** – This option evaluated a double circuit 110 kV line from Norwood to Scottsdale, with a single circuit 110 kV line from the Scottsdale tee to Derby.

- **Option 3 - Single circuit 110 kV Option** – This option evaluated a single circuit 110 kV line from Norwood to Scottsdale and Derby.

- **Option 4 - Distribution network reinforcement plus dispersed generation** – This option evaluated dispersed generation (5 x 5 MW wood fired units) located in Bridport, Scottsdale and Derby areas plus distribution network reinforcement. No new capital investments in the transmission system were included.

3.2 Network Options

3.2.1 Option 0 – Double circuit 88 kV option (Reference Case)

The reference case (or base option considered, by which other options were compared) was to bring to Code compliance the existing 88 kV line and re-string a second circuit as part of this upgrade. It should be noted that for this option the existing towers would be strengthened and re-used to keep costs down. This is not the case in the 110 kV options where new towers would be required.

The cost estimate for the double circuit 88 kV line is $13.8 million, assuming a double circuit from Norwood to Scottsdale and a single circuit from the Scottsdale tee to Derby. Even though the line would be a single circuit from the Scottsdale tee to Derby, there is a back-up available through the 22 kV distribution network in the case of the failure of the main 88 kV line.

As part of this option, various substation works would be required at Norwood, Scottsdale and Derby.

Total capital expenditure for this option (for both line and substation work) is $25.6 million.
3.2.2 Option 2 – Double Circuit 110 kV line

This option assumes that the line will be double circuit from Norwood to Scottsdale and single circuit from the Scottsdale tee to Derby. As with the double 88 kV option, one distribution 22 kV feeder from Scottsdale Substation will provide a backup to Derby Substation, making it more secure than a single circuit line.

Capital costs for the double circuit 110 kV line are estimated at $17.5 million for the transmission line. Additional substation works are planned at Norwood, Scottsdale and Derby.

Total capital expenditure for this option (for both line and substation work) is $25.2 million.

3.2.3 Option 3 – Single circuit 110 kV line

This option assumes that the line will be a single circuit 110 kV from Norwood through to Scottsdale and Derby.

The capital cost of the single circuit 110 kV line is $12.6 million. These costs include the de-commissioning of two transformers at Norwood, the fixing of sub-standard clearances and the upgrade of SCADA equipment.

As per the reference case, various substation works would be required at Norwood, Scottsdale and Derby.

The total capital cost for this option is $23.3 million.

It has been assumed that when the load reaches 45 MVA a second circuit would be added at a cost of $4.8 million, as the line would have reached the limits of its capacity. This would bring VoLL and power losses back to the same level as the double 110 kV line.

3.3 Non-Network options

3.3.1 Option 1 - Hybrid embedded generation plus single circuit 110 kV line

This option is a hybrid option consisting of a 25 MW wood fired power generator based at Scottsdale and a single 110 kV line from Norwood to Scottsdale and Derby.

The capital cost of the single circuit 110 kV line has been estimated at $12.6 million. These costs include the de-commissioning of two transformers at Norwood, the rectification of sub-standard clearances and the upgrade of SCADA equipment.

As per the reference case, various sub-station works would be required at Norwood, Scottsdale and Derby.

The total cost for the transmission line and substation component is $22.6 million.

The power station capital costs have been modeled at $1.5 million per MW of output. This figure is on the lower end of estimates obtained from SEDA, CSIRO and the proponent involved in the wood-fired power station proposal in Tasmania.

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4 Sustainable Energy Development Authority (SEDA) commissioned report on “Investigation of Potential for Electricity Generation from Forestry by-products in New South Wales” Final report – June 1999 report compiled by Enecon Energy Pty Ltd and CSIRO Forestry and Forest products division
The initial power station size is modeled at 25 MW and increases in 2 MW increments as load growth demands (also at a capital cost of $1.5 million per MW).

These figures put the total capital cost of the hybrid option at $60.0 million plus the capital increments required to cater for load growth.

