FINAL REPORT

PROPOSED NEW LARGE TRANSMISSION NETWORK ASSET

AND

PROPOSED NEW LARGE DISTRIBUTION NETWORK ASSET

DEVELOPMENT OF THE ELECTRICITY SUPPLY NETWORK IN THE HOBART EASTERN SHORE REGION

UNCONTROLLED WHEN PRINTED

CONTACT

Refer to section 6 of final report.

This document is the joint responsibility of:

- Transend's Asset Strategy & Planning Group, Transend Networks Pty Ltd, ABN 57 082 586 892

- Aurora's System and Asset Management Group within the Network Division of Aurora Energy Pty Ltd ABN 85 082 464 622.

REVIEW DATE

This document is due for review - Not Applicable

RESPONSIBILITIES

Compliance

Refer to Appendix B of this application notice.

Document Management

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- Aurora's System and Asset Management Group within the Network Division of Aurora Energy Pty Ltd ABN 85 082 464 622.

Disclaimers

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1 EXECUTIVE SUMMARY

Transend Networks Pty Ltd (Transend) as the Tasmanian Transmission Network Service Provider (TNSP), and Aurora Energy Pty Ltd (Aurora) as the Tasmanian Distribution Network Service Provider (DNSP), have obligations under the National Electricity Rules (NER) and the Electricity Supply Industry Regulations 2007 (Network Performance Requirements), to ensure that the state's transmission and distribution networks meet the required minimum performance standards.

Transend and Aurora have identified emerging network limitations within the Hobart Eastern Shore transmission and distribution networks. In addition, Aurora has submitted a connection application to Transend requesting a new 110/33 kV connection point in the Hobart Eastern Shore region by May 2011.

The Hobart Eastern Shore region is the area extending from Risdon Vale east to Seven Mile Beach and Pitt Water, and south to Lauderdale, Clifton Beach and South Arm. This region can be predominately characterised as residential, rural, and rural residential, with some modest industrial and commercial areas throughout the region.

In accordance with the requirements of the NER, Transend and Aurora have undertaken joint planning to determine alternative options and establish plans to address the emerging network limitations. As part of this process, Transend and Aurora have decided to conduct a joint consultation process, and have prepared this application notice in accordance with the requirements of the NER.

In undertaking joint planning, Transend and Aurora have considered a number of regional development growth scenarios, as well as known significant developments. Consideration has also been given to the impact of recent global economic events, as well as the potential impact of the proposed Carbon Pollution Reduction Scheme (CPRS) on the regional growth scenarios.

The Hobart Eastern Shore region is currently supplied from Transend's 110 kV network via Lindisfarne and Rokeby substations. Plans are also well advanced to augment Lindisfarne with the addition of a 220 kV supply in 2010. These substations provide supply to Aurora's Bellerive, Geilston Bay, and Cambridge zone substations, which supply the regions 11 kV distribution network. Transend's Rokeby Substation also provides 11 kV supply to the region's distribution network.

Transend and Aurora have conducted studies of the transmission and distribution networks in the Hobart Eastern Shore region over the 10 year planning period commencing in 2009. These studies have identified a number of existing and emerging network limitations. In order to manage these limitations, Transend and Aurora have adopted operational strategies to enable the optimum utilisation of available capital resources and strategically address the broader emerging supply limitations within the Hobart Eastern Shore region.

Under the medium (expected) winter demand forecast for the Hobart Eastern Shore region, the current transmission network supply arrangements are non-compliant with the requirements of the NER. Additionally, the supply arrangements at Lindisfarne Substation will also be non-compliant with the requirements of the Electricity Supply Industry Regulations 2007 (Network Performance Requirements) by the winter of 2011. Consequently, any transmission network augmentations that arise out of the inability of the current network to meet these requirements are reliability augmentations in accordance with the NER. Furthermore, the current subtransmission and distribution supply arrangements will be unable to meet the required service standards by the winter of 2012 and beyond.

To address the emerging supply limitations, Transend and Aurora have considered a range of alternative options – covering both network and non-network solutions. Both Transend and Aurora are of the view that there are currently no practical non-network solutions available in the Hobart

Eastern Shore region.

Three network alternative options were identified as being practical alternatives to addressing the identified emerging supply limitations. Specifically these options are:

- a third transformer at Lindisfarne 110/33 kV Substation (Option 1). This option also requires a significant amount of associated works, including the eventual replacement of the two existing transformers, upgrading of Rokeby with two new transformers and the development of two new zone substations in the Kangaroo Bay and Shoreline areas. The present value cost of this option is estimated at $51.3 million;
- establishment of a new 33 kV connection point between the Mornington and Clarendon Vale areas by means of a new 110/33 kV substation (Option 2). This option includes replacement of the two existing transformers at Lindisfarne, the development of new zone substations in the Kangaroo Bay, Shoreline and Lauderdale areas, and rearrangement of the associated 33 kV subtransmission network. The present value cost of this option is estimated at $49.0 million; and
- augmentation of the Rokeby 110/11 kV Substation to provide a 110/33 kV supply point (Option 3). This option also requires associated 110 kV cable works, replacement of the two existing Lindisfarne transformers and the development of new zone substations in the Kangaroo Bay, Shoreline areas and Lauderdale areas, along with the rearrangement of the associated 33 kV subtransmission network. The present value cost of this option is estimated at $50.3 million.

It is concluded that in the majority of scenarios, option 2 is the least cost solution to address the emerging supply limitation in the Hobart Eastern Shore region. This assessment includes sensitivity analysis on the key variables – including regional load growth, discount rate, and cost estimates. It is also concluded that option 2 passes the Regulatory Test under the reliability limb.

Transend and Aurora published an Application Notice to all Registered Participants and NEMMCO on 22 December 2009, recommending the implementation of the new large transmission and new large distribution developments as set out in option 2. In accordance with clause 5.6.6(f) of the NER, Transend and Aurora invited submissions from Registered Participants in relation to its Application Notice. The closing date for the submission was 23 February and no submissions were received.

This document is Transend and Aurora’s Final Report in relation to its application to establish a new large transmission and a new large distribution network asset (“Final Report”). This Final Report has been prepared in accordance with, and meets the requirements of clause 5.6.6 of the NER. It explains the rationale for the proposed investment with reference to requirements of the regulatory test.

2 INTRODUCTION

Transend Networks Pty Ltd (Transend) is the Tasmanian electricity Transmission Network Service Provider (TNSP), and is responsible for the planning and development of the state's transmission network.

Aurora Energy Pty Ltd (Aurora) is the Tasmanian electricity Distribution Network Service Provider (DNSP), and is responsible for the planning and development of the state's subtransmission and distribution networks.

Transend and Aurora have responsibilities under the National Electricity Rules (NER), and local jurisdictional requirements. These responsibilities include planning to facilitate the economic development of the electricity networks, and ensuring ongoing compliance with the required system standards[1]. Meeting these obligations is important in addressing the customer's needs, and in facilitating the operation of the National Electricity Market (NEM).

Transend has identified limitations within the Hobart Eastern Shore transmission network. In addition, Aurora has identified emerging limitations within the Hobart Eastern Shore distribution network, and has submitted a connection application to Transend requesting a new 110/33 kV connection point in the Hobart Eastern Shore region by May 2011.

In accordance with the requirements of the NER, Transend and Aurora have undertaken joint planning to determine alternative options to address the emerging network limitations. Through this joint planning process, Transend and Aurora have established plans which are set out in this application notice.

2.1 PURPOSE

Transend and Aurora published an Application Notice on their respective web sites and submitted to NEMMCO on 22 December 2009, recommending the implementation of the new large transmission and new large distribution developments as set out in option 2. In accordance with clause 5.6.6(f) of the NER, Transend and Aurora invited submissions from Registered Participants in relation to its Application Notice. The closing date for the submission was 23 February and no submissions were received.

This document is Transend and Aurora's Final Report in relation to its application to establish a new large transmission and a new large distribution network asset ("Final Report"). This Final Report has been prepared in accordance with, and meets the requirements of clause 5.6.6 of the NER.

Clause 5.6.6(c)(6) of the NER requires the Final Report to set out a detailed analysis of why Transend and Aurora consider that the investment satisfies the regulatory test. The Final Report details the information required under clause 5.6.6.

Transend and Aurora will progress with implementing the recommendation as presented in this document.

2.2 SCOPE

This final report sets out a proposal for a new large transmission network asset, and a new large distribution network asset, that will jointly address the limitations emerging within the Hobart Eastern Shore electricity networks. In setting out these proposals, this final notice provides

[1] Network performance must comply with Schedule 5.1 of the National Electricity Rules, and with the requirements of the Tasmanian Electricity Supply Industry Act.

information necessary to satisfy the requirements of the clauses 5.6.2 and 5.6.6 of the NER.

The remainder of this final report is divided into four sections as follows:

Regional overview	this section provides a general description of the Hobart Eastern Shore region and its development as background to the development scenarios and the regional electricity demand forecast. The existing electricity supply arrangements are also presented along with details of the emerging supply limitations.
Alternative options	the non-network and network alternatives alternative options that were considered are presented in this section. The alternative options are compared and ranked, and a sensitivity analysis is presented.
Conclusions and recommendations	this section presents concluding points along with a recommendation to implement the preferred alternative option.
Enquiries and disputes	contact details for enquiries, along with details of the dispute process and the address for notices is provided in this section.

2.3 KEY REQUIREMENTS OF THE NER AND LOCAL JURISDICTION

Both Transend and Aurora are required under the NER and under local jurisdiction to undertake a consultation process in relation to any proposed new large network investments. This section provides an overview of the key elements of these requirements.

2.3.1 Joint planning

In accordance with clause 5.6.2(b) of the NER, Transend conducts annual planning reviews with Aurora to consider the demand forecast submitted by Aurora, and to review the adequacy of the existing transmission connection points, and the transmission network itself, as well as proposals for future connection points. Through this process, Transend and Aurora have identified limitations within the Hobart Eastern Shore transmission network, and the necessity for augmentation or a non-network alternative.

Transend and Aurora have undertaken joint planning in order to determine plans that can be considered by relevant Registered Participants, NEMMCO and interested parties.

In addition, Transend’s Annual Planning Reports of 2006, 2007, and 2008 provide descriptions of the emerging limitations in the Hobart Eastern Shore region.

2.3.2 NER compliance

Clause 5.6.6 of the NER requires that the applicant proposing to establish a new large transmission network asset must make available to all Registered Participants, interested parties and NEMMCO an application notice which sets out certain matters as detailed in the NER. In addition, clause 5.6.2 of the NER sets out certain requirements in relation to a Distribution Network Service Provider that is proposing the development of new large distribution network asset. For reference, details of the compliance with clauses 5.6.2 and 5.6.6 of the NER are set out in Appendix B of this report.

2.3.3 Regulatory test requirements

Chapter 10 of the NER defines a reliability augmentation as:

> *“a transmission network augmentation that is necessitated principally by inability to meet the minimum network performance requirements set out in schedule 5.1 or in relevant legislation, regulations or any statutory instrument of a participating jurisdiction”.*

Furthermore, Version 3 of the Regulatory Test[2] states (in part) that an option satisfies the regulatory test if, in the event the option is necessitated principally by inability to meet the service standards linked to the technical requirements of schedule 5.1 of the NER (or in applicable regulatory instruments), the option minimises the costs of meeting those requirements, compared with alternative option(s) in a majority of reasonable scenarios.

Section 3.4, and section 4 of this report address the requirements of clause 5.6.6(c)(6) of the NER which requires analysis of why the applicant considers that the asset is a reliability augmentation, and why the applicant considers that the asset satisfies the regulatory test.

2.3.4 Local jurisdictional requirements

The Tasmanian Electricity Supply Industry Regulations 2007 (Network Performance Requirements) sets out requirements in relation to the performance of the electricity supply network. Transend has obligations under these regulations which are discussed section 3.4 of this report.

2.4 REFERENCES

Transend. 2008 Annual Planning Report. Transend, 2008.

Transend. Reliability Modelling and Analysis, Hobart Eastern Shore region. Transend 2008.

Aurora Energy. Options Analysis Report, Proposed New Large Distribution Asset, Hobart Eastern Shore Upgrade. Aurora Energy, 2008.

Australian Energy Market Commission. National Electricity Rules (version 23). November 2008.

State of Tasmania, Electricity Supply Industry Act. Tasmanian Attorney-General's Office.

Australian Energy Regulator. Final Decision Regulatory Test Version 3 & Application Guidelines. November 2007.

Transend/Aurora. Application Notice Development of the Electricity Supply Network in the Hobart Eastern Shore Region. December 2008.

[2] Australian Energy Regulator. Final Decision Regulatory Test version 3 & Application Guidelines. November 2007.

3 REGIONAL OVERVIEW

This section provides an overview of the Hobart Eastern Shore region, the anticipated development within this region, as well as the regional development scenarios considered. This information serves as background to the presentation of the regional demand forecast which has been used as the basis for studies of the electricity network. An overview of the existing electricity supply arrangements within the region is also presented, and this section concludes with a discussion of the emerging supply limitations that have been identified.

Broadly, the Hobart Eastern Shore region has been defined as the area extending from Risdon Vale in the northwest, to Seven Mile Beach and Pitt Water in the east, and south to encompass the southern beach communities of Lauderdale, Clifton Beach and South Arm. Figure 3-1 shows a map of this region.

While the overall region shown in Figure 3-1 is considered, it should be noted that the area to the east and northeast of Mt Rumney and Acton Park is considered mainly in terms of its contribution to the regional demand forecast. However, it is the area to the west of Mt Rumney and Acton Park that is of primary concern, as the existing supply arrangement for Hobart Eastern Shore region is largely located in this area. In addition, it is the expected load growth in the Lindisfarne to Rokeby and South Arm areas that contributes largely to the emerging supply limitations.

It should also be noted that the area to the east and northeast of Mt Rumney and Acton Park will be supplied from the new Cambridge Zone Substation following its commissioning in April 2009. Reference should be made to section 3.3 for further details.

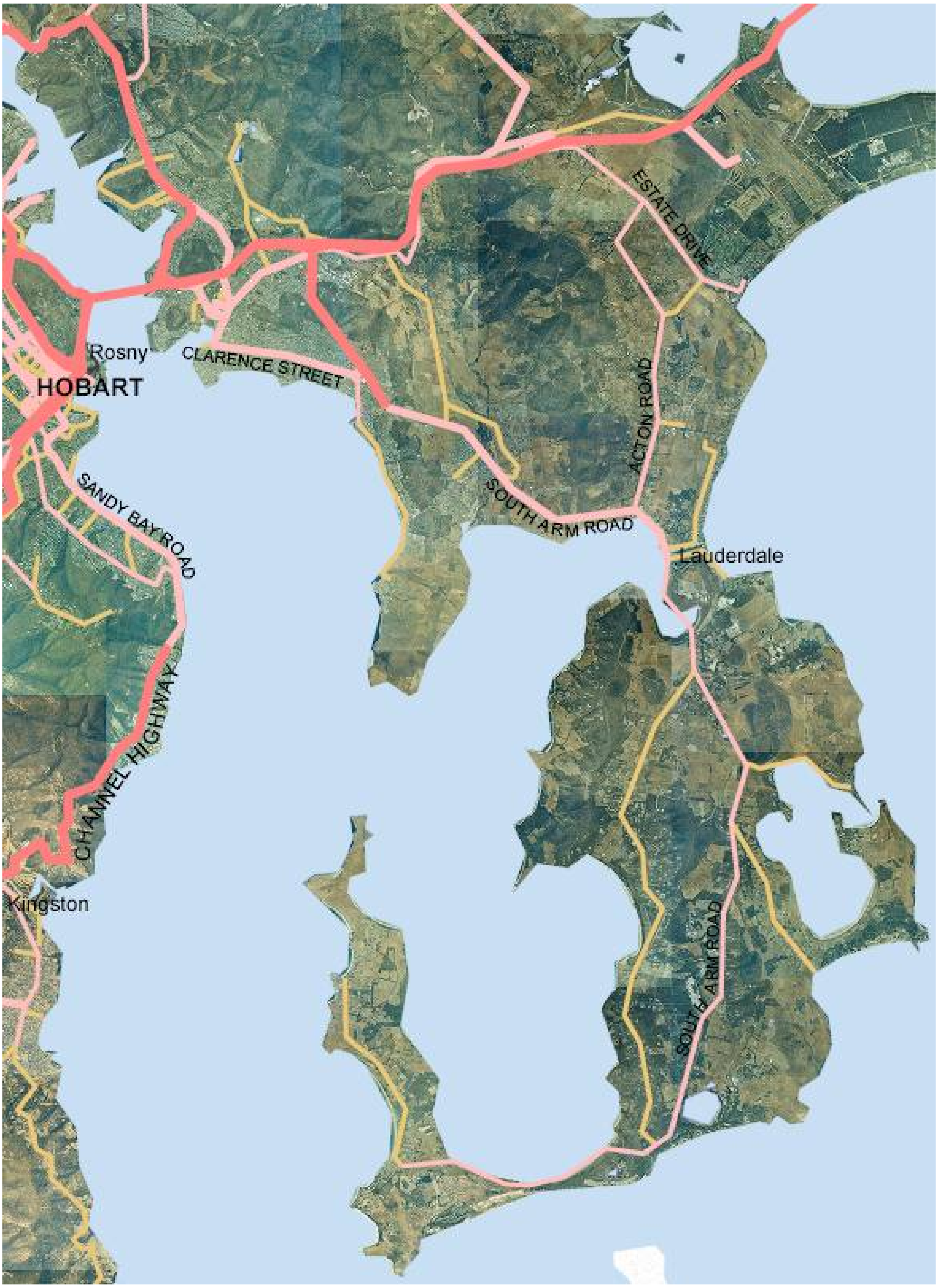
3.1 REGIONAL DEVELOPMENT

The Hobart Eastern Shore region can be characterised predominately as residential, rural, and rural residential, with some modest industrial zones in the Mornington and Cambridge areas, and some local commercial areas located throughout the region.

The area to the east and northeast of Mt Rumney and Acton Park is characterised by undulating plains. While this area is generally of a rural and rural residential nature, Cambridge township, and Seven Mile Beach are largely residential. In the Cambridge area there are a number of larger commercial developments (bulky goods, offices, etc), and the Cambridge aerodrome and Hobart Airport are also located on the eastern fringe of this area. Proposed developments include both rural residential subdivisions, and commercial developments. Development is geographically constrained in the east by Frederick Henry Bay and Pitt Water.

