REVIEW OF THE ELECTRICITY TRANSMISSION CODE

FINAL DECISION

February 2012

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GLOSSARY OF TERMS

AEMO	Australian Energy Market Operator
AER	Australian Energy Regulator
AMD	Agreed Maximum Demand
CBD	Central Business District
CODE	Electricity Transmission Code
COMMISSION, ESCOSA	Essential Services Commission of SA
DNSP	Distribution Network Service Provider
ESIPC	Electricity Supply Industry Planning Council
ESC ACT	Essential Services Commission Act 2002
MVA	Mega Volt Amps
MW	Mega Watt – 1,000,000 Watts
N RELIABILITY	Means the Transmission System is able to supply maximum demand provided all of the network elements are in service.
N–1 RELIABILITY	Means the ability of the transmission system to continue to supply the contracted loads connected to the system even if any one element were to fail.
N–2 RELIABILITY	Means the ability of the transmission system to continue to supply the contracted loads connected to the system following the failure of any two single independent and diverse transmission elements.
NEM	National Electricity Market
NER	National Electricity Rules
RIT-T	Regulatory Investment Test - Transmission
SA	South Australia
TNSP	Transmission Network Service Provider
USE	Unserved Energy
VCR	Value of Customer Reliability

1 INTRODUCTION

In anticipation of a new regulatory control period to commence from 1 July 2013 for South Australia's major electricity transmission business, ElectraNet Pty Ltd (**ElectraNet**), the Essential Services Commission (**Commission**) has reviewed and amended the terms of the Electricity Transmission Code.

The code establishes the standards of service which ElectraNet must meet in providing transmission services in this State and in that sense is a key driver of ElectraNet's revenue requirements, which are regulated by the Australian Energy Regulator (**AER**) under the provisions of the National Electricity Rules (**NER**).

This Final Decision of the Commission sets out 14 decisions and explains the amendments made to the code (to be termed ETC/07) as a result of the decisions and the reasons for those amendments.

Although the amended code will not commence for some time, the Commission has made it available on its website, along with the current version of the code (TC/06, which will apply until the commencement of TC/07).[1]

This Final Decision should be read alongside the provisions of the amended code (TC/07).

1.1 Background

Licensing of electricity transmission businesses in South Australia is one of the statutory functions of the Commission, the independent economic regulator of essential services in this State.

A central part of the Commission's licensing function in the electricity transmission sector is setting standards of service as binding obligations under the terms of each licence.[2] The Commission undertakes that task through the provisions of an industry code, the Electricity Transmission Code (**code**), which it has made pursuant to its statutory code-making powers under the Essential Services Commission Act 2002 (**ESC Act**).[3] Compliance with the code's provisions is a mandatory licence condition.[4]

In setting the terms of the code, the Commission is guided by its paramount statutory objective, as specified in section 6 of the Essential Services Commission Act 2002 (**ESC**

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1 Refer generally http://www.escosa.sa.gov.au/electricity-overview/codes-guidelines-rules/electricity-codes.aspx

2 Pursuant to the provisions of the Electricity Act 1996, the operation of a transmission network in South Australia attracts the obligation to be licensed by the Commission. Licensing is also a requirement in respect of the operation of electricity system control and electricity generation, distribution and retail undertakings. In each case, the Commission is the licensing authority and, through that role, has various functions in respect of setting standards of service to apply to licensees.

3 Essential Services Commission Act 2002, Part 4, available at www.legislation.sa.gov.au

4 A failure to comply with licence conditions is a breach of the Electricity Act 1996, punishable by fines of up to $1 million.

Act) to protect the long-term interests of South Australian consumers with respect to the price, quality and reliability of electricity services.

The code forms part of a broader regulatory scheme for transmission in the National Electricity Market (**NEM**). The reason for regulation of the transmission system is that while, in one sense, it may be seen as a physical system which transports wholesale energy from generator connection points to market customers and retailers, in a fundamental sense it provides the means by which the NEM operates.

Regulation of the system occurs at two levels: the NER establish technical standards, dealing with matters such as frequency, system stability, voltage and fault clearance;[5] jurisdictional standards, such as those set under the code, provide for security and reliability standards which align with and complement the NER technical standards.

A key point of interaction between the code and the NER arises from the requirement under the NER that any new asset constructed by ElectraNet, including those required to meet a standard mandated under the code, must satisfy a regulatory test referred to as a Regulatory Investment Test – Transmission (**RIT-T**).[6]

> *(b) The purpose of the regulatory investment test for transmission is to identify the credible option that maximises the present value of net economic benefit to all those who produce, consume and transport electricity in the market (the preferred option). For the avoidance of doubt, a preferred option may, in the relevant circumstances, have a negative net economic benefit (that is, a net economic cost) where the identified need is for reliability corrective action.*

For a reliability augmentation to satisfy the regulatory test, the transmission entity must demonstrate that the proposed new transmission asset is necessary so as to meet the minimum network performance requirements set out in the NER, relevant legislation, regulations or any statutory instruments which apply to that entity.

The Commission's role is to develop and administer security and reliability standards under the code, with the Australian Energy Market Operator (**AEMO**) having responsibilities under the NER for technical matters.[7] The Australian Energy Regulator (**AER**) is responsible for regulation of the revenue which transmission businesses are permitted to earn, having regard to the standards set by the Commission and AEMO.

The code applies to all licensed transmission entities; however, the exit point reliability standards established under clause 2 of the code apply only to ElectraNet.[8] Currently,

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5 Refer Schedule 5.1 of the NER, available from the Australian Energy Market Commission website at http://www.aemc.gov.au/Electricity/National-Electricity-Rules/Current-Rules.html

6 Refer National Electricity Rules, clause 5.6.5B *et seq*, available on the AEMC website at http://www.aemc.gov.au/Electricity/National-Electricity-Rules/Current-Rules.html; Australian Energy Regulator, 2010, *Regulatory investment test for transmission*, http://www.aer.gov.au/content/index.phtml/itemId/730920

7 For further information on AEMO's role, refer the AEMO website at www.aemo.com.au

8 This is because the exit points (or groups of exit points) specified in that clause, which are owned and operated by ElectraNet, provide electricity to ETSA Utilities (for distribution to all customers connected to the National Electricity Market in this State) and a small number of directly connected customers. Those exit points have a significant role in and impact on electricity supply in this State.

there are six categories established for exit points on ElectraNet's transmission network, with each category having defined reliability and supply restoration standards. Refer to the Appendix for current and amended reliability point categories.

The standards are graduated; currently Category 1 has the lowest reliability and supply restoration requirements and Category 6 (the Adelaide Central Area) has the highest. The establishment and population of each category and its associated standards is achieved following economic analysis of the value of reliability for each exit point and the capital costs of improving reliability over time. The standards require, in effect, a level of security (also referred to as spare capacity or redundancy) to be built into ElectraNet's transmission system so that it can maintain electricity supply even following equipment failures due to faults or outages.

Importantly, whatever the means by which ElectraNet chooses to meet the exit point reliability standards, two principles apply: the manner in which the standard is met should be as efficient, technically and economically, as possible and the obligation to meet and maintain those standards is the responsibility of ElectraNet alone.

This means that where ElectraNet determines that it will rely on network support arrangements to meet a reliability standard, for example through the use of ETSA Utilities' distribution system, the costs of doing so (including the costs of any upgrades to those network support arrangements to ensure ongoing adherence to the exit point reliability standards) are to be borne by ElectraNet and recovered through prescribed transmission service charges.

The code does not require any other party, regulated or otherwise, to make any investment nor does it have anything to say about the manner in which such an investment, when sought by ElectraNet, is to be funded – the assumption of the code is that ElectraNet will source and fund such investments.

The Commission does, however, acknowledge that where, as a result of a change in a standard applicable to ElectraNet at an exit point, a person taking supply from that exit point must augment its system to take an increased supply, then that person will be responsible for sourcing and funding that element.

1.2 The impetus for review of the code

As a monopoly service provider, ElectraNet is subject to economic regulation in respect of the revenues it is permitted to earn from South Australian consumers, with the AER responsible for establishing that regulatory regime under the NER.

As may be appreciated from the nature and scope of transmission operations, the exit point reliability standards established by the Commission under the code are a fundamental driver of ElectraNet's revenue requirements. Hence, any changes to the exit point reliability standards over time will have cost implications for ElectraNet and therefore price implications for South Australian consumers.

It is therefore important that standards are set in an efficient manner, appropriately balancing the need for reliability of supply and the costs of operating and maintaining the transmission system. This implies a need for on-going review and oversight of the standards, a function undertaken by the Commission. A periodic review of this nature must consider load growth and the means by which ElectraNet can provide flexible solutions to reliability augmentations at the lowest possible cost to South Australians.

For the purposes of ElectraNet's revenue allowance for the 5-year regulatory period to 30 June 2018, the AER will, during 2012-13, be reviewing ElectraNet's proposed revenue requirements. Given that timing, it has been necessary for the Commission to review the need to vary any of the existing exit point reliability standards. The new standards set under the amended code, as described in this Final Decision, will allow the efficient costs of ElectraNet's reliability obligations to be taken into account by the AER.

1.3 Reliability terminology

Terminology such as "**N**", "**N-1**" and "**N-2**" is used in section 2 of the code (and throughout this Final Decision) to describe levels of reliability of the ElectraNet transmission system.

N reliability means that the transmission system is able to supply the maximum demand, provided that all the network elements are in service. This means that the loss of a single transmission element (a line, a transformer or other associated equipment) could cause supply interruption to some customers.

A higher level of reliability is provided by **N-1 reliability.** With this reliability standard no customers would be affected even with one network element out of service. It is also possible to define N–1 reliability for a percentage of the time or for a percentage of the maximum demand.

N–2 reliability means that no customers would be affected even if two network elements were out of service. This is a very high level of security that is expensive in terms of capital expenditure. Accordingly, this level of reliability is generally limited to Central Business District (**CBD**) areas where such a high level of security is deemed necessary.

1.4 Process

In March 2010, as a key input into the Commission's review, the Commission requested AEMO[9] to investigate the transmission network exit point reliability standards specified in the code to determine their appropriateness for the regulatory period 2013 to 2018. In providing that advice, AEMO utilised a probabilistic cost-benefit methodology to compare the capital cost of moving to another reliability category with the value of the increased reliability delivered to the relevant connection point.

Specifically, AEMO was asked to consider:

[9] AEMO has a statutory function of providing technical advice to the Commission.

- How should connection point reliability be established?
- Is the current reliability standard for each connection point appropriate?
- Should the reliability standards for any connection points be amended, taking into consideration load growth, demographic changes, and/or network developments (transmission and distribution) etc?
- If the reliability standard of any connection point is considered to be inappropriate, what should the standard be and what network extension and/or augmentation would be required to meet such a standard in a cost effective and efficient way (transmission and/or distribution)? What would be the indicative capital cost required to meet the new standard?

AEMO's report was provided to the Commission in December 2010 and is available on the Commission's website.[10]

In April 2011, having considered the advice provided by AEMO, the Commission released an Issues Paper that sought comment from interested parties on recommendations for amendments to the code.[11] In addition to the review of connection point reliability, the Commission canvassed various amendments to existing clauses of the code and the inclusion of new clauses which AEMO had advised may be useful to the extent that there were any interpretational ambiguities within the code.

The Commission received submissions from ETSA Utilities and ElectraNet in response to the Issues Paper.

In September 2011, the Commission released a Draft Decision on proposed amendments to the code, having regard to the submissions it had received and further consideration of each of the matters it raised in the Issues Paper.[12]

The Commission received submissions on the Draft Decision from ElectraNet and St. Kitts Associates (**SKA**). Following the close of submissions, in December 2011 and then again in January 2012, the Commission received further representations from ElectraNet on specific matters which it had not raised in its initial submission to the Draft Decision.

Having regard to those submissions and the Commission's statutory requirements as established under the ESC Act and the Electricity Act the Commission has amended the code as described and for the reasons set out in this Final Decision, to take effect on and from 1 July 2013.

10 Refer the Commission's website at http://www.escosa.sa.gov.au/projects/165/review-of-the-electricity-transmission-code.aspx

11 A copy of the Issues Paper may be accessed from the Commission's website at http://www.escosa.sa.gov.au/projects/165/review-of-the-electricity-transmission-code.aspx

12 A copy of the Draft Decision may be accessed from the Commission's website at http://www.escosa.sa.gov.au/projects/165/review-of-the-electricity-transmission-code.aspx

1.5 Summary of Final Decisions

The Final Decisions of the Commission in relation to the amendments made to the code to apply from 1 July 2013 are as follows:

Final Decision 1.

The Commission will reclassify the Baroota and Dalrymple connection points from Category 1 to Category 2 from December 2017 and December 2016 respectively.

Final Decision 2.

Current Category 5 exit points have been moved to Category 4. The existing Category 5 and associated arrangements, providing for network support arrangements for the Adelaide Central Area, have been removed from the code. The existing Category 6 classification has been renamed Category 5.

Final Decision 3.

Clause 6.3.1 of the code has been amended to read:

*"A **transmission entity** must use its **best endeavours** to complete all necessary design work, obtain all necessary planning approvals and acquire all necessary land and easements on the basis of **forecast agreed maximum demand** prior to the **forecast agreed maximum demand** breaching the reliability standards in this industry code so as to ensure that the **transmission entity** is in a position to meet its obligations."*

A new definition for forecast agreed maximum demand has been included in Section 10.1 of the code (definitions) as follows:

*"**Forecast agreed maximum demand** means the **agreed maximum demand** forecast for a given year that is agreed with the **customer** three years prior to when the **agreed maximum demand** is required to be contracted."*

A new clause 2.11 "Obligations to provide sufficient capacity following changes in agreed forecast maximum demand" has been added:

*2.11.1 Subject to clause2.11.2, in the event that a change **in forecast agreed maximum demand** at an **exit point** or group of **exit points** will result in a future breach of a standard specified in this clause 2, a **transmission entity** must ensure that the **equivalent capacity** at the **exit point** or group of **exit points** is sufficient to meet the required standard within 12 months of the identified future breach date.*

*2.11.2 Where a change in **forecast agreed maximum demand** at an **exit point** or group of **exit points** under clause 2.11.1 was not able to be identified by the **transmission entity** in the **forecast agreed maximum** demand 3 years prior, a **transmission entity** must:*

*(a) use its **best endeavours** to ensure that the **equivalent capacity** at the **exit point** or group of **exit points** is sufficient to meet the required standard within 12 months of the identified future breach date; and*

*(b) in any event, ensure that the **equivalent capacity** at the **exit point** or group of **exit points** is sufficient to meet the required standard within 3 years of the identified future breach date.*

Final Decision 4.

The Commission will not seek to enhance the current N-1 reliability standard of connection points supplying Adelaide Central at this time.

Final Decision 5.

The Commission has included new clause 6.4.1 in the following terms:

*6.4.1. Where the most economically feasible option to meet the reliability standards of clauses 2.5 to 2.9 relies on a combination of transmission and sub-transmission services, the **transmission entity** must ensure that the reliability standard required by that category is capable of being delivered to the **agreed maximum demand** points within that category, including for any contingency events that the category requires for that reliability category.*

To ensure that a distributor assists in meeting the obligations incumbent on the transmission entity, and in accordance with the NER, the Commission has included the additional clause 6.4.2, that requires the distributor to undertake work associated with meeting the reliability standard at an exit point in a timely manner.