The operating and maintenance costs used are 2% for the capital cost of all transmission line, substation and power station equipment. In addition to these costs it is assumed that the boiler/turbine power station in the CSIRO study is implemented, which would require 395,180 tonnes of wood fuel per annum at an assumed cost of $30/t. An additional $1.2 million per annum would also be required for operating costs.

It is assumed that the wood-fired plant would be eligible to sell Renewable Energy Certificates (RECS). The revenue received from these certificates is included in operating and maintenance expenditure as a “negative operating expense”. The revenue is calculated by modeling the power station runs at 25 MW for 90% of the year multiplied by $37 per MWh for each REC. The power station would run at full capacity and be able to export all the power it produces to the grid, and therefore be able to claim RECS on everything it produces.

### 3.3.2 Option 4 – Embedded Generation with no transmission line

This option proposes 5 x 5 MW wood fired generation plants, one in Bridport, three in Scottsdale and one in Derby. In this proposal the transmission line would be decommissioned and the distribution system would be strengthened to cope with the new generating scenario. The existing Derby and Scottsdale substations would become switching substations with no transformation capability.

The capital costs for the 5 MW wood fired plants are set at $1.5 million per MW installed which is on the low side of the capital estimates from the SEDA paper. It is also used that $0.5 million worth of substation modifications will be required to turn them into the switching substations and $5 million capital to strengthen the distribution system. This puts the total capital cost for this option at $43 million, plus the capital increments required to cater for load growth.

The operating and maintenance costs are modeled as 2% of all distribution system modifications and power station capital equipment costs. In addition to these costs it is assumed that the most efficient 5MW power station in the SEDA study is implemented. The 5 stations in aggregate would require 490,000 tonnes of wood fuel per annum at an assumed cost of $30/t. An additional $0.1 million per annum would also be required for operating costs.

It is included in the model that the wood-fired plants would be eligible to sell Renewable Energy Certificates (RECS). The revenue received from these certificates is included in operating and maintenance expenditure as a “negative operating expense”. The revenue is calculated by assuming the power stations run at 25 MW for 90% of the year multiplied by $37 per MWh for each REC. It is assumed that the power stations would run at full capacity and be able to export all the power they produce to the grid, and therefore be able to claim RECS on everything produced.
3.3.3 Demand Side Management

No demand-side management proposals were received during the public consultation process.

Demand side management options in the region are limited to agreements with major customers in the area. After discussing load-shedding proposals with some of the main industries, it is clear that there is no viable opportunity for demand side management.
4 COMPARATIVE EVALUATION OF OPTIONS AND SCENARIOS

4.1 Assumptions

4.1.1 Basic Assumptions

- The study period was set to be 25 years (i.e. 2003-2028),
- Residual value of assets was calculated on a further 25 year period (i.e. 2029-2054),
- The base load forecast would be the one submitted by Aurora, with 2 MW subtracted to adjust for the loss of Simplot,
- Estimated capital and operating costs on wood fired power stations are from SEDA and National Power Partners.

In addition to the basic assumptions above, the following assumptions were used in the model:

