Forecast Expenditure Summary

Corporation Initiated Augmentation

2015 to 2020

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1. About this summary document

This section explains the purpose and structure of this summary document.

1.1 Purpose

The purpose of this summary document is to explain and justify Ergon Energy Corporation's Corporation Initiated Augmentation (CIA) capital expenditure for its standard control services (SCS) for the next regulatory control period, 1 July 2015 to 30 June 2020.

It aims to provide the reader with a full understanding of Ergon Energy's CIA capital expenditure forecasts. However, because it is a summary document, it necessarily addresses some matters at a relatively high level and refers out to other documents for further detail.

This summary document provides details of actual, estimated and forecast CIA capital expenditure for the previous (1 July 2005 to 30 June 2010), current (1 July 2010 to 30 June 2015) and next regulatory control periods. All capital expenditure presented in this document is in real 2014-15 dollars, except where otherwise stated.

Importantly, this summary document only explains and justifies Ergon Energy's direct costs for its CIA capital expenditure. Ergon Energy applies real cost escalations and shared costs (overheads) to these direct costs to determine its total CIA capital expenditure. Ergon Energy has prepared, and provided to the Australian Energy Regulator (AER), separate documents that explain and justify – for all of its capital expenditure categories – how it applies these real cost escalations and shared costs (overheads).

Readers should take care in examining the (un-escalated) direct costs in this summary document to ensure that they do not confuse them with either Ergon Energy's:

- Direct costs, inclusive of real cost escalations
- Total costs, inclusive of direct costs, real cost escalations and shared costs (overheads).

1.2 Structure

The remainder of this summary document is structured as follows:

- Section 2 details Ergon Energy's CIA capital expenditure for the previous, current, and next regulatory control periods. This is intended to provide the reader with a clear view of the profile of Ergon Energy's actual, estimated, and forecast CIA capital expenditure that will be explained and justified in the remainder of this summary document.
- Section 3 describes the conceptual nature of Ergon Energy's CIA capital expenditure. It explains why it is necessary, including having regard for customer expectations, as well as Ergon Energy's legislative and regulatory obligations.
- Section 4 examines why Ergon Energy's CIA capital expenditure in the current regulatory control period differed from the forecasts that it presented to the AER in its regulatory proposal (and revised regulatory proposal) as well as the AER's own capital expenditure allowance in its distribution determination. It also explains how Ergon Energy has incorporated learnings about these differences into its capital expenditure forecasts for the next period.
- Sections 5 and 6 explain Ergon Energy's CIA expenditure forecasting methodology for its sub-transmission and distribution networks respectively for the next regulatory control period.
- Section 7 details Ergon Energy's approach to demand management in the distribution network.
- Section 8 details Ergon Energy's forecasts for its CIA capital expenditure for the next regulatory control period that it is proposing that the AER approve.
- Section 9 draws on the material in the previous sections to explain and justify Ergon Energy's forecast CIA capital expenditure against the capital expenditure objectives and criteria in Clause 6.5.7 of the National Electricity Rules (NER). It therefore outlines why the AER should approve this capital expenditure forecast as part of its distribution determination for Ergon Energy's next regulatory control period.

2. Expenditure profile

This section details Ergon Energy's CIA capital expenditure for the previous, current and next regulatory control periods. This is intended to provide the reader with a clear view of the profile of Ergon Energy's actual, estimated, and forecast CIA capital expenditure that will be explained and justified in the remainder of this summary document.

2.1 Direct costs

Table 1 details the following information about Ergon Energy's CIA capital expenditure, in direct costs, for the previous, current and next regulatory control periods:

- The CIA capital expenditure forecast that Ergon Energy:
    - presented in its regulatory proposals, and revised regulatory proposals, to the Queensland Competition Authority (QCA) for the previous regulatory control period and to the AER for the current regulatory control period
    - is now presenting in its regulatory proposal to the AER for the next regulatory control period.
- The QCA's and the AER's CIA capital expenditure allowance for the previous and current regulatory control periods respectively
- Ergon Energy's actual and estimated CIA capital expenditure for the previous and current regulatory control periods.

Note that this table shows expenditure on SCS only. Consistent with the 'AER's Framework and Approach – Ergon Energy and Energex 2015–2020'[1], all capital expenditure associated with CIA is recovered by Ergon Energy through SCS. This is because the purpose of the works is to augment the existing shared network (as opposed to extending the network to a new customer) and is hence generally treated as shared costs because augmentation typically benefits a group of customers. As a result, CIA services are classified as SCS rather than Alternative Control Services (ACS).

[1] Australian Energy Regulator, Framework and Approach – Ergon Energy and Energex 2015-2020, April 2014

Table 1: Corporation Initiated Augmentation (CIA) capital expenditure (Direct costs, $m real 2014-15[2])

	2005-06	2006-07	2007-08	2008-09	2009-10	Total	2010-11	2011-12	2012-13	2013-14	2014-15	Total	2015-16	2016-17	2017-18	2018-19	2019-20	Total
Regulatory Proposal	94	92	101	91	73	**451**	219	282	335	392	449	**1,677**[3]	118	117	115	83	83	**516**[7]
Revised Regulatory Proposal	114	180	180	122	101	**695**	224	295	354	413	465	**1,751**[4]	n/a	n/a	n/a	n/a	n/a	**n/a**
QCA/AER Determination	117	128	140	140	140	**665**	200	194	239	285	327	**1,244**[5]	n/a	n/a	n/a	n/a	n/a	**n/a**
Actual/Estimate	109	158	201	198	185	**853**	100[6]	118[6]	103[6]	106[6]	116[7]	**543**	n/a	n/a	n/a	n/a	n/a	**n/a**
Variance – Actual v Determination	**-7%**	**23%**	**44%**	**41%**	**32%**	**28%**	**-50%**	**-39%**	**-57%**	**-63%**	**-65%**	**-56%**	**n/a**	**n/a**	**n/a**	**n/a**	**n/a**	**n/a**

[2] Indexation based on Australian Bureau of Statistics Series 6401.0 Consumer Price Index Weighted Average of Eight Capital Cities, All Groups CPI.

[3] Regulatory Proposal to AER – Distribution Services for period – 1 July 2010 to 30th June 2015 – 1 July 2009, Page 31, Table 6 (and converted into direct costs).

[4] Revised Regulatory Proposal to AER – Distribution Services for period – 1 July 2010 to 30 June 2015 – 14 Jan 2010, Page 11, Table 1-1 (and converted as above).