*6.4.2. Where a **distributor** is required, in accordance with the **National Electricity Rules**, to extend or augment its distribution system associated with a **transmission entity's** obligations under clause 6.4.1, the **distributor** must undertake that work in a timeframe which will enable the **transmission entity** to achieve the required reliability standard at an **exit point**.*

Final Decision 6.

The Commission has amended the provision for contracted maximum demand to permit ElectraNet to contract for levels of AMD above the installed transmission line and transformer capacity on the following terms (clause 2.12):

2.12 Contracted agreed maximum demand and network support arrangement requirements

*2.12.1 Where a **transmission entity has a network support arrangement in place and delivers transformer or transmission** line capacity by means of **equivalent capacity**, the **transmission entity** may contract for any amount of **agreed maximum demand** provided that:*

*(a) if the level of contracted **agreed maximum demand** is less than 120% of the installed **transformer** or **transmission line capacity**, the **network support arrangement** must have at least 95% availability for the 12 months to 30 June each year; and*

*(b) if the level of contracted **agreed maximum demand** exceeds 120% of the installed **transformer** or **transmission line** capacity, the **network support arrangement** must have a level of availability at least equal to the availability standard applicable to the relevant **transformer** or **transmission line**.*

*2.12.2 Where a **transmission entity** relies on a **network support arrangement** provided by an independent network support provider to meet the required **transformer** or **transmission line capacity**, the **transmission entity** must enter into a **network support agreement** with that network support provider to ensure the capability and availability of the **network support arrangement**.*

*2.12.3 Where a **transmission entity** does not have a **network support agreement** in place, the **transmission entity** must not:*

*(a) contract for an amount of **agreed maximum demand** which is greater than 100% of the installed **transmission line** and **transformer** capacity at the **exit point**; and*

*(b) rely on a **network support arrangement** to meet the required **transformer** or **transmission line** capacity unless the **network support arrangement** is provided by the **transmission entity**.*

Final Decision 7.

The code has been amended to require consideration by ElectraNet of the broader impacts on the provision of transmission network capability and reliability to the Riverland via Murraylink, with new clauses 6.4.3 and 6.4.4 introduced as follows:

*6.4.3. A **transmission entity** that provides **equivalent transmission line capacity** or **equivalent transformer capacity** for the purposes of Chapter 2 of this code must consider network plant failures in any NEM region, including distribution systems, where such plant failures might impact on the applicable level of redundancy or reliability.*

*6.4.4. For the purpose of assessing **connection point** reliability, the capability of the Murraylink interconnector should be calculated using the Murraylink transfer limit equation under peak Victorian demand conditions.*

Final Decision 8.

Clause 2.7.1 has been amended as follows to include the provision for post contingent operation:

*2.7.1. In respect of Category 3 **exit points**, a **transmission entity** must:*

*(a) provide "N-1" **equivalent line capacity** for at least 100% of contracted **agreed** maximum demand (including through the use of post-contingent operation) and:*

*(b) provide "N-1" equivalent transformer capacity for at least 100% of contracted agreed **maximum demand** (including through the use of post-contingent operation) and:*

Final Decision 9.

Clauses 2.1.1 and 2.1.2 of the code have been amended as follows:

*2.1.1. Subject to the service standards specified in this clause 2, a **transmission entity** must use its **best endeavours** to plan, develop and operate the transmission network to meet the standards imposed by the **National Electricity Rules** in relation to the quality of **transmission services** such that there will be no requirements to shed load to achieve these standards under normal and reasonably foreseeable operating conditions.*

*2.1.2. Subject to the service standards specified in this clause 2, a **transmission entity** must use its **best endeavours** to plan, develop and operate the transmission system so as to meet the standards imposed by the **National Electricity Rules** in relation to **transmission network** reliability such that there will be minimal requirements to shed load under normal and reasonably foreseeable operating conditions.*

Final Decision 10.

The Commission is satisfied that clauses 2.3 and 2.4 of the code define the application of reliability standards where electricity exits the transmission network. The Commission has therefore amended clauses 2.3 and 2.4 of the code by replacing the defined term, "connection point", with the defined term, "exit point".

*2.3.1. A **transmission entity** must plan and develop its **transmission system** such that each **exit point** or group of **exit points** allocated to a category in accordance with clause 2.4 meets the relevant standards for that category as set out in clauses 2.5 to 2.9**.***

2.4.1. The allocation of ***exit points*** *to categories is set out in the table below* ***(exit points*** *in square brackets refer to a group of* ***exit points):***

The Commission has amended clause 2.12 by renumbering it to 2.13 and separating it into two clauses to clarify the approval requirements (clause 2.13.1) and standards

development (clause 2.13.2. Reference to the distance from Adelaide Central (previously sub-clause 2.12.1(e)) has been deleted.

Final Decision 11.

The Commission accepts the connection point upgrade recommendations made by AEMO and is satisfied that the additional connection point studies require no further assessment or action for the purposes of this code review.

Final Decision 12.

The Commission will amend clause 6.2.5 of the code to provide for quarterly reporting of breaches of entities' internal switching manuals in association with regular quarterly performance reporting with serious breaches of switching manuals will be reported within 20 business days as follows:

*6.2.5 An **electricity entity** must report to the **Commission**, quarterly, all breaches of its internal switching manual, including breaches by a contractor or customer of which it has become aware. Any breach resulting in a fatality or serious injury, significant impact on **transmission system** availability or significant asset damage must be reported to the Commission within 20 **business days**.*

Final Decision 13.

The Commission is of the opinion that ETSA Utilities' concerns regarding indemnity for losses (and claims against ETSA Utilities) due to interruptions that occur while providing network support to ElectraNet should be dealt with in a formal network support agreement. An agreement should be specific in the expectations of each entity such that network capability and redundant capacity are determined and the area of affected network is segregated to apportion responsibility for reliability. There is, therefore, no need for specific code provisions in this regard.

Final Decision 14.

The Commission has amended the provisions of clause 2 of the code to clarify ElectraNet's restoration obligations in the event of:

- the unavailability of a network element which provides the relevant reliability standard; and

- an outage due to the unavailability of all relevant network elements which provide the relevant reliability standard.

The Commission has introduced clause 2.10, "Obligation to restore capacity", into the code to strengthen the best endeavours standard for a transmission entity to restore a failed network element.

*2.10.1 The obligation to restore a failed **transmission line**, **transformer** or **network support arrangement** as soon as practicable so as to meet the standards specified in this clause 2 includes, without limitation, a requirement that the **transmission entity** must have regard to:*

*(a) **good electricity industry practice**;*

(b) the need to minimise the duration of any interruption arising from that failure; and

*(c) the need to minimise the likelihood of an interruption as a result of the failure of any other **transmission line**, **transformer** or **network support arrangement** utilised at that **exit point** or group of **exit points**.*

2 METHODOLOGY

This Chapter describes the methodology utilised by the Commission's advisor, AEMO, in recommending amendments to the code and assesses the various arguments put to it by SKA in relation to that methodology.

2.1 Overview of methodology

The assessment process for each exit point involved the following considerations:[13]

- Calculating the average number of hours each exit point will be without power. This probabilistic method relies on typical failure rate data, which is based on historical observations, and is collected for different categories of equipment (transformers, lines, cables) at different voltage levels.
- Multiplying the number of outage hours by the exit point demand to establish the number of megawatt hours (MWh) that, on average, are unable to be supplied each year.
- Assessing the value of lost customer load or unserved energy,[14] as being the number of lost MWh multiplied by the value of unserved energy to customers. The value developed for this review for South Australia was $45,767/MWh with sensitivities of +/-20%.
- For exit points with a high value of lost customer load, comparing the capital cost of upgrading to a higher reliability standard with the benefit in reduced unserved energy provided by the upgrade.

Through the review process, the Commission sought stakeholder comment on whether or not the approach utilised by AEMO was sound, such that the Commission could rely on that advice in reaching its Final Decision on amendments to the code.

No respondent to the review process made a submission commenting on AEMO's overall approach. The Commission itself carefully reviewed the approach adopted by AEMO and, noting that the approach was consistent with that used successfully by the Commission in the past, formed the view that it provided a sound basis on which advice on specific reliability standards could be provided.

2.2 Assumptions within the methodology

The AEMO exit point study was based on assumptions made on the components listed below. A more complete description of the assessment methodology and the assumptions used can be found in Chapter 4 of the AEMO report.

13 A detailed review of the methodology is set out in Chapter 4 of the AEMO report.

14 The unserved energy reliability standard is a measure of the expected amount of energy at risk of not being delivered to consumers due to a lack of available capacity. Refer "Reliability Standard and Reliability Settings Review" 30 April 2010 www.aemc.gov.au

2.2.1 Network Demand

The maximum demand forecasts at connection points used by AEMO in its assessment are ETSA Utilities' medium growth connection point forecasts, which represent the summer peak demand forecasts. The forecasts present the undiversified annual connection point maximum demands from 2010/11 to 2029/30 as presented in ElectraNet's Annual Planning Report 2010–2030.[15]

AEMO argued that transformers are more likely to fail when under stress during peak load periods, hence the forecast maximum demand was assumed for calculating the value of expected unserved energy due to transformer outages. Transmission line and cable faults are generally less dependent on line loading and as such, an average load factor was used to convert the maximum demand to average demand, which was then used when calculating the value of expected unserved energy due to line outages.

An average load factor was used for calculating the value of expected unserved energy due to line outages and expected unserved energy during planned outages, including demand not met due to forced outages for planned maintenance. The average load factor applied to all connection points was 49%, based on the 2009/10 South Australian total system load duration curve.

2.2.2 Transmission system reliability

The expected hours of unserved energy per annum for each connection point was calculated using ElectraNet's historical data on the average failure rates and outage durations due to planned and unplanned outages which was compared with industry-wide statistics for consistency.

When applying the failure rates, AEMO assumed that single supply lines are maintained through live line techniques to minimise supply outages to radial connection points. AEMO also assumed that single supply lines have zero annual maintenance outage hours.

Overhead transmission lines are shown to be highly reliable and terminal stations connected by four or more transmission lines, such as Para, Davenport, and Robertstown, are expected to be particularly reliable points of supply. The probability of having three or more concurrent line outages is very low and therefore these supply points are almost always expected to be capable of supplying power to the local transmission network. It is the reliability of the transmission network directly supplying a connection point that predominantly determines the overall connection point reliability.

Probabilistically, these highly reliable supply points are expected to contribute negligibly to amounts of unserved energy, with the majority of unserved energy being caused by the network connecting these supply points to the connection point.

[15] ElectraNet (2010), *Annual Planning Report 2010-2030,* http://www.electranet.com.au/network_planning_review.html

Highly reliable terminal stations with four or more connecting transmission lines have been used as reference points, and the reliability of each connection point was based on the transmission plant reliability between these supply points and each connection point.

2.2.3 Value of customer reliability (VCR)[16]

As described by SKA in a submission made to AEMO during 2011, VCR:

> … *represents the dollar value that customers place on the reliable supply of electricity – an indicator of customers' willingness to pay for not having supply interrupted*.[17]

Further, as described by AEMO in its recent Final Decision for its VCR review, it should be noted in respect of VCR that:

> *The value of a reliable supply of electricity is a key part of understanding the relative economic merits of alterations to the electricity network. In probabilistic transmission planning, a Value of Customer Reliability or VCR is needed to value the benefit of a proposed augmentation project that is expected to reduce unserved energy in the future, so that this benefit can be compared to the costs of the augmentation. In deterministic transmission planning, a VCR may be used to value the partial market benefit of reducing the likelihood of having unserved energy in the future.*
>
> *Therefore the value that consumers place on a reliable supply of electricity plays a vital role in the transmission planning process as the valuation of reliability is a key element to the social benefit of network augmentations.*[18]

A VCR for the Victorian region was originally estimated in 1997, using direct survey methods. This work was updated for AEMO in 2002 and 2008. The baseline VCR was indexed to Victorian income measures between surveys so that the values are updated annually to reflect current income growth and consumption shares for identified economic sectors (agricultural, industrial, commercial, and residential).

In 2010, AEMO undertook to develop VCR estimates for regions other than Victoria using existing Victorian survey data to calculate individual VCRs. The 2007 VCR for each sector and each region was updated to 2010 values using an indexation method.

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16 The term "value of customer reliability" or "VCR" can tend to distract from the use of the concept in transmission planning scenarios. As noted by AEMO in its Final Decision on its VCR Review, "*The terminology variously used to describe the value/cost of unserved energy includes the 'value of unserved energy', the 'value of lost load', 'value of supply security', 'customer cost of service interruption, or simply 'outage cost'. The term VCR was adopted by AEMO to distinguish the value used to evaluate transmission projects from the applicable market price cap*". The Commission notes that the "applicable market price cap" referred to by AEMO is termed the "value of lost load" or "VOLL".

17 Refer SKA, *Value of Customer Reliability in the NEM – A review of the Australian Energy Market Operator – a submission to the June 2011 Issues Paper from a small customer perspective*, July 2011 at page 1; available at http://www.aemo.com.au/planning/0409-0016.pdf

18 Refer AEMO< *National Value of Customer Reliability*, Final Decision, January 2012, at page 2. Available at www.aemo.com.au

The regional data on outages and sector consumption were provided by the distribution network service providers (DNSPs) within each region.

The VCR developed for South Australia was $45,767/MWh (in 2010 dollars) and was used by AEMO as a base value in its report to the Commission. The sensitivity analysis for that VCR applied values of $38,240 and $53,295 (in 2010 dollars).

2.2.4 Transmission upgrade costs

Transmission augmentation projects were nominated by ElectraNet. Those augmentation projects and the associated transmission costs were outlined in ElectraNet's Annual Planning Report.[19] Where included, additional distribution costs were provided by ETSA Utilities, based on recent connection cost estimates obtained for similar projects.

Sensitivity analysis was performed with variations of ±30% on these cost estimates.

A comparison of the transmission augmentation costs supplied by ElectraNet and the costs used by AEMO when undertaking its planning functions found the two sets of costs to be reasonably consistent.

2.2.5 Economic assumptions

AEMO's cost-benefit assessment was performed for the period from 2010/11-2029/30. Based on information provided by ElectraNet, a new transformer was assumed to have an asset life of 45 years, and a new transmission line or underground cable was assumed to have an asset life of 55 years.