<table>
<thead>
<tr>
<th>Variable</th>
<th>Minimum Value</th>
<th>Likely Value</th>
<th>Max Value</th>
<th>Issues and Comment</th>
</tr>
</thead>
<tbody>
<tr>
<td>Discount rate for transmission (real)</td>
<td>6%</td>
<td>7.5%</td>
<td>9%</td>
<td></td>
</tr>
<tr>
<td>Forecast load growth</td>
<td>0.9%</td>
<td>2.9%</td>
<td>4.9%</td>
<td>The “likely value” is set at the Aurora forecast of 2.9% for the region.</td>
</tr>
<tr>
<td>Value of lost load (VoLL)</td>
<td>$1,000 per MWh</td>
<td>$10,000 per MWh</td>
<td>$20,000 per MWh</td>
<td>Work done on the industries in the area have confirmed that these figures are appropriate although on the low side of the range.</td>
</tr>
<tr>
<td>Capital costs of transmission equipment</td>
<td>Base -10%</td>
<td>Base cost estimates</td>
<td>Base +20%</td>
<td></td>
</tr>
<tr>
<td>Operating and maintenance costs</td>
<td>1%</td>
<td>2%</td>
<td>3%</td>
<td>Percent of capital cost</td>
</tr>
<tr>
<td>Renewable Energy Certificates</td>
<td>$29/kWh</td>
<td>$37/kWh</td>
<td>$45/kWh</td>
<td>In the DPL model there is also included a 10% chance that RECS will be $0 to include the possibility that this class of scheme may be excluded from the RECS system.</td>
</tr>
<tr>
<td>Wood fired power station fuel costs</td>
<td>$20/t</td>
<td>$30/t</td>
<td>$40/t</td>
<td>In the DPL model there is also included a 10% chance that fuel could be sourced for $0 Although this may be viable for small scale plants located at mills, it is not likely for a large scale plant. It was included to see the effect on sensitivities.</td>
</tr>
<tr>
<td>Value of losses</td>
<td>3.5 cents/kWh</td>
<td>4.5 cents/kWh</td>
<td>5.5 cents/kWh</td>
<td></td>
</tr>
</tbody>
</table>

4.1.2 Value of Lost Load

The “ESAA guidelines for Reliability Assessment Planning, April 1995” gives the Value of Lost Load (VoLL) for various customers, by market segment, as shown in Table 5.1 below:

---

5 Source – Aurora Terminal Substation Forecasts 2001 (AUR-108050 6/2/2002 No Gas Forecast Rev. 2)

Table 5.1: Value of Lost Load (VoLL) values – ESAA report

<table>
<thead>
<tr>
<th>Market Segment</th>
<th>Upper $ / kWh</th>
<th>Lower $ / kWh</th>
</tr>
</thead>
<tbody>
<tr>
<td>Residential</td>
<td>10</td>
<td>2</td>
</tr>
<tr>
<td>Commercial</td>
<td>25</td>
<td>15</td>
</tr>
<tr>
<td>Central Business District</td>
<td>25</td>
<td>15</td>
</tr>
<tr>
<td>Industrial</td>
<td>10</td>
<td>6</td>
</tr>
</tbody>
</table>

These values are lower than, but still in line with that produced recently by Monash University in the “Monash” Paper. The above figures do not however include a value for rural / agricultural uses.

The “Monash” report supplies the following expected VoLL figures.

Table 5.1: Value of Lost Load (VoLL) values – Monash Report

<table>
<thead>
<tr>
<th>Market Segment</th>
<th>Expected value $ / kWh</th>
</tr>
</thead>
<tbody>
<tr>
<td>Residential</td>
<td>0.6</td>
</tr>
<tr>
<td>Commercial</td>
<td>53</td>
</tr>
<tr>
<td>Agricultural</td>
<td>104</td>
</tr>
<tr>
<td>Industrial</td>
<td>11</td>
</tr>
</tbody>
</table>

These were combined using the following proportions, to provide a “composite” value for VoLL for the region using the Monash report figures as shown in Table 5.2 below:

Table 5.2: NE Region Mix of Customers for VoLL Consideration

<table>
<thead>
<tr>
<th>Substation</th>
<th>Domestic</th>
<th>Commercial</th>
<th>Rural</th>
<th>Industrial</th>
<th>Composite $ / kWh</th>
</tr>
</thead>
<tbody>
<tr>
<td>Scottsdale &amp; Derby customer mix</td>
<td>25%</td>
<td>5%</td>
<td>28%</td>
<td>42%</td>
<td>36.54</td>
</tr>
<tr>
<td>Scottsdale &amp; Derby weighted average VoLL</td>
<td>0.15</td>
<td>2.65</td>
<td>29.12</td>
<td>4.62</td>
<td></td>
</tr>
</tbody>
</table>

Due to the high numbers of dairy farms in the area, and the impact that an outage can have on their production, it is logical that a higher value of VoLL could be expected in the region.