[5] AER Final decision, Queensland distribution determination 2010-11 to 2014-15, Page xxxiii, Table 12 (allocated by Ergon Energy into the capex categories and converted as above).

[6] 2010-11 to 2013-14 Ergon Energy Annual Performance RINs, Table 2.4 (2010-11 to 2011-12), Table 1 (2012-13 to 2013-14) (and converted as above).

[7] Network Capital Expenditure Forecast Model (for Ergon Energy 2015-20 regulatory proposal), escalated for CPI only to 2014-15 dollars and excludes non-CPI input price escalations and overhead as per the Cost Allocation Method (CAM).

Table 1 shows that, for the 2005-10 regulatory control period, the actual CIA capital expenditure exceeded the QCA determination by some 28%. This period was characterised by high economic growth in Queensland. As a result of this economic growth, peak demand growth exceeded forecasts and consequently additional distribution network augmentation was required to address this customer demand and maintain network security at acceptable levels as well as comply with standards specified in the NER. This regulatory control period had been preceded by the Electricity Distribution and Service Delivery (EDSD) Review in 2004 in response to concerns about security of supply in the electricity distribution networks. The EDSD Review recommended (and the Government subsequently accepted) applying a purely deterministic security of supply standard based on N-1 redundancy at zone substation level and above. There was a significant amount of augmentation works initiated in an attempt to make the distribution network compliant with this security criteria as well as address the growing peak demand.

For the current regulatory control period, 2010-15, the CIA capital expenditure will be significantly below both Ergon Energy's forecasts and the AER's allowance. The primary reasons for this underspend are as follows:

- External conditions – the growth in peak demand and overall energy consumption has been lower than that forecast by either Ergon Energy or the AER before the start of the present regulatory control period. This is due to several exogenous factors including:
  - the Global Financial Crisis (GFC) and subsequent subdued economic growth in Queensland
  - persistent cyclone activity over summer periods and milder summer temperatures
  - the rate of growth in solar photovoltaic (PV) system connections and solar hot water systems
  - the impact of higher electricity prices
  - government run programs such as Climate Smart and insulation.

  These factors have together had a material downward impact on the growth in peak demand and overall energy consumption across the entire Ergon Energy network. This has resulted in a significantly reduced level of augmentation expenditure (Augex) required to maintain the distribution network security of supply to customers.
- Changes to standards – in late 2011 the Queensland Department of Energy and Water commissioned the Electricity Network Capital Program (ENCAP) review. The ENCAP review reduced the required security of supply standard as a result of improved performance by Ergon Energy in restoring supply to customers following contingencies. The security of supply standard was again revised by the department from 1 July 2014 to use a less deterministic process which considers the 'Value of Customer Reliability' (VCR) applied to the energy at risk as a result of a network contingency. Although this new security of supply standard commenced on 1 July 2014, Ergon Energy conducted all future augmentation planning in compliance with the new standard during the 2013-14 planning cycle in anticipation of the change. The effect of changing the security of supply standards has been a significant reduction in Augex required to maintain the network within the required standard and a significant reduction in the number of zone substations that are non-compliant with the security criteria.

- Ergon Energy initiatives – Ergon Energy has been undertaking an increasing level of demand management projects during this regulatory control period to prove the approach is successful and, if so, to optimise expenditure on augmentation. This has deferred the need for augmentation at a number of targeted sites to well beyond the end of this regulatory control period. Additionally, Ergon Energy has been undertaking a project with the other Queensland distribution network service provider (DNSP), Energex, to identify areas where a common approach to standards and procedures could provide efficiency gains. This project has delivered efficiency improvements, which have reduced the augmentation program during this, and future regulatory control periods.
- Shareholder expectations – the expectations of shareholding Ministers underwent changes during this regulatory control period. In March 2012, a new government was elected in Queensland. The change in government brought with it changes in shareholder expectations for Ergon Energy. In particular shareholding Ministers wrote to Ergon Energy on 6 September 2012 and stated the following expectations of Ergon Energy to:
    - position itself so that in the next regulatory control period, the network price for electricity will not increase greater than the CPI
    - generate savings to the capital program that will limit growth in debt levels
    - ensure efficiency savings are balanced against ongoing delivery of safe, secure and reliable services to appropriate technical conditions.

As a consequence of the combined impacts detailed above, the overall augmentation program has been reduced and consequently the level of expenditure has been adjusted.

Sections 4 and 6 of this summary document explain the reasons for the trend in this CIA capital expenditure in the current and next regulatory control periods respectively.

2.2 Total costs

Table 2 below provides the same information as is in Table 1 above but, instead of presenting the CIA capital expenditure in direct costs, it presents it in total costs (i.e. inclusive of real cost escalations and shared costs (overheads)).

Table 2: Corporation Initiated Augmentation (CIA) capital expenditure (Total costs, $m real 2014-15[8])

	2005-06	2006-07	2007-08	2008-09	2009-10	Total	2010-11	2011-12	2012-13	2013-14	2014-15	Total	2015-16	2016-17	2017-18	2018-19	2019-20	Total
Regulatory Proposal	141	140	148	135	112	**675**	303	384	454	524	587	**2,250**[9]	171	174	178	132	135	**790**[13]
Revised Regulatory Proposal	170	273	263	180	154	**1041**	309	402	478	551	606	**2,347**[10]	n/a	n/a	n/a	n/a	n/a	**n/a**
QCA/AER Determination	183	200	219	225	229	**1,057**	283	277	336	398	447	**1,740**[11]	n/a	n/a	n/a	n/a	n/a	**n/a**
Actual/Estimate	152	220	301	291	273	**1,237**	148[12]	175[12]	152[12]	166[12]	168[13]	**809**	n/a	n/a	n/a	n/a	n/a	**n/a**
Variance – Actual v Determination	**-17%**	**10%**	**37%**	**29%**	**19%**	**17%**	**-48%**	**-37%**	**-55%**	**-58%**	**-62%**	**-54%**	**n/a**	**n/a**	**n/a**	**n/a**	**n/a**	**n/a**

This total cost information is provided for comparative purposes only should the reader be seeking to compare Ergon Energy's total costs with those in other documents. As discussed in Section 1, the remainder of this document explains and justifies Ergon Energy's direct costs only (i.e. the costs in Table 1 above).

[8] Indexation based on Australian Bureau of Statistics Series 6401.0 Consumer Price Index Weighted Average of Eight Capital Cities, All Groups CPI.

[9] Regulatory Proposal to AER – Distribution Services for period – 1 July 2010 to 30 June 2015 – 1 July 2009, Page 31, Table 6.