The annual payments resulting from each investment were calculated using the appropriate asset life and an assumed real discount rate of 10% (for the base case), with sensitivities of 7% and 13%.[20] In its advice to the Commission on this point, AEMO noted:

> *The annual payments resulting from each investment were calculated using the appropriate asset life and an assumed real discount rate of 10% (for the base case), with sensitivities of 7% and 13%. These assumptions are consistent with the RIT-T, which specifies that the assessment must use a commercial discount rate appropriate for the analysis of a private enterprise investment in the electricity sector.*[21]

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19 Refer to ElectraNet web site http://www.electranet.com.au/assets/Uploads/annualplanningreport2010.pdf

20 AEMO advised the Commission that this range (7%-13%, with a mid-point of 10%) is consistent with the requirements of the AER's *Regulatory Test for Transmission Investment*, June 2010 at clause 15, "*The present value calculations must use a commercial discount rate appropriate for the analysis of a private enterprise investment in the electricity sector. The discount rate used must be consistent with the cash flows being discounted*." Refer http://www.aer.gov.au/content/item.phtml?itemId=737902&nodeId=74fd77fd6b4eb092d34f5d4956f4f1fb&fn=Final%20RIT-T%20(June%202010).pdf at page 6

21 Refer AEMO, *Review of the South Australian Electricity Transmission Code*, December 2010. Available at http://www.escosa.sa.gov.au/library/101223-ReviewSAElectricityTransmissionCode-AEMO.pdf

The RIT-T also suggests that the sensitivity testing should be performed with the lower bound being the AER-mandated regulatory real pre-tax weighted average cost of capital (WACC) for transmission investments.

The annual capital costs payments and the costs of unserved energy were discounted to a net present value using the same discount rates (and sensitivities). A terminal value approach was used to reflect the value of the capital expenditure and the unserved energy at the end of the assessment period (2029/30). To calculate the terminal value it was assumed that the previous year's unserved energy costs continued in perpetuity.

2.3 Assessment of the assumptions

Respondents to the review broadly supported the assumptions utilised by AEMO; however, specific concerns with respect to forecasts for connection point maximum demand and the VCR were raised by ElectraNet and SKA (respectively).

2.3.1 Forecasts for connection point maximum demand

With respect to forecasts for connection point maximum demand, ElectraNet submitted that it broadly supported the assumptions but noted that the values used in the review were based on ETSA Utilities' medium growth forecasts. ElectraNet submitted that, in its view, the forecasts do not reflect the potential impact of uncommitted significant step load increases in the ETSA Utilities distribution network, whereas they may be accounted for in the high growth forecasts.

By way of example, ElectraNet noted a demand increase of 40-80MW on the Eyre Peninsula to account for possible mining demand. ElectraNet proposed an amendment to clause 2.12 of the code such that it allows for a review of an existing connection point (under the current assessment methodology) in response to material change in demand and that criteria should be specified to address any change to an existing connection point classification.

In response to ElectraNet's concerns, the Commission notes that the medium growth demand forecasts provided by ETSA Utilities, and used by AEMO to compile its report, represent the undiversified maximum demand forecast. This means that no diversification (i.e. reduction) factor is applied to the demand based on patterns of consumption. The approach to forecasting demand growth by ETSA Utilities could therefore be considered conservative.

The medium growth demand forecast includes the impact of committed (known) load increases at a connection point, as required under regulatory planning obligations. However, to consider uncommitted loads, such as in the high growth example for the West Coast as noted by ElectraNet, may lead to the over-design of the networks. This ultimately impacts on the cost of electricity to customers.

As described below, the VCR is based on current knowledge of the State's customer base and type and not on hypothetical values. Nonetheless, any increase in demand at a connection point brought about by a "drop-in" load may render the capacity of the connection point unsatisfactory. In effect, this is a capacity issue rather than a reliability issue. The Commission is not, therefore, persuaded that there has been any error on the part of AEMO in the assumption it has made in this regard in its methodology.

2.3.2 Value of customer reliability

In respect of AEMO's assumption as to the value of VCR, SKA submitted that the Commission should note the submission which SKA had recently made to AEMO in which it expressed concerns with the application of a South Australian regional value of $38,037 (at the time based on extrapolation from the Victorian value derived in 2007, applying a ±20% sensitivity: lower bound $30,429; upper bound $45,644).

SKA highlighted that a number of submissions to a more recent AEMO VCR Issues Paper[22] expressed concerns about the validity of the methodology used to derive the VCR value. SKA noted that AEMO's consultants on the VCR review expressed a view that AEMO's chosen approach of updated nationwide surveys extrapolated from previous Victorian surveys was not the best solution to arrive at the value used in the code review.

SKA submitted that the VCR methodology that derives the figure recommended to the Commission by AEMO also showed a residential figure of $15-20,000 and therefore argued that the methodology for the review includes a sensitivity test that does not include the residential figure.

The implication of this, according to SKA, is that significant transmission investment will exceed the willingness to pay of the most numerous customer class, residential customers, representing a significant challenge to the economic efficiency of these investments. SKA suggested that the Commission should reconsider the weightings used to derive a state-wide VCR for transmission; in its view a VCR value that better acknowledged customer numbers, not just sales volumes, might be more equitable.

To properly consider and address SKA's submission, which the Commission understands to be a proposition that VCR should include weightings of both customer numbers and loads (not simply loads, as is presently the case) the Commission sought further confirmation from AEMO on the appropriate value of VCR.

AEMO acknowledged that the thinking on the application of VCR values had changed from the position set out in its VCR Issues Paper. As an initial point, however, it was noted that the particular proposal identified by SKA was one which was made over six months after AEMO completed its code review, and hence was not applied in its code review studies. Further, the Commission notes that, in making a Final Decision on a national VCR on 19 January 2012[23], AEMO has acknowledged that specific customer survey work in each State is required in order to derive a more robust VCR. This may include processes such as those proposed by SKA. In the absence of that further work, the Commission is constrained from applying a different approach to VCR for the

[22] Refer AEMO Issues Paper at www.aemo.com.au/planning/vcr.html

[23] Refer AEMO Final Report "National Value of Customer Reliability (VCR)" at www.aemo.com.au/planning/vcr.html

purposes of the present review; while acknowledging the shortcomings of the current process, there is not another agreed, reliable process to which it can turn at this stage.

The Commission therefore acknowledges the submission of SKA and notes that further work in this area will be of significance for South Australia.

That said, the Commission acknowledges that this matter was under review by AEMO at the time of the release of its Draft Decision. AEMO's final report recommended a regional VCR for SA of $44,300/MWh, a figure that is marginally less than the $45,767 used in the connection point studies but well within the lower bound of $38,240. Having reconsidered the cost/benefit analysis for each connection point using the revised values, the Commission notes that the outcomes in each case are the same as initially proposed by AEMO in its advice. There is, therefore, no need to depart from the Commission's position as expressed in the Draft Decision as a result of AEMO's revised VCR values.

3 THE ISSUES

This Chapter describes each of the amendments made to the code and the Commission's reasons for making those amendments.

3.1 Specific exit point categories

Through the review process, the Commission sought comment on the proposal put forward by AEMO that, based on its analysis, the Baroota and Dalrymple exit points should be moved from Category 1 to Category 2. Currently, Baroota and Dalrymple are among the few remaining Category 1 exit points (other than small pumping station loads and remote mining sites). AEMO recommended increasing the reliability standard of these two exit points from Category 1 to Category 2, i.e. from 'N' (line and transformer) to 'N' (line) and 'N-1' (transformer), thus adding a level of redundancy at each exit point.

When assessing the value of expected unserved energy on a probabilistic basis, AEMO found that the Category 1 exit points at Baroota and Dalrymple showed a positive net present value based on the capital cost estimates to install a new supply transformer at each connection point.

AEMO therefore advised that upgrading the reliability of supply at both the Baroota and Dalrymple exit points from Category 1 to Category 2 would be economically appropriate within ElectraNet's upcoming regulatory period (2013-2018).

Baroota has a forecast maximum demand of approximately 10MW, and Dalrymple has a forecast maximum demand of approximately 12MW. The assessment of each exit point by AEMO shows that installing an additional exit point transformer is economically justifiable based on the expected level and annual cost of unserved energy. Each installation requires both transmission and distribution elements to be augmented.

Table 1 and Table 2 show the net present value of installing additional transformers at Baroota and Dalrymple within the 2013-2018 regulatory period to be positive. Sensitivities to VCR, discount rate and augmentation costs can be found in Appendix D of the AEMO report, while detailed connection point assessments for these and other connection points can be found in Appendix F of that report.

Table 1 - Baroota economic assessment

Reliability standard category	2017/18 forecast demand (MW)	Expected unserved energy (MWh/annum)	Annual cost of unserved energy ($USE)
Category 1	10.0	103	$5,548,000
Category 2	10.0	7	$163,000
		Annual Benefits in 2017/18	**$5,385,000**
		NPV net benefits of augmentation (over 45 year project life)	**$13,263,000**

Table 2 - Dalrymple economic assessment

Reliability standard category	2017/18 forecast demand (MW)	Expected unserved energy (MWh/annum)	Annual cost of unserved energy ($USE)
Category 1	12.1	128	$5,615,000
Category 2	12.1	12	$310,000
		Annual Benefits in 2016/17	**$5,305,000**
		NPV net benefits of augmentation (over 45 year project life)	**$27,743,000**

With the Baroota and Dalrymple installations demonstrating positive net economic benefits of approximately $13 million and $28 million (respectively) over the life of the assets, AEMO recommended moving the Baroota and Dalrymple exit points from Category 1 to the Category 2 reliability standard.

To allow reasonable time for the proposed augmentations, the proposed timing for reclassification was as follows:

- Baroota reclassified to Category 2 effective from 1 December 2017; and
- Dalrymple reclassified to Category 2 effective from 1 December 2016.

3.1.1 Comment Received

ETSA Utilities supported the proposal to upgrade the Baroota and Dalrymple connection points from Category 1 to Category 2. ETSA Utilities noted that it will be required to incur capital expenditure in respect of its distribution network for both connection points in the amount of approximately $16 million in conjunction with the connection point reliability upgrade.[24] ETSA Utilities made no comment on the timing of the upgrade.

ElectraNet also supported the reclassification of Baroota and Dalrymple connection points from Category 1 to Category 2 from December 2017 and December 2016 respectively. ElectraNet supported the timing of the proposed connection point reclassification period, (December) in the relevant years, as it is of the view that a mid-regulatory year date aligns more closely to summer peak demand and avoids an arbitrary deadline of 30 June that might otherwise apply 12 months after the new code takes effect.

ElectraNet also put a view that if the regulatory investment test supports the proposition that reinforcing the 33kV network is the most efficient option, then it should be pursued as a distribution augmentation. ElectraNet considers that the cost of a distribution investment, which passes the applicable regulatory investment test, should be recovered directly by ETSA Utilities from customers via distribution charges. ElectraNet asserts that it is not clear how the recovery of cost for distribution investments via transmission charges is consistent with the prevailing NER framework.

24 ETSA Utilities' costs were included within AEMO's cost-benefit analysis shown in Tables 2 and 3.

ElectraNet was also concerned that, where it is required to satisfy the requirements of the code at connection points to the distribution network, there is no complementary obligation on ETSA Utilities to be ready to take supply within the same timeframe.

3.1.2 The Commission's Final Decision

The Commission notes ElectraNet's support for AEMO's recommendation and also its submission that, as a matter of principle, ETSA Utilities should be responsible for capital expenditure for any distribution work required where the relevant regulatory investment test under the NER determines that a distribution, rather than transmission, solution should be undertaken.

In respect of that latter submission, the Commission agrees that, where the NER dictate a distribution solution for a network upgrade or augmentation, ETSA Utilities should undertake that work and recover its costs through distribution charges. The Commission would observe, however, that in instances where the NER determines that a non-distribution solution is appropriate and ElectraNet is obliged to deliver a transmission solution (whether it ultimately does so by the provision of transmission assets or through network support arrangements, such as reliance on ETSA Utilities distribution network), then ElectraNet is responsible for procuring and paying for those services.

Therefore, for non-distribution solutions, the overarching obligation is for ElectraNet to achieve the level of reliability mandated at the connection point in accordance with the outcome of the regulatory investment test.

There are two considerations in assigning responsibility for capital expenditure when upgrading connection point reliability. First, ETSA Utilities is required to make ready its distribution assets to be capable of conveying the demand available at the connection point. In the case of the Baroota and Dalrymple connection points, the installation of an additional transformer, which is the obligation of ElectraNet, requires ETSA Utilities to construct connection assets to link its distribution assets to the new transformer. ElectraNet has carried out its obligation in providing the required level of reliability. The onus is then on ETSA Utilities to ensure that the level of reliability is replicated through the availability of its distribution network.

Second, if the regulatory investment test dictates that the increased reliability obligation (N-1) should be implemented by a transmission solution, then the means by which that is delivered (transmission assets, sub transmission assets, generation or combination of those) is for ElectraNet to determine. The cost of providing that level of reliability is the responsibility of ElectraNet.

The Commission's position, as noted earlier in this Final Decision, in its Draft Decision and in the Issues Paper, is that exit point reliability standards apply to ElectraNet and that it is the responsibility of ElectraNet to meet and fund implementation of those standards in the most efficient economic and technical manner possible. While it is appropriate for ETSA Utilities to fund and manage network augmentations downstream of an ElectraNet exit point in order to receive higher levels of supply, works related to the exit point itself, or upstream, are ElectraNet's responsibility.

Having made those observations, the Commission is confident that AEMO has made its assessment of the Baroota and Dalrymple connection points in a sound manner, taking into account the timing of the upgrade in consideration of both ElectraNet's and ETSA Utilities' regulatory reset processes.

Final Decision 1.

The Commission will reclassify the Baroota and Dalrymple connection points from Category 1 to Category 2 from December 2017 and December 2016 respectively.

3.2 Category 5 exit points

The Adelaide eastern suburbs exit points of Dry Creek East, Magill (East), and Northfield are currently Category 5 exit points. Historically, there was a higher reliability standard for Category 5 than for any other category due to the fact that the exit points in this category were, until 1 January 2012 (the date on which the new Adelaide City West transmission substation commenced operation as required by the Commission through the provisions of the code), the only way in which supply was brought into the Adelaide Central region by ElectraNet. [25]

Under the previous provisions of the code, the transmission line and transformer capacity requirements at Category 5 exit points were defined, in part, by an equation in clauses 2.9.1 and 2.9.2 of the code based on demand at the connection point as well as the demand within the Adelaide Central region as follows;

2.9.1 (c) provide ***N-2 equivalent line capacity*** for at least X% of Z, where:

(i) Z = the sum of the ***agreed maximum demand*** for all ***connection points*** within Category 5 and Category 6;

(ii) X% = $Y\% + \left(\frac{100\% - Y\%}{2}\right)$;

(iii) Y% = $\left(\frac{AMD_{CBD}}{Z}\right) \times 100$; and

(iv) AMD_{CBD} = the ***agreed maximum demand*** for ***Adelaide Central***;

2.9.2 (c) provide ***N-2 equivalent transformer capacity*** for at least X% of Z, where the terms X% and Z have the meanings given in clause 2.9.1(c);

25 As defined in the code – the area of Adelaide located east of West Terrace, North of South Terrace, west of East Terrace and south of the River Torrens.

A similar mathematical approach was used in the code prior to the Category 6 reliability standard and was intended to represent the requirement for an increased reliability standard in the Adelaide Central region rather than in the eastern suburbs themselves.