To the west and southwest of Mt Rumney and Acton Park, and across to the Derwent River is the area stretching from Risdon Vale and Lindisfarne in the north to Tranmere and Lauderdale in the south. This is an existing well developed area, consisting of residential, rural residential, as well as some commercial areas. There are a number of proposed residential and commercial developments within this area. In particular, the proposed developments in the Rokeby, Lauderdale and Tranmere areas are of significance with regards to the electricity supply network. In addition, there are a number of commercial developments proposed in the Rosny area. Development in this area is constrained geographically by the Derwent River to the west and south, and by Frederick Henry Bay in the southeast. Development is also constrained to the area below 60m above sea level due to water supply limitations, and land above this level is zoned to preclude general development. Council zoning, and environmental limitations, also restrict development within the area.

Figure 3-1 Hobart Eastern Shore region



3.2 Development Scenarios and Demand Forecast

Three regional development scenarios have been considered in undertaking joint planning for this region. These scenarios consider high growth, medium or expected growth, and low growth possibilities.

Under each of the three scenarios, regional growth in electricity demand is driven fundamentally by state population growth and growth in the number of households (state-wide). This growth is underpinned by the economic conditions that are taken into account through forecasts of key economic indicators. In developing the demand forecasts, three different growth rates of electricity demand have been developed based on the three regional growth scenarios considered.

The high growth scenario represents an annual growth rate 1.4% greater than the expected regional growth rate. The medium growth scenario represents the regions expected growth, and as such there is an equal probability (50% probability) that the actual regional demand will fall above or below this forecast. The low growth scenario represents an annual growth rate 1.0% less than the expected regional growth rate.

In addition to general underlying growth, proposed significant developments (point loads) have been identified and considered on a case-by-case basis using specific information gathered from developers working within the region. These significant developments (point loads) are added separately to the relevant underlying growth forecasts.

Aurora has produced summer and winter demand forecasts for each development scenario, and for each substation and zone substation within the Hobart Eastern Shore region. Winter demand forecasts are however the most relevant for network planning in this region, due to Tasmania’s climatic conditions and the region’s largely residential and rural residential land use.

The 2007 winter demand forecasts for the high, medium and low growth scenarios are given in Table 3-1, Table 3-2, and Table 3-3 respectively. These forecasts have been used as the basis for the network studies of this region.

Table 3-1 High Growth Winter Demand Forecast (MVA)

Year	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
Lindisfarne Substation														
Forecast	67	75	85	90	95	98	101	103	106	109	113	116	119	123
Transferred	3	2	-	-	-	-	-	-	-	-	-	-	-	-
Point Loads	2	2	2	2	-	-	-	-	-	-	-	-	-	-
Total	72	79	87	92	95	98	101	103	106	109	113	116	119	123
Rokeby Substation														
Forecast	47	46	48	50	52	53	55	56	58	60	61	63	65	67
Transferred	-3	-2	-	-	-	-	-	-	-	-	-	-	-	-
Point Loads	-	3	-	-	-	-	-	-	-	-	-	-	-	-
Total	44	47	48	50	52	53	55	56	58	60	61	63	65	67
Regional Total														
Total	116	127	135	142	146	151	155	160	165	169	174	179	184	190
Growth (%)	7.4	9.6	6.9	4.8	3.2	3.1	3.0	2.9	2.9	2.8	2.9	2.9	2.9	2.9

Source: Forecast load based on the 2007 UES load growth forecast.

Table 3-2 Medium (Expected) Growth Winter Demand Forecast (MVA)

Year	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
Lindisfarne Substation														
Forecast	65	73	81	84	88	89	91	92	94	95	96	98	99	101
Transferred	3	2	-	-	-	-	-	-	-	-	-	-	-	-
Point Loads	2	2	2	2	-	-	-	-	-	-	-	-	-	-
Total	70	77	83	86	88	89	91	92	94	95	96	98	99	101
Rokeby Substation														
Forecast	46	44	46	47	48	48	49	50	51	51	52	53	54	55
Transferred	-3	-2	-	-	-	-	-	-	-	-	-	-	-	-
Point Loads	-	3	-	-	-	-	-	-	-	-	-	-	-	-
Total	42	45	46	47	48	48	49	50	51	51	52	53	54	55
Regional Total														
Total	113	122	129	133	136	138	140	142	144	146	148	151	153	155
Growth (%)	6.0	8.3	5.6	3.5	1.8	1.7	1.6	1.5	1.5	1.4	1.5	1.5	1.5	1.5

Source: Forecast load based on the 2007 UES load growth forecast.

Table 3-3 Low Growth Winter Demand Forecast (MVA)

Year	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
Lindisfarne Substation														
Forecast	64	71	78	81	83	84	84	85	85	86	86	86	87	87
Transferred	3	2	-	-	-	-	-	-	-	-	-	-	-	-
Point Loads	2	2	2	2	-	-	-	-	-	-	-	-	-	-
Total	69	75	80	83	83	84	84	85	85	86	86	86	87	87
Rokeby Substation														
Forecast	45	43	44	44	45	45	45	46	46	46	46	47	47	47
Transferred	-3	-2	-	-	-	-	-	-	-	-	-	-	-	-
Point Loads	-	3	-	-	-	-	-	-	-	-	-	-	-	-
Total	42	44	44	44	45	45	45	46	46	46	46	47	47	47
Regional Total														
Total	110	119	124	127	128	129	130	130	131	132	132	133	134	134
Growth (%)	5.0	7.4	4.6	2.5	0.8	0.7	0.6	0.5	0.5	0.4	0.5	0.5	0.5	0.5

Source: Forecast load based on the 2007 UES load growth forecast.

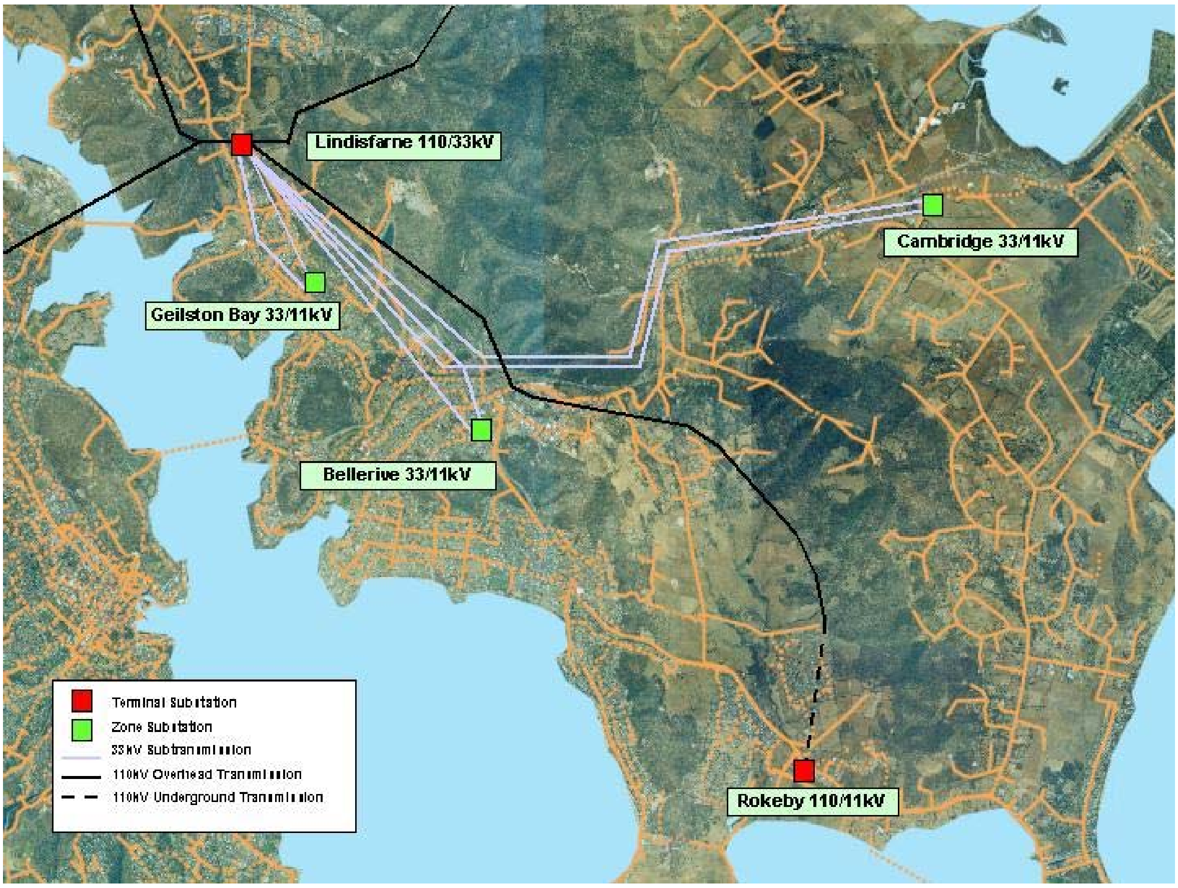
In light of the recent global economic events, Aurora has undertaken a review of the demand forecasts. This review has considered the current global economic conditions, as well as the potential impact of the proposed Carbon Pollution Reduction Scheme (CPRS) on the regions load growth.

As the western part of the Hobart Eastern Shore region is generally located within 30 minutes drive of Hobart, has good quality readily available land, and offers good amenities, it has been, and remains, a prime development area. The historical growth rate in this area has averaged around 3.3%, and a number of major subdivision developments are currently occurring, with several others in late stages of planning. In general, as the region has historically shown rates of growth above state averages, Aurora is of the view that had the financial crisis not developed, or the CPRS not been proposed, then the area would have most likely experienced a higher growth rate than is currently forecast (particularly in the Howrah and Rokeby areas). Consequently, Transend and Aurora are of the opinion that the medium (expected) winter demand forecast is appropriate for planning in this region, given the potential impacts of the global economic conditions and the proposed CPRS.

3.3 EXISTING SUPPLY ARRANGEMENTS

Figure 3-2 shows the geographic arrangement of the transmission and subtransmission networks within the Hobart Eastern Shore region. A simplified single line diagram of the transmission network is also presented in Figure 3-3.

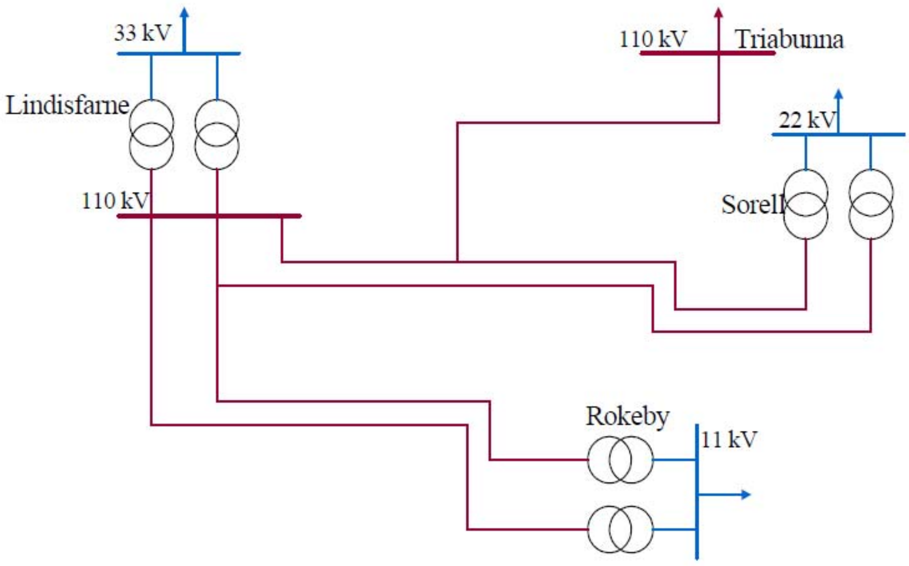
Figure 3-2 Transmission and Subtransmission Network Geographic Arrangement



Lindisfarne Substation, located in the northwest of the Hobart Eastern Shore region, is the regions primary point of supply. This substation has two 110/33 kV, 45 MVA transformers, with six 33 kV outgoing subtransmission feeders. The substations firm rating is 45 MVA, with a cyclic rating[3] of 54 MVA.

[3] Cyclic rating may also be referred to as short term rating or emergency rating.

Figure 3-3 Transmission Network Single Line Diagram



Lindisfarne supplies Rokeby Substation via a double circuit 110 kV transmission line, as well as Bellerive, Geilston Bay, and Cambridge[4] zone substations via six 33 kV subtransmission lines[5].

Rokeby Substation, located in the southeast of the region, supplies the 11 kV distribution network in the Rokeby and surrounding areas (refer Figure 3-4). This substation has two 110/11 kV, 35 MVA transformers, with ten 11 kV outgoing distribution feeders. The substations firm rating is 35 MVA, with a cyclic rating of 42 MVA.

Lindisfarne and Rokeby substations, as well as the interconnecting 110 kV transmission lines are owned and managed by Transend.

The geographic arrangement of the distribution network in the Hobart Eastern Shore region is shown in Figure 3-4.

Currently, Lindisfarne Substation is supplied at 110 kV from Risdon Substation via a double circuit transmission line, from Bridgewater Substation via a single circuit transmission line, and from Waddamana Substation via a single circuit transmission line. Plans are well advanced to augment Lindisfarne with the addition of a 220 kV supply from Waddamana in 2010[6].

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4 Cambridge Zone Substation is currently being developed, and will be commissioned in April 2009. For the purposes of joint planning within the region, Cambridge Zone Substation has been treated as existing.

5 Lindisfarne Substation also supplies Sorell Substation and Triabunna Substation which are to the northeast of the Hobart Eastern Shore region.

6 Reference should be made to and Transend's Annual Planning Reports, and to the Waddamana – Lindisfarne 220 kV Application to establish a new large transmission asset, June 2007.

Figure 3-4 Distribution Network Geographic Arrangement

The Hobart Eastern Shore region has an 11 kV distribution network that is supplied from Geilston Bay Zone Substation, Bellerive Zone Substation, and Cambridge Zone Substation. Each of these substations is supplied via two 33 kV feeders arranged as a radial network that originates at Lindisfarne Substation. Rokeby Substation also supplies the 11 kV distribution network in the Rokeby and surrounding areas in the south of the region.

Geilston Bay Zone Substation supplies the distribution network in the northwest of the region, and to the south of Lindisfarne. This substation has two 33/11 kV, 22.5 MVA transformers with eight 11 kV distribution feeders and one spare 11 kV feeder bay. The substation's firm rating is 22.5 MVA, with an emergency (cyclic) rating of 27 MVA.

Bellerive Zone Substation supplies the distribution network immediately to the south of the Geilston Bay Zone Substation supply area. This substation has two 33/11 kV, 22.5 MVA transformers with ten 11 kV distribution feeders and no spare 11 kV feeder bays. The substations firm rating is 22.5 MVA, with an emergency (cyclic) rating of 27 MVA.

Cambridge Zone Substation will be commissioned in April 2009. On commissioning, this substation will supply the distribution network in the eastern and north eastern part of the region and offload the adjacent zone substations. Cambridge Substation has two 33/11 kV, 20 MVA transformers and capacity for twelve 11 kV distribution feeders. The substations firm rating is 20 MVA, with an emergency (cyclic) rating of 23 MVA[7].

The southern area of the Hobart Eastern Shore region is supplied from Rokeby Substation which (as noted above) has two 110/11 kV, 35 MVA transformers, with ten 11 kV outgoing distribution

[7] The emergency rating is to be confirmed on commissioning.

feeders. The substations firm rating is 35 MVA, with a cyclic rating of 42 MVA.

While the 11 kV distribution network is interconnected, as shown in Figure 3-4, the capacity of the cross-feeder and cross-zone substation distribution feeder ties is limited due to the existing distribution feeder loads and topography. Distribution network interconnection is also limited due to the topology of the area.

Geilston Bay, Bellerive, and Cambridge zone substations, as well as the interconnecting 33 kV subtransmission lines, and 11 kV distribution feeders, are owned and managed by Aurora. Rokeby Substation is a Transend asset.

3.4 EMERGING SUPPLY LIMITATIONS

Transend and Aurora have conducted studies of the transmission and distribution networks in the Hobart Eastern Shore region over the 10 year planning period commencing in 2009. These studies are based on the regional development scenarios and demand forecasts presented in section 3.2, and the existing supply arrangements presented in section 3.3.

Transend's transmission network has a number of supply limitations, in the Hobart Eastern Shore region. Similarly, Aurora's subtransmission and distribution network also has emerging supply limitations. The nature and timing of these supply limitations is different for the transmission and distribution networks, and also varies under the demand forecast for each of the regional development scenarios. Consequently, this section firstly considers the transmission network supply limitations under the high, medium and low growth scenarios. The distribution network supply limitations are then considered under each of the scenarios.

Transmission network limitations

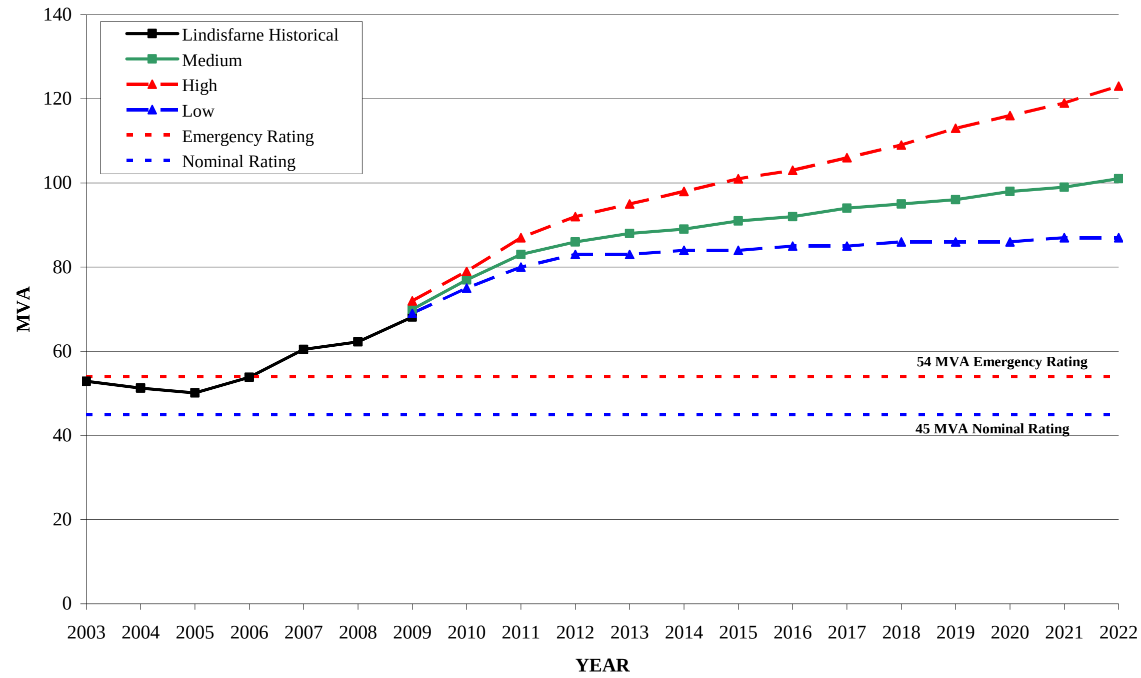
Under Schedule 5.1, clause S5.1.2 of the NER, Transend is required to plan and develop the network to meet forecast electricity demand for a credible contingency event. Clause S5.1.2.2 also sets out the minimum standards in relation to amount of network redundancy the must be provided under a connection agreement. In addition, clause 5(1)(a)(iv) of the Electricity Supply Industry Regulations 2007 (Network Performance Requirements), requires that "the unserved energy to load that is interrupted consequent on damage to a network element resulting from a credible contingency event is not to be capable of exceeding 300 MWh at any time".