Transend has approached the two major customers in the region, and the following values of VoLL were calculated for these customers:

- $10 per kWh and
- $12 per kWh

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7 “Study of the Value of Lost Load” undertaken by the centre for Electrical Power Engineering (CEPE), Department of Electrical and Computer Systems Engineering, Monash University. Study conducted for the Victorian Power Exchange (VPX), provided to working group members on 12/9/2000.
According to the major milk producer in the region the farmers produced almost $100,000 less milk product than they would normally produce due to the outage on 16 September 2002. The Monash study values losses to the agricultural sector at $104 per kWh (see Table 12.6 on page 19 in the Monash report) which is significantly higher in comparison with residential, commercial, and industrial/major users sectors.

Although the work and consultation done on the value of power security in the North East region have indicated that the area may place a higher value on security of supply than other regions, the values for VoLL have been kept in the model at $1 per kWh for the low value, $10 per kWh for the expected value and $20 per kWh for the high value.

Lower values of VoLL will tend to favour less secure solutions, such as single circuit options.

In calculating the frequency and duration of outages for the three transmission options, Transend’s data and data published by other utilities were used.

From these sources, it was modelled that a double circuit 110 kV line has an average number of outages of 0.7 outages per year, with an outage duration of 0.91 hours per annum. A single circuit 110 kV line has an average number of outages of 1.77 outages per year, with a total outage duration of 2.19 hours per annum. For the purposes of the model, the double 88 kV line option, uses the same outage statistics as a double 110 kV line.

### 4.2 Scenarios

All the options have been evaluated in the context of the following range of credible scenarios, in order to test their robustness and sensitivity to likely economic outcomes.

- SCENARIO 1– Base load forecast,
- SCENARIO 2– High load forecast,
- SCENARIO 3– Low load forecast,
- SCENARIO 4 – High discount rate,
- SCENARIO 5 – Low discount rate,
- SCENARIO 6 – 20% increase in capital costs,
- SCENARIO 7 – 10% decrease in capital costs,
- SCENARIO 8 – Low value of lost load (VoLL).

### 4.3 Methodology used

A reliability assessment model for the North-East region using all of the assumptions discussed above was constructed using DPL. A decision analysis was then undertaken with the model calculating the expected value of the least cost planning function for all 116,640 combinations of the various assumptions agreed with the Panel.

The components of the least cost planning functions are:

- Capital costs, including costs for new asset and replacement, refurbishment costs,
- Operating and maintenance costs,
• Costs of loss of load,
• Costs of power loses.

4.4 Results: Net present values of Market Benefit

The results of the detailed model for each option (subtracted from the base option) for each scenario are as follows (2003 million dollars).

Table 2 Net market benefit by scenario

<table>
<thead>
<tr>
<th>Options</th>
<th>Market Development Scenarios</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>Base</td>
</tr>
<tr>
<td>Double 88 kV</td>
<td>-</td>
</tr>
<tr>
<td>Hybrid</td>
<td>-146.72</td>
</tr>
<tr>
<td>Double 110 kV</td>
<td>11.61</td>
</tr>
<tr>
<td>Single 110 kV</td>
<td>10.28</td>
</tr>
<tr>
<td>Distributed gen</td>
<td>-86.97</td>
</tr>
</tbody>
</table>

The double circuit 110 kV option provides the greatest market benefit over seven of the eight selected scenarios. The results are below in a graphical form.

Figure 4 Graph of net market benefits over the eight agreed scenarios

See Appendix A for more details.

4.5 Discussions and conclusions

It can be seen from the graph below that the embedded generation options do not compete favourably with the transmission options. High construction and operating costs for both
embedded generation options mean that transmission options in this instance are more favourable.

![Expected value for all options](image)

Figure 5 Costs by component of all five options considered
The graph above shows the costs of each option using the “most likely” values for each assumption. It can be seen (refer also to appendix A) that although the double circuit 110 kV option is $1.838 million more expensive to build and operate than the single circuit 110 kV option, it provides a benefit in greater security and lower losses of $3.159 million. This leads to a net positive benefit of the double circuit 110 kV option of $1.3210 million.