The 2006 code review established Category 6, which includes the existing East Terrace and the recently commissioned City West exit points, which directly serve Adelaide Central, with the intention of defining the Adelaide Central region's current and future reliability standard. However, the previous code review retained Category 5 connection points, Dry Creek East, Magill (East), and Northfield, to cover the time until the new City West exit point is commissioned and the Adelaide Central Area has an N-1 capability.

As a result, AEMO recommended that, given that the new version of the code will come into effect from 2013 when the Adelaide Central Area has N-1 capability, the exit points in Category 5; namely Dry Creek East, Magill (East), and Northfield be moved back into Category 4, as the additional support they provide will no longer be required. In effect, this will require the current Category 5 be removed from the code (making current Category 6 into a new Category 5).

3.2.1 Comment Received

ETSA Utilities expressed no concerns with the proposal to move the current Category 5 connection points to Category 4 and renaming Category 6 as Category 5 (thus reducing the number of categories).

ETSA Utilities also noted that, with the provision of a second transformer at Mt Barker South, it is likely that the Mt Barker connection point will cease operation. ETSA Utilities therefore put a view that the amended code should either include Mt Barker South as a Category 4 connection point or list Mt Barker and Mt Barker South as a combined connection point. Further, ETSA Utilities advised that the City West Substation will have two connection points; one for Metro South and one for the Adelaide Central Area. As a consequence, ETSA Utilities suggests that City West should become two connection points, e.g. City West South and City West ACR, the former as a Category 4 connection point and the latter as a Category 5 connection point.

ElectraNet submitted that it is appropriate to move the current Category 5 loads to Category 4, noting that there is no effective reduction in the transmission reliability standards applying to the grouped connection points.

ElectraNet contended that historically, the formulae associated with the current Category 5 have proven difficult to interpret and harder still to explain to customers. ElectraNet agreed that, following the construction of the City West substation and the planned decommissioning of the Magill-Whitmore Square distribution cable, there is no ongoing requirement for the existing Category of load to be defined in the code.

3.2.2 The Commission's Final Decision

The Commission notes that ETSA Utilities and ElectraNet both support moving the current Category 5 connection points to Category 4. Moving the Category 5 connection points to Category 4 does not reduce the reliability standard of the connection points supplying Adelaide's surrounding suburbs.

The overall number of categories would be reduced with Category 6 connection points being renamed Category 5.

The identification of additional connection points for Mt Barker and City West advised by ETSA Utilities were also raised by ElectraNet, along with further clarification of the identification of other existing connection points. The Commission has accepted the advice of the parties in relation to those matters.

Final Decision 2.

Current Category 5 exit points will be moved to Category 4. The existing Category 5 and associated arrangements, providing for network support arrangements for the Adelaide Central Area, will be removed from the code. The existing Category 6 classification will be renamed Category 5.

3.3 Timeframe to remedy exit point reliability breaches

Network planning by ElectraNet to meet code reliability standards is based on contracted agreed maximum demand (**AMD**). Currently, AMD is contracted on a 12-month forecast and could be considered to provide limited opportunity for planning. A small error in the forecast would not have a significant impact. However, if the forecast is substantially over-stated, ElectraNet could be forced to invest unnecessarily to meet what may be perceived as an illusory reliability standard.

The majority of transmission network augmentations have protracted lead-times. It is therefore inevitable that the reliability standard will rarely be achieved within the 12-month obligation to rectify a breach under the code provisions. That requirement may be found, for example, in the current (TC/06) clause 2.6.3 of the code (dealing with line and transformer repair obligations for Category 4) in the following terms (noting that equivalent provisions appear in respect of each Category):

> *In the event that **agreed maximum demand** at an **exit point** or group of **exit points** exceeds the **equivalent line capacity** or **equivalent transformer capacity** standards required by this clause 2.6, a **transmission entity** must:*
>
> *(a) use its **best endeavours** to ensure that the **equivalent line capacity** or **equivalent transformer capacity** at the **exit point** or group of **exit points** meets the required standard within 12 months; and*
>
> *(b) ensure that the **equivalent line capacity** or **equivalent transformer capacity** at the **exit point** or group of **exit points** meets the required standard within 3 years.*

AEMO noted that it was advised by ElectraNet of the difficulty it experienced in receiving regulated funding to complete augmentations within the 12-month best endeavours period because of the timeframe permitted by the code to rectify such a breach within a 3-year period.

The code aids in reducing the likely period of breach by placing a best endeavours obligation on the transmission entity to obtain planning approvals and acquire easements based on forecasts prior to agreed maximum demand breaching the required reliability standard.

Due to the difficulties in contracting agreed maximum demand beyond a 12-month forecast, AEMO recommended (and the Commission's draft Decision was) that the code be expanded to expressly include reference to forecast AMD and a best endeavours obligation on the transmission entity to complete all necessary design work, approvals and acquisitions. This was achieved by the amendment of clause 6.3.1 (additional text underlined) as follows:

> *6.3.1. A **transmission entity** must use its **best endeavours** to complete all necessary design work, obtain all necessary planning approvals and acquire all necessary land and easements on the basis of forecast demand prior to **forecast** **agreed maximum demand** breaching the reliability standards in this industry code so as to ensure they are in a position to meet their obligations.*

Consistent with that recommendation, AEMO also proposed (and the Commission's Draft Decision was to adopt) a new definition to be included in the section 10.1 (definitions) of the code, as follows:

> ***Forecast agreed maximum demand*** *means the* ***agreed maximum demand*** *forecast for a given year that is provided by the customer three years prior to when the* ***agreed maximum demand*** *is contracted.*

AEMO suggested that the proposed amendments to clause 6.3.1 would assist in reducing any breach period and also proposed that the 3-year grace period should be removed from the code to clarify the application of the 12-month best endeavours obligation to rectify any breach; achieved through removal of the best endeavours requirement from clause 2.6.3(a) and deletion of 2.6.3(b) with equivalent changes for other categories.

However, the main concern is that eventual contracted AMD may possibly exceed the forecast AMD as a result of unanticipated increases in demand such as concentrated industrial loads that were not included in the forecast. To avoid such unforeseen demand increases giving rise to a possible reliability breach, AEMO recommended (and the Commission's Draft Decision was for) the inclusion of the additional clause 2.11 which defines the obligation to provide sufficient capacity following changes in agreed forecast maximum demand.

3.3.1 Comment Received

ETSA Utilities submitted no concerns with the proposed amendment of clause 6.3.1, the new definition of forecast agreed maximum demand or the amendments proposed.

However, in relation to clause 2.11, ETSA Utilities noted that while it understood the thrust of the proposal, it had some concern should a constraint associated with a "drop-in" (unanticipated and unforeseen) load occur early in ElectraNet's regulatory period. In such a circumstance, ETSA Utilities noted that ElectraNet would not be funded to undertake the augmentation required for the additional demand. ETSA Utilities was of the view that funding of the augmentation should be considered in any change in obligations.

ElectraNet put the following propositions:

- ElectraNet submitted that the proposed changes to clause 6.3.1 and the introduction of the new clause 2.11 will provide additional clarity as to the Commission's expectations for the time to remedy forecast or actual breaches. As noted in the Draft Decision this will generally provide a clearer trigger for funding to be received via the periodic revenue determinations issued by the AER.
- However, ElectraNet was concerned that the requirement to satisfy the reliability standard for significant new drop-in loads within three years may not be achievable where the construction of significant transmission lines is required given the lead times involved in investments of this magnitude; such as would be required to satisfy major new loads on the Eyre Peninsula.
- ElectraNet contended that the code should recognise that there will still be circumstances which challenge the achievement of these timeframes, particularly where large scale augmentations involving long project lead times are required to meet step load increases.

3.3.2 The Commission's Final Decision

There were no objections by ElectraNet or ETSA Utilities to the proposed amendment to 6.3.1.

Clause 6.3.1 of the code aids in reducing the likely period of breach by placing a best endeavours obligation on the transmission entity to obtain planning approvals and acquire easements based on forecasts prior to AMD breaching the required reliability standard.

The inclusion of the completion of all design work and land acquisitions with the other elements of the process in remedying a breach of the reliability standards assures that those aspects are considered early in the process, particularly where the outcomes are reliant on project elements that may become protracted.

The forecast AMD provides a three-year planning horizon which is based on longer term trend data from ETSA Utilities' 10-year connection point forecasts and ElectraNet's 20-year planning horizon as set out in its Annual Planning Report. The Commission is of the view that the 3-year forecast AMD presents an extended forward planning window and should provide the appropriate indicators as to the probability of a breach of the reliability standard at a given exit point.

It should be noted that clause 2.10 (Category 6 loads) and its sub-clauses have been deleted from the code with the renaming of Category 6 to Category 5.

ElectraNet argued that a best endeavours standard should apply in ensuring that an exit point(s) meets the required standard within 12 months of the forecast date of the applicable capacity being exceeded. However, the Commission believes that a mandatory timeframe is appropriate given the preceding 3-year forecast period. A best endeavours standard opens the possibility of further extending the remediation period.

In regard to forecast AMD, ElectraNet proposed that the demand forecast should be *agreed with* the customer rather than *provided by* the customer. The Commission notes that this would provide a platform for negotiation which would establish the basis on which the agreed maximum demand forecast is based; whether the ETSA Utilities' medium growth forecast (summer peak demand forecasts) or medium peak demand forecast, as proposed by ElectraNet, are used. Such negotiations on the agreed forecast however, may give rise to disputes and subsequent resolution procedures involving an independent arbitrator. However, this may not be appropriate in circumstances where the customer is an entity other than ETSA Utilities.

The Commission acknowledges the impact of possibly inaccurate demand forecasting and step load increases brought about by unforeseen and unanticipated loads. However, the Commission believes that there is a sufficient experience in demand forecasting for deriving general demand growth for reviewing exit point capacity. As noted previously, ETSA Utilities and ElectraNet use 10/20-year forecast/planning horizons in determining the requirements for network capability.

Demand increases due to unforeseen and unanticipated loads can be difficult to plan for. Whereas a high growth demand forecast scenario may consider a 40-80MW mining load increase on Eyre Peninsula as noted by ElectraNet in its submission to the Issues Paper, it would be inefficient to provide for the additional capacity based on a possibility and not a certainty. Noting ETSA Utilities' submission as to cost recovery for ElectraNet in these circumstances, the Commission's position is that for an unforeseen and unanticipated load, such a demand requirement would be subject to commercial arrangements between the provider, be it ETSA Utilities or ElectraNet, and the customer.

To simplify the approach, the Commission had added a separate clause, inclusive of the intent of amendment to clause 2.[6-9].3 and new clause 2.11 proposed by AEMO, to Chapter 2 of the code. The introduction of the separate, expanded clause 2.11 in lieu of the proposed clause 6.3.2 removes the need to repeat clause 2.[6-9].3 for each category and connects the obligations of the transmission entity.

New clause 2.11 places a mandatory requirement on ElectraNet to remedy a breach within 12 months based on a forecast agreed maximum demand (which is reviewed annually), established three years prior to the identified breach. This, in effect, provides a four-year timeframe to remedy the breach, which the Commission believes provides ample time and also assists in satisfying clause 6.3.1. Clause 2.11 also provides a best endeavours standard to remedy a breach that does not appear in the forecast agreed maximum demand within 12 months of time of the breach. This clause mandates a 3-year timeframe to remedy such a breach. The Commission considers that this provides adequate time to resolve a breach in relation to the capacity of an exit point.

Having regard to the uncertainties around the nature and magnitude of future unspecified loads being connected to the transmission network, the Commission is satisfied that the amended code provisions provide adequate time for ElectraNet to meet the reliability standards.

Final Decision 3.

Clause 6.3.1 of the code has been amended to read:

*"A **transmission entity** must use its **best endeavours** to complete all necessary design work, obtain all necessary planning approvals and acquire all necessary land and easements on the basis of **forecast agreed maximum demand** prior to the **forecast agreed maximum demand** breaching the reliability standards in this industry code so as to ensure that the **transmission entity** is in a position to meet its obligations."*

A new definition for forecast agreed maximum demand has been included in Section 10.1 of the code (definitions) as follows:

*"**Forecast agreed maximum demand** means the **agreed maximum demand** forecast for a given year that is agreed with the **customer** three years prior to when the **agreed maximum demand** is required to be contracted."*

A new clause 2.11 "Obligations to provide sufficient capacity following changes in agreed forecast maximum demand" has been added:

*2.11.1 Subject to clause2.11.2, in the event that a change **in forecast agreed maximum demand** at an **exit point** or group of **exit points** will result in a future breach of a standard specified in this clause 2, a **transmission entity** must ensure that the **equivalent capacity** at the **exit point** or group of **exit points** is sufficient to meet the required standard within 12 months of the identified future breach date.*

*2.11.2 Where a change in **forecast agreed maximum demand** at an **exit point** or group of **exit points** under clause 2.11.1 was not able to be identified by the **transmission entity** in the **forecast agreed maximum** demand 3 years prior, a **transmission entity** must:*

*(a) use its **best endeavours** to ensure that the **equivalent capacity** at the **exit point** or group of **exit points** is sufficient to meet the required standard within 12 months of the identified future breach date; and*

*(b) in any event, ensure that the **equivalent capacity** at the **exit point** or group of **exit points** is sufficient to meet the required standard within 3 years of the identified future breach date.*

3.4 Reliability standard – Adelaide Central Region

Under the current (TC/06) code provisions, Category 5 and Category 6 exit points comprised grouped exit points that, together with ETSA Utilities' meshed distribution network, supplied Adelaide Central and surrounding suburbs. The provisions of the code were intended to deliver a highly reliable electricity transmission supply to Adelaide Central and Adelaide's surrounding suburbs.

The Category 5 required ElectraNet to provide transmission line capacity and transformer capacity at the grouped exit points of Dry Creek East, Magill and Northfield, as follows:

- N-1 equivalent capacity for 100% of agreed maximum demand equal to that of Adelaide's surrounding eastern suburbs' load;
- N-1 equivalent capacity for 100% of agreed maximum demand equal to that of Adelaide Central's load;
- N-2 equivalent capacity for 50% of agreed maximum demand equal to that of Adelaide's surrounding eastern suburbs' load; and
- N-2 equivalent capacity for 100% of agreed maximum demand equal to that of Adelaide Central's load (obligation via Category 5) post 31 December 2011.

Importantly, this required level of reliability was for the Dry Creek East, Magill, and Northfield group of transmission exit points, and not the main Adelaide Central (Category 6) exit point of East Terrace.

For Adelaide Central, the code provides that ElectraNet was to provide N transformer and transmission line capacity until the end of 2011, after which time it is required to provide N-1 transformer and transmission line capacity. That N-1 capacity is itself required to be provided by means of an independent and diverse substation located west of King William Street.