The Lindisfarne medium (expected) winter demand forecast, the current available capacity, and the resulting load at risk is given in Table 3-4. Figure 3-5 presents a graph of the historical actual demand, as well as the high, medium and low forecast winter demand against the available capacity at Lindisfarne. This graph shows that during the winters of 2007 and 2008, the historical load on Lindisfarne exceeded the emergency (cyclic) rating. Hence the current supply arrangements at Lindisfarne are non-compliant with the requirements of the NER and the requirements of clause 5(1)(a)(iv) of the Electricity Supply Industry Regulations 2007 (Network Performance Requirements) under a credible contingency event.

Table 3-4 Lindisfarne Demand Forecast and Load at Risk (MVA)

Year	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018
Maximum demand (MVA)	70	77	83	86	88	89	91	92	94	95
Firm Rating	45 MVA (54 MVA emergency)									
Load at Risk (MVA)	25 (16)	32 (23)	38 (29)	41 (32)	43 (34)	44 (35)	46 (37)	47 (38)	49 (40)	50 (41)

Figure 3-5 Lindisfarne – Comparison of Demand Forecast to Capacity



The Rokeby medium (expected) winter demand forecast, the current available capacity, and the resulting load at risk is given in Table 3-5. It is important to note, that while the supply arrangements at Lindisfarne and Rokeby are either currently non-compliant, or are expected to become non-compliant with the requirements of the NER and/or the Electricity Supply Industry Regulations, Transend has adopted operational strategies to enable the optimum utilisation of available capital resources and strategically address the broader emerging supply limitations within the Hobart Eastern Shore region.

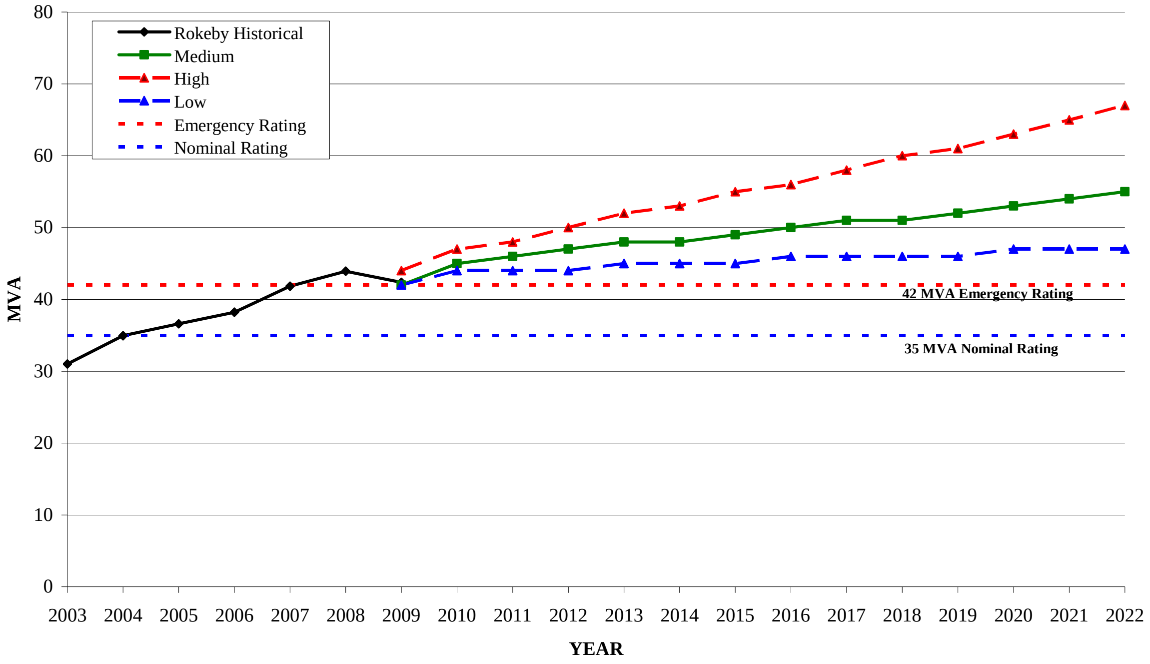
Under the medium (expected) winter demand forecast for the Hobart Eastern Shore region, current transmission network supply arrangements will be non-compliant with the requirements of Schedule 5.1, clause S5.1.2 of the NER and clause 5(1)(a)(iv) of the Electricity Supply Industry Regulations 2007 (Network Performance Requirements), by the winter of 2010 and beyond. Consequently, any transmission network augmentations that arise out of the inability of the current network to meet these requirements, are reliability augmentations in accordance with the definition in Chapter 10 of the NER.

Figure 3-6 presents a graph of the historical actual demand as well as the high, medium, and low forecast winter demand against the available capacity at Rokeby. This graph shows that during the winter of 2008, the load on Rokeby exceeded the emergency (cyclic) rating. Currently, under a credible contingency event, the supply arrangements at Rokeby are non-compliant with the requirements of the NER as set out above, and based on the medium (expected) demand forecast, the supply arrangements at Rokeby will be non-compliant with the requirements of clause 5(1)(a)(iv) of the Electricity Supply Industry Regulations 2007 (Network Performance Requirements) by winter 2010 and beyond.

Table 3-5 Rokeby Demand Forecast and Load at Risk (MVA)

Year	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018
Winter demand (MVA)	42	45	46	47	48	48	49	50	51	51
Firm Rating	35 MVA (42 MVA emergency)									
Load at Risk (MVA)	7 (0)	10 (3)	11 (4)	12 (5)	13 (6)	13 (6)	14 (7)	15 (8)	16 (9)	16 (9)

Figure 3-6 Rokeby – Comparison of Demand Forecast to Capacity



Distribution network limitations

Aurora is required to meet service standards which are linked to the technical requirements of Schedule 5.1 of the NER. Accordingly, Aurora has developed System Planning Standards which are set out in section 6 of Aurora's Asset Management Plan. These standards require that zone substations in medium to high density areas are managed under a 'Group Firm' philosophy as opposed to an individual substation N-1 criterion.

The Group Firm philosophy requires that an N-1 planning criteria is applied across all zone substations within an area with a shared load network[8]. Hence the Group N-1 firm rating is the sum of the N-1 firm ratings of the individual zone substations within the group. A 'Group Nominal' rating is also defined where load can be transferred to accommodate the failure of an individual transformer within the group. The Group Nominal rating is defined as the Group N-1 firm rating plus the rating of one additional group transformer.

Figure 3-7 shows the Hobart Eastern Shore regional historical demand as well as the high, medium, and low forecast winter demand against the available zone substation group capacity. This graph shows that based on the medium (expected) winter demand forecast, the Group Nominal rating will be exceeded in 2013 and beyond.

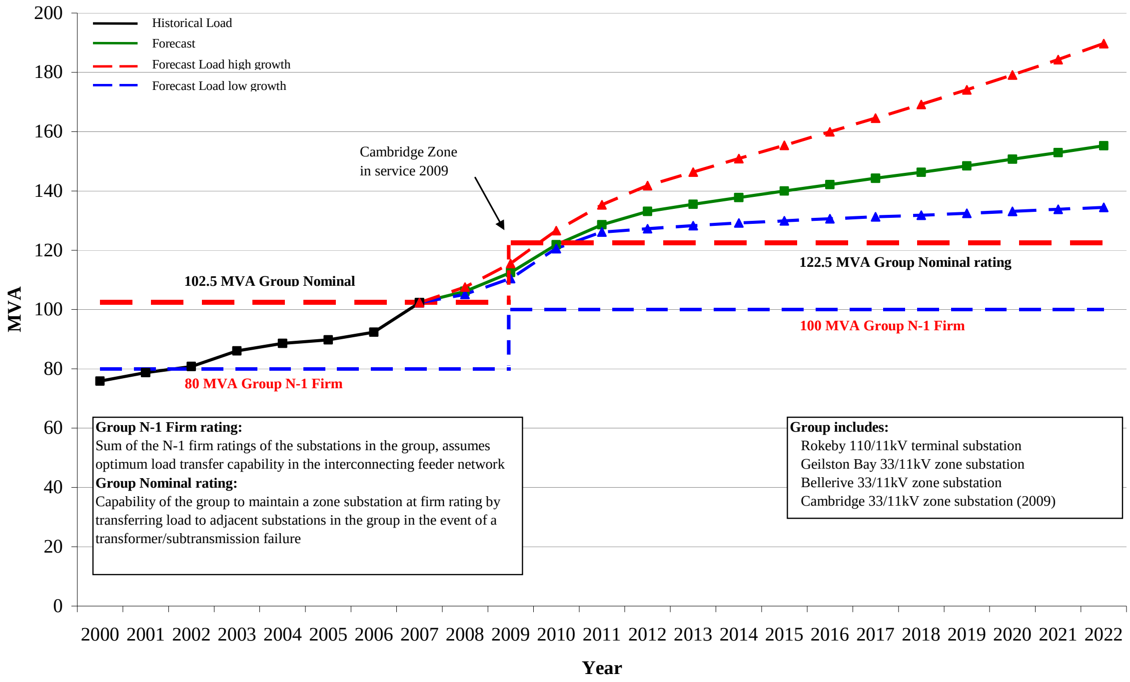
It should be noted that in Figure 3-7, the step change in the group rating in 2009 is due to the commissioning of Cambridge Zone Substation in April 2009.

While Figure 3-7 clearly shows the emerging regional distribution network constraint, there are specific constraints emerging at each of the regions existing zone substations. Figure 3-8 shows the emerging constraints at Geilston Bay and Bellerive zone substations. The supply constraints at Rokeby, which supplies 11 kV in the south of the region, are addressed under transmission network

8 It is not always possible to apply the group firm philosophy as it requires a meshed high voltage network to support inter zone load transfer.

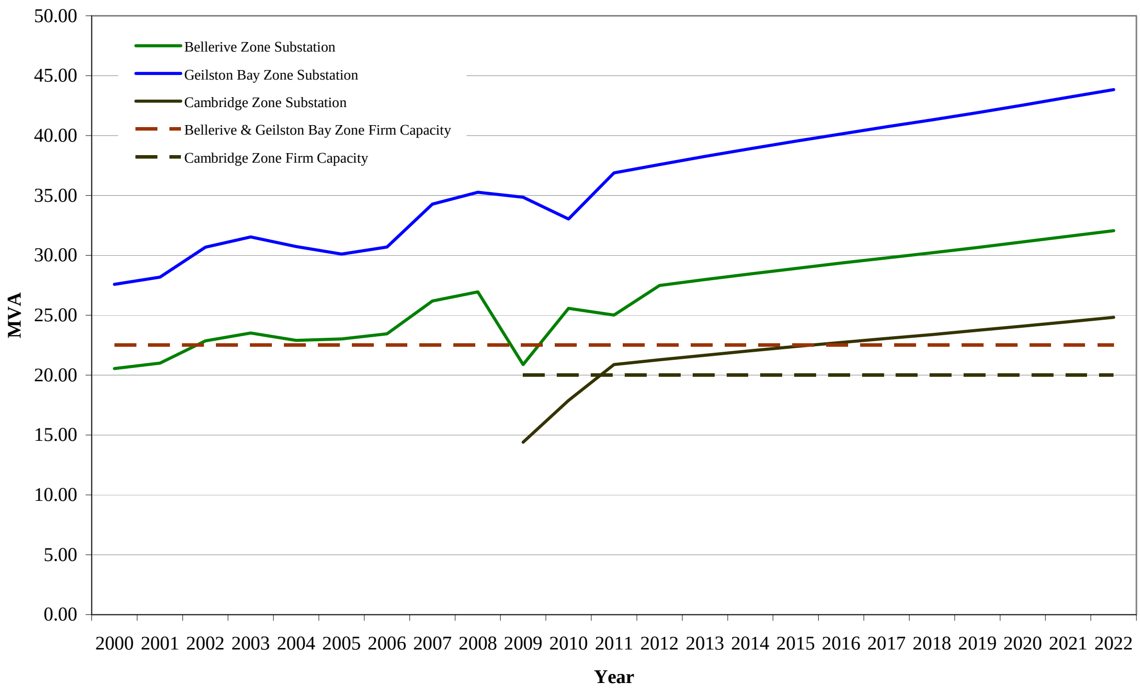
limitations above.

Figure 3-7 Hobart Eastern Shore Region – Comparison of Demand Forecast to Capacity



As Figure 3-8 shows, the firm (N-1) capacity of Geilston Bay and Bellerive zone substations is currently exceeded, and the firm (N-1) capacity of Cambridge Zone Substation is expected to be exceeded by the winter of 2016 under the medium (expected) growth demand forecast.

Figure 3-8 Regional Zone Substations – Comparison of Demand Forecast to Capacity



It should be noted that load transfers between the region's zone substations has been undertaken to manage the impact of the overall regional demand on the available capacity. However, the existing 11kV feeders in the Rokeby, Kangaroo Bay, Howrah and Lauderdale areas are currently at, or near to, their 5MVA capacity rating, and further load transfers are impractical.

Under the medium (expected) winter demand forecast for the Hobart Eastern Shore region, current subtransmission and distribution supply arrangements will be unable to meet the service standards which are linked to the technical requirements of Schedule 5.1 of the NER by the winter of 2011 and beyond.

4 ALTERNATIVE OPTIONS

This section outlines the alternative options which have been considered as practical solutions to address the emerging supply limitations in the Hobart Eastern Shore region as identified in section 3.4. The feasibility of not undertaking any action (i.e. the 'Do Nothing' option) is first considered, then consideration is given to non-network options, and lastly the practical network options are examined.

4.1 DO NOTHING

Under Schedule 5.1 clause S5.1.2 of the National Electricity Rules (NER), Transend is required to plan and develop the network to meet forecast electricity demand for a credible contingency event.

Currently, the winter demand in the Hobart Eastern Shore region exceeds the available capacity of a number of the regions existing substations. While Transend and Aurora have adopted operational measures to manage the existing demand, under the medium (expected) winter demand forecast for the region, current supply arrangements will be non-compliant with the requirements of Schedule 5.1, clause S5.1.2 of the NER and clause 5(1)(a)(iv) of the Electricity Supply Industry Regulations 2007 (Network Performance Requirements), by the winter of 2011 and beyond. Therefore, Transend and Aurora must take action under their current obligations, and the do nothing option has not been considered further.

The following alternative options should be considered as an application of the reliability limb of the 'Regulatory Test' under the requirements of the NER.

4.2 NON-NETWORK ALTERNATIVE OPTIONS

This section considers a number of non-network alternative options to reduce demand on the exiting Hobart Eastern Shore network as a means to addressing the emerging network constraints.

4.2.1 Demand side management and embedded generation

Demand Side Management (DSM) schemes have been successfully employed both nationally and internationally to reduce network demand. Similarly, embedded generation could offer an alternative to a network solution. However, to be viable, any DSM scheme or embedded generation scheme would need to provide a reduction of approximately 5 MVA of the peak winter demand across the region, and offset an annual peak demand growth of approximately 3.3%[9]. Such schemes could provide deferral of the lowest cost practical network alternative option, which is valued at approximately $1.2 million per annum[10]. On average, over the first five years of deferral, this is equivalent to approximately $225 per kVA per annum of peak winter demand reduction.

While DSM schemes have been implemented elsewhere, these schemes typically involve the participation of the industrial and commercial sectors. However, the Hobart Eastern Shore region is mostly residential and has very few significant individual loads that can readily employ a DSM scheme. Consequently, demand aggregation would be necessary to achieve the required demand

9 The demand growth in the Hobart Eastern Shore region has historically averaged approximately 3.3%.

10 Based on the deferral of option 2, and using the regulatory WACC as the appropriate discount rate.

reduction. Such demand aggregation is likely to require the extensive roll-out of smart metering[11] or load control technology, an appropriate tariff structure, and the active support of retailers to achieve in the required timeframe.

Embedded generation would require a suitable fuel source and a suitable site with appropriate land zoning to support development. Transend and Aurora are of the view that the topography of the area is unsuitable for embedded generation of a reasonable scale, and that current land zoning may preclude such development. In addition, with no gas supply currently in the region, a suitable fuel supply is presently unavailable. Consideration has also been given to the potential uptake of small scale photovoltaic systems; however Transend and Aurora are of the view that the uptake of such systems would not be sufficient to overcome the developing capacity problems in the region.

Transend and Aurora are not aware of any available DSM options, or embedded generation proposals in the Hobart Eastern Shore region; particularly in the critical area to the west and southwest of Mornington. No responses proposing non-network solutions were received.

4.2.2 Other non-network alternative options

Fuel substitution, can be an effective means of reducing electricity demand. This involves encouraging consumers to reduce their electricity demand by using an alternative fuel to (in part) meet their energy needs. In practice this could be achieved by the substitution of electric appliance with gas appliances; and particularly those appliances that drive peak residential demand such as those appliances used in heating and cooking. For a fuel substitution scheme to be practical, it would need to achieve a winter peak demand reduction at least similar to that discussed in section 4.2.1 above.

However, there is currently no reticulated gas supply in the Hobart Eastern Shore region, and no known plans for such a supply. In addition, Transend and Aurora are of the opinion that a bottled gas solution, sufficient to provide the required winter peak demand reduction, would not be commercially viable given the annual deferral value discussed in section 4.2.1 above.

Transend and Aurora are of the view that a viable fuel substitution scheme is impractical in the Hobart Eastern Shore region at this time; particularly in the critical area to the west and southwest of Mornington.

4.2.3 Non-network alternative options conclusion

Transend and Aurora have investigated a number of non-network alternative options to address the emerging network constraints discussed in section 3.4. Both Transend and Aurora are of the view that there are currently no practical non-network solutions available in the Hobart Eastern Shore region.