[10] Revised Regulatory Proposal to AER – Distribution Services for period –1 July 2010 to 30 June 2015 – 14 Jan 2010, Page 11, Table 1-1.

[11] AER Final decision Queensland distribution determination 2010-11 to 2014-15, Page xxxiii, Table 12 (allocated by Ergon Energy into the capex categories).

[12] 2010-11 to 2013-14 Ergon Energy Annual Performance RINs, table 2.4 (2010-11 to 2011-12), table 1 (2012-13 to 2013-14).

[13] Network capital expenditure Forecast Summary Model escalated for Ergon Energy 2015-20 regulatory proposal in accordance with Ergon Energy Forecasting Methodology- i.e. applying CPI indexation to 2014-15 dollars, non-CPI input price escalations, overhead as per the CAM.

3. Nature of expenditure

This section describes the conceptual nature of Ergon Energy's CIA capital expenditure. It explains why it is necessary, including having regard for customer expectations, as well as Ergon Energy's legislative and regulatory obligations. This section also defines the difference between CIA and Customer Initiated Capital Works (CICW).

3.1 Customer informed

To ensure that Ergon Energy's Regulatory Proposal is aligned with the long-term interests of our customers and communities, we have undertaken significant customer and stakeholder engagement. A comprehensive description of the customer engagement process, and how its outcomes have informed Ergon Energy's decision-making process, is found in the document 'Informing Our Plans, Our Engagement Program'.

Our customers are concerned about the cost of electricity, and want prices to stabilise so that they can continue to experience existing levels of reliability at the best possible price. In response, we are applying a new network security criteria, moving from the requirement to duplicate investment to ensure security of supply, to a criteria that considers the customer value of the investment from a reliability perspective, and applies a safety net to define the maximum times allowed for restoration of various levels of load following a single contingency event. We will continue to assess this approach as we move forward to best balance our customers' expectations around reliability and price. We are also looking to build on our demand management success, and increasingly use non-network alternative solutions – from embedded generation to more innovative demand management and demand response projects – as a more cost effective way to respond to constraints on the network.

Through listening to our customers, we were able to refresh our service commitments and build on our understanding of the impact of potential future demand on the network. These have in turn helped inform the expenditure forecasts outlined in this summary.

Our commitment to delivering the best possible price has provided the framework for the forecast. In every way we have aimed to be as prudent and efficient as possible in our investment plans.

In addition, in formulating our plans we have also considered our commitments around delivering peace of mind, by way of a safe, dependable electricity service, and supporting greater customer choice and control in electricity supply solutions. In both of these areas the augmentation of the network plays a central role.

Our strategic objectives are detailed in Ergon Energy's annual Statement of Corporate Intent, which sets out our strategy and obligations each financial year to our shareholders.

Our demand forecasts have been reviewed against insights on general energy usage trends, market intelligence on regional development and potential block loads. We have detailed these reviews within the supporting document 'Network Strategy and Planning Energy Demand Forecasting'.

3.2 Legislative obligations

Our service commitments are in line with legislative obligations. Ergon Energy is obliged under the *Electricity Act 1994* (Qld) to operate, maintain and protect its supply network in a manner that ensures adequate, economic, reliable and safe connection and supply of electricity to its customers.[14] This includes maintenance of voltages and other system parameters within acceptable tolerances. The Act also obliges Ergon Energy to consider both demand and supply side options in order to provide, as far as technically and economically practicable, for the efficient supply of electricity.[15]

Ergon Energy is also subject to obligations in the NER. Specifically, clause 6.5.7 of the rules requires Ergon Energy to propose capital expenditure to 'meet or manage the demand for standard control services'. How Ergon Energy's proposed CIA capital expenditure meets this and other NER requirements is described in detail in Section 9 of this document.

Ergon Energy is also required to submit Safety Net Measures for regulatory approval under the *Electricity Act 1994* (Qld). These Safety Net Measures are now a requirement of Ergon Energy's Distribution Authority.

3.3 Types of Corporation Initiated Augmentation (CIA) capital expenditure

There are several general types of customer activity that can cause constraints in Ergon Energy's distribution system that creates a need to invest:

- organic growth that occurs when existing customers increase their electricity usage in a particular part of the network, or across the network
- increases in the number of residential or small commercial customers in a particular part of the network due to population growth
- block loads connecting to a particular part of the network, such as new large commercial or industrial customers
- high penetration of photovoltaic energy systems on weak sections of the networks, causing voltage regulation problems.

Without network investment, or alternative action, customers' increased demand can result in Ergon Energy exceeding its network's existing capacity and failing to comply with:

- our security of supply requirements
- minimum service standards
- the requirements of the NER
- the requirements of the *Electricity Act 1994* (Qld).

As a result, Ergon Energy needs to augment or reinforce its network's capacity or alternatively pursue non-network activity. Such works are subject to the application of the Regulatory Investment Test – Distribution (RIT-D).

Powerlink, the Queensland Transmission Network Service Provider can also be a driver of Corporation Initiated Augmentation works within the Ergon Energy network. Work on the Powerlink network may require complementary activity within the Ergon Energy network at the interface in order to ensure the transmission capacity can be delivered to the distribution network. In addition,

[14] Refer section 42(b) of the *Electricity Act 1994* (Qld).

[15] Refer section 42(d) of the *Electricity Act 1994* (Qld).

augmentation of the transmission network may cause fault levels to rise in the distribution network, which may result in augmentation being necessary that is not directly related to customer activity. Such works are analysed and reviewed as part of the Joint Network Planning process conducted between Ergon Energy and Powerlink as required by the NER and are generally subject to the Regulatory Investment Test – Transmission (RIT-T).

Ergon Energy distinguishes between CIA capital expenditure on its:

- Sub-transmission network, where assets are generally 33 kV and above and used to supply zone substations
- Distribution network, where assets are generally below 33 kV

3.4 Relationship between CIA and CICW expenditure

Both of Ergon Energy's CIA and CICW capital expenditure categories may result in the design and construction of shared network assets.

The distinction between the two expenditure categories is that shared network assets are included in:

- CIA where they are not dedicated to a particular customer connection but rather relate to meeting the future needs of customers generally. CIA expenditure is solely related to augmentation of shared assets so where customer block loads (driven from customer requests) have been included in the demand forecast then the Augex remains as CIA.
- CICW only where they relate directly to a dedicated customer connection/request. It will typically involve new connection assets and, depending on existing network capacity, augmentation of shared assets (if the load has not been included in the demand forecast) to ensure the connection can be supplied.