This regime was established by the Commission in 2006. In its Final Decision on exit point reliability standards at that time, the Commission noted that:

> *For connection points that are assigned to Category 6 (being any connection points for the Adelaide Central area), the Commission's Final Decision is that ElectraNet will be required, from 1 July 2008, to provide a level of reliability for transmission lines and transformers such that:*

- *until 31 December 2011, 100% of AMD can be supplied provided that all relevant lines and transformers are in service (that is, an N reliability standard); and*
- *after 1 January 2012, 100% of AMD can be supplied provided that all relevant lines and transformers are in service, even in the event that one line or transformer is out of service (that is, an N-1 reliability standard).*

> *This outcome is achieved through specification of standards for transmission line and transformer capacity for two distinct periods (1 July 2008 to 31 December 2011; and 1 January 2012 onwards). There are two elements to that process, with the second element*

further divided based on the two time periods. First, ElectraNet is prohibited (by clauses 2.10.1(a) and 2.10.2(a) respectively) from contracting with its customers to deliver amounts of AMD in excess of 100% of the installed line or transformer capacity.

Secondly, the reliability standards for both transmission lines and transformers are specified by reference to requirement in the period 1 July 2008 to 31 December 2011 and then from 1 January 2012 onwards.

In relation to the period 1 July 2008 to 31 December 2011, clauses 2.10.1(b) and 2.10.2(b) require ElectraNet to be able to supply AMD provided that all relevant lines and transformers are in service. That is, the required standard for both transmission lines and transformers for this period is N.

After 1 January 2012, clauses 2.10.1(c)(i) and 2.10.2(c)(i) require ElectraNet to be able to supply AMD even in the event that one transmission line or transformer (noting that equivalent capacity is not applicable to Category 6 – all capacity must be actual capacity) is out of service; i.e. the standard applicable after 1 January 2012 is N-1.

Supporting the requirements of clauses 2.10.1(c)(i) and 2.10.2(c)(i) in relation to the N-1 standard, clauses 2.10.1(c)(ii) and 2.10.2(c)(ii) require the relevant capacity to be provided by means of independent and diverse substations, which must be commissioned and available by 1 January 2012, one of which must be located west of King William Street. This mandatory obligation, which is unusual in its specificity, is appropriate in this case to ensure diversity in the transmission system supplying the Adelaide Central area.[26]

Notwithstanding the N and N-1 obligations established for ElectraNet, there has always been inherent operational network support capacity for Adelaide Central provided by ETSA Utilities' network. That support, while not mandated as a regulatory exit point reliability requirement under the code, provides ElectraNet with operational redundancy for Adelaide Central – but only following switching and the possible loss of up to 50% of the load in the eastern suburbs of Adelaide, depending on load conditions at the time. As has been previously recognised by the Commission, the capacity for ETSA Utilities to provide this level of network support is expected to diminish over time due to demand growth in Adelaide Central and surrounding suburbs.[27]

In its report, AEMO has noted this underlying operational network support provided to Adelaide Central by ETSA Utilities' sub-transmission and distribution network and the fact that, following the commencement of the N-1 exit point reliability standard for that area from 2012, it will operationally be the case that, in certain circumstances, equivalent operational N-2 reliability may be achieved. The AEMO report therefore suggested that, to the extent that there is a need for an enhanced standard to be mandated for Adelaide Central, the code would need to be amended in that regard.

[26] Essential Services Commission, Review of the Reliability Standards specified in clause 2.2.2 of the Electricity Transmission Code, Final Decision, pages 39 to 40. Available at http://www.escosa.sa.gov.au/library/060906-ElectricityTransmissionCode-ReliabilityStandards-FinalDecision.pdf

[27] Essential Services Commission, Review of the Reliability Standards specified in clause 2.2.2 of the Electricity Transmission Code, Final Decision, pages 25 to 26 and page 31. Available at http://www.escosa.sa.gov.au/library/060906-ElectricityTransmissionCode-ReliabilityStandards-FinalDecision.pdf

The Commission notes that the proposal suggested by AEMO would involve a change to the position adopted by the Commission in 2006. That is to say, in 2006 the Commission, relying on advice from the then Electricity Supply Industry Planning Council, determined that the relevant regulatory standard to apply to ElectraNet for exit point reliability into the Adelaide Central area should move from N to N-1 from 2012.

While the Commission considered the need for further enhancement of exit point reliability for Adelaide Central during the 2006 review, at that time it concluded that:

> *Taking into consideration the very high costs associated with reinforcing supply to the Adelaide Central area with additional transmission entry points, the Commission is satisfied that the risk of sustained outages in the Adelaide Central area is minimised if ElectraNet installs an additional independent and diverse transmission entry point into the Adelaide Central area in the near future.*[28]

The Commission went on to note that the existence of ETSA Utilities' network support as described above would provide an equivalent operational N-2 outcome in certain circumstances, albeit that the reliability of that outcome would diminish over time given load growth.

The question posed by the Commission as a result of AEMO's proposition was whether or not, having established the formal N-1 exit point reliability standard, the Commission should consider further enhancing the exit point reliability standard for, or some time during, the 2013 to 2018 regulatory period?

In posing that question, the Commission noted that it ultimately is one to be answered on efficiency grounds, through the conduct of a cost/benefit analysis in a manner consistent with the provisions of the NER.

3.4.1 Comment Received

In its response, ETSA Utilities submitted that a mandatory requirement should be placed on ElectraNet for a Network Support Agreement with ETSA Utilities, where ETSA Utilities is requested to provide operational support for ElectraNet to meet its obligations under the code. The formal agreement should specify the terms and conditions associated with the support arrangements. The Commission notes that, in respect of Adelaide Central, such an agreement is now in place.

Furthermore, ETSA Utilities considered that any requirement of the code, specifying continuous N-2 standards for Adelaide Central, should be delayed until after 2018 (e.g., 2020) in line with what ETSA Utilities considers to be good industry practice.

ElectraNet put the view that the N-1 standard for Adelaide Central which applies from 1 January 2012 is appropriate given the high cost to customers of providing an additional diverse supply for what it deems to be extremely low-probability events. ElectraNet

[28] Essential Services Commission, Review of the Reliability Standards specified in clause 2.2.2 of the Electricity Transmission Code, Final Decision, page 27. Available at http://www.escosa.sa.gov.au/library/060906-ElectricityTransmissionCode-ReliabilityStandards-FinalDecision.pdf

noted that its understanding of AEMO's recommendation in AEMO's report, with respect to the provision of an N-2 standard for Adelaide Central, related to the clarification of the existing (Category 5) code provision rather than arguing the economic efficiency or technical merit of an increased N-2 standard. ElectraNet noted that an economic assessment clearly does not support the provision of an N-2 standard to Adelaide Central (refer Table 3 below).

Table 3 - Adelaide Central economic assessment - 20-year horizon

		Move from N line and transformer (pre Jan 2012) to N-1 line and transformer (Current Standard)	Move from current standard to N-2 line and transformer
VCR	Discount Rate	NPV of benefits	NPV of Benefits
Lower bound $36,990 (-16.4%)	7%	$2,263,933,717	-$177,321,366
	10%	$2,064,951,104	-$177,494,888
	13%	$1,927,210,294	-$177,604,604
$44,300*	7%	$2,746,708,669	-$176,989,632
	10%	$2,508,402,917	-$177,197,447
	13%	$2,343,441,633	-$177,328,845
Upper bound $51,565 (+16.4%)	7%	$3,226,511,682	-$176,659,941
	10%	$2,949,124,862	-$176,901,836
	13%	$2,757,110,673	-$177,054,783

* *Most recent VCR from latest review by AEMO January 2012 (refer section 2.3.2)*

ElectraNet also noted that while the capability to provide a degree of additional, non-continuous, support to Adelaide Central via the distribution network currently exists due to the historical design of the network, it did not consider it prudent or efficient to require this be increased to an N-2 standard.

ElectraNet asserted that the use of any available distribution capacity to support Adelaide Central following an interruption affecting the East Terrace or City West substations is best addressed by the maintenance of appropriate operational protocols between ElectraNet and ETSA Utilities. ElectraNet also put a view that the obligation to maintain supply should be expressed using a best endeavours standard as the level of available distribution network support will decline over time as demand grows.

Ultimately, ElectraNet submitted that, as analysis does not justify an N-2 reliability standard in Adelaide Central at this time, the option of such a standard should be reconsidered at a future review of the code. However, should reclassification to an N-2 reliability standard be considered, ElectraNet put a further submission that, if a distribution network option is determined to be the most efficient solution, it is proper that this investment is delivered and costs recovered directly by ETSA Utilities from customers via distribution charges, which ElectraNet believes to be consistent with the intent of the joint planning framework under the NER. In the case of network support secured by ElectraNet through non-distribution solutions such as demand side participation or generation support, the network support pass-through provisions of the NER would apply.

3.4.2 The Commission's Final Decision

For Adelaide Central, ElectraNet has provided N-1 transformer and transmission line capacity from 1 January 2012. This will not change in moving to a revised version of the code to apply from July 2013; the N-1 capacity will continue to be provided by means of an independent and diverse substation located west of King William Street. [29]

Neither ElectraNet nor ETSA Utilities supported the need for an N-2 reliability standard at this time; this was considered an issue which should be considered in a subsequent review of the code for the regulatory period 2018-23. ETSA Utilities' view was based on what it perceives to be "good industry practice"; ElectraNet's view was based on an economic assessment. In both cases, the parties have noted that Adelaide Central only moved to an N-1 scenario from 1 January 2012. As such, it would be premature to move to an enhanced level of reliability.

As noted in ElectraNet's submission, the failure of the N-1 transmission capability would be a low-probability event for which the high cost to customers of providing an additional diverse connection point, would not be appropriate. The Commission is mindful of the need to ensure that consumers pay no more than the efficient cost of supply and this is a key factor in its decision not to further consider enhancement of reliability standards for Adelaide Central at this time.

The requirement for an enhanced reliability standard may better form a part of the review of exit point reliability standards in time for the subsequent revenue reset submission by ElectraNet.

As noted above, a formal agreement has now been established between ETSA Utilities and ElectraNet in respect of Adelaide Central.

Final Decision 4.

The Commission will not seek to enhance the current N-1 reliability standard of connection points supplying Adelaide Central at this time.

3.5 Planning

In addition to the obligations of the NER for joint planning,[30] AEMO proposed (and the Commission's Draft Decision was) that a new clause be included under section 6 of the code, as follows:

[29] The connection point, referred to as the City West substation, is currently under construction by ElectraNet. Refer ElectraNet website: http://www.electranet.com.au/network/current-planned-developments/near-metro/adelaide-central-reinforcement/

[30] Refer NER Clause 5.6.2 (c) http://www.aemc.gov.au/Electricity/National-Electricity-Rules/Current-Rules.html

6.4.1. Where the most economically feasible option to meet the reliability standards of clauses 2.5 to 2.10 relies on a combination of transmission and sub-transmission services, the ***transmission entity*** *must ensure that the reliability standard required by that category is capable of being delivered to the* ***agreed maximum demand*** *points within that category, including for any contingency events that the category requires for that reliability category.*

That proposal reinforces the view of the Commission that it is ElectraNet's responsibility under the code to ensure that, where it chooses to rely on non-transmission options to meet its exit point reliability obligations, it needs to ensure that such options are firm, robust and available to meet the needs of South Australian consumers.

3.5.1 Comment Received

ETSA Utilities expressed no concerns with the additional clause as proposed by AEMO. However, ETSA Utilities submitted that where it is required to provide Network Support to ElectraNet for it to satisfy its (reliability) obligation, such support should be subject to a formal Network Support Agreement.

ElectraNet submitted that the proposed clause 6.4.1 would make ElectraNet solely responsible for the delivery of both transmission and distribution components of any augmentation required to achieve the standards in the code, acknowledging that this reflects the position the Commission has previously articulated.

In noting that, however, ElectraNet remained strongly of the view that, where the application of the applicable regulatory test identifies a distribution solution as the most cost effective solution, that solution must be progressed by ETSA Utilities.

ElectraNet argued that, in the absence of any specific obligation on ETSA Utilities to comply with the timing requirements of the code, there is no clear ability on its part to enforce the implementation of the distribution works, nor for it to recover those charges through network support pass-through under the NER (the scope of which is limited to non-network solutions).

ElectraNet put the view that the joint planning provision must recognise that where the most economically feasible option is a combination of transmission and distribution components, then that option must be funded and delivered by the respective parties on a regulated basis, consistent with the intent of the joint planning arrangements under the Rules. ElectraNet believes that this would ensure that least-cost solutions are delivered and as a consequence, consumers would not be subject to the prospect of additional costs if distribution solutions are delivered on a non-regulated basis.

3.5.2 The Commission's Final Decision

The principle to be applied in this area is that an onus shall be formally placed on the transmission entity to ensure that the reliability standards are not compromised by the choice of the combination of transmission services delivering the services at the connection point.

It is noted that ETSA Utilities has no concerns regarding the introduction of the proposed clause but is insistent on the need for a formal Network Support Agreement as noted previously.

The Commission understands ElectraNet to be concerned with the ramifications of the inability of ETSA Utilities, whether by choice or circumstance, to meet the regulatory timelines required by the code in addressing capacity requirements or reliability obligations. ElectraNet's concerns relate to a lack of its own powers to ensure that a non-transmission solution is implemented in a timely manner and the financial issues around provisions for cost recovery.

Although the concerns expressed on the issue in ElectraNet's submission are aimed at distribution solutions, non-transmission solutions are not limited to distribution services. The reliability standard and capacity requirements of the Category 3 connection point at Pt Lincoln are dependent on the provision of local generation. The choice of a generation solution is based on economic rationale; it is not economically efficient to duplicate the transmission line to Pt Lincoln.

From the Commission's perspective, the important point is that the service provided must meet the requirements of the code. It is therefore incumbent on ElectraNet, not the alternative service provider, to ensure that its obligations are met. The type and standard of service is a contractual arrangement between ElectraNet and that provider, funded by ElectraNet. The proposed clause 6.4.1 is not restricted to distribution solutions. Obviously, the code cannot, and should not, discriminate between the types of services employed by ElectraNet for network support arrangements.

That said, as acknowledged earlier in this Final Decision, the Commission accepts that where the NER dictate that a distribution solution ought to be utilised, then ETSA Utilities should fund and deliver that solution (with the costs being recovered through distribution charges), rather than ElectraNet seeking to procure a solution from ETSA Utilities.

The Commission therefore agrees that ElectraNet's concerns are valid in that options should be funded and delivered by the respective parties on a regulated basis, consistent with the intent of the joint planning arrangements under the NER.

Further, the Commission agrees that it is appropriate to place an obligation on the distributor to ensure that its system is able to receive supply from an upgraded ElectraNet exit point in a timeframe which will enable ElectraNet to achieve the relevant reliability standard.

Finally, it is noted that where, as a result of a change in a standard applicable to ElectraNet at an exit point, a person taking supply from that exit point (for example, where a distributor has to augment or build new sub-transmission assets to take an increased supply), will be responsible for sourcing and funding that element. Associated costs would be recovered through prescribed distribution service charges.

The Commission believes that the proposed clause confirms ElectraNet's responsibility under the code to ensure that, whatever the best option to meet its exit point reliability obligations, transmission or non-transmission, such options must be firm, robust and available to meet the needs of South Australian consumers.

Final Decision 5.