4.3 NETWORK ALTERNATIVE OPTIONS

Through the joint planning process, Transend and Aurora have identified three practical alternative network options to address the emerging network constraints discussed in section 3.4.

It should be noted that each of the network options has been developed to achieve the same functional outturn, in order to equivalently address the emerging network constraints. It should also be noted that the committed commissioning of Cambridge Zone Substation in early 2009, has been included in the analysis of all options.

4.3.1 Cost estimates and WACC

All cost estimates have been prepared on the same basis in order to ensure a fully equivalent

[11] The adoption of smart metering is currently under consideration in Tasmania.

assessment of the alternative options. These cost estimates have been prepared in accordance with the cost estimating policies and procedures of Transend and Aurora. All direct costs as defined by the Regulatory Test have been included. Transend cost estimates are based on its standard estimating procedure and have a nominal accuracy of ±30%. While Aurora's cost estimates have a nominal accuracy of ±25%. The impact of the accuracy of the cost estimates on the selection of the preferred option is examined in the sensitivity analysis presented in section 4.5.

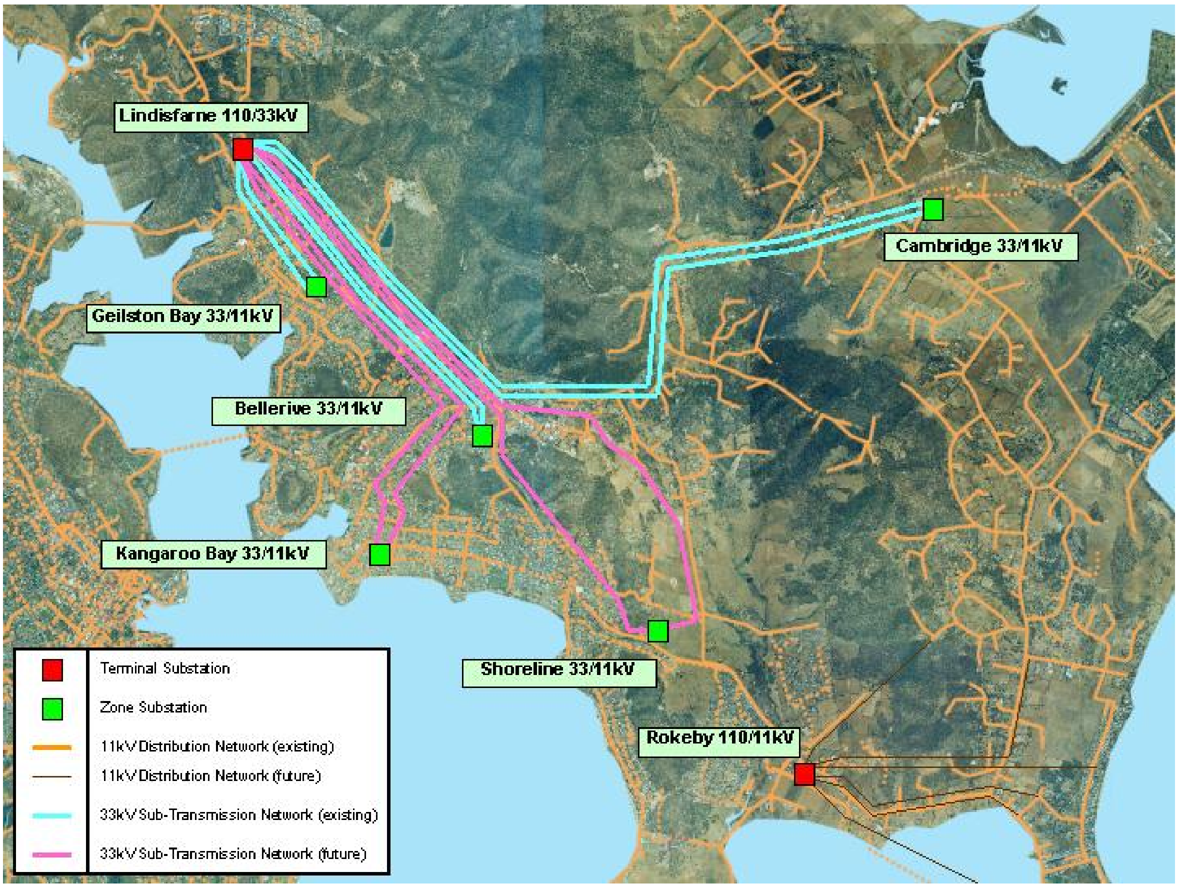
The discount rates used in undertaking the present value analysis are 7.46% pre-tax real for Transend, and 6.64% pre-tax real for Aurora. In Aurora's case, the WACC value used is the value set in the regulatory determination for the current regulatory period, while for Transend's, the value is based on the AER draft determination figure at the time of publishing the application notice. The impact of variation in the discount rate on the selection of the preferred option is examined in the sensitivity analysis presented in section 4.5 The AER has since set Transend's WACC at 6.66% and this variation is included in the sensitivity analysis.

4.3.2 Option 1 – Lindisfarne Substation third 110/33 kV transformer

Description

Figure 4-1 shows the proposed ultimate network geographic arrangement resulting from the work proposed under this option.

Figure 4-1 Option 1 – Ultimate Network Geographic Arrangement



At present, Lindisfarne Substation consists of two 110/33 kV, 45 MVA transformers. This option involves Transend augmenting Lindisfarne to install a third 110/33 kV 60 MVA transformer[12], as

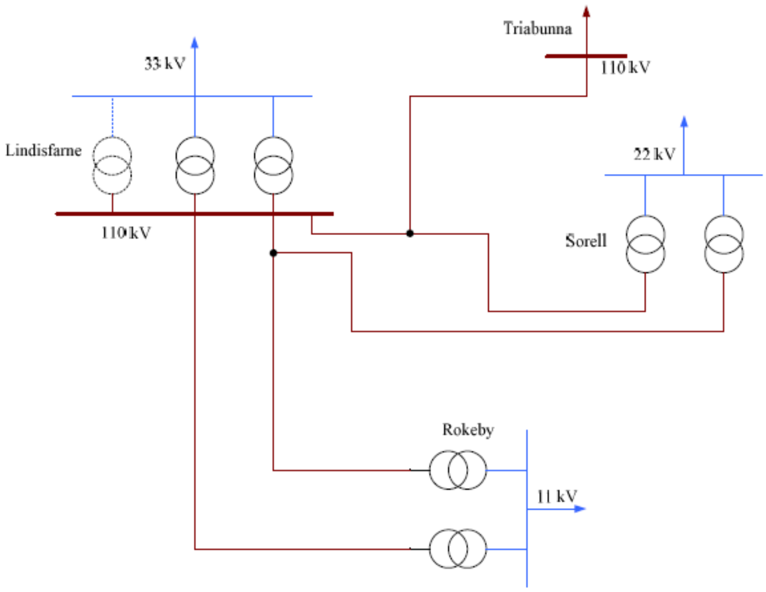
12 Under Transend's asset management plan and transformer strategy, all new power transformers are 60 MVA capacity.

well as extending the existing 33kV busbar. The two existing 110/33 kV 45MVA transformers with be replaced with 60 MVA transformers once the N-1 firm capacity is exceeded in 2011.

The Rokeby Substation currently consists of two 110/11 kV, 35 MVA transformers. Under this option Transend will also upgrade Rokeby Substation with two new 110/11 kV, 35 MVA transformers (four in total), and replace 2 km of existing 110 kV cable at Rokeby to augment the Lindisfarne to Rokeby 110 kV transmission line. This work will bring the station up to a capacity of 70 MVA[13].

Figure 4-2 presents the single line diagram of the proposed arrangement.

Figure 4-2 Option 1 - Proposed Single Line Diagram



(Option 3 – Rokeby 110/33 kV substation development, considers an alternative arrangement at Rokeby and is described in section 4.3.4 below).

This option also includes augmentation of Aurora's distribution network. This involves the development of two new zone substations in the Kangaroo Bay and Shoreline areas, and four new 33 kV subtransmission feeders from Lindisfarne Substation. Distribution feeder works would also be undertaken to integrate the new zone substations into the existing 11 kV network, and offload the existing Geilston Bay, Bellerive, and Rokeby substations. This arrangement is shown in Figure 4-1 above.

It should be noted that under this option, Lindisfarne would supply five 33/11 kV zone substations in the Hobart Eastern Shore region. It should also be noted that under this option, the proposed Lauderdale Zone Substation would not be developed, and the Lauderdale and South Arm areas would be supplied via a greatly augmented 11 kV network originating at Rokeby Substation.

Timing

Construction on the works proposed in this option would need to commence in 2009, with commissioning of the Lindisfarne third transformer, and replacement of the existing transformers by the winter of 2011.

[13] Currently the 110 kV transmission line from Lindisfarne to Rokeby transition structure is rated at 180 MVA.

Construction of the Shoreline Zone Substation, and the associated 33kV subtransmission feeders from Lindisfarne, would be undertaken to achieve commissioning by the winter of 2011. Installation of additional 11kV feeders from Shoreline to the Geilston Bay area would be completed by 2011. Similarly, Construction of the Kangaroo Bay Zone Substation, and associated feeders, would be undertaken to achieve commissioning by the winter of 2012.

Transend's upgrade of the Rokeby Substation with two new 35MV transformers will take place by 2015 to service demand growth in the Lauderdale area. This work would also include the development by Aurora of additional 11kV feeders into the Lauderdale area (Although this is outside the 10 year planning horizon, the project is a key part of the strategy and hence it has been included).

Key outcomes

The winter demand forecasts for Lindisfarne and Rokeby substations in comparison to the proposed capacity resulting from the implementation of this option are shown in Figure 4-3, Figure 4-4, and Figure 4-5 for high, medium, and low forecasts respectively.

Figure 4-3 Option 1 – High Demand Forecast V's Proposed Transmission Capacity

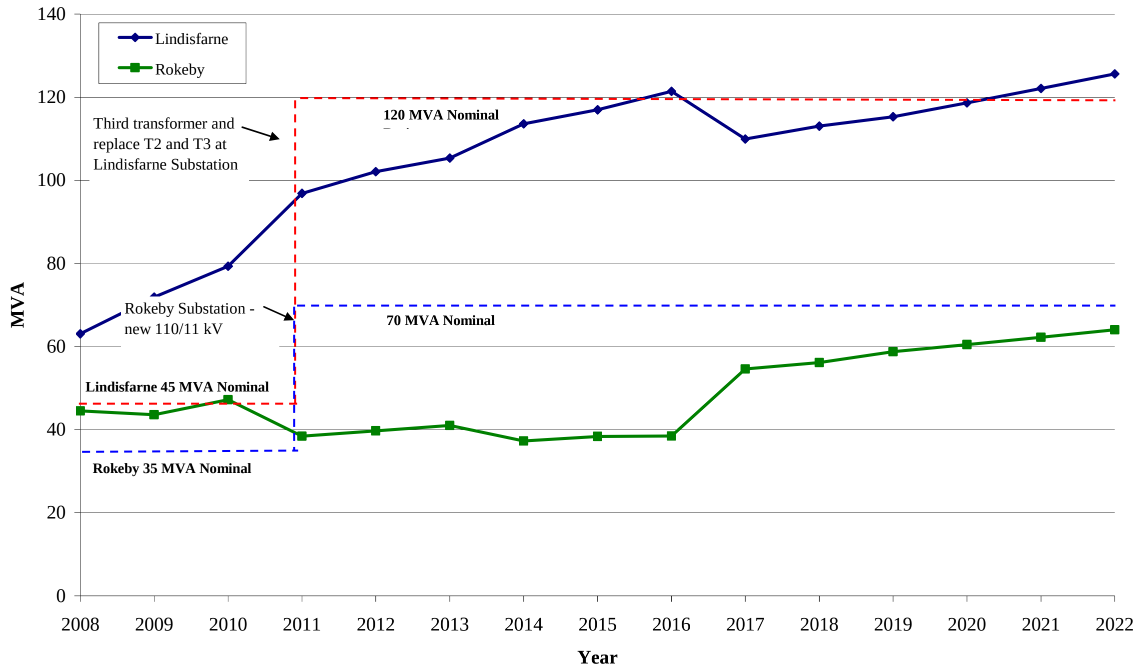


Figure 4-4 Option 1 – Medium Demand Forecast V's Proposed Transmission Capacity

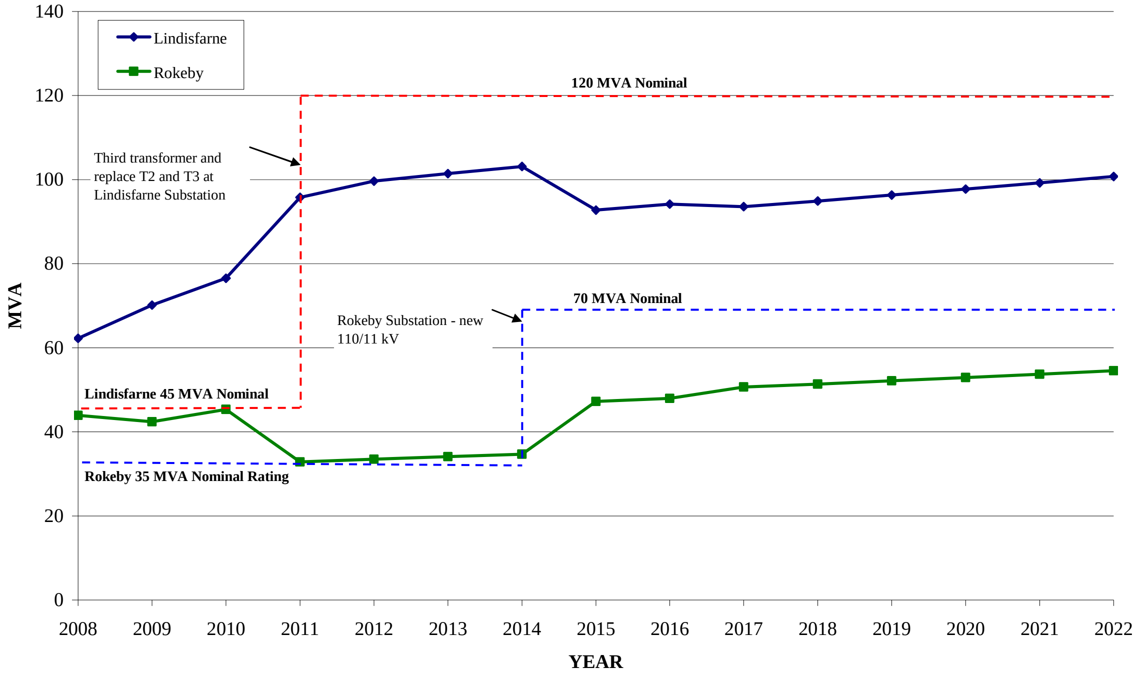


Figure 4-5 Option 1 – Low Demand Forecast V's Proposed Transmission Capacity

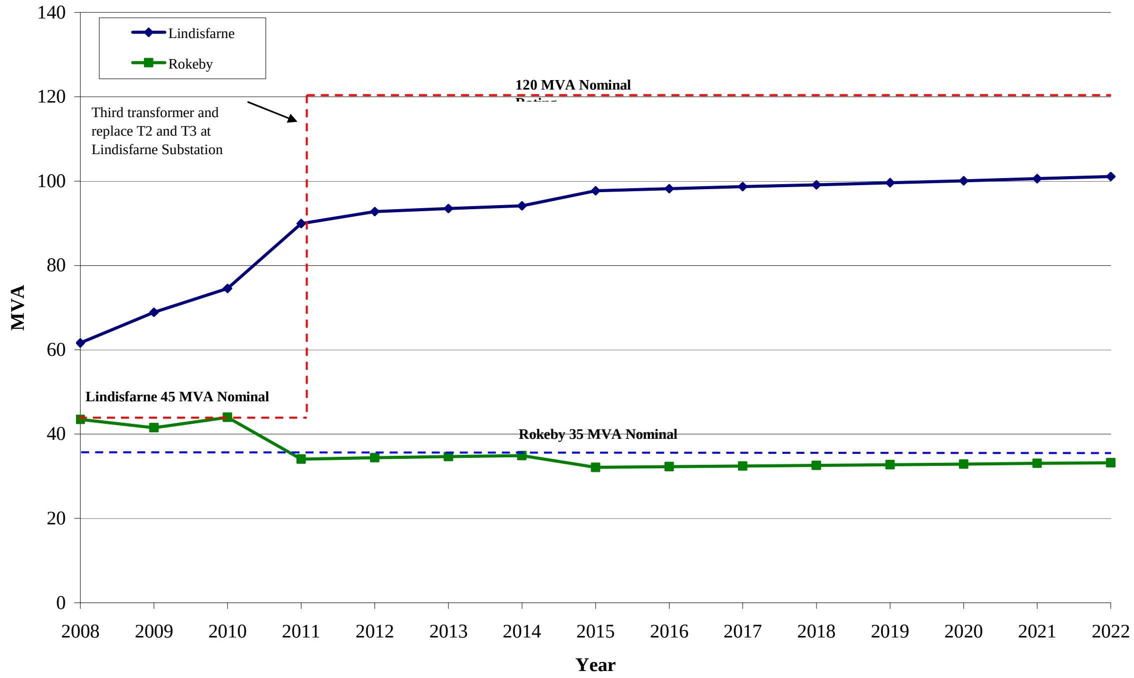
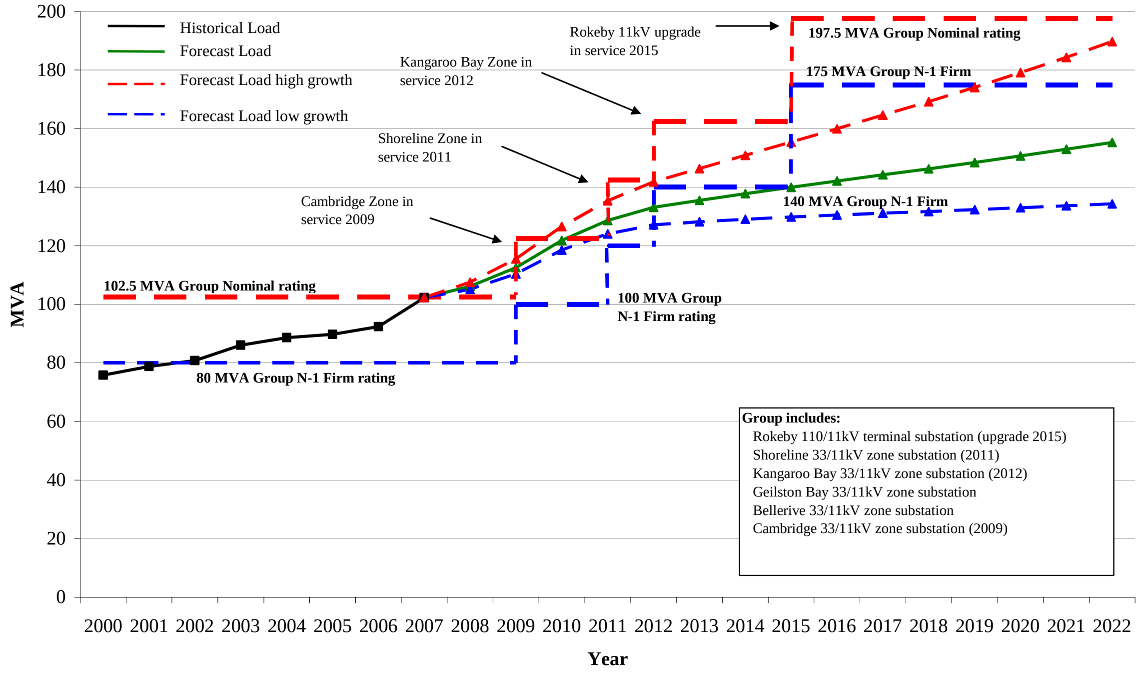


Figure 4-6 shows the high, medium, and low winter demand forecasts for the Hobart Eastern Shore region in comparison to the proposed zone substation group capacity resulting from the implementation of this option.