3.5 Demand forecasting

3.5.1 The 2010-15 regulatory review process

In its submission to the AER, Ergon Energy took a top down and bottom-up approach to forecasting maximum demand. This approach was based on linear trend analysis of (weather corrected) annual season peak demands at the zone substation level combined with the addition of spot or load blocks. These forecasts were then compared to econometrically derived National Institute of Economic and Industry Research (NIEIR) forecasts in order to understand and reconcile significant differences in outputs.

Ergon Energy based its capital expenditure forecasts on its September 2007 system maximum demand forecasts, as they were lower than subsequent Ergon Energy forecasts, and because they were validated by reference to the NIEIR forecasts.

During the AER's consultant's review of demand forecasts, they raised a number of issues with Ergon Energy's forecasts, namely:

- an apparent difference between the historic and forecast elasticity of maximum demand to economic growth
- unexplained substantial increases in temperature sensitive load in 2012
- uncertainty about the inclusion of large spot loads, including criteria for inclusion, timing and whether these loads were connected to the distribution network or transmission system
- inconsistent regional diversity factors between the NIEIR and Ergon Energy 2009 forecasts.

Within its Determination, the AER did not consider it prudent to use the 2007 maximum demand forecast as the basis for the capital expenditure forecast proposed by Ergon Energy. This was because Ergon Energy's 2009 demand forecast was substantially lower than its 2007 forecast (the 2009 regional sum maximum demand forecasts were on average 5.6% lower than the 2007 forecast). The AER also concluded that Ergon Energy's spatial demand forecast overestimated the size and timing of spot loads.

The AER did not consider it appropriate to use the NIEIR's forecast for adjusting Ergon Energy's forecast. The AER accepted their consultant's top down system maximum demand forecast model and the input assumptions (e.g. GSP, dwelling, and air conditioner forecasts). The AER considered that the forecasts produced with this model provide a more accurate forecast of Ergon Energy's system maximum demand than Ergon Energy's methodology.

A comparison of the relevant forecasts is provided in Table 3 and Figure 1 below.

Table 3: Ergon Energy's maximum demand forecast vs actual (MW)

Maximum demand (MW)	2010-11	2011-12	2012-13	2013-14	2014-15	5-year average
Regulatory Proposal	2,967	3,063	3,153	3,243	3,330	3,151
Draft Decision	2,693	2,811	2,928	3,031	3,121	2,917
Revised Regulatory Proposal	2,807	3,052	3,181	3,282	3,365	3,137
AER Decision	2,778	2,907	3,017	3,100	3,171	2,995
Actual	2,319	2,417	2,380	2,441	N/A	*2,389

* – averaged over 4 years

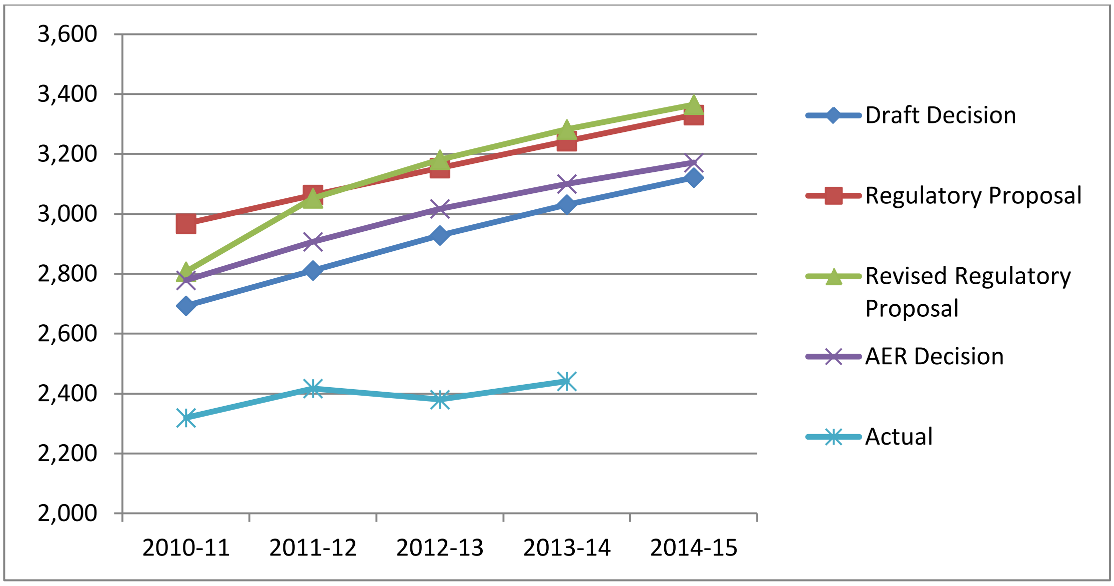

Figure 1: Ergon Energy's maximum demand forecast vs actual demand (MW)

3.5.2 Forecasting inputs and approach

Following the AER's concern over Ergon Energy's forecasting methods, Ergon Energy enhanced its forecasting approach using additional econometric methods and temperature corrected values. Ergon Energy uses a combination of top-down and bottom-up approaches to provide a robust methodology. Following implementation of the new forecasting process ACIL Allen performed an independent review of the process. The document 'Load Forecasting System Maximum Demand reference', details the outcome of this review. In the document, ACIL Allen states, in relation to the new forecasting process, that:

- Ergon Energy has developed an independent system maximum demand methodology that can be used to reconcile spatial forecasts
- Ergon Energy has developed a methodology that allows for variation in key economic, demographic, appliance and weather factors
- Ergon Energy now applies a weather normalisation process to its forecasting process
- Ergon Energy has documented its processes and methodology where previously documentation was sparse.

As a result of this report and additional work done by Ergon Energy to address recommendations in the report Ergon Energy believes its methodology is reasonable, as it was reviewed independently as being consistent with good demand forecasting practice. The supporting document, 'Network Strategy and Planning Energy Demand Forecasting', gives a detailed explanation on the approach and methodology applied.

The system maximum demand forecast provides a top-down forecast based on identified factors, which affect the load at a system-wide level. Ergon Energy produces an econometric ten-year system maximum demand forecast, which is based upon a number of inputs, including:

- economic growth through the Gross State Product
- temperature
- air conditioning sales.