The Commission has included new clause 6.4.1 in the following terms:

*6.4.1. Where the most economically feasible option to meet the reliability standards of clauses 2.5 to 2.9 relies on a combination of transmission and sub-transmission services, the **transmission entity** must ensure that the reliability standard required by that category is capable of being delivered to the **agreed maximum demand** points within that category, including for any contingency events that the category requires for that reliability category.*

To ensure that a distributor assists in meeting the obligations incumbent on the transmission entity, and in accordance with the NER, the Commission has included the additional clause 6.4.2, that requires the distributor to undertake work associated with meeting the reliability standard at an exit point in a timely manner.

*6.4.2. Where a **distributor** is required, in accordance with the **National Electricity Rules**, to extend or augment its distribution system associated with a **transmission entity's** obligations under clause 6.4.1, the **distributor** must undertake that work in a timeframe which will enable the **transmission entity** to achieve the required reliability standard at an **exit point**.*

3.6 Limitation on supply from non-network support

Under the code provisions which applied from 2008, to meet code reliability standards the AMD for each connection point category must not exceed 100% of line capacity or 100% of transformer capacity or, in the case of Categories 1, 2 and 3, 120% of line or transformer capacity where appropriate network support arrangements are in place.

However, limiting the AMD based on network capability may impose a requirement for transmission network augmentation on ElectraNet, notwithstanding that a more cost-efficient, reliable option of local non-transmission support may be available.

AEMO has put a view that the amount of supply that can be provided from network support arrangements or non-network support options should be based on the reliability and economics of utilising non-network support in comparison to augmenting the transmission network. It recommended code amendments to give effect to this view; these amendments were incorporated in the Commission's draft decision.

3.6.1 Comment Received

ETSA Utilities suggested that AEMO's proposals were more complicated and confusing than the existing clauses.

In principle, ElectraNet considered the proposed amendments reasonable noting that, as proposed, a network support arrangement providing up to 120% of the AMD must satisfy a less onerous reliability standard than one providing above 120% of the AMD. However ElectraNet was concerned that any incremental increase in demand beyond 120% of installed capacity would require the entire equivalent capacity to be provided at the equivalent availability of the relevant line and/or transformer, i.e. the physical assets. ElectraNet submitted that this could result in a substantial increase in the volume and cost of network support required to meet the higher reliability requirement for the entire load, once the 120% threshold is exceeded.

3.6.2 The Commission's Final Decision

This same issue arose in the Final Decision of the previous code review in 2006 and the Commission made reference to the matter as follows:

> *In the Discussion Paper, the Commission canvassed the proposition that the Category 1 definition be amended such that only 80% of AMD need be provided by line and transformer capacity, with up to 20% of the remaining AMD able to be supplied through non-network options. This would provide flexibility to ElectraNet in meeting its Category 1 reliability obligations during peak load conditions. Such additional flexibility should result in reducing future capital expenditure by ElectraNet, thereby reducing transmission costs to consumers in the future.*
>
> *Submissions to the Commission noted that recognition of the role of alternate non-network supply arrangements for Category 1 connection points could also be achieved through permitting ElectraNet to be able to contract for an AMD that is higher than the capacity of the network (lines and transformers) by a specified amount, say 20%. Such an approach for Category 1 connection points was therefore incorporated into the Draft Decision, requiring ElectraNet to establish appropriate non-network support contract(s) if the AMD exceeds line and transformer capacity.* [31]

AEMO put a view in its report that the amount of supply that can be provided from network support arrangements or non-network support options, should be based on the reliability and economics of utilising non-network support in comparison with augmenting the transmission network. In support of the proposed code amendments, AEMO suggested that limiting the supply that can be provided by network support arrangements potentially conflicts with the NER's intent, where non-network options must be considered as alternatives to network augmentation.

[31] Refer Commission's web site http://www.escosa.sa.gov.au/library/060906-ElectricityTransmissionCode-ReliabilityStandards-FinalDecision.pdf

The means by which non-transmission support is provided to meet the required demand, that proves cost-efficient and reliable, perhaps should not be limited, but should be encouraged where possible to mitigate the imposition of more costly transmission network augmentation. The most cost-efficient option will be determined by the RIT-T and if the regulatory test supports a non-network solution then that option would be adopted.

The Commission notes the in-principle agreement of ElectraNet to AEMO's proposal. As it stands, ElectraNet is only permitted to contract up to the physical capacity limits of its transmission assets. However, ElectraNet can contract for up to 120% of the physical capacity of its transmission assets for Categories 1-3, provided that it has alternative support arrangements which can deliver the equivalent reliability and capacity. By providing equivalent line capacity to all connection point categories as proposed, the way is made clear to provide the agreed maximum demand by a mix of options. It is questionable as to what additional capacity can be safely and sensibly relied on by way of alternative support arrangements. In the 2006 code review, the amount of 20% (for categories 1-3) of the installed transmission capacity was settled on as an acceptable upper limit. This upper limit however, was based on historic operational practices, i.e. the short-term overload ratings of assets, and might be considered as limiting the use of non-network support.

Under the AEMO proposal, ElectraNet could contract to the extent it deems satisfactory (depending on the outcome of an RIT-T), provided it has a robust mix of transmission and network support arrangements to do so regardless of the installed transmission capacity.

Where the contracted AMD equals or is less than 120% of installed transmission line and transformer capacity, it could use network support arrangements up to that amount to deliver the AMD. In such cases, the necessary reliability standard for the network support arrangements would be set at 95% availability (refer clause 2.11 in the current code).

Where, on the other hand, the contracted AMD is greater than 120% of installed transmission line and transformer capacity, the required reliability of the network support arrangements would need to be at least that of a transmission line or transformer. The Commission notes that, for the period 2005 to 2009, the average circuit availability reported by ElectraNet was 99.5% (with a target availability for that period of 99.25%).[32]

The AEMO proposal could be considered as managing the reliability of the risk assessment of mixed system options as opposed to managing the reliability of firm transmission assets. The important consideration is the maintenance of the appropriate level of reliability for customers.

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[32] Refer Essential Services Commission, *2009/10 Annual Performance Report*, November 2010, at Table a%.15, page 152. Available from the Commission's website at http://www.escosa.sa.gov.au/library/101124-AnnualPerformanceReport_2009-10.pdf

The reliability standard for contracted demand that is up to 20% greater than the installed line or transformer capacity presently applies to Categories 1-3 only. The Commission is of the view that the proposition put by AEMO appears to have efficiency benefits and, provided appropriate reliability standards for varying levels of contracted AMD are specified, then it would be supportive of the AEMO proposal. To achieve the appropriate level of certainty, the Commission has set network support reliability levels as follows:

- where network support is used and the contracted AMD does not exceed 120% of installed transmission line and transformer capacity – at 95% availability; and
- where network support is used and the contracted AMD exceeds 120% of installed transmission line and transformer capacity – 100% of the network support at least equal to the availability standard applicable to the relevant transmission line and transformer.

The Commission also considers that the proposed inclusion of a new clause is appropriate to ensure that formal agreements exist for network support arrangements as opposed to the “automatic” arrangement that has existed in the Adelaide Central area. AEMO’s proposal stated that network support capability and availability “should” be ensured; however, the Commission is of the view that a formal agreement should be mandatory.

Final Decision 6.

The Commission has amended the provision for contracted maximum demand to permit ElectraNet to contract for levels of AMD above the installed transmission line and transformer capacity on the following terms (clause 2.12):

2.12 Contracted agreed maximum demand and network support arrangement requirements

*2.12.1 Where a **transmission entity has a network support arrangement in place and delivers transformer or transmission** line capacity by means of **equivalent capacity**, the **transmission entity** may contract for any amount of **agreed maximum demand** provided that:*

*(a) if the level of contracted **agreed maximum demand** is less than 120% of the installed **transformer** or **transmission line capacity**, the **network support arrangement** must have at least 95% availability for the 12 months to 30 June each year; and*

*(b) if the level of contracted **agreed maximum demand** exceeds 120% of the installed **transformer** or **transmission line** capacity, the **network support arrangement** must have a level of availability at least equal to the availability standard applicable to the relevant **transformer** or **transmission line**.*

*2.12.2 Where a **transmission entity** relies on a **network support arrangement** provided by an independent network support provider to meet the required **transformer** or*

***transmission line capacity**, the **transmission entity** must enter into a **network support agreement** with that network support provider to ensure the capability and availability of the **network support arrangement**.*

*2.12.3 Where a **transmission entity** does not have a **network support agreement** in place, the **transmission entity** must not:*

*(a) contract for an amount of **agreed maximum demand** which is greater than 100% of the installed **transmission line** and **transformer** capacity at the **exit point**; and*

*(b) rely on a **network support arrangement** to meet the required **transformer** or **transmission line** capacity unless the **network support arrangement** is provided by the **transmission entity**.*

3.7 Murraylink capability and assessment of reliability standards

ElectraNet includes the capability of Murraylink in its assessment of the Riverland area reliability. The capability of Murraylink is prescribed in the connection agreement for the provision of prescribed transmission services between the parties. ElectraNet is also reliant on AEMO for the available level of inter-regional transfer capacity (i.e., via the constraint equation) at times of peak demand.

Transfer from Victoria to South Australia via the Murraylink interconnector is determined by factors in regions other than South Australia, such as voltage stability and thermal line constraints in Victoria. Murraylink's design transfer capability (220MW) is based on a Victorian demand of 9,600MW. This transfer capability decreases by approximately 5MW for each 100MW increase in Victorian demand above 9,600MW.

AEMO recommends that the capacity of Murraylink should be calculated using the Murraylink transfer limit equation and assuming worst-case peak-demand conditions, including applying the Victorian maximum demand forecast. In addition, AEMO considers it appropriate for ElectraNet to approach other TNSPs to undertake joint planning (as required by the NER) to identify the most economically viable solution to meet reliability standards.

The inclusion of a new clause 6.4.1 (refer section 3.5 of this final decision) promotes identification of the most economically viable reliability solution, whether through augmentation of transmission or distribution networks or new generation. AEMO proposes a further extension to that new clause to assist in clarifying the treatment of Murraylink's capability and to ensure that contingencies in networks other than ElectraNet's transmission system are considered in meeting the reliability standards.

This is because contingencies in the sub-transmission network or other regions can potentially have a higher impact on supply capability through Murraylink than outages on ElectraNet's transmission network. The additional sub-clauses under the new joint planning clause are proposed by AEMO as follows:

> *6.4.2. A **transmission entity** which provides **equivalent transmission line capacity** or **equivalent transformer capacity** for the purposes of Chapter 2 must consider network plant failures in any NEM region, including distribution systems, where such plant failures might impact on the applicable level of redundancy or reliability.*
>
> *6.4.3. For the purpose of assessing **connection point** reliability, the capability of the Murraylink interconnector should be calculated using the Murraylink transfer limit equation under peak Victorian demand conditions.*

It should be noted that, with the inclusion of new clause 6.4.2 as set out in the Commission's Final Decision 5 (refer section 3.5 of this Final Decision), the proposed clauses 6.4.2 and 6.4.3 in this section will be renumbered as 6.4.2 and 6.4.3 respectively. References to the clauses, as proposed by AEMO, remain unchanged in the discussion but are presented in Final Decision 7 as numbered in the amended code.

3.7.1 Comment Received

ETSA Utilities submitted that it has no objection to the introduction of clauses 6.4.2 and 6.4.3 and is of the view that TNSPs should consider contingent events and demand in other NEM Regions where an event or demand will influence an interconnector and that interconnector is relied upon to meet TNSP's reliability standards. ETSA Utilities believes that the majority of these considerations should focus on Victoria but may need to include other significant events in other NEM jurisdictions.

ElectraNet supported the proposed amendment as it provides additional clarity in the assessment of the Riverland area reliability. It put the view that the capacity of the adjoining New South Wales network also needs to be considered in making assessment of the capability of the Murraylink interconnector.

3.7.2 The Commission's Final Decision

The AEMO report recommended that the capacity of Murraylink should be calculated using the Murraylink transfer limit equation and assuming worst-case peak-demand conditions, including applying the Victorian maximum demand forecast. Contingencies in other regions (or the sub-transmission network) can potentially have a higher impact on supply capability through Murraylink than outages on ElectraNet's transmission network.

The Commission notes the concurrence of views in ElectraNet's and ETSA Utilities' submissions on this issue. Both organisations are of the opinion that events in the broader NEM should be considered in addition to events in Victoria. Thus, the Commission considers it appropriate, as recommended by AEMO, for ElectraNet to approach other TNSPs to undertake joint planning (as required by the NER) in determining the most economically viable solution to meet its reliability and capacity standards.

Final Decision 7.

The code has been amended to require consideration by ElectraNet of the broader impacts on the provision of transmission network capability and reliability to the Riverland via Murraylink, with new clauses, 6.4.3 and 6.4.4 introduced as follows:

6.4.3. A ***transmission entity*** *that provides* ***equivalent transmission line capacity*** *or* ***equivalent transformer capacity*** *for the purposes of Chapter 2 of this code must consider network plant failures in any NEM region, including distribution systems, where such plant failures might impact on the applicable level of redundancy or reliability.*

6.4.4. For the purpose of assessing ***connection point*** *reliability, the capability of the Murraylink interconnector should be calculated using the Murraylink transfer limit equation under peak Victorian demand conditions.*

3.8 Clarification that Category 3 loads have an N-1 interruptible reliability level

The N-1 capacity of Category 3 loads can be provided by transmission system capability, distribution system capability, generation capability, or any combination of these where load interruptibility may be required to meet the reliability standard.

There are two Category 3 connection points, Pt. Lincoln and Snuggery. The Pt. Lincoln connection point is interruptible as, once transmission supply is lost, back-up generation, requiring time to start, must be brought on-line and associated switching must occur prior to restoration. Therefore, while there is N-1 capability, that can only be invoked once those processes have occurred.

When an interruption occurs at Snuggery, manual switching is required for network restoration. Restoration of the equivalent line and transformer capacity at these two connection points must occur within one hour. These operations required to restore supply after interruption are referred to as “post-contingent operations”.

Without altering obligations under the Category 3 reliability standards, AEMO recommended that clause 2.7.1 (b) and 2.7.2 (b) be expanded to further clarify what it considers to be “the intent”, and confirm that Category 3 loads do not require an N-1 supply on a firm, uninterruptible basis.

As a result, AEMO proposed the amendment of clause 2.7.1 (b) and 2.7.2 (b) to include the phrase “through post-contingent operation” as follows, which the Commission included in its Draft Decision:

> *2.7.1 (b) provide* ***equivalent line capacity*** *such that at least 100% of* ***agreed maximum demand*** *can be met, through post-contingent operation, following the failure of any relevant* ***transmission line*** *or* ***network support arrangement****;*

> *2.7.2 (b) provide **equivalent transformer capacity** such that at least 100% of **agreed maximum demand** can be met, through post-contingent operation, following the failure of any installed **transformer** or **network support arrangement**;*

3.8.1 Comment Received

Both ETSA Utilities and ElectraNet supported the proposed code amendment clarifying the Category 3 reliability standard. Neither organisation provided any argument or comment to the contrary in their submissions.

3.8.2 The Commission's Final Decision

The Commission notes that the proposed amendments to clauses 2.7.1 (b) and 2.7.2(b) were supported by ElectraNet and ETSA Utilities. In the absence of compelling reasons to the contrary, the Commission will vary the code to reflect those proposed amendments.