Figure 4-6 Option 1 – Comparison of Demand Forecast to Proposed Distribution Capacity



As shown in Figure 4-4, under this option the augmentation of Lindisfarne and Rokeby substations addresses the transmission network supply constraints as discussed in section 3.4, and hence enables Transend to meet is obligations.

However, this option has a number of limitations with respect to the subtransmission and distribution network. In particular:

- access to Lindisfarne for the development of additional subtransmission lines is currently limited, and under this option and other current works (i.e. 220 kV Lindisfarne upgrade project), access may become impractical;
- the capacity of the 33 kV subtransmission lines will be limited below their thermal rating due to the length of a number of these lines. Consequently, the capacity available at the Shoreline Zone Substation would be limited. It should be noted that the available capacity at Cambridge Zone Substation is limited to 20 MVA for this reason;
- under a high load growth scenario, all zone substations would be operating above firm capacity post 2012, the capability to bring Geilston Bay Zone Substation back below firm capacity would be limited, and Cambridge Zone Substation capacity would be exceeded in post 2017.

Cost

The timing and present value analysis of expenditure for this alternative option under the medium (expected) winder demand forecast is shown in Appendix 2. Under the medium growth scenario the expected cost of this option is estimated at $51.3 million in present value terms. This involves the expenditure (in present value terms) of $15.4 million by Transend, and $35.9 million by Aurora.

4.3.3 Option 2 – Mornington/Clarendon Vale 110/33 kV substation development

Description

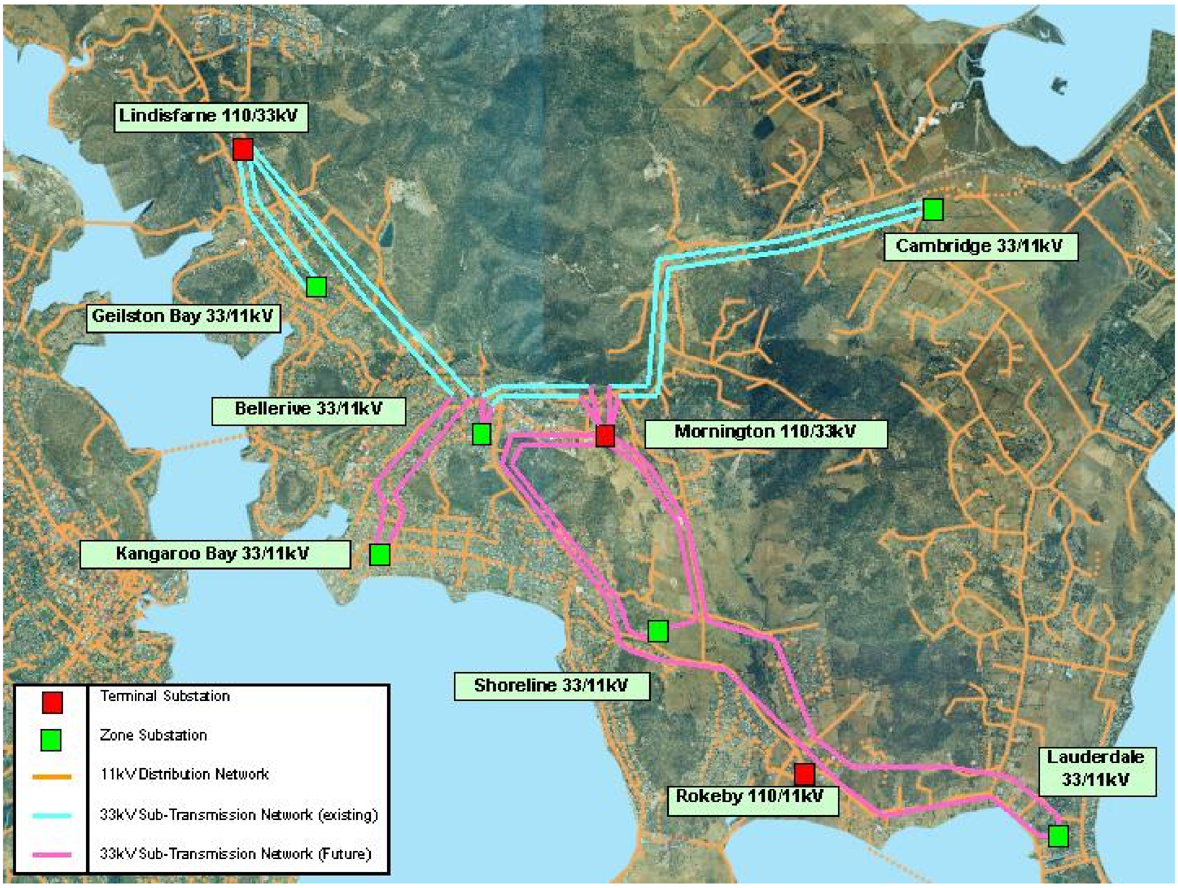
This option involves the development by Transend of a new 33 kV connection point in the Hobart

Eastern Shore region, between the Mornington and Clarendon Vale areas. The new connection point would be supplied from the existing 110kV transmission line from Lindisfarne to Rokeby, and would comprise a double bus bar, single bus coupler breaker arrangement, with two 110/33 kV 60 MVA transformers.

In addition, Transend will also replace the two existing 110/33 kV 45MVA transformers at Lindisfarne, with 60 MVA transformers once the N-1 firm capacity is exceeded in 2014.

Figure 4-7 shows the proposed ultimate network geographic arrangement resulting from the work proposed under this option, while Figure 4-8 presents the single line diagram of the proposed arrangement.

Figure 4-7 Option 2 – Ultimate Network Geographic Arrangement

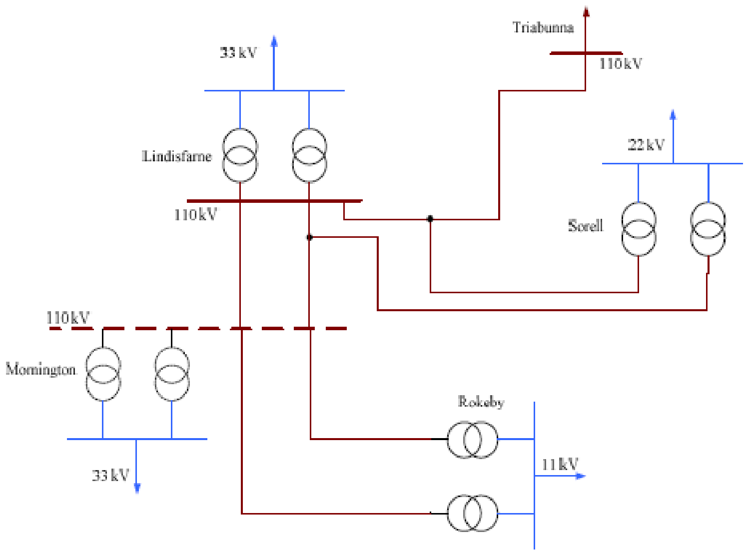


This option also includes augmentation of Aurora's distribution network. This involves the development of two new zone substations in the Kangaroo Bay and Shoreline areas. While Lindisfarne would continue to supply Geilston Bay Zone Substation, two new 33 kV subtransmission lines would be developed to supply Bellerive Zone Substation from the new connection point in the Mornington/Clarendon Vale area. In addition, the existing 33 kV subtransmission lines from Lindisfarne to Bellerive would be diverted and extended to supply the new Kangaroo Bay Zone Substation, and Cambridge Zone Substation.

To address demand growth in the Lauderdale area, Aurora would develop a Lauderdale Zone Substation for commissioning in 2015. This substation would be supplied via two new 33 kV subtransmission lines from the new connection point in the Mornington/Clarendon Vale area.

This arrangement is shown in Figure 4-7.

Figure 4-8 Option 2 - Proposed Single Line Diagram



Timing

Construction work on the new 110/33 kV connection point in the Mornington/Clarendon Vale area would commence in 2009, with commissioning prior to the winter of 2011. Replacement of the two existing transformers at Lindisfarne would occur to enable their commissioning also by winter 2014.

Construction of new 33 kV subtransmission feeders between the new connection point and Bellerive Zone Substation would commence in 2010, for commissioning in 2011. Shoreline Zone Substation construction and the development of the associated 33 kV subtransmission feeders from the new connection point, would also be completed prior to winter 2011. While Kangaroo Bay Zone Substation, and the associated 33 kV subtransmission feeders, would be completed for commissioning prior to winter 2012, with Lauderdale Zone Substation commissioned prior to the winter of 2015.

Key outcomes

The winter demand forecasts for Lindisfarne and Rokeby substations in comparison to the proposed capacity resulting from the implementation of this option are shown in Figure 4-9, Figure 4-10, and Figure 4-11 for high, medium, and low forecasts respectively.

Figure 4-9 Option 2 – High Demand Forecast V's Proposed Transmission Capacity

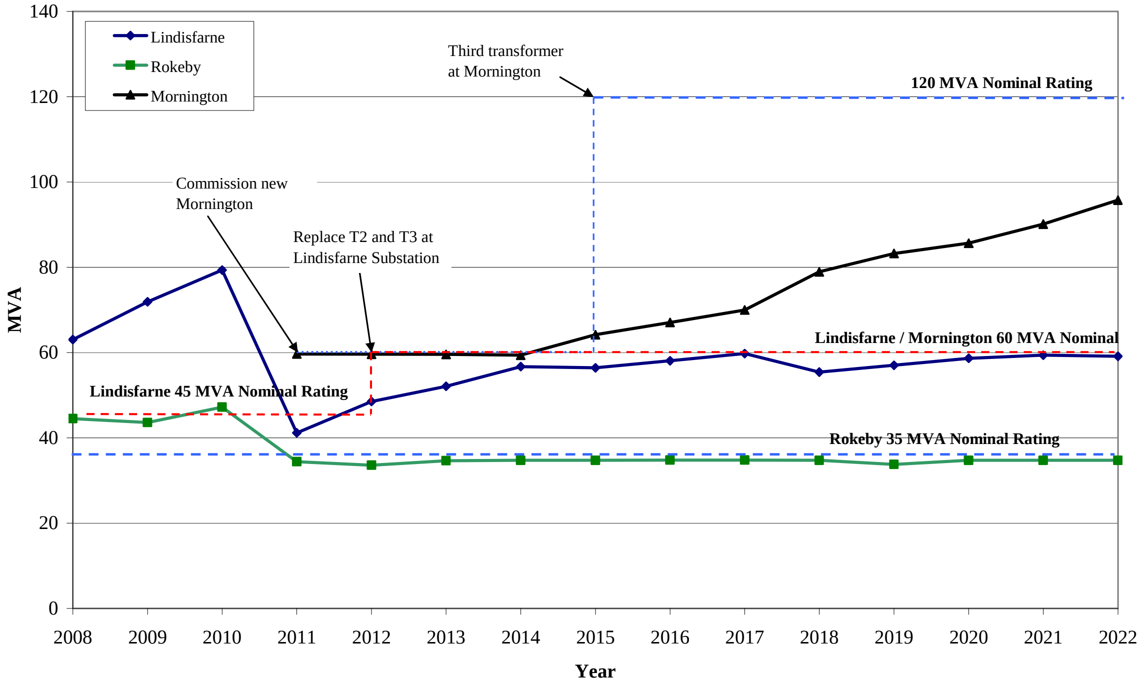


Figure 4-10 Option 2 – Medium Demand Forecast V's Proposed Transmission Capacity

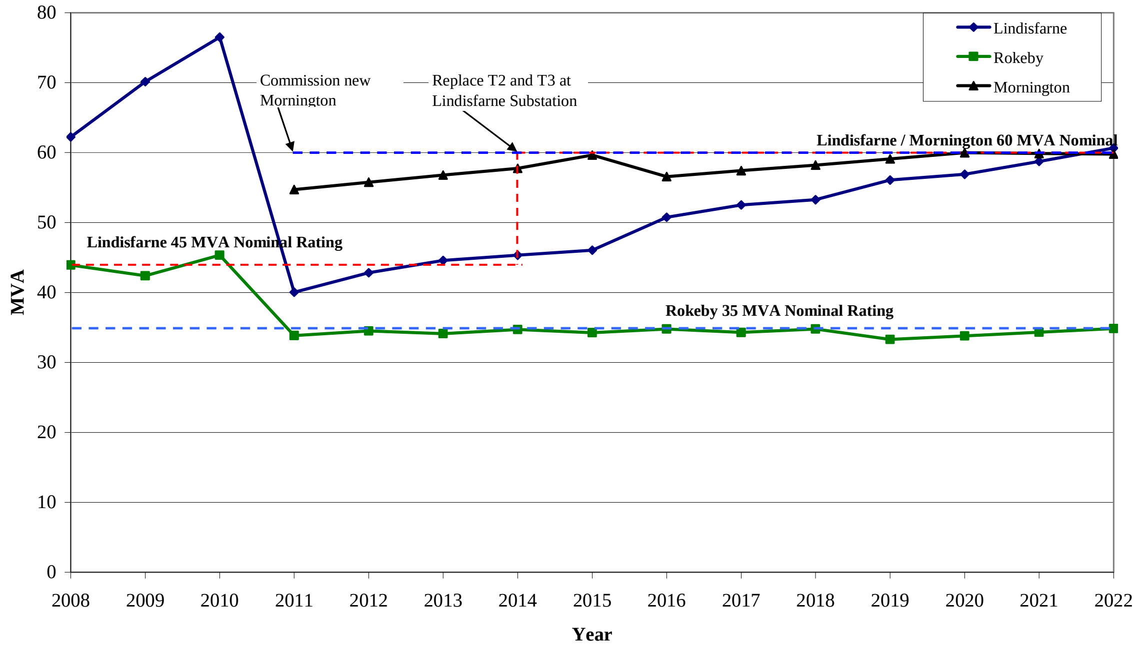


Figure 4-11 Option 2 – Low Demand Forecast V's Proposed Transmission Capacity

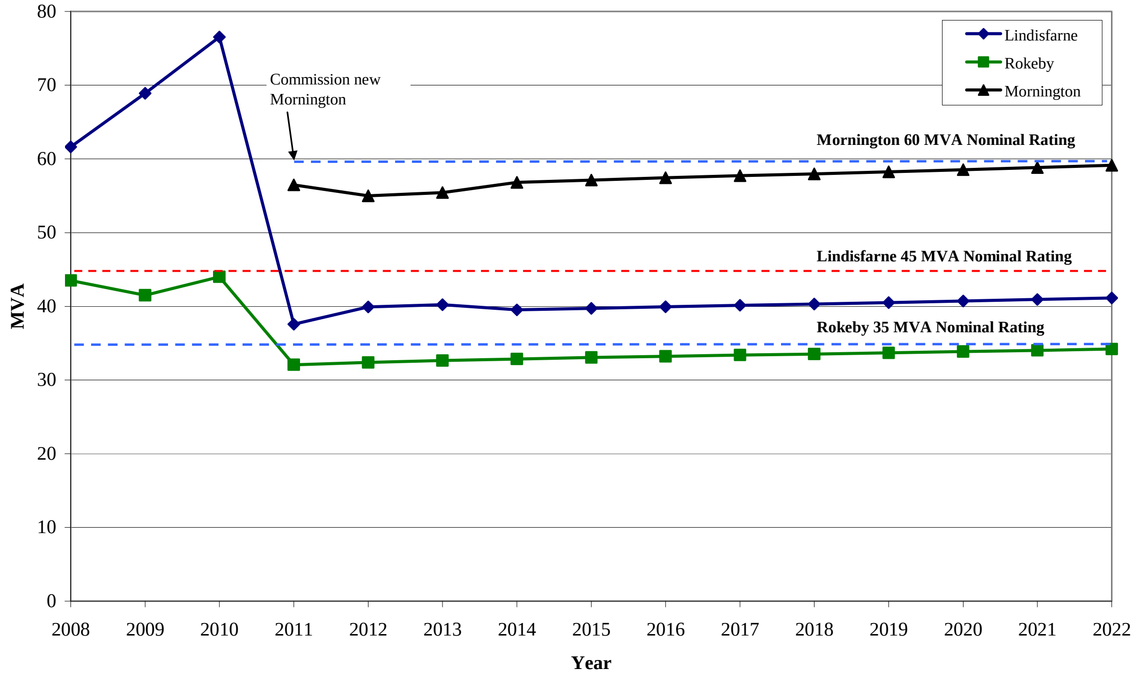
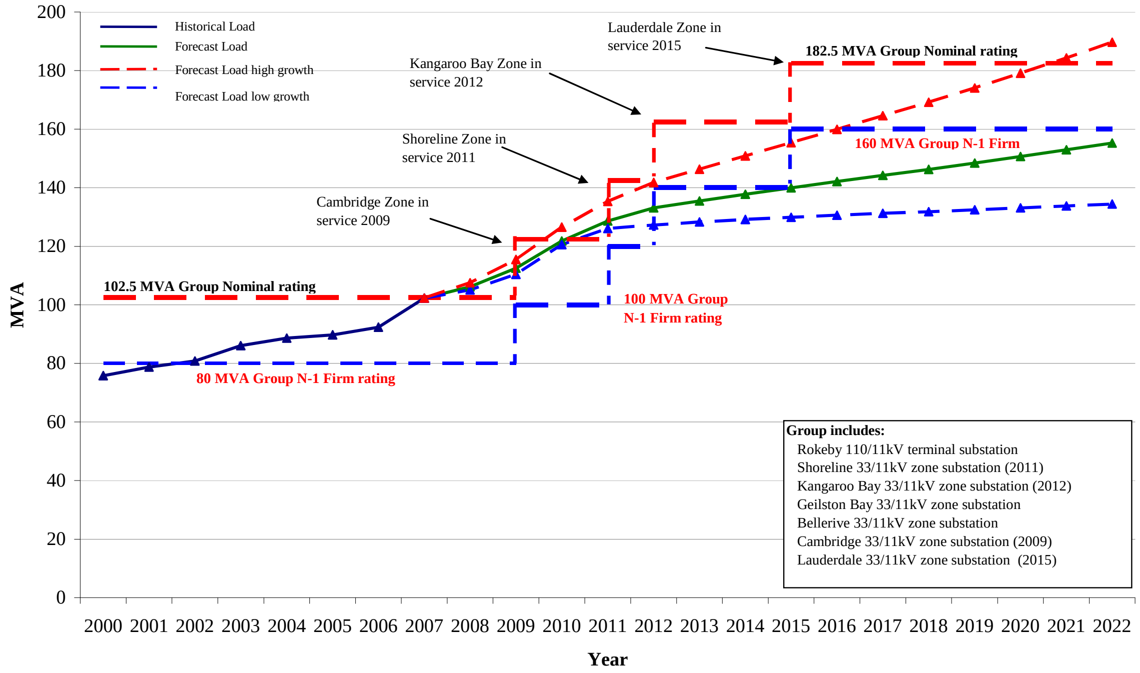


Figure 4-12 shows the high, medium, and low winter demand forecasts for the Hobart Eastern Shore region in comparison to the proposed zone substation group capacity resulting from the implementation of this option.