Ergon Energy also produces ten-year maximum demand forecasts for all zone substations, bulk supply substations, and connection points. These forecasts are based upon a number of inputs, including:

- network topology
- load history (from system metering database)
- known future developments (new major customers, network augmentation, etc.)
- temperature corrected start values
- forecast growth rates for organic growth
- system maximum demand forecasts.

This forecast provides a method that is:

- consistent with recommendation from the AER
- consistent with the review performed by an independent forecasting consultant
- is robust, veracious, justifiable, defensible and reproducible
- offers a solution that is prudent and economical.

These factors have been used in other areas of Ergon Energy such as consumption forecasts and CICW forecasts. Ergon Energy believes this approach to be reasonable, as similar approaches have been adopted by demand forecasting both by Energex and the Australian Energy Market Operator (AEMO).

3.5.3 Forecasting methodology

After completing the top-down system forecast, an extensive bottom-up forecast is developed for each individual zone substation (i.e. spatial forecasts), which are determined using a temperature adjusted starting point and projecting forward using a set of annual growth rates. The temperature adjustment determines the load, which would have occurred for an average year. Growth rates are determined using a regression model on the load history. The automatically determined growth rates are reviewed and validated by a panel of subject matter experts using a Delphi process.[16] This determines a base growth, and any known step changes (large customer connections, transfers between substations, etc.) are then included to produce a final ten-year forecast for each zone substation.

The forecasts produced for all zone substations are aggregated to bulk supply substations and connection points. Forecasts are also aggregated to an Ergon Energy system total, and reconciled to the econometrically derived system maximum demand. It is an accepted practice to constrain the aggregate Spatial Maximum Demand to be no greater than the system maximum demand. This process is illustrated in Figure 2: Overview of demand forecasting process.

[16] Delphi process is a structured, systematic, interactive forecasting method which relies on a panel of experts.

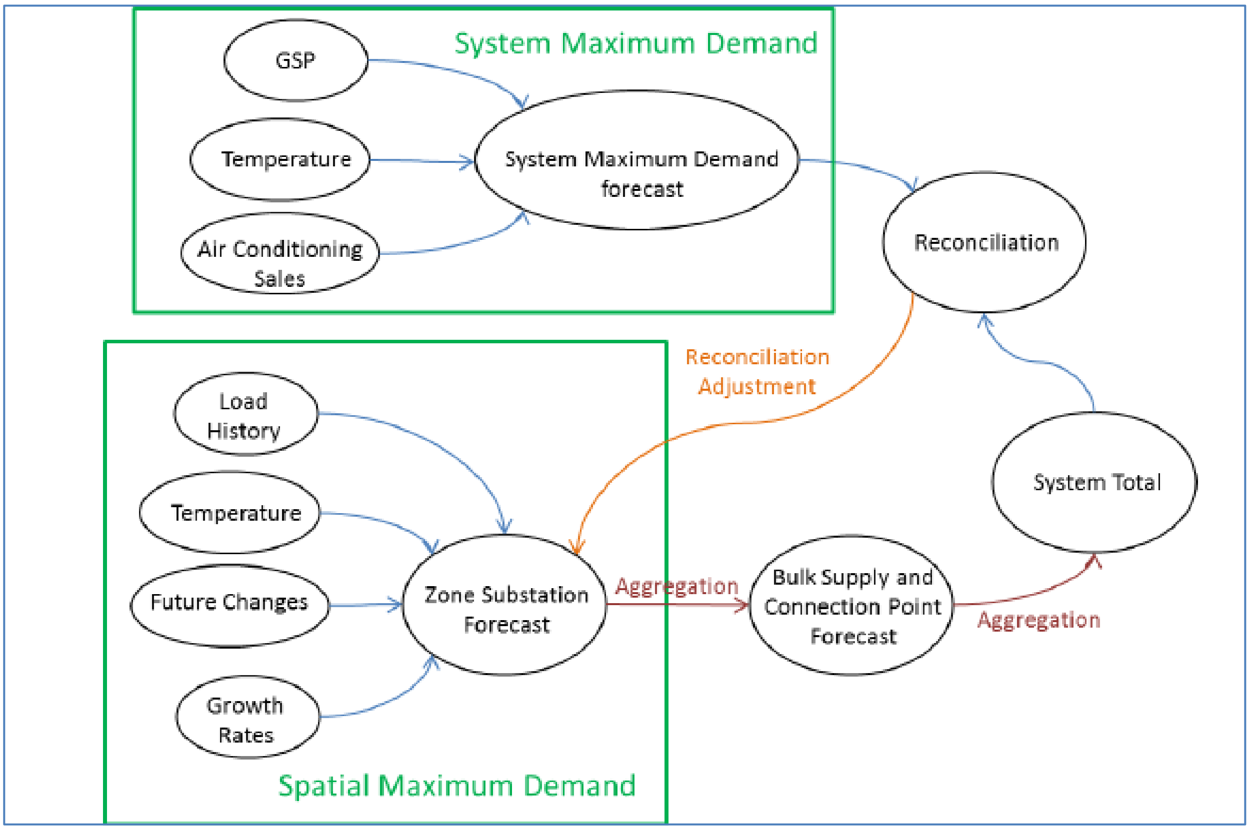

Figure 2: Overview of demand forecasting process

In the forecasting process, uncertainty is accommodated using statistical methods to produce a set of forecasts at differing levels of probability. The statistical measure used is a Probability of Exceedance (PoE). Typically, 10% PoE, 50% PoE, and 90% PoE values are produced, meaning a forecast with a 10%, 50%, or 90% probability of being exceeded. In practical planning terms for an electricity distribution network, planning for a 90% PoE level would leave the network far too vulnerable to under capacity issues, so only the 10% PoE and 50% PoE values are significant. These PoEs effectively represent an 'extreme' (high) and a 'normal' forecast value respectively.

Figure 3: Energy network total annual maximum demand growth rate shows the volatility of maximum demand in previous years, including the effects of two summer peaks driven by average temperatures much higher than a 10% PoE, let alone the 50% PoE on which forecasts were based, and how mild summers contributed to a reduced demand.

Figure 3: Energy network total annual maximum demand growth rate

Seasonal variations are addressed through separate forecasts for summer and winter at all levels of the forecast. In general, most of Ergon Energy's substations are summer peaking, although a few do exhibit a winter peak. The reconciliation is performed separately for summer and winter forecasts. The system maximum demand forecasts are updated biannually following the relevant season. Summer forecasts are produced annually following the summer peak (generally March each year) and winter forecasts are produced annually following the winter peak (generally September each year).