The N-1 capacity of Category 3 loads can be provided by transmission system capability, distribution system capability, generation capability, or any combination of these where load interruptibility may be required to meet the reliability standard.

There are two Category 3 connection points in the State (Pt Lincoln and Snuggery). When an interruption occurs at these two connection points, restoration of the equivalent line and transformer capacity must occur within one hour. Switching operations, required to restore supply after interruption, are referred to as "post-contingent operations". The time-lag that occurs after an interruption necessitates that supply is interruptible.

The Commission has amended the code to clarify that the N-1 requirement for Category 3 loads is of a non-continuous nature. However, in restructuring the clauses for each category, the provision for post contingent operation has been embodied within the clause for the Category 3 requirements.

Final Decision 8.

Clause 2.7.1 has been amended as follows to include the provision for post contingent operation:

*2.7.1. In respect of Category 3 **exit points**, a **transmission entity** must:*

*(a) provide "N-1" **equivalent line capacity** for at least 100% of contracted **agreed maximum demand** (including through the use of post-contingent operation) and:*

*(b) provide "N-1" **equivalent transformer capacity** for at least 100% of contracted **agreed maximum demand** (including through the use of post-contingent operation) and:*

3.9 Quality of supply and system reliability

Clauses 2.1.1 and 2.1.2 of the current code (TC/06) are concerned with the quality of supply and system reliability respectively. The clauses were designed to ensure that load is not shed by ElectraNet under normal and reasonably foreseeable operating conditions in the planning, development and operation of its network to achieve the reliability standards.

Although these clauses relate to the quality of transmission services, rather than the reliability standards, AEMO believed that these clauses could be misinterpreted to contradict the reliability standards defined in the code.

To clarify the intent of the code, AEMO recommended that clauses 2.1.1 and 2.1.2 be modified to be subject to the clause 2 reliability standards as follows, which the Commission incorporated into its Draft Decision:

> *2.1.1. Subject to the service standards specified in this clause 2, a **transmission entity** must use its **best endeavours** to plan, develop and operate the **transmission network** to meet the standards imposed by the **National Electricity Rules** in relation to the quality of **transmission services** such that there will be no requirements to shed load to achieve these standards under normal and reasonably foreseeable operating conditions.*
>
> *2.1.2. Subject to the service standards specified in this clause 2, a **transmission entity** must use its **best endeavours** to plan, develop and operate the **transmission system** so as to meet the standards imposed by the **National Electricity Rules** in relation to **transmission network** reliability such that there will be minimal requirements to shed load under normal and reasonably foreseeable operating conditions.*

3.9.1 Comment Received

ETSA Utilities noted that it was not concerned by the proposed amendment clarifying clauses 2.1.1 and 2.1.2.

ElectraNet considered the practical implementation in meeting its quality and reliability standards whilst avoiding load shedding is assisted by the proposed amendments to clauses 2.1.1 and 2.1.2.

ElectraNet noted, for example, that strengthening the requirement to minimise shedding the entire load to undertake planned outage works at remaining Category 1 sites would require minor works. ElectraNet believes that this would achieve a material improvement in customer reliability outcomes at these locations at minimal cost.

3.9.2 The Commission's Final Decision

The Commission notes that the amendment to clauses 2.1.1 and 2.1.2 is supported by ElectraNet and that ETSA Utilities is unconcerned regarding the amendment. The Commission has, therefore, given effect to this proposal in the amended code.

While the amendment is of little or no consequence to ETSA Utilities, ElectraNet highlighted an example of providing continuity of supply to Category 1 sites during planned outages in its submission. It should be noted that the two clauses apply to all connection points. The intent is to ensure that load shedding is not used as a load management tool and that no parts of the network are disconnected to achieve quality and reliability standards in other parts of the transmission system under circumstances where load could possibly be shed to maintain such things as voltage fluctuation, distortion, unbalance or stability levels within the requirements imposed on the TNSP.

The intention of the additional words "*Subject to the service standards specified in this clause 2*," is to ensure that load can still be shed following loss of a network element, such as under Category 1 connection points, where there is only a single element supply.

This additional wording ensures that any minimum requirements set out under clause 2 of the code are not overwritten by potentially less onerous requirements set out in NER Schedule 5.1; so the code remains the minimum service level required, including for the quality of transmission services and for network reliability.

Final Decision 9.

Clauses 2.1.1 and 2.1.2 of the code have been amended as follows:

*2.1.1. Subject to the service standards specified in this clause 2, a **transmission entity** must use its **best endeavours** to plan, develop and operate the transmission network to meet the standards imposed by the **National Electricity Rules** in relation to the quality of **transmission services** such that there will be no requirements to shed load to achieve these standards under normal and reasonably foreseeable operating conditions.*

*2.1.2. Subject to the service standards specified in this clause 2, a **transmission entity** must use its **best endeavours** to plan, develop and operate the transmission system so as to meet the standards imposed by the **National Electricity Rules** in relation to **transmission network** reliability such that there will be minimal requirements to shed load under normal and reasonably foreseeable operating conditions.*

3.10 New connection points

Clause 2.12 of the code outlines ElectraNet's approval process for establishing new connection points. It should be noted that clause 2.12 to be renumbered 2.13 and is set out in Draft Decision 10 as it will be presented in the amended code. References to clause 2.12 in this discussion remain as presented in the Draft Decision.

In its Draft decision, the Commission supported the view that the distance from Adelaide Central, (current clause 2.12.1(e)), was superfluous information and was satisfied that it should be deleted from the criteria in developing a connection point standard.

Of greater consequence, the AEMO report proposed that this clause should have application to transmission and distribution entities so as to specifically exclude generation entities.

The terminology in clause 2.12, referring to a ***connection point***, covers all connection types, direct-connect (transmission) customers, generators and distributors, and does not discriminate as to the type of connection to the transmission network (whether importing or exporting electricity). As provided for under the current version of the code (TC/06), clause 2.12.1 satisfied all customer types and could be applied to both entry and exit points where the transmission entity is establishing new connection points. In that sense, clause 2.12.1 does not set the connection point standards but provides for the transmission entity to nominate the standard for the type of connection.

3.10.1 Comment Received

ETSA Utilities submitted that it is concerned about the reasons behind exempting new connection points with generators from the applicable standards. However, ETSA Utilities noted, in subsequent discussion, that it may not have appreciated the import of the issue raised by AEMO and, on further consideration, agreed with AEMO's proposal.

ElectraNet submitted that the wording of clause 2.12.1 suggested that ElectraNet must make a recommendation to the Commission on the appropriate categorisation of all new connection points including entry points, yet clauses 2.3 and 2.4 of the code clearly only apply to exit points. ElectraNet recommended that the Commission adopts the amendment to clause 2.12.1 to include "*transmission customer or distributor*" as originally proposed by AEMO to provide clarity, i.e. it should not include generator connection points.

3.10.2 The Commission's Final Decision

The Commission acknowledges that Chapter 2 of the code is primarily about meeting the requirements for establishment and reliability of exit points and agrees that clause 2.12 should correspond contextually with clauses 2.3 and 2.4 as suggested by ElectraNet in its submission.

Rather than define the types of connections in clause 2.12, the Commission prefers to replace the defined term, "connection point", with the defined term, "exit point", in clauses 2.3 and 2.4 which relate to importing of electricity from the transmission network.

Final Decision 10.

The Commission is satisfied that clauses 2.3 and 2.4 of the code define the application of reliability standards where electricity exits the transmission network. The Commission has therefore amended clauses 2.3 and 2.4 of the code by replacing the defined term, "connection point", with the defined term, "exit point".

*2.3.1. A **transmission entity** must plan and develop its **transmission system** such that each **exit point** or group of **exit points** allocated to a category in accordance with clause 2.4 meets the relevant standards for that category as set out in clauses 2.5 to 2.9**.***

2.4.1. The allocation of ***exit points*** *to categories is set out in the table below* ***(exit points*** *in square brackets refer to a group of* ***exit points):***

The Commission has amended clause 2.12 by renumbering it to 2.13 and separating it into two clauses to clarify the approval requirements (clause 2.13.1) and standards development (clause 2.13.2. Reference to the distance from Adelaide Central (previously sub-clause 2.12.1(e)) has been deleted.

3.11 AEMO connection point studies – Pt Lincoln and Fleurieu Peninsula

The connection point reliability at Pt. Lincoln and the capacity of the electrical supply system to the Fleurieu Peninsula are of particular interest to the Commission, as the level of reliability at Pt. Lincoln is perceived as "degrading" with no available alternative transmission line options, and the Fleurieu Peninsula is experiencing steady and firm growth. The Kadina East and Pt. Lincoln connection points were identified by AEMO for detailed assessment due to the amount of expected unserved energy.

3.11.1 Comment Received

ETSA Utilities expressed no issues with connection points identified by AEMO for upgrading, other than its concern that the retention of Pt. Lincoln as a Category 3 rather than Category 4 potentially limits/inhibits new connections within the region given the limited capacity and radial nature of the existing 132kV supply. Further, it submitted that retention in Category 3 may limit operational flexibility to undertake work on the transmission line, i.e. outages required to perform maintenance.

ElectraNet was concerned that the growing level of interest from prospective mining loads has not been taken into consideration in the potential reclassification of the Pt. Lincoln connection point. As noted previously, ElectraNet considered it appropriate to allow for the reclassification of existing connection points during a regulatory control period where material load changes occur that were not forecast.

Given that there is, at present, uncertainty regarding the Fleurieu Peninsula connection point, ElectraNet was of the view that the appropriate classification of the connection point is best dealt with via clause 2.12.

3.11.2 The Commission's Final Decision

The major issue raised in the submissions is the concern of both ETSA Utilities and ElectraNet in respect of the Pt. Lincoln connection point and the limit to connection opportunities under the current arrangements. The Commission acknowledges the limits on operational flexibility as highlighted by ETSA Utilities; however, AEMO's analysis, based on unserved energy alone, indicates that a reliability upgrade cannot be justified in the near future and that a significant increase in demand would be required to do so.

Further, it is difficult to commit to a higher level of reliability on the basis of prospective customers or possible missed opportunities due to network limitations. AEMO recommended that ElectraNet investigate alternative augmentation options to meet the continuing Category 3 obligations beyond 2017/18 (noting that ElectraNet is concerned that major line augmentation will be required on Eyre Peninsula by approximately 2017/18).

The Commission does not support upgrading of the Category 3 connection point at Pt Lincoln on the basis of AEMO's cost-benefit analysis. However, the Commission is aware of the impact of unanticipated and unforeseen loads in the Eyre Peninsula, where the mining industry is involved. The factors of location and demand may play an important part in any augmentation of the network. In addition, a customer would be required to contribute to the capital cost of the works which may or may not require reinforcement of the Pt. Lincoln connection point. The primary concern is the uncertainty of the size, nature and location of an unanticipated and unforeseen load and the commitment to expenditure based on such uncertainty is not justifiable.

ElectraNet's question of the reassessment of connection point categories can be best addressed via a request for a code amendment, which can occur at any time. Any material change in demand which impacts significantly on a connection point would be assessed by the Commission and, if the assessment proves sound, receive its approval.

For the Fleurieu region, the joint Regulatory Test between ETSA Utilities and ElectraNet will identify the most efficient option to provide a transmission solution to the region. AEMO's assessment, based on estimated augmentation costs, shows that a Category 4, N-1 reliability standard provides positive benefits over the life of the asset. Once the outcomes of the RIT-T are known, the Commission will act on the approval of the reliability standard for the connection point.

There were no issues raised regarding the other connection point studies provided by AEMO and it is expected that a further review of the code will identify the need for any further upgrades.

Final Decision 11.

The Commission accepts the connection point upgrade recommendations made by AEMO and is satisfied that the additional connection point studies require no further assessment or action for the purposes of this code review.

3.12 Reporting of switching incidents

Clause 6.2.5 requires an electricity entity to report to the Commission, within 20 business days, all breaches of its internal switching manual including breaches by contractors or customers of which it becomes aware (who are contractually bound to comply with the entities' internal manual).

Switching incidents occur much less frequently on ElectraNet's transmission network than occur on ETSA Utilities' distribution network. This is due to the nature of the distribution network, where switching is required more frequently for things such as access for customer work, network faults and switching due to third party causes such as pole collisions and cables being damaged by excavation.

ElectraNet has reported around six switching incidents each year over the past 3 years. ETSA Utilities, by comparison, has reported between 20 and 40 switching incidents per year over the past six years, of which between 15 and 25 are due to human error. The Commission is concerned that, with the number of switching incidents that occur on the distribution network, the reporting of each incident within 20 business days involves an obligation that, due to the number of events, makes a breach of clause 6.2.5 more likely.

It may be considered that the reporting requirements for ElectraNet should be more stringent than that for ETSA Utilities, as there is possibly greater potential to compromise system security by switching incidents on the transmission network than the impact of switching incidents on the local distribution network.

Under the current code provisions, the reporting of switching incidents by ElectraNet to the Commission is effective and assists the Commission in monitoring the performance of ElectraNet. However, in terms of the likelihood of ETSA Utilities' switching incidents affecting the transmission network, the current requirement for reporting may exceed the benefits of monitoring ETSA Utilities' performance.

Because of the number of incidents, the provision of collective reports by ETSA Utilities to the Commission on a regular basis, e.g. monthly or quarterly rather than individual reports within 20 business days, could be considered. Such a proposal may allow for more relevant reporting based on the number of incidents as shown in the frequency of switching incidents by ETSA Utilities.

However, having regard to the potentially serious nature of switching incidents, an integral part of any such proposal would involve a grading of incidents, with different reporting requirements applying to different grades. For example, where injury or major asset damage occurs as a result of a switching incident, such matters would continue to be required to be reported to the Commission within current timeframes. For more minor incidents, a monthly (or other appropriate time period) batched report of incidents may suffice to ensure appropriate oversight of this important regulatory area.

3.12.1 Comment received

ETSA Utilities considered that reporting of all switching incidents in its quarterly operational performance report to the Commission would provide an appropriate mechanism and frequency for reporting.

ETSA Utilities noted its legislative obligations to report any injury to a person from shock or burns to the Technical Regulator within 1 to 10 business days. Consequently, ETSA Utilities considered that reporting such incidents to the Commission within 20 business days creates confusion and duplication and, as such, it is not an advocate of the current reporting requirements for these events.

ETSA Utilities considered that it should only be required to report switching incidents using the current timeframes (i.e., 20 business days) where the switching incident has the potential to affect (transmission) system security.

ElectraNet questioned the appropriateness of the reporting obligations relating to switching incidents and asserts that it maintains rigorous protocols for the investigation of switching incidents. ElectraNet considers that summary reporting to the Commission on a quarterly basis is appropriate.

ElectraNet submitted that the processes and procedures relating to transmission switching and the investigation of switching incidents to be a safety and technical regulation issue and would most appropriately be directed to the Office of the Technical Regulator rather than the Commission.

3.12.2 The Commission's Final Decision

Clause 6.2.5 of the code requires an electricity entity to report to the Commission within 20 business days, all breaches of its internal switching manual including breaches by contractually bound contractors or customers. This requirement extends to DNSPs as well as TNSPs; all licensed entities are required under the current code to report switching incidents to the Commission.