Figure 4-12 Option 2 – Comparison of Demand Forecast to Proposed Distribution Capacity



As shown in Figure 4-10, the development of a new 110/33 kV connection point in the Mornington/Clarendon Vale area with the subsequent off-loading of Rokeby, and the augmentation of Lindisfarne Substation, addresses the transmission network supply constraints as discussed in section 3.4, and hence enables Transend to meet is obligations.

Figure 4-12 shows also that the emerging capacity constraints in the distribution network as discussed in section 3.4, will be fully addressed by this option, and hence enable Aurora to meet is obligations. Aurora is of the view that this option also provides the best strategic position to address longer term growth within the Hobart Eastern Shore region.

Cost

The timing and present value analysis of expenditure for this alternative option under the medium (expected) winter demand forecast is shown in Appendix 2. Under the medium growth scenario the expected cost of this option is estimated at $49.0 million in present value terms. This involves the expenditure (in present value terms) of $19.0 million by Transend, and $30.0 million by Aurora.

4.3.4 Option 3 – Rokeby 110/33 kV substation development

Description

This option involves Transend augmenting Rokeby 110/11 kV Substation to provide a 110/33 kV connection point in the Rokeby area. Specifically, this will require the installation of a 110 kV double busbar with a single bus coupler and 110 kV transformer circuit breakers. Two 110/33 kV 60 MVA transformers would be installed along with 33 kV switchgear, 33kV bus coupler and 33kV feeder connections.

The firm capacity of the cable section of the Lindisfarne to Rokeby 110 kV transmission line[14] will be exceeded in 2013, and Transend will need to replace these cables.

In addition, Transend will also replace the two existing 110/33 kV 45MVA transformers at Lindisfarne, with 60 MVA transformers once the N-1 firm capacity is exceeded in 2011.

Under this option Lindisfarne would continue to supply Bellerive, Geilston Bay and Cambridge zone substations.

Figure 4-13 shows the ultimate network geographic arrangement resulting from the work proposed under this option, while Figure 4-14 presents the single line diagram of the proposed arrangement.

[14] This is a 2 km section involving two cables with a current firm rating of 77 MVA.

Figure 4-13 Option 3 – Ultimate Network Geographic Arrangement

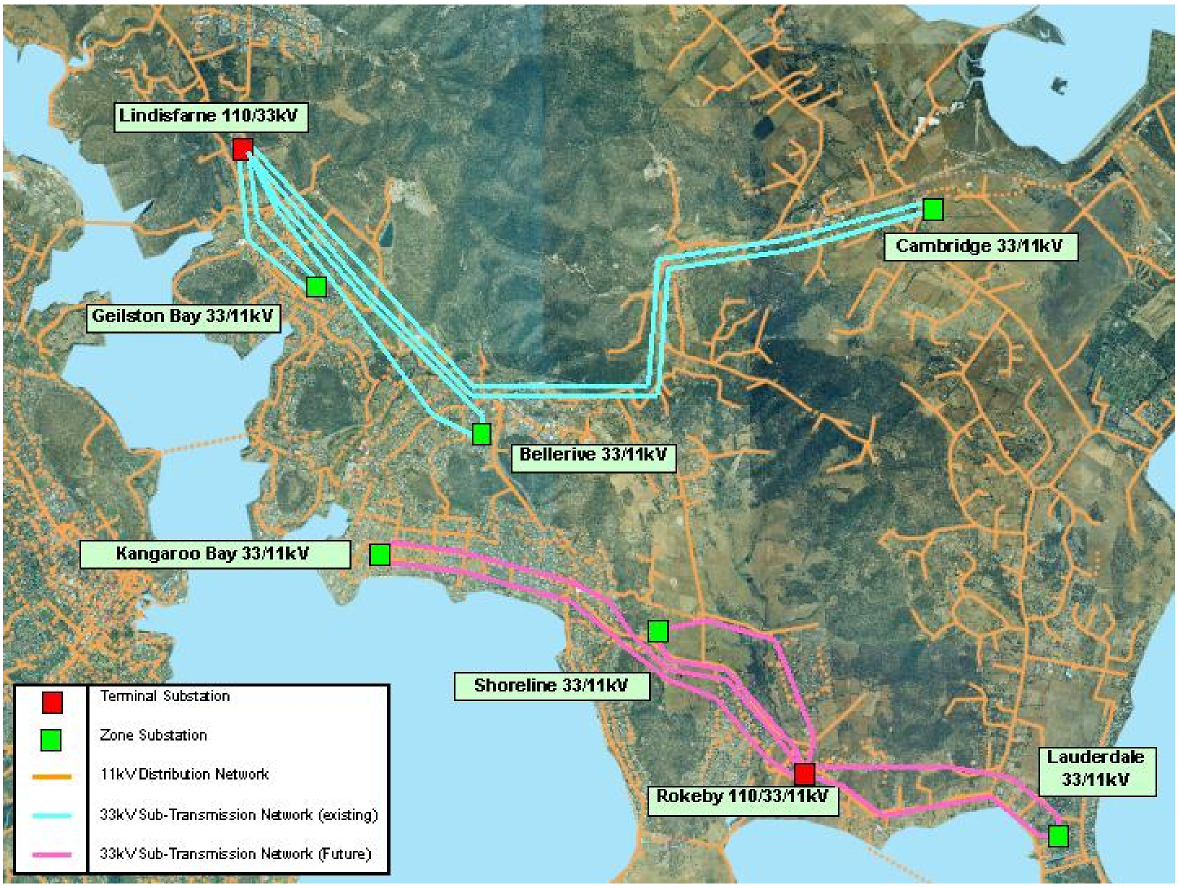
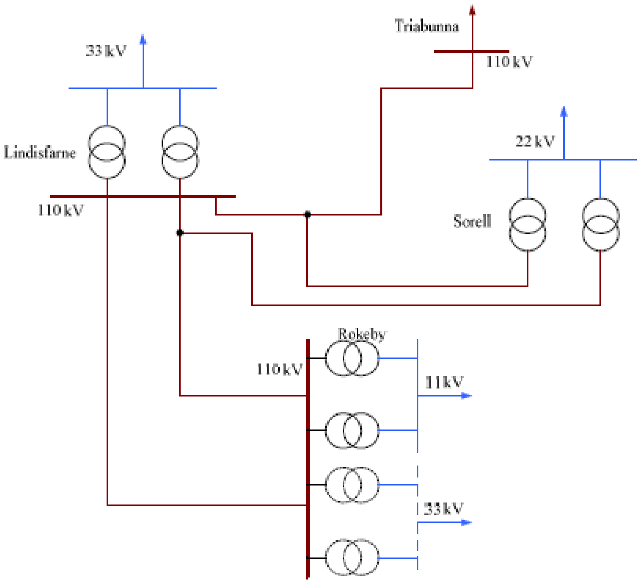


Figure 4-14 Option 3 - Proposed Single Line Diagram



This option also includes augmentation of Aurora's distribution network. This involves Aurora developing two new zone substations in the Kangaroo Bay and Shoreline areas, as well as four new 33 kV subtransmission lines from Rokeby to supply these new substations.

To address demand growth in the Lauderdale area, Aurora would then develop a Lauderdale Zone Substation for commissioning in 2015, which would be supplied via two new 33 kV subtransmission lines from Rokeby. Note that Rokeby will continue to provide 11 kV supply into the Rokeby and South Arm areas. This arrangement is shown in Figure 4-13.

Timing

Conversion of Rokeby to a 110/33/11 kV Substation will be undertaken for commissioning prior to the winter of 2011. The new Shoreline Zone Substation, and the associated 33 kV subtransmission feeders from Rokeby, will also be commissioned prior to the winter of 2011. The Kangaroo Bay Zone Substation will be developed for commissioning in 2012, with Lauderdale Zone Substation expected to be commissioned in 2015.

Replacement of the 110 kV transmission cables supplying Rokeby is expected to be completed in 2013 prior to the Rokeby Substation demand exceeding the firm capacity of these cables.

Key outcomes

The winter demand forecasts for Lindisfarne and Rokeby substations in comparison to the proposed capacity resulting from the implementation of this option are shown in Figure 4-15, Figure 4-16, and Figure 4-17 for high, medium, and low forecasts respectively.

Figure 4-15 Option 3 – High Demand Forecast V's Proposed Transmission Capacity

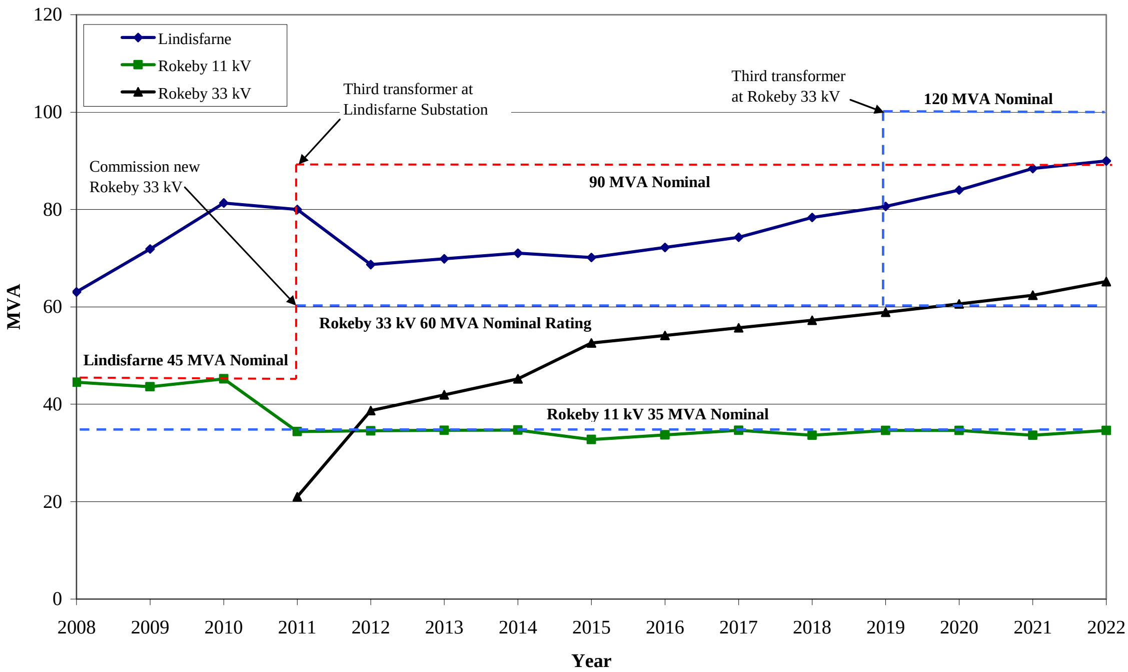


Figure 4-16 Option 3 – Medium Demand Forecast V's Proposed Transmission Capacity

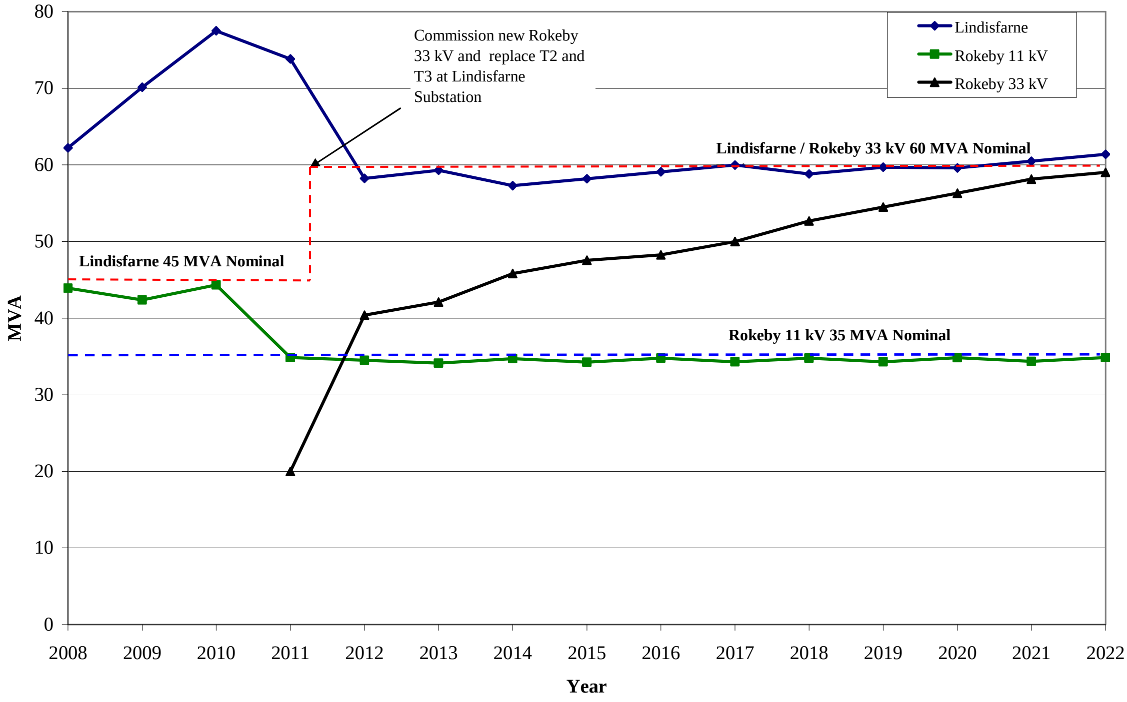


Figure 4-17 Option 3 – Low Demand Forecast V's Proposed Transmission Capacity

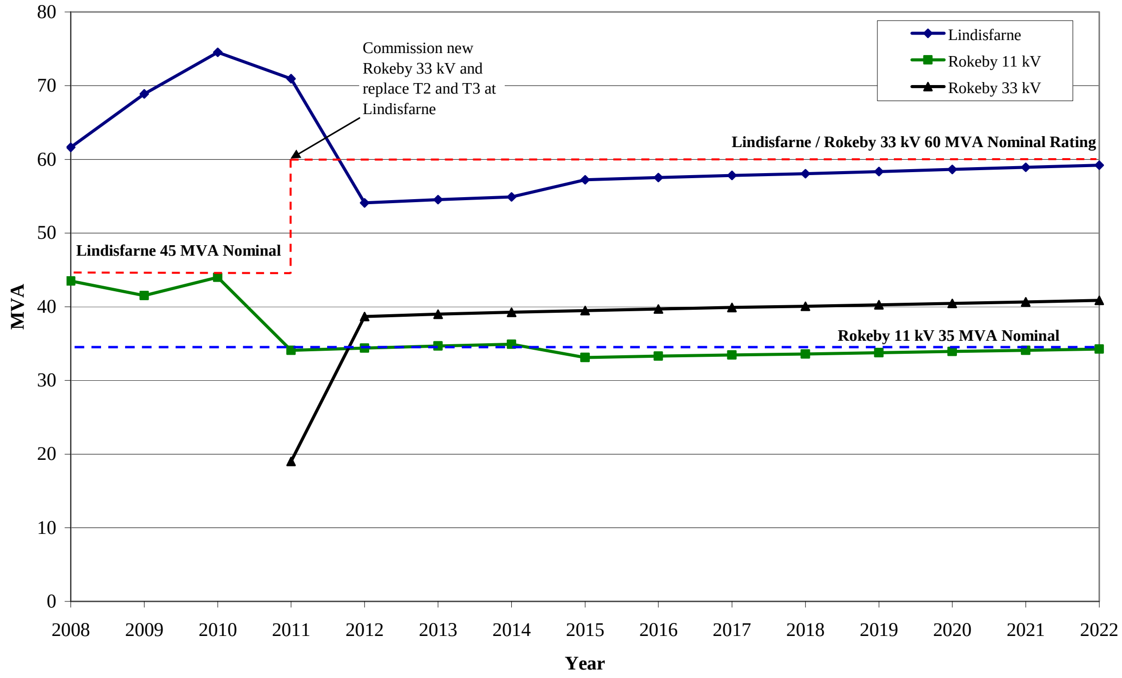
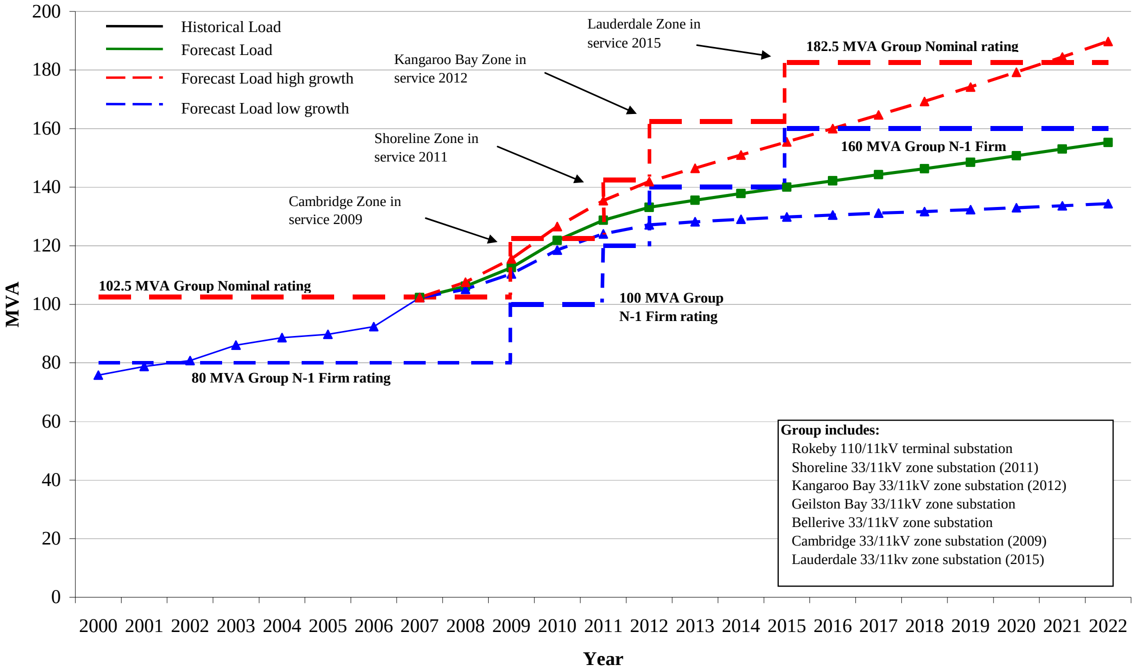


Figure 4-18 shows the high, medium, and low winter demand forecasts for the Hobart Eastern Shore region in comparison to the proposed zone substation group capacity resulting from the implementation of this option.