The maximum demand spatial forecasts for a ten year period are produced annually. The spatial forecasting process, which considers both summer and winter demand, begins after the summer period (typically mid-March). The fundamental steps in the process are:

- gather load history data since previous forecast[17]
- update augmentation project data
- update network data (new plant, changed connectivity, ratings, etc.)
- update Block Load data
- determine Growth Rates from multivariate regression
- determine PoE Start values
- apply data to produce forecast review.

Since the last regulatory review process, the forecasting methodology has been changed to incorporate recommendations from AER and a number of recommendations produced from joint

[17] Data cleansing and normalisation: Some intermediate data processing is performed to avoid anomalies. Processing to improve weather correction modelling can include if appropriate:

- Removal of weekends and non-working days from the dataset
- Removal of two-week period around Christmas within the summer model
- Removal of cooler days from the summer model dataset (i.e. where average temperature is less than 23.5 degrees)
- Removal of warmer days from the winter model (i.e. where average temperature exceeded 20 degrees)

The decision to include or exclude the above data is made by measuring the performance of the resulting models using standard statistical validation techniques. Other data cleansing includes:

- Imputation of missing weather data points
- Substitution or removal of switching events that would distort the substation load data (switching events represent contingency events outside the normal situation being forecast)

working studies undertaken by Ergon Energy with Energex. An implementation project ensured that all recommended changes were implemented.

ACIL Allen has since been used by the AER as a consultant, and the methodologies adopted by Ergon Energy are consistent with the latest ACIL Allen recommendations.

3.5.4 Historical Maximum Demand Trend

In 2013-14, Ergon Energy's aggregate peak in network demand remained steady (significantly less than anticipated), and peaked at 2,441MW, which was up slightly on the previous summer. This in an increase of 2.6% from 2012-13 maximum demand of 2,380MW owing to average high temperature over the 2013-14 summer season. However on average there is a slowdown in consumption growth generally.

This slowdown was also partly due to the transfer of load from two mines in the Mackay region off Ergon Energy's distribution network and on to Powerlink's transmission network, as well as the effects of the weather system associated with Cyclone Oswald, which occurred in January 2013 during the peak demand period.

The most significant slowdown has been in average household use – in 2012-13 the downward trend saw a 5% fall from 2011-12. Overall energy distributed was down slightly to 15,097GWh in 2012-13 and a slight increase to 15,247GWh in 2013-14 due to season's higher temperatures.

However, maximum or peak demand is still forecast to increase steadily into the future. To best inform the development of forecasts, Ergon Energy is continuing to build on our understanding of how tariff reform and other demand-related matters are best incorporated into aggregate demand modelling. The highest maximum demand experienced to date for the whole of Ergon Energy's grid-connected network was 2,584MW during the summer of 2006-07.

Figure 4 shows the total Ergon Energy monthly demand since 2001.

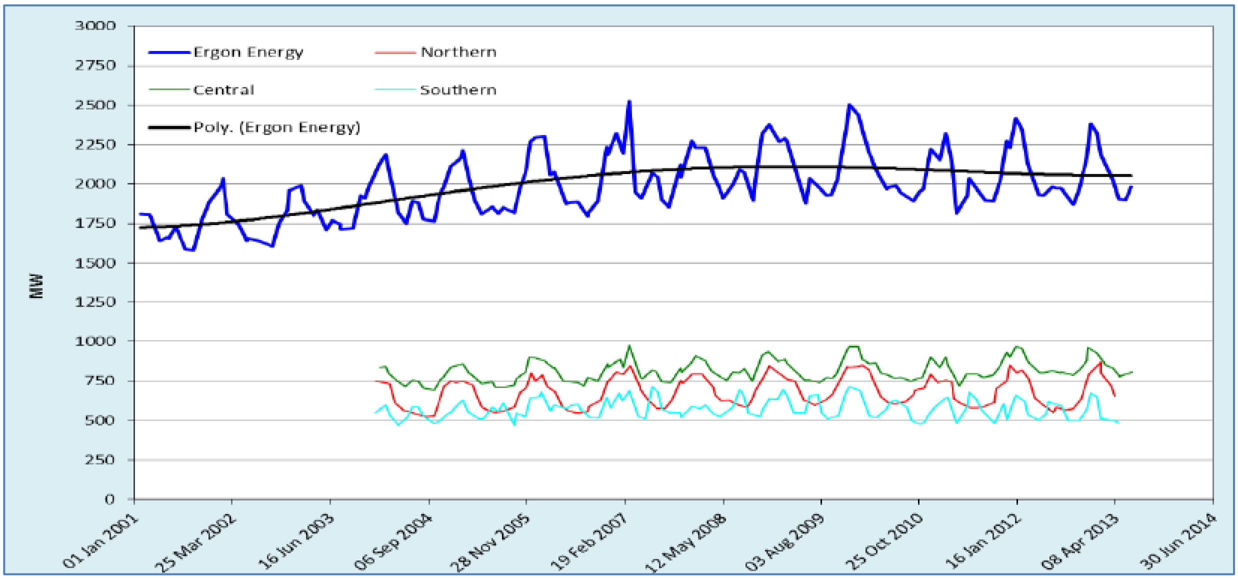

Figure 4: Ergon Energy monthly maximum demand

3.5.5 Maximum demand forecast

Figure 5 shows the latest maximum demand forecast for the whole of Ergon Energy's grid-connected network[18]. Last year's growth is slowly returning to growth patterns evident before the downturn of 2007-08, and prior to the GFC. A full recovery is some way off as Australia and Queensland are influenced by severe weather conditions and other recent world economic events, such as the European sovereign debt crisis and influences from the high Australian dollar.

The average growth in system demand over the next five years is forecast at 1.3 % to 1.5% a year. The expected increases in coal mining activity within Central Queensland and LNG activity in Central and Southern Queensland are a significant factor in this growth. The total Ergon Energy 10% and 50% PoE lines shown in the forecast are not reflective of the 10% and 50% PoE at each individual site due to the variation of maximum demand days across the state. The 'High' and 'Low' curves are the 50% PoE forecasts for high and low levels of economic growth respectively.

Figure 5 shows the most likely (50% PoE) forecast for base economic conditions (dotted line).