What the model is showing is that the extra security and lower losses provided by a double circuit 110 kV option, more than makes up for the extra cost of building the second circuit.

The main conclusion from the analysis is that a double circuit 110 kV transmission line option to replace the current 88 kV line from Norwood to Derby and Scottsdale is the best option over the majority of market development scenarios analysed.

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8 This figure represents the PV of the difference between the Capital and Operating and Maintenance costs of options 2 & 3.

9 This figure represents the PV of the difference between the Unserved Energy and VoLL costs of options 2 & 3.

10 This figure represents the increase in market benefit if the double 110 kV option is chosen over the single 110 kV option, using the “most-likely” values agreed with the RNPP.
5 IMPACT ON ELECTRICITY PRICES

5.1 The cost of the proposed network project
The Tasmanian Energy Regulator determines Transend aggregate annual revenue requirement (AARR). This is made up of a return on investment, depreciation and operation and maintenance costs.

Table 5.1 shows the cost of the proposed network project:

<table>
<thead>
<tr>
<th>Table 5.1: Capital Expenditure for North-East Project</th>
</tr>
</thead>
<tbody>
<tr>
<td>110 kV double circuit transmission line</td>
</tr>
</tbody>
</table>

This results in minimal change to network prices to customers as the following broad-brush analysis illustrates.

<table>
<thead>
<tr>
<th>Table 5.2: Return on investment for North-east Project</th>
</tr>
</thead>
<tbody>
<tr>
<td>WACC @ 7.5%</td>
</tr>
<tr>
<td>Network Assets - TL</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Table 5.3: Impact on Customers</th>
</tr>
</thead>
<tbody>
<tr>
<td>Average cost increase per customer per annum due to Transend’s Investment</td>
</tr>
<tr>
<td>Total number of customers</td>
</tr>
<tr>
<td>Total Energy served MWhr in 2001</td>
</tr>
<tr>
<td>Average increase in cents per kWhr</td>
</tr>
</tbody>
</table>
6 PROJECT TIMING

The following timing is proposed:

- RNPP Submission, February 2003,
- Submission to Transend Networks Board, March 2003,
- Project functional specification and tender documentation from March 2003 to May 2003,
- Tendering process, from June 2003 to August 2003,
- Award contract, August 2003,
- Start of construction, September 2003,
- Construction, from September 2003 to November 2004,
Transend received from Hydro Tasmania a formal connection application for connection of Musselroe Bay wind farm on 14 June 2002. The capacity of the wind farm will rise from 50 MW in stage one to 150 MW in stage two. The proposed timing for the connection to the network at Derby Substation indicated in the connection application is December 2004 for the stage one and December 2005 for the stage two.

In addition, Transend received from Hydro Tasmania a preliminary connection inquiry for connection of Rushy Lagoon wind farm to Derby Substation as well. The Rushy Lagoon site is about eight kilometres south of the proposed Musselroe Bay wind farm. The proposed capacity of this wind farm is also 150 MW. The indicated timing for the farm to be in service is January 2006.

Following the process outlined in the Code Transend has undertaken technical studies to analyse the impact of these connections to the grid.

To accommodate these 300 MW wind generation additional connection assets and transmission network augmentation is required. Transend is required by the Code to negotiate the reasonable network charges for these connections, augmentation and use of the transmission network with the Generator. It is anticipated when these wind farms would be ready for connection to the grid that the relevant pricing rules will be those contained in the National Electricity Code. Currently Schedule 6.8.2. of the National Electricity Code deems that “the percentage share of benefits resulting from the establishment and use of the new network investment of Generators is zero and of Transmission Network customers connected to its network is 100%”. A review is underway by National Electricity Code Administrator (NECA) and it is anticipated that Generators will be deemed to be beneficiaries too. If and when this occurs it would result in the reduction of retail charges.