Figure 4-18 Option 3 – Comparison of Demand Forecast to Proposed Distribution Capacity



As shown in Figure 4-16, the redevelopment of Rokeby Substation as a 110/33/11 kV supply point, with the subsequent off-loading and augmentation of Lindisfarne Substation, addresses the transmission network supply constraints as discussed in section 3.4, and hence enables Transend to meet is obligations.

Figure 4-18 shows also that the emerging capacity constraints in the distribution network as discussed in section 3.4, will be fully addressed by this option, and hence enable Aurora to meet is obligations.

Cost

The timing and present value analysis of expenditure for this alternative option under the medium (expected) winder demand forecast is shown in Appendix 2. Under the medium growth scenario the expected cost of this option is estimated at $50.3 million in present value terms. This involves the expenditure (in present value terms) of $21.0 million by Transend, and $29.3 million by Aurora.

4.4 Transmission Network Impacts

Transend has assessed whether the proposed new large transmission network asset could reasonably have a material impact on any interconnected transmission networks and has concluded that no adverse impacts could occur under any of the network alternative options considered in this report.

4.5 Sensitivity Analysis

The various options were subjected to sensitivity analysis to determine if changing any of the underlying assumptions had an effect on the cost ranking of the options. Table 4-1 shows the results of this sensitivity analysis on the options' costs, and ranks the options in terms of lowest present value cost under the various scenarios.

Table 4-1 Sensitivity Analysis Results and Option Ranking

	Range	Option 1	Option 2	Option 3
Medium Load Growth Base Case		$51.3m	$49.0m	$50.3m
Rank		3	1	2
Low Load Growth	1.0% less than base	$37.1m	$41.4m	$40.0m
Rank		1	3	2
High Load Growth	1.4% above base	$57.2m	$53.6m	$54.0m
Rank		3	1	2
High WACC	1.0% above draft determination	$50.5m	$48.4m	$49.6m
Rank		3	1	2
Low WACC	1.0% below draft determination	$52.1m	$49.6m	$51.1m
Rank		3	1	2
Capex Overspend (underestimated)	25% overspend	$60.1m	$56.3m	$57.5m
Rank		3	1	2
Capex Under spend (overestimated)	25% under spend	$42.4m	$41.6m	$43.2m
Rank		2	1	3
Opex Over Budget (underestimated)	50% overspend	$51.5m	$49.2m	$50.6m
Rank		3	1	2
Opex Under Budget (overestimated)	50% under spend	$51.0m	$48.7m	$50.1m
Rank		3	1	2

The first sensitivity test shown in Table 4-1 relates to changes in forecast load growth. It can be seen from the table that the cost of the three options is very similar under quite different load growth scenarios. Under the high and medium growth forecasts, option 2 is the least cost option. However, under the low load forecast, option 1 is the least cost option. As the forecast demand reduces from the medium demand to the low demand, option 1 becomes the lowest present value cost option. This has been analysed, and it has been determined that a reduction in the medium demand forecast of more than 23% would be required before option 1 becomes the lowest present value cost option[15].

Since the publication of the application notice, Aurora has produced a new 2008 Distribution Network Connection Ten-Year Consumption and Maximum Demand Forecast. Over the 15 year planning period, the 2008 forecast indicates that growth in the eastern shore area is predicted to increase compared to that indicated in the 2007 forecast. This increase puts the 2008 medium growth scenario between the medium and high 2007 load growth scenarios explored in this sensitivity analysis. Therefore, as indicated in Table 4-1, option 2 remains the preferred option for the eastern shore area's long term requirements under the new forecast. Due to existing constraints in the eastern shore area, the required timing of this project will not change with the new forecast. .

The second sensitivity test shown in Table 4-1 relates to changes in the assumed discount rate. The AER has set the weighted average cost of capital (WACC) for Aurora at 6.64% for the current regulatory period. However, at the time of the application notice, the AER had still to make its final decision on Transend's WACC for the next regulatory period. Consequently a WACC of 7.46% pre tax real was used in the case of Transend's costs, as this aligns with the WACC adopted in the AER's recent draft determination. For the purposes of this sensitivity analysis, no variation was applied to Aurora's WACC as it has been fixed over the regulatory period, while a variation in Transend's WACC of ±1% was applied to the Transend cost components. As shown in Table 4-1,

15 As discussed in section 3.2, Transend and Aurora do not believe that demand in this region will fall significantly below the medium (expected) demand forecast.

variation in the discount rate did not change the order of ranking of the options, and option 2 remains the least present value cost option.

The AER has since set Transend’s WACC at 6.66%, which falls within the low range used in the analysis.

Sensitivity analysis was also applied to the capital cost estimates to test if overspends or underspends would impact on the ranking of the options. The options were tested under the assumption that capital cost could vary by ±25%, which is approximately the accuracy of the capital estimates for this work. As shown in Table 4-1, if Transend’s and Aurora’s capital expenditure is 25% below estimate, then option 1 becomes the least present value cost option, while option 2 remains the least present value cost option if capital expenditure is 25% above the estimate. A similar analysis was undertaken for the operating cost estimates and it was found that even with a variation of ±50%, option 2 remained the least present value cost option.

From this analysis, it can be concluded that in the majority of scenarios, option 2 remains the least cost solution to addressing the emerging supply limitation in the Hobart Eastern Shore region.

4.6 CONCLUSION

Under the medium (expected) winter demand forecast, option 2, the Mornington 110/33 kV connection point is the preferred option, as it has the lowest present value cost of the practical alternative options. That is, it is the least cost network option to overcome the emerging network supply limitations as discussed in section 3.4, in the Hobart Eastern Shore region. Sensitivity analysis has also shown that under the majority of reasonable scenarios, option 2 is the lowest present value cost solution. Consequently, option 2 meets the requirements to pass the reliability limb of the Regulatory Test.

Transend and Aurora, the ‘Applicants’ believe that the Option 2 asset satisfies the regulatory test because it is the least cost option to establish new transmission and distribution assets which are necessitated by the inability to otherwise meet network performance requirements as set out in Schedule 5.1 of the NER and under local jurisdictional requirements. Having identified and examined all reasonable alternatives, Option 2 represents the least cost reliability augmentation.

4.7 SUBMISSIONS

As part of the application notice, submissions were invited with respect to the application notice and proponents were also invited to submit proposals on non-network solutions that may not have been identified in the application notice.

No submissions were received.

5 CONCLUSION AND RECOMMENDATION

Based on the analysis undertaken by Transend and Aurora, and subject to any disputes lodged in relation to this final report, it is concluded that option 2 is the lowest present value cost option under a majority of reasonable scenarios that fully addresses the emerging supply constraints in the Hobart Eastern Shore region. It is also concluded that option 2 passes the Regulatory Test under the reliability limb.

Based on this conclusion, it is recommended that Transend and Aurora take appropriate action to implement the new large transmission and new large distribution developments as set out in option 2 of this report in order to address the emerging supply limitations in the Hobart Eastern Shore region.

6 ENQUIRIES AND DISPUTES

Any person intending to dispute this Final Report under clause 5.6.6(j) – (s) of the NER is reminded that lodgement of a dispute notice with the AER required within 30 business days of the Final Report summary being published on NEMMCO's website. A copy of the dispute notice must be provided to Transend and Aurora. Any enquiries or any copies of dispute notices in relation to this Final Report should be directed to:

Mr Brent Dalton
Aurora Energy Pty Ltd
Level 1, 177 Main Road
Moonah, TAS 7008
Email: Brent.Dalton@auroraenergy.com.au

Appendix A

Options Financial Analysis

APPENDIX 1A - MEDIUM LOAD GROWTH SCENARIO

	WACC		MIN NPV	$48,965,899
Transend	0.0746			
Aurora	0.0664			

Option 1 - Lindisfarne 3rd Transformer upgrade plus upgrade Rokeby 11kV

	WACC		2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
			1	2	3	4	5	6	7	8	9	10	11	12	13	14	15
Transend Capital costs						$7,790,000				$13,742,000							
Transend O&M costs					$420,000						$426,000						$507,500
Transend Total Costs			$0	$0	$420,000	$7,790,000	$0	$0	$0	$13,742,000	$426,000	$0	$0	$0	$0	$0	$507,500
Transend NPC		**$15,370,939**															
Aurora Capital costs																	
	Substation			$250,000	$7,250,000	$7,000,000											
	substransmission				$7,130,000	$5,970,000											
	11kV feeder				$1,905,000	$2,310,000				$10,164,750							$4,190,890
	pole replacement																$111,138
Aurora O&M costs																	
	Kangaroo bay					$21,572	$21,572	$21,572	$21,572	$21,572	$21,572	$21,572	$21,572	$21,572	$21,572	$21,572	$281,333
	Shoreline						$23,033	$23,033	$23,033	$23,033	$23,033	$23,033	$23,033	$23,033	$23,033	$23,033	$300,384
	Lauderdale																
Aurora Total costs			$0	$250,000	$16,285,000	$15,301,572	$44,605	$44,605	$44,605	$10,209,355	$44,605	$44,605	$44,605	$44,605	$44,605	$44,605	$4,883,746
Aurora NPC		**$35,901,549**															
Total NPC		$51,272,487															

Option 2 - Mornington 110/33kV connection point

			2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
			1	2	3	4	5	6	7	8	9	10	11	12	13	14	15
Transend Capital costs						$19,568,000			$3,710,000								
Transend O&M costs			$0	$0	$420,000	$0	$0	$0	$0	$0	$470,000	$0	$0	$0	$0	$0	$470,000
Transend Total Costs			$0	$0	$420,000	$19,568,000	$0	$0	$3,710,000	$0	$470,000	$0	$0	$0	$0	$0	$470,000
Transend NPC	$13,284,635.84	**$18,978,051**															
Aurora Capital costs																	
	Substation			$250,000	$7,250,000	$7,000,000			$250,000	$7,000,000							
	substransmission				$4,260,000	$2,080,000				$4,160,000							
	11kV feeder				$1,905,000	$2,310,000				$1,125,000							
	pole replacement																$42,127
Aurora O&M costs																	
	Kangaroo bay					$14,908	$14,908	$14,908	$14,908	$14,908	$14,908	$14,908	$14,908	$14,908	$14,908	$14,908	$194,422
	Shoreline						$14,616	$14,616	$14,616	$14,616	$14,616	$14,616	$14,616	$14,616	$14,616	$14,616	$190,608
	Bellerive subtransmission					$770	$770	$770	$770	$770	$770	$770	$770	$770	$770	$770	$10,042
	Lauderdale										$23,008	$23,008	$23,008	$23,008	$23,008	$23,008	$300,058
Aurora Total costs			$0	$250,000	$13,415,000	$11,405,678	$30,294	$30,294	$280,294	$12,315,294	$53,302	$53,302	$53,302	$53,302	$53,302	$53,302	$737,258
Aurora NPC		**$29,987,848**															
Total NPC		$48,965,899															

Option 3 - Rokeby 110/33kV substation development

			2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
			1	2	3	4	5	6	7	8	9	10	11	12	13	14	15
Transend Capital costs						$17,452,000		$8,780,000									
Transend O&M costs			$0	$0	$420,000	$0	$0	$0	$0	$0	$507,500	$0	$0	$0	$0	$0	$507,500
Transend Total Costs			$0	$0	$420,000	$17,452,000	$0	$8,780,000	$0	$0	$507,500	$0	$0	$0	$0	$0	$507,500
Transend NPC		**$21,025,501**															
Aurora Capital costs																	
	Substation			$250,000	$7,250,000	$7,000,000			$250,000	$7,000,000							
	substransmission				$1,735,000	$5,155,000				$2,660,000							
	11kV feeder				$1,905,000	$2,310,000				$1,125,000							
	pole replacement																$28,085
Aurora O&M costs																	
	Kangaroo bay					$16,514	$16,514	$16,514	$16,514	$16,514	$16,514	$16,514	$16,514	$16,514	$16,514	$16,514	$215,370
	Shoreline						$14,589	$14,589	$14,589	$14,589	$14,589	$14,589	$14,589	$14,589	$14,589	$14,589	$190,265
	Bellerive subtransmission																
	Lauderdale										$19,750	$19,750	$19,750	$19,750	$19,750	$19,750	$257,565
Aurora Total costs			$0	$250,000	$10,890,000	$14,481,514	$31,104	$31,104	$281,104	$10,816,104	$50,853	$50,853	$50,853	$50,853	$50,853	$50,853	$691,285
Aurora NPC		**$29,323,455**															
Total NPC		$50,348,956															

APPENDIX 1B - HIGH LOAD GROWTH SCENARIO

	WACC		MIN NPV	$53,563,263
Transend	0.0746			
Aurora	0.0664			

Option 1 - Lindisfarne 3rd Transformer upgrade plus upgrade Rokeby 11kV

			2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
			1	2	3	4	5	6	7	8	9	10	11	12	13	14	15
Transend Capital costs						$21,532,000											
Transend O&M costs			$0	$0	$420,000	$0	$0	$0	$0	$0	$420,000	$0	$0	$0	$0	$0	$420,000
Transend Total Costs			$0	$0	$420,000	$21,532,000	$0	$0	$0	$0	$420,000	$0	$0	$0	$0	$0	$420,000
Transend NPC		**$18,105,069**															
Aurora Capital costs																	
	Substation			$250,000	$7,250,000	$7,000,000											
	substransmission				$7,130,000	$5,970,000											
	11kV feeder				$1,905,000	$12,474,750					$5,082,375						
	pole replacement																$111,138
Aurora O&M costs																	
	Kangaroo bay					$21,572	$21,572	$21,572	$21,572	$21,572	$21,572	$21,572	$21,572	$21,572	$21,572	$21,572	$281,333
	Shoreline						$23,033	$23,033	$23,033	$23,033	$23,033	$23,033	$23,033	$23,033	$23,033	$23,033	$300,384
	Lauderdale																
Aurora Total costs			$0	$250,000	$16,285,000	$25,466,322	$44,605	$44,605	$44,605	$44,605	$5,126,980	$44,605	$44,605	$44,605	$44,605	$44,605	$692,855
Aurora NPC		**$39,137,126**															
Total NPC		$57,242,196															

Option 2 - Mornington 110/33kV connection point

			2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
			1	2	3	4	5	6	7	8	9	10	11	12	13	14	15
Transend Capital costs						$19,568,000	$3,710,000			$4,080,000							
Transend O&M costs			$0	$0	$470,000	$0	$0	$0	$0	$0	$470,000	$0	$0	$0	$0	$0	$470,000
Transend Total Costs			$0	$0	$470,000	$19,568,000	$3,710,000	$0	$0	$4,080,000	$470,000	$0	$0	$0	$0	$0	$470,000
Transend NPC		**$21,859,882**															
Aurora Capital costs																	
	Substation			$250,000	$7,250,000	$7,250,000	$7,000,000										
	substransmission				$4,260,000	$2,080,000	$4,160,000										
	11kV feeder				$1,905,000	$2,310,000	$1,125,000										
	pole replacement																$58,794
Aurora O&M costs																	
	Kangaroo bay					$14,908	$14,908	$14,908	$14,908	$14,908	$14,908	$14,908	$14,908	$14,908	$14,908	$14,908	$194,422
	Shoreline						$14,616	$14,616	$14,616	$14,616	$14,616	$14,616	$14,616	$14,616	$14,616	$14,616	$190,608
	Bellerive subtransmission					$770	$770	$770	$770	$770	$770	$770	$770	$770	$770	$770	$10,042
	Lauderdale							$23,008	$23,008	$23,008	$23,008	$23,008	$23,008	$23,008	$23,008	$23,008	$200,054
Aurora Total costs			$0	$250,000	$13,415,000	$11,655,678	$12,315,294	$53,302	$53,302	$53,302	$53,302	$53,302	$53,302	$53,302	$53,302	$53,302	$653,920
Aurora NPC		**$31,703,380**															
Total NPC		$53,563,263															

Option 3 - Rokeby 110/33kV substation development

			2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
			1	2	3	4	5	6	7	8	9	10	11	12	13	14	15
Transend Capital costs						$17,822,000		$8,780,000							$4,080,000		
Transend O&M costs			$0	$0	$507,500	$0	$0	$0	$0	$0	$507,500	$0	$0	$0	$0	$0	$507,500
Transend Total Costs			$0	$0	$507,500	$17,822,000	$0	$8,780,000	$0	$0	$507,500	$0	$0	$0	$4,080,000	$0	$507,500
Transend NPC		**$23,120,114**															
Aurora Capital costs																	
	Substation			$250,000	$7,250,000	$7,250,000	$7,000,000										
	substransmission				$1,735,000	$5,155,000	$2,660,000										
	11kV feeder				$1,905,000	$2,310,000	$1,125,000										
	pole replacement																$39,196
Aurora O&M costs																	
	Kangaroo bay					$16,514	$16,514	$16,514	$16,514	$16,514	$16,514	$16,514	$16,514	$16,514	$16,514	$16,514	$215,370
	Shoreline						$14,589	$14,589	$14,589	$14,589	$14,589	$14,589	$14,589	$14,589	$14,589	$14,589	$190,265
	Lauderdale							$19,750	$19,750	$19,750	$19,750	$19,750	$19,750	$19,750	$19,750	$19,750	$257,565
Aurora Total costs			$0	$250,000	$10,890,000	$14,731,514	$10,816,104	$50,853	$50,853	$50,853	$50,853	$50,853	$50,853	$50,853	$50,853	$50,853	$702,397
Aurora NPC		**$30,867,280**															
Total NPC		$53,987,394															