In the Issues Paper, the Commission canvassed the idea that, because of the number of incidents, the provision of collective reports by ETSA Utilities (and in effect, all DNSPs) to the Commission on a regular basis, e.g. monthly or quarterly rather than individual reports within 20 business days, could be considered. Such a proposal may allow for more relevant reporting, reflecting the number of incidents on the distribution system because of the frequency of switching and the limited impact on transmission network security.

Both submissions supported the option of reporting on a quarterly basis in line with other regulatory reporting requirements. However, ElectraNet is opposed reporting to the Commission on events where it has an obligation to report to the Office of the Technical Regulator; ElectraNet put the view that reporting to the Office of the Technical Regulator is more appropriate than reporting to the Commission.

The Commission, along with industry participants and other regulatory bodies, developed the Switching Manual to define the high voltage (HV) switching and associated safety policies for all licensed electricity entities and HV customers in SA in accordance with the Electricity Act 1996. [33] The policies in the manual define the boundaries, interfaces, coordination requirements, and safety principles that must be observed by electrical industry participants when switching HV electrical equipment. Entities are required develop a detailed switching manual and/or safe work procedures for their staff/contractors and specific equipment. The internal manual developed by each entity must be developed in accordance with the Commission's Switching Manual policies and safety principles.

Entities must ensure processes exist to adequately and appropriately investigate and report switching incidents pertaining to their assets and employees. Switching incidents must be thoroughly investigated and reported to determine if existing work practices are adequate to cover the circumstances of the switching incident or need to be altered as a result of the findings of the investigation of the switching incident.

Clause 20.3.3 of the Switching Manual *"Reports to external organisations,"* requires that an accident, that involves electric shock caused by the operation or condition of electricity infrastructure or an electrical installation, must be reported to the Technical Regulator in accordance with Electricity (General) Regulations 1997. There is also a requirement to report these incidents to Safework SA.

Clauses 6.1.1 and 6.1.2 of the code require a transmission entity to collect information and report on power system incidents relating to its transmission system. Each power system incident must be reviewed in accordance with the Commission's guidelines to determine the cause of the power system incidents and minimising similar future occurrences.

The Commission notes that switching incidents are not required to be reported to an external authority unless they involve electric shock or electrical burns to an operator. However, the transmission code requires a transmission entity to report all power system incidents relating to the transmission system to the Commission. The Commission is of the view that reporting of all system incidents may, over time, reveal trends of endemic issues around deteriorating practices or deteriorating asset condition.

Clause 6.2.5 of the code extends the requirement to all entities; the system controller, transmission, generator and distributor all report breaches of their internal switching manual developed in accordance with the Commission's manual.

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[33] Refer Commission's web site http://www.escosa.sa.gov.au/library/040622-SwitchingManual-Final.pdf

Understandably, there would be a duplication of reporting where electric shock or electrical burns occur as these would be brought about by a breach of operational policies and therefore captured under the requirement to report to the Technical Regulator and the Commission.

The Commission prefers to avoid the duplication of reporting and would be satisfied to receive a copy of any report of an incident that involves a breach of a switching manual. Furthermore, the Commission, having experience with the reporting process over a number of years, agrees that the provision of collective reports of switching incidents from entities on a quarterly basis would suffice for the Commission to gauge performance and trends. However, any switching incident that results in serious injury or a fatality, significant impact on the transmission system availability or significant asset damage should be reported within 20 business days or earlier where it involves a breach of the switching manual and requires a report to the Technical Regulator.

Final Decision 12.

The Commission will amend clause 6.2.5 of the code to provide for quarterly reporting of breaches of entities' internal switching manuals in association with regular quarterly performance reporting with serious breaches of switching manuals will be reported within 20 business days as follows:

*6.2.5 An **electricity entity** must report to the **Commission**, quarterly, all breaches of its internal switching manual, including breaches by a contractor or customer of which it has become aware. Any breach resulting in a fatality or serious injury, significant impact on **transmission system** availability or significant asset damage must be reported to the Commission within 20 **business days**.*

3.13 ETSA Utilities: indemnification for outages caused by the failure of the transmission system

Through the review process, ETSA Utilities noted, in a submission, that its distribution system is normally automatically configured to supply customers in the event of the failure of ElectraNet's system. ETSA Utilities therefore submitted that it should be indemnified for any loss (such as the making of guaranteed service level payments) where customers lose supply from a failure of its system where that failure would not normally have resulted in loss of supply to customers but was due primarily to the failure of the transmission system (i.e. the failure occurred under network support arrangements).

3.13.1 The Commission's Final Decision

The Commission is of the opinion that ETSA Utilities' concerns regarding indemnity for losses (and claims against ETSA Utilities) due to interruptions that occur while providing network support to ElectraNet should be dealt with in a formal network support agreement. An agreement should be specific in the expectations of each entity such that network capability and redundant capacity are determined and the area of affected network is segregated to apportion responsibility for reliability.

A further issue for ETSA Utilities is the payment of Guaranteed Service Level (GSL) payments that ETSA Utilities is required to pay to customers for the duration and frequency of interruptions. If GSL payments are due to customers following an interruption that results as a consequence of any network support arrangements, the Commission considers that the recovery of such payments should also form a part of the network support agreement.

Final Decision 13.

The Commission is of the opinion that ETSA Utilities' concerns regarding indemnity for losses (and claims against ETSA Utilities) due to interruptions that occur while providing network support to ElectraNet should be dealt with in a formal network support agreement. An agreement should be specific in the expectations of each entity such that network capability and redundant capacity are determined and the area of affected network is segregated to apportion responsibility for reliability. There is, therefore, no need for specific code provisions in this regard.

3.14 Obligations to restore standards and supply under clause 2

Although not raised by respondents through the review process, the Commission has identified that the restoration requirements under clause 2 of the code have, in the past, arguably been ambiguous in terms of ElectraNet's obligations to restore network elements and supply following equipment failure or outages.

This ambiguity stems from the practical differences between the failure of a network element (particularly in cases where a standard higher than "N" is mandated, where an element failure will not result in a loss of customer supply – this is essentially a capacity issue) and an interruption (which implies that all relevant network elements have failed in some manner).

The Commission considers that this matter should be clarified for each category; particularly where the line and transformer standards differ, e.g. in Category 2 exit points. In the event of an interruption, the requirement to restore supply within a short time frame is the first priority, followed by the reinstatement of the capacity/capability at the exit point.

3.14.1 Comment received

Both ETSA Utilities and ElectraNet expressed support for the proposal to clarify the ambiguity identified by the Commission and provided further submissions as to the appropriate timeframes including, in the case of the Adelaide Central region, practicable percentages of restoration within those timeframes.

3.14.2 The Commission's Final Decision

The Commission has amended each category under clause 2 to clarify the restoration requirements. It should be noted that there is no change from the existing restoration requirements, which currently contain an implied obligation to restore the required standard (i.e., revert to N-1) even where there is no interruption following failure of a network element. Category 4 connection points that were previously required to provide, and still capable of providing network support to Adelaide Central, have restoration times equivalent to that under the previous Category 5. In summary, the changes are as follows:

- Category 1 ("N" line and transformer)
  - Line outage: best endeavours to restore supply as soon as practicable and in any event within 2 days.
  - Transformer element unavailability: best endeavours to restore as soon as practicable and in any event within 8 days.
- Category 2 ("N" line, "N-1" transformer):
  - Line outage: best endeavours to restore supply as soon as practicable and in any event within 2 days.
  - Transformer element unavailability: best endeavours to restore "N-1" as soon as practicable.
  - Transformer outage: must restore "N" within 8 days and use best endeavours to restore "N-1" as soon as practicable.
- Category 3 ("N-1" line and transformer):
  - Line element unavailability: best endeavours to restore "N-1" as soon as practicable.
  - Line outage: must restore "N" within 1 hour and use best endeavours to restore "N-1" as soon as practicable.
  - Transformer element unavailability: best endeavours to restore "N-1" as soon as practicable.
  - Transformer outage: must restore "N" within 1 hour and use best endeavours to restore "N-1" as soon as practicable.
- Category 4 ("N-1" line and transformer):
  - Line element unavailability: best endeavours to restore "N-1" as soon as practicable.

- Line outage where connected to the Adelaide Central Area: must restore "N" within 4 hours and use best endeavours to restore "N-1" as soon as practicable.
- Line outage where not connected to the Adelaide Central Area: must restore "N" within 12 hours and use best endeavours to restore "N-1" as soon as practicable.
- Transformer element unavailability: best endeavours to restore "N-1" as soon as practicable.
- Transformer outage where connected to the Adelaide Central Area: must restore "N" within 4 hours and use best endeavours to restore "N-1" as soon as practicable.
- Transformer outage where not connected to the Adelaide Central Area: must restore "N" within 12 hours and use best endeavours to restore "N-1" as soon as practicable.

- Category 5 ("N-1" line and transformer to ACR):
  - Line element unavailability: best endeavours to restore "N-1" as soon as practicable.
  - Line outage: must restore 65% of "N" capacity within 4 hours and use best endeavours to restore "N-1" as soon as practicable.
  - Transformer element unavailability: best endeavours to restore "N-1" as soon as practicable.
  - Transformer outage: must restore 65% of "N" capacity within 4 hours and use best endeavours to restore "N-1" as soon as practicable

The above amendments impose a best endeavours standard for restoration and remediation in the case of equipment failures. However, there is need to ensure that the effects of an interruption, caused by the failure of a transmission network element, are minimised in respect to the duration of the interruption and the likelihood of further interruptions being caused by the failure.

Accordingly, a new clause, 2.10 has been introduced into the code to define the term "as soon as practicable", thus strengthening the best endeavours restoration standard.

Final Decision 14.

The Commission has amended the provisions of clause 2 of the code to clarify ElectraNet's restoration obligations in the event of:

- the unavailability of a network element which provides the relevant reliability standard; and

- an outage due to the unavailability of all relevant network elements which provide the relevant reliability standard.

The Commission has introduced clause 2.10, "Obligation to restore capacity", into the code to strengthen the best endeavours standard for a transmission entity to restore a failed network element.

2.10.1 The obligation to restore a failed ***transmission line****,* ***transformer*** *or* ***network support arrangement*** *as soon as practicable so as to meet the standards specified in this clause 2 includes, without limitation, a requirement that the* ***transmission entity*** *must have regard to:*

(a) ***good electricity industry practice****;*

(b) the need to minimise the duration of any interruption arising from that failure; and

(c) the need to minimise the likelihood of an interruption as a result of the failure of any other ***transmission line****,* ***transformer*** *or* ***network support arrangement*** *utilised at that* ***exit point*** *or group of* ***exit points****.*

4 NEXT STEPS

For the reasons set out in this Final Decision, the Commission has amended the code to take effect from 1 July 2013. That version of the code will be entitled TC/07.

The current version of the code, TC/06, will remain in force until 1 July 2013 (subject to any subsequent amendments which occur between the date of this Final Decision and 1 July 2013, albeit that this is not expected to occur).

5 APPENDIX – EXIT POINT CATEGORIES

Existing exit point reliability categories to apply <u>until 30 June 2013</u>

CATEGORY NAME	CONNECTION POINT
Category 1	• Baroota • Dalrymple • Florieton SWER • Kanmantoo Mine • Leigh Creek Coal * • Leigh Creek South • Mannum/Adelaide 1 * • Mannum/Adelaide 2 * • Mannum/Adelaide 3 * • Middleback* • Millbrook * • Morgan/Whyalla 1 * • Morgan/Whyalla 2 * • Morgan/Whyalla 3 * • Morgan/Whyalla 4 * • Mt Gunson • Murray/Hahndorf 1 * • Murray/Hahndorf 2 * • Murray/Hahndorf 3 * • Neuroodla • Roseworthy* • Stony Point (Whyalla Refiners) - distribution • Stony Point* • Waterloo- until 31 December 2009 • Whyalla LMF • Davenport * • Pimba * • Woomera* • Wudinna (until 30 June 2009) ** denotes a customer but does not include a distributor*
Category 2	• Ardrossan West • Kadina East • Wudinna (on and from 1 July 2009) • Yadnarie
Category 3	• Port Lincoln • Snuggery Rural • Whyalla Terminal – Main Bus (until 30 June 2010)
Category 4	• Angas Creek • Berri/Monash • Blanche • Brinkworth • [Bungama and Pt Pirie] • Clare North • Coonalpyn West • Dorrien • Templers • Hummocks • Keith • Kincraig • Mannum • Mobilong • Mt Barker • Mt Gambier • North West Bend • Playford • Snuggery Industrial • Tailem Bend • Waterloo – from 1 January 2010 • Whyalla Terminal – Main Bus (on and from 1 July 2010) • Penola West • [Dry Creek West, Kilburn, Lefevre, New Osborne and Torrens Island 66kV] • [Happy Valley , Magill and Morphett Vale East] • [Para and Parafield Gardens West]
Category 5	• [Dry Creek East, Magill and Northfield]
Category 6	• Adelaide Central [East Tce, new CityWest substation]

Amended exit point reliability categories to apply <u>on and from 1 July 2013</u>

CATEGORY	EXIT POINT [ ] = GROUPED
Category 1	• Baroota (until 1 December 2017) • Dalrymple (until 1 December 2016) • Davenport * • Florieton SWER • Kanmantoo Mine • Leigh Creek Coal * • Leigh Creek South • Mannum/Adelaide 1 * • Mannum/Adelaide 2 * • Mannum/Adelaide 3 * • Middleback* • Millbrook * • Morgan/Whyalla 1 * • Morgan/Whyalla 2 * • Morgan/Whyalla 3 * • Morgan/Whyalla 4 * • Mt Gunson • Murray/Hahndorf 1 * • Murray/Hahndorf 2 * • Murray/Hahndorf 3 * • Neuroodla • Pimba * • Roseworthy* • Stony Point (Whyalla Refiners) - distribution • Stony Point* • Whyalla Central - Main Bus • Woomera* ** denotes a customer but does not include a distributor*
Category 2	• Ardrossan West • Baroota (on and from 1 December 2017) • Dalrymple (on and from 1 December 2016) • Kadina East • Wudinna • Yadnarie
Category 3	• Port Lincoln • Snuggery Rural
Category 4	• Angas Creek • [Berri/Monash] • Blanche • Brinkworth • Clare North • Coonalpyn West • Dorrien • Templers • Hummocks • Keith • Kincraig • Mannum • Mobilong • [Mt Barker, Mt Barker South] • Mt Gambier • North West Bend • Penola West • Davenport West • Snuggery Industrial • Tailem Bend • Waterloo • Whyalla Terminal – Main Bus • [Bungama and Pt Pirie] • [Dry Creek (West), Kilburn, LeFevre, New Osborne and Torrens Island 66kV] • [Happy Valley, Magill (South), Morphett Vale East and City West (South)] • [Para, Munno Para and Parafield Gardens West] • [Dry Creek (East), Magill (East) and Northfield]
Category 5	• Adelaide Central [East Tce, City West (ACR)]