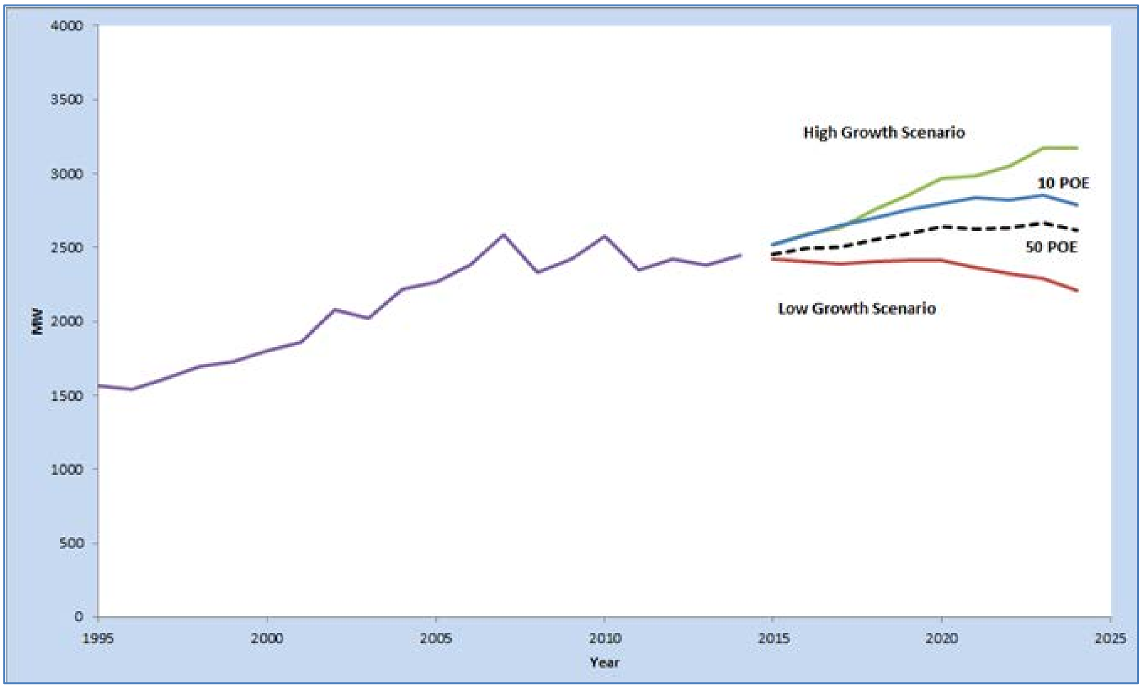

Figure 5: Ergon Energy total demand forecast maximum demand 2014

The biggest influence on future demands will be economic growth levels, as indicated by the high and low growth curves. Several companies are developing and proposing to develop LNG fields in the Darling Downs and west of Clermont, and demand is expected to be driven upwards as local supply centres grow to supply accommodation and service industries. Port development is also expected to add considerable load. The scale of demand from these project investments will be dependent upon the extent of fiscal policy and the level of perceived sovereign risk.

Taking into account the temperature variations, the revised economic growth, and the take-up rate of air conditioning and solar PV systems, Ergon Energy has revised downwards its system-wide maximum demand from previous forecast estimates. Whether this is temporary or permanent is uncertain. The increased uncertainty highlights the need for network providers to have flexibility and options in the way they manage demand for network capacity. Long term trends still forecast growth. In light of this uncertainty, Ergon Energy has used the load forecast associated with the low

[18] Excluding Mt Isa and the other isolated generation networks

economic growth scenario to formulate the augmentation program of works for the 2015-20 regulatory control period.

In 2011, the AER had a number of concerns about the Zone Substation forecast. Specifically they had concerns about:

- documentation
- lack of temperature correction
- lack of alignment with system level forecast
- version management of forecasts.

These concerns have been addressed by the implementation of the Substation Investment Forecasting Tool (SIFT).

SIFT incorporates a number of factors and generates ten-year Summer Day and Winter Night forecasts for each location:

- calculated growth rate
- starting point
- block loads
- load Transfers
- approved Ergon Energy projects.

Temperature correction of load history and statistical forecast of growth rates have now been incorporated into SIFT, but up until 2014 have been calculated outside of SIFT using the same techniques in another database system.

Because of the diversity of activity across Ergon Energy's regions, a range of substation forecast growth rates result in some substations growing while others are static or might have negative growth.

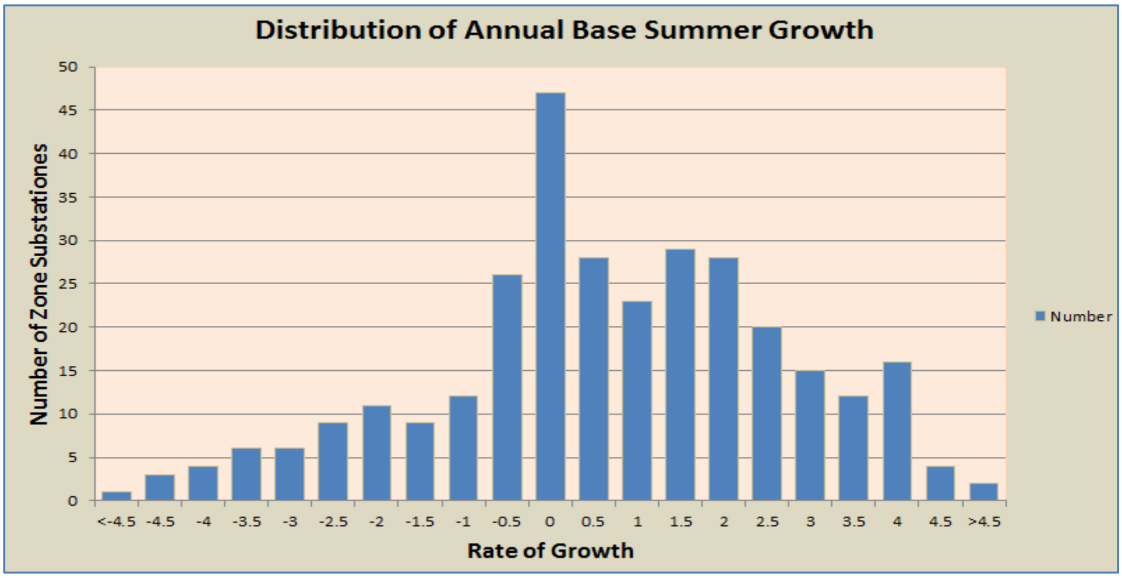

Figure 6: Distribution of Annual Base Summer Growth

Ergon Energy's regional planners take these zone substation forecasts, determine whether there are network capacity or other constrains on a case-by-case basis, and produce a capital works program for required network investment.

The forecast, and the capital works program are published in the 'Distribution Annual Planning Report' (DAPR) annually. This is a requirement of Section 5 of the NER.