APPENDIX 1C - LOW LOAD GROWTH SCENARIO

	WACC		MIN NPV	$37,064,505
Transend	0.0746			
Aurora	0.0664			

Option 1 - Lindisfarne 3rd Transformer upgrade plus upgrade Rokeby 11kV

			2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
			1	2	3	4	5	6	7	8	9	10	11	12	13	14	15
Transend Capital costs						$7,790,000											
Transend O&M costs			$0	$0	$420,000	$0	$0	$0	$0	$0	$420,000	$0	$0	$0	$0	$0	$420,000
Transend Total Costs			$0	$0	$420,000	$7,790,000	$0	$0	$0	$0	$420,000	$0	$0	$0	$0	$0	$420,000
Transend NPC		**$7,030,944**															
Aurora Capital costs																	
	Substation			$250,000	$7,250,000	$7,000,000											$0
	substransmission				$7,130,000	$5,970,000											$0
	11kV feeder				$1,905,000	$2,310,000											$5,699,221
	pole replacement																$111,138
Aurora O&M costs																	
	Kangaroo bay					$21,572	$21,572	$21,572	$21,572	$21,572	$21,572	$21,572	$21,572	$21,572	$21,572	$21,572	$281,333
	Shoreline						$23,033	$23,033	$23,033	$23,033	$23,033	$23,033	$23,033	$23,033	$23,033	$23,033	$300,384
	Lauderdale																
Aurora Total costs			$0	$250,000	$16,285,000	$15,301,572	$44,605	$44,605	$44,605	$44,605	$44,605	$44,605	$44,605	$44,605	$44,605	$44,605	$6,392,076
Aurora NPC		**$30,033,561**															
Total NPC		$37,064,505															

Option 2 - Mornington 110/33kV connection point

			2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
			1	2	3	4	5	6	7	8	9	10	11	12	13	14	15
Transend Capital costs						$19,568,000											
Transend O&M costs			$0	$0	$470,000	$0	$0	$0	$0	$0	$470,000	$0	$0	$0	$0	$0	$470,000
Transend Total Costs			$0	$0	$470,000	$19,568,000	$0	$0	$0	$0	$470,000	$0	$0	$0	$0	$0	$470,000
Transend NPC		**$16,612,039**															
Aurora Capital costs																	
	Substation			$250,000	$7,250,000	$7,000,000											$4,344,804
	substransmission				$4,260,000	$2,080,000											$2,487,323
	11kV feeder				$1,905,000	$2,310,000											$672,654
	pole replacement																
Aurora O&M costs																	
	Kangaroo bay					$14,908	$14,908	$14,908	$14,908	$14,908	$14,908	$14,908	$14,908	$14,908	$14,908	$14,908	$194,422
	Shoreline						$14,616	$14,616	$14,616	$14,616	$14,616	$14,616	$14,616	$14,616	$14,616	$14,616	$190,608
	Bellerive subtransmission					$770	$770	$770	$770	$770	$770	$770	$770	$770	$770	$770	$10,042
	Lauderdale																
Aurora Total costs			$0	$250,000	$13,415,000	$11,405,678	$30,294	$30,294	$30,294	$30,294	$30,294	$30,294	$30,294	$30,294	$30,294	$30,294	$7,899,853
Aurora NPC		**$24,826,020**															
Total NPC		$41,438,059															

Option 3 - Rokeby 110/33kV substation development

			2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
			1	2	3	4	5	6	7	8	9	10	11	12	13	14	15
Transend Capital costs						$17,452,000											
Transend O&M costs			$0	$0	$507,500	$0	$0	$0	$0	$0	$507,500	$0	$0	$0	$0	$0	$507,500
Transend Total Costs			$0	$0	$507,500	$17,452,000	$0	$0	$0	$0	$507,500	$0	$0	$0	$0	$0	$507,500
Transend NPC	$10,481,868.70	**$14,974,098**															
Aurora Capital costs																	
	Substation			$250,000	$7,250,000	$7,000,000											$4,344,804
	substransmission				$1,735,000	$5,155,000											$1,590,452
	11kV feeder				$1,905,000	$2,310,000											$672,654
	pole replacement																
Aurora O&M costs																	
	Kangaroo bay					$16,514	$16,514	$16,514	$16,514	$16,514	$16,514	$16,514	$16,514	$16,514	$16,514	$16,514	$215,370
	Shoreline						$14,589	$14,589	$14,589	$14,589	$14,589	$14,589	$14,589	$14,589	$14,589	$14,589	$190,265
	Bellerive subtransmission																
	Lauderdale																
Aurora Total costs			$0	$250,000	$10,890,000	$14,481,514	$31,104	$31,104	$31,104	$31,104	$31,104	$31,104	$31,104	$31,104	$31,104	$31,104	$7,013,545
Aurora NPC		$24,786,423															
Total NPC		$39,760,521															

Appendix B

Compliance with Clauses 5.6.2 and 5.6.6 of the NER

This section sets out a "compliance checklist" which demonstrates the compliance of this Final Report with the requirements of clauses 5.6.2 and 5.6.6 of the NER.

NER clause	Summary of Requirements	Comments/evidence of compliance
5.6.2 (a1)	The terms Network Service Provider, Transmission Network Service Provider and Distribution Network Service Provider when used in this clause 5.6.2 are not intended to refer to, and are not to be read or construed as referring to, any Network Service Provider in its capacity as a Market Network Service Provider.	Note
5.6.2 (a)	Each Transmission Network Service Provider and Distribution Network Service Provider must analyse the expected future operation of its transmission networks or distribution networks over an appropriate planning period, taking into account the relevant forecast loads, any future generation, market network service, demand side and transmission developments and any other relevant data.	Refer to section 2.3 of this Final Report Transend has provided its analysis in the published Annual Planning Reports
5.6.2 (b)	Each Transmission Network Service Provider must conduct an annual planning review with each Distribution Network Service Provider connected to its transmission network within each region. The annual planning review must incorporate the forecast loads submitted by the Distribution Network Service Provider in accordance with clause 5.6.1 or as modified in accordance with clause 5.6.1(d) and must include a review of the adequacy of existing connection points and relevant parts of the transmission system and planning proposals for future connection points.	Refer to section 2.3 of this Final Report Transend has documented its planning review in the published Annual Planning Reports.
5.6.2 (c)	Where the necessity for augmentation or a non-network alternative is identified by the annual planning review conducted under clause 5.6.2(b), the relevant Network Service Providers must undertake joint planning in order to determine plans that can be considered by relevant Registered Participants, NEMMCO and interested parties.	Refer to section 2.3.1 of this Final Report Transend and Aurora Energy have undertaken a joint planning process to develop the options and solution presented in this Final Report.
5.6.2 (d)	The minimum planning period for the purposes of the annual planning review is 5 years for distribution networks and 10 years for transmission networks.	Refer to Transend Annual Planning Report 2008, & Aurora Energy Distribution System Planning Report 2008. Transend and Aurora planning horizons comply with this requirement

5.6.2 (e)	Each Network Service Provider must extrapolate the forecasts provided to it by Registered Participants for the purpose of planning and, where this analysis indicates that any relevant technical limits of the transmission or distribution systems will be exceeded, either in normal conditions or following the contingencies specified in schedule 5.1, the Network Service Provider must notify any affected Registered Participants and NEMMCO of these limitations and advise those Registered Participants and NEMMCO of the expected time required to allow the appropriate corrective network augmentation or non-network alternatives, or modifications to connection facilities to be undertaken.	Refer to Transend Annual Planning Report 2008, & Aurora Energy Distribution System Planning Report 2008. This Final Report forms the final stage in the required consultation process.
5.6.2 (f)	Within the time for corrective action notified in clause 5.6.2(e) the relevant Distribution Network Service Provider must consult with affected Registered Participants, NEMMCO and interested parties on the possible options, including but not limited to demand side options, generation options and market network service options to address the projected limitations of the relevant distribution system except that a Distribution Network Service Provider does not need to consult on a network option which would be a new small distribution network asset.	Refer to section 2.3 of this Final Report Aurora Energy and Transend have undertaken a joint planning process to develop the options and solution presented in this Final Report. This Final Report forms the final stage in the DNSP consultation process required by this clause.
5.6.2 (g)	Each Distribution Network Service Provider must carry out an economic cost effectiveness analysis of possible options to identify options that satisfy the regulatory test, while meeting the technical requirements of schedule 5.1, and where the Network Service Provider is required by clause 5.6.2(f) to consult on the option this analysis and allocation must form part of the consultation on that option.	Refer section 2.3 and 4.3 of this Final Report Aurora Energy and Transend have undertaken a joint planning process to develop the options and solution presented in this Final Report. The options analysis is presented in section 4.
5.6.2 (h)	Following conclusion of the process outlined in clauses 5.6.2(f) and (g), the Distribution Network Service Provider must prepare a report that is to be made available to affected Registered Participants, NEMMCO and interested parties which: (1) includes assessment of all identified options; (2) includes details of the Distribution Network Service Provider's preferred proposal and details of: (A) its economic cost effectiveness analysis in accordance with clause 5.6.2(g); and (B) its consultations conducted for the purposes of clause 5.6.2(g); (3) summarises the submissions from the consultations; and 4) recommends the action to be taken.	This provision is not applicable to the preparation of the Final Report. This Final Report forms the final stage in the DNSP consultation process. Following the initial consultation, Aurora Energy and Transend has prepared this final report in accordance with Transend's obligations under clause 5.6.6 (h). This document also addresses Aurora Energy's obligations under clause 5.6.2 (h)

5.6.2 (i) to (j)	These clauses contain provisions relating to the processes applying where a Registered Participant disputes certain matters in relation to the final report.	This document is the Final Report, in accordance with this provision.
5.6.2 (i)	Registered Participants may dispute the recommendation of the report prepared under clause 5.6.2(h) within 40 business days after the report is made available in respect of any proposal that is a new large distribution network asset or is reasonably likely to change the distribution use of system service charges applicable to that Registered Participant by more than 2% at the date of the next price review, based on the assumption that the same approach to distribution network pricing is taken for the next review period as that taken for the current review period.	This document is the Final Report.
5.6.2 (j)	Where any Registered Participant disputes a recommendation under clause 5.6.2(i), the Distribution Network Service Provider and the affected Registered Participants must negotiate in good faith with a view to reaching agreement on the action to be taken	This document is the Final Report.
5.6.2 (k)	Following: (1) completion of the 40 business day period referred to in clause 5.6.2(i) or on resolution of any dispute in accordance with rule 8.2, in relation to proposals to which clause 5.6.2(j) applies; or (2) completion of the report referred to in clause 5.6.2(h), in relation to any other network option recommended by the report, the relevant Distribution Network Service Provider must arrange for the network options (if any) recommended by its report made in accordance with clause 5.6.2(h) to be available for service by the agreed time.	This document is the Final Report, in accordance with this provision.
5.6.2 (kl)	The Distribution Network Service Provider must include the cost of the relevant assets of the network options referred to in clause 5.6.2(k) in the calculation of distribution service prices determined in accordance with Chapter 6.	This document is the Final Report, in accordance with this provision.
5.6.2 (l)	If a use of system service or the provision of a service at a connection point is directly affected by a transmission network or distribution network augmentation, appropriate amendments to relevant connection agreements must be negotiated in good faith between the parties to them.	This document is the Final Report, in accordance with this provision.

5.6.2 (m)	Where the relevant Transmission Network Service Provider or Distribution Network Service Provider decides to implement a generation option as an alternative to network augmentation, the Network Service Provider must: (1) register the generating unit with NEMMCO and specify that the generating unit may be periodically used to provide a network support function and will not be eligible to set spot prices when constrained on in accordance with clause 3.9.7; and (2) include the cost of this network support service in the calculation of transmission service and distribution service prices determined in accordance with Chapter 6 or Chapter 6A, as the case may be.	This document is the Final Report, in accordance with this provision.
5.6.2 (n)	NEMMCO must provide to the Inter-Regional Planning Committee, and to other Network Service Providers on request, a copy of any report provided to NEMMCO by a Network Service Provider under clause 5.2.3(d)(12). If a Registered Participant reasonably considers that it is or may be adversely affected by a development or change in another region, the Registered Participant may request the preparation of a report by the relevant Network Service Provider as to the technical impacts of the development or change. If so requested, the Network Service Provider must prepare such a report and provide a copy of it to NEMMCO, the Registered Participant requesting the report and, on request, any other Registered Participant.	This document is the Final Report, in accordance with this provision.
5.6.6 (a)	In addition to the procedures to establish a connection to a network in clause 5.3 [establishing and modifying a connection], applications to establish a new large transmission network asset must comply with the access arrangements and procedures set out in this clause 5.6.6.	Transend proposes to comply with this provision by adhering to the processes detailed in clause 5.3 regarding establishing connection points, and meeting the requirements set out in the whole of clause 5.6.6. See below for further details.
5.6.6 (b)	A person who proposes to establish a new large transmission network asset (the applicant) must consult all Registered Participants, NEMMCO and interested parties about the proposed new large transmission network asset in accordance with this clause 5.6.6.	Transend proposes to comply with this provision by adhering to the processes, and meeting the requirements set out in the whole of clause 5.6.6. See below for further details
5.6.6 (c)	The applicant must make available to all Registered Participants and NEMMCO a notice (the Application Notice) which sets out, in relation to a proposed new large transmission network asset:	Transend and Aurora submitted its joint Application Notice to NEMMCO in December 2008 and invited submissions by 23 February 2009. No submissions were received by the due date.
	(1) a detailed description of: (i) the proposed asset;	A description of the proposed asset is provided in 4.3.3 of this Final Report.

(ii) the reasons for proposing to establish the asset (including, where applicable, the actual or potential constraint or inability to meet the network performance requirements set out in schedule 5.1 or relevant legislation or regulations of a participating jurisdiction, including load forecasts and all assumptions used); and	The reasons for the proposed works are explained in sections 3.3 and 3.4 of this Final Report. Section 3.1 and 3.2 provide an overview of the anticipated regional development scenarios and energy demand used in the planning process. These provide further detailed information relating to the reasons and assumptions used by Transend for the network augmentation.
(iii) all other reasonable network and non-network alternatives to address the identified constraint or inability to meet the network performance requirements identified in clause 5.6.6(c)(1)(ii). These alternatives include, but are not limited to, interconnectors, generation options, demand side options, market network service options and options involving other transmission and distribution networks	Section 4 of this Final Report explains the rationale for the alternatives examined to address the emerging supply limitation. Based on the information presented in section 4, Transend believes that it has considered all other reasonable alternatives to network augmentation to address the constraints in the transmission network.
(2) all relevant technical details concerning the proposed asset;	Information regarding the technical details of the proposed assets is presented in section in 4.3.3 of this Final Report.
(3) the construction timetable and commissioning date for the asset;	The construction timetable and proposed commissioning date are set out in for each option considered in section 4 of this Final Report.
(4) an analysis of the ranking of the proposed asset and all reasonable alternatives as referred to in clause 5.6.6(c)(1)(iii). This ranking must be undertaken by the applicant in accordance with the principles contained in the regulatory test;	A summary of the analysis of the ranking of options and the sensitivity analysis is provided in section 4.5.
(5) an augmentation technical report prepared by the Inter-regional Planning Committee in accordance with clause 5.6.3(j) but only if: (i) the asset is reasonably likely to have a material inter-network impact; and (ii) the applicant has not received consent to proceed with such construction from all Transmission Network Service Providers whose transmission networks are materially affected by the asset; and	The proposed augmentation has no material inter-network impact.
(6) a detailed analysis of why the applicant considers that the asset satisfies the regulatory test and, where the applicant considers that the asset satisfies the regulatory test as a reliability augmentation, analysis of why the applicant considers that the asset is a reliability augmentation.	The proposed augmentation is required to address the emerging supply limitations on the Hobart Eastern Shore network. A summary of the applicability of the reliability limb of the Regulatory Test is set out in section 2.3.3 of this Final Report.

5.6.6 (d)	In assessing whether a new large transmission network asset: (1) is reasonably likely to have a material inter-network impact for the purposes of clause 5.6.6(c)(5); or (2) is a reliability augmentation for the purposes of clause 5.6.6(c)(6), an applicant must have regard to the objective set of criteria published by the Inter-regional Planning Committee in accordance with clause 5.6.3(i) or clause 5.6.3(l) (whichever is relevant), but only if any such criteria have been published	See comments relating to clause 5.6.6(c)(5) above
5.6.6 (e)	The applicant must provide a summary of the application notice to NEMMCO. Within 3 business days of receipt of the summary, NEMMCO must publish the summary on its website. The applicant must, upon request by an interested party, provide a copy of the application notice to that person within 3 business days of the request.	A separate copy of the executive summary of this Application Notice was provided to NEMMCO in December 2008 for the purpose of this provision.
5.6.6 (f)	Within 30 business days of publication of the summary of the application notice on NEMMCO's website, interested parties may make written submissions to the applicant on any matter in the application notice, and may request a meeting.	No submissions were received by due date 23 February 2009.
5.6.6 (g)	The applicant must consider all submissions received in accordance with the requirements of clause 5.6.6(f) within a further 30 business days. The applicant must use its best endeavours to hold a meeting with interested parties who have requested such meeting, within a further 21 business days if: (1) after having considered all submissions received in accordance with the requirements of clause 5.6.6(f), the applicant considers that it is necessary or desirable to hold a meetings; or (2) a meeting is requested by 2 or more interested parties.	No submissions were received and therefore this provision is not relevant.
5.6.6 (h)	The applicant must prepare a final report (final report) to be made available to all Registered Participants, NEMMCO and interested parties who responded to the application notice. The final report must set out the matters detailed in clause 5.6.6(c) and summarise the submissions received from interested parties and the applicant's response to each such submission.	This document is Transend's Final Report, in accordance with this provision. No submissions were received and therefore this provision is not relevant. This document is Transend's Final Report, in accordance with this provision.
5.6.6 (i)	The applicant must provide to NEMMCO a summary of the final report, and NEMMCO must publish the summary on its website within 3 business days of its receipt.	A summary of this Final Report will be provided to NEMMCO.

5.6.6 (j) to (s)	These clauses contain provisions relating to the processes applying where: • an interested party disputes certain matters in relation to the final report; and • the AER's determination of whether the proposed augmentation satisfies the Regulatory Test.	These provisions are only relevant to disputes raised in relation to this Final Report.