The recommendation of this submission will facilitate any embedded generation development in the region.
Transend Networks recommends:

The establishment of a double circuit 110 kV line between Norwood and Scottsdale, with a single circuit 110 kV line between the Scottsdale “tee” and Derby Substation to satisfy Aurora Energy’s long term planning need. The estimated cost of this project is $17.5 million.
Appendix A – Model Outputs (raw numbers used by graphs in main report)

(note: all figures are in 2003 dollars and are in millions unless otherwise indicated)

Table 3 Market benefit figures broken up by area for the 110 kV options

<table>
<thead>
<tr>
<th>Transmission options graph information</th>
<th>PV - Capital</th>
<th>PV - O&amp;M</th>
<th>PV - Losses</th>
<th>PV - USE</th>
</tr>
</thead>
<tbody>
<tr>
<td>Option 0 - Do Minimum</td>
<td>26.71</td>
<td>7.34</td>
<td>7.76</td>
<td>2.00</td>
</tr>
<tr>
<td>Option 3 - Single 110 kV</td>
<td>20.85</td>
<td>6.21</td>
<td>2.18</td>
<td>4.28</td>
</tr>
<tr>
<td>Option 2 - Double 110kV</td>
<td>22.10</td>
<td>6.79</td>
<td>1.31</td>
<td>2.00</td>
</tr>
</tbody>
</table>

Table 4 Market benefit for each option by scenario

<table>
<thead>
<tr>
<th>Scenario table data</th>
<th>Base</th>
<th>High load</th>
<th>Low Load</th>
<th>High disc</th>
<th>Low Disc</th>
<th>Capital +20%</th>
<th>Capital -10%</th>
<th>Low VoLL</th>
</tr>
</thead>
<tbody>
<tr>
<td>Double 88 kV</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Hybrid</td>
<td>-146.72</td>
<td>-184.16</td>
<td>-124.62</td>
<td>-123.84</td>
<td>-180.27</td>
<td>-156.32</td>
<td>-141.92</td>
<td>-146.72</td>
</tr>
<tr>
<td>Double 110 kV</td>
<td>11.61</td>
<td>22.06</td>
<td>6.69</td>
<td>9.30</td>
<td>14.92</td>
<td>12.53</td>
<td>11.14</td>
<td>11.61</td>
</tr>
<tr>
<td>Single 110 kV</td>
<td>10.28</td>
<td>20.20</td>
<td>6.44</td>
<td>8.45</td>
<td>12.89</td>
<td>11.45</td>
<td>9.70</td>
<td>12.15</td>
</tr>
<tr>
<td>Distributed gen</td>
<td>-86.97</td>
<td>-119.50</td>
<td>-67.22</td>
<td>-71.91</td>
<td>-109.49</td>
<td>-93.69</td>
<td>-83.60</td>
<td>-86.97</td>
</tr>
</tbody>
</table>
Table 5 Breakeven analysis to demonstrate what variable values would make options 2 & 3 equal

<table>
<thead>
<tr>
<th>Breakeven Analysis</th>
<th>With 10MW MI in 2010</th>
<th>Without 10MW MI in 2010</th>
</tr>
</thead>
<tbody>
<tr>
<td>VoLL</td>
<td>-13,586.66</td>
<td>3,612 $/MWh</td>
</tr>
<tr>
<td>Load growth</td>
<td>-7.4%</td>
<td>-2.58% % of base forecast</td>
</tr>
</tbody>
</table>

Table 6 Illustration of the difference in market benefit for options 2 & 3 by scenario

<table>
<thead>
<tr>
<th>Difference in market benefit between 110kV options by scenario (figures in $M 2003 dollars)</th>
<th>Base</th>
<th>High load</th>
<th>Low Load</th>
<th>High disc</th>
<th>Low Disc</th>
<th>Capital +20%</th>
<th>Capital -10%</th>
<th>Low VoLL</th>
</tr>
</thead>
<tbody>
<tr>
<td>Difference in net market benefit (double 110 minus single 110)</td>
<td>1.32</td>
<td>1.87</td>
<td>0.24</td>
<td>0.85</td>
<td>2.03</td>
<td>1.07</td>
<td>1.45</td>
<td>-0.54</td>
</tr>
</tbody>
</table>
Figure 7 Graph of difference in market benefit between double 110 kV and single 110 kV by scenario