The SIFT forecasting system was implemented to meet AER and Ergon Energy Joint working requirements, and signed off by ACIL Allen. ACIL Allen concluded that:

- the methodology used in SIFT was appropriate
- SIFT implemented the recommended methodology.

SIFT handles demand management either as negative block loads or by specifically modelling behaviour as part of Demand Response functionality. The forecast demand management outcomes are applied as an input to the SIFT model so that future augmentation and resulting expenditure forecasts take into account the lowered demand as a result of demand management initiatives.

photovoltaic has not yet been modelled on a zone substation basis. It is included in the system forecast only.

3.5.6 Distribution network load forecast

In Ergon Energy, distribution feeder load forecasting process is based on a combination of bottom-up and top-bottom spatial forecasts. The top-bottom component incorporates SIFT methodology applied in substation spatial forecasting with relevant macroeconomic and demographic aggregates. Bottom-up forecasts, like load transfers, new customer connections and penetration of air-conditioning systems, capture individual feeder specifics and can be used, in combination with other factors, in re-prioritisation of feeder improvement in the capital expenditure planning process.

In general, load forecasting on the system level (load growth of the entire network) considers load and energy growth with different patterns and logic. In this domain, weather/temperature correction based on 50PoE and 10PoE probabilities is critical for understanding future trends in conjunction with natural (and historic) growth, economic drivers and global demographics.

Distribution network load forecasting can be segmented into three stages with associated components:

- Deterministic (or Distribution Feeder Database - DFD) stage
- Distribution Network Augmentation Plan (DNAP) stage
- Distribution Planning or Recommended Works Request (RWR) stage.

Distribution feeder load forecasting in the DFD stage is based on ten-year planning horizons segmented in two periods – years one to five (1-5) and years six to ten (6-10). Growth rates for these periods are developed in two stages. In the first stage, using the zone substation load forecasting tool SIFT. In the second stage, compound growth based on individual feeder adjustments using premise number growth. The DFD load growth is based on peak load recorded by SCADA (Supervisory Control and Data Acquisition) (approximately 50% of Ergon Energy distribution feeders are metered) and manual Maximum Demand Indicator (MDI) readings. All peaks are filtered from contingency events and only normal maximum demands are included.

New premise counts, land resources and planned customer connections are added to individual feeder growth based on the CICW database, including load category, expected after diversity maximum demand (ADMD) figures and time of connection. Historic trends with new subdivisions related to different economic cycles and regional specifics are also considered.

It is important to note that in the DFD stage, distribution feeder forecasts are not structured between seasonal and day time periods, but only between the two five-year periods. In addition, it is based on the total feeder load forecast, applied at underground cable exits and initial sections of overhead conductors.

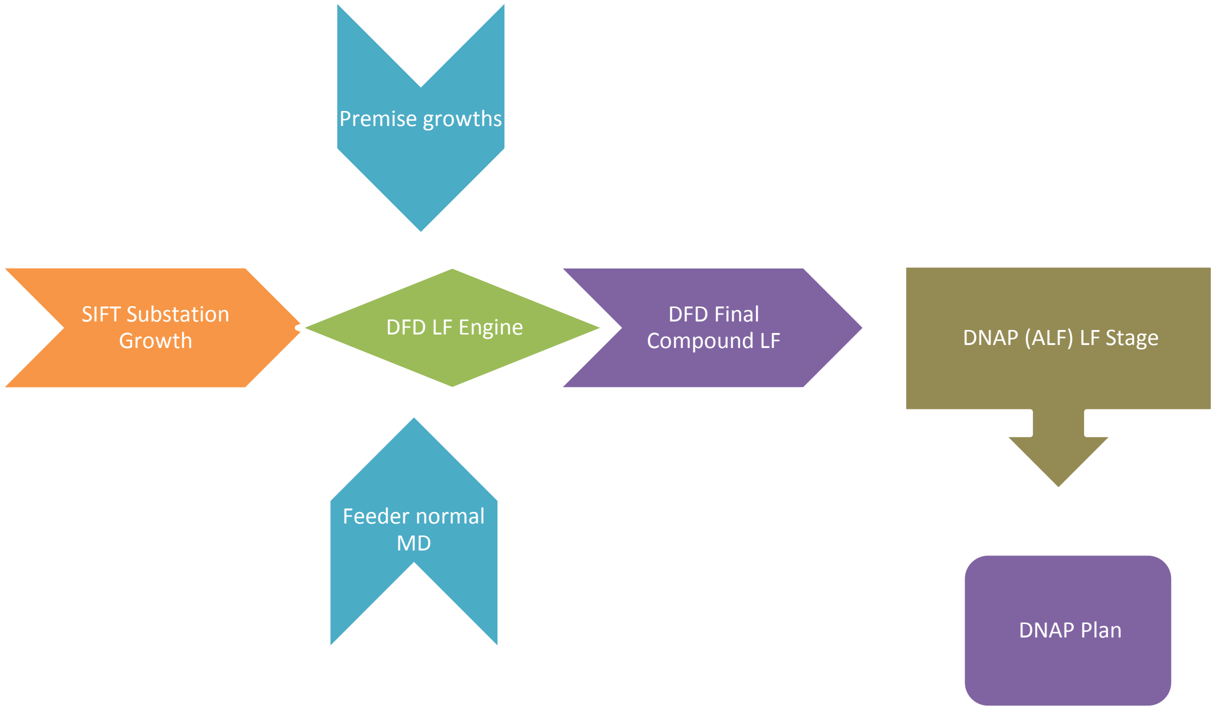

Figure 7: Distribution Feeder Database (DFD) and Distribution Network Augmentation Plan (DNAP) Load Forecasting Stages

In the next DNAP stage, a detailed Automated Load Flow (ALF) audit of all distribution feeders is applied using the SINCAL[19] modelling tool. Based on the DFD maximum demand, rating data and load growth figures, the ALF audit analyses the load and voltage profile of every section on a distribution feeder and determines parts of distribution feeder experiencing existing or future constraints not identified during the DFD stage.

Determination of distribution feeders requiring augmentation and their placement in the DNAP five-year program is a function of different factors, including load forecasting. There are three general models, which demonstrate complex interaction between feeder forecasting, current utilisation levels and their potential placement in Ergon Energy's DNAP plans. In Figure 8 below, 'red' and 'black' feeders are referred to feeders loaded above 75% (planning criteria for urban feeders) and 100% of their normal capacity.

[19] Siemens Load Flow Analysis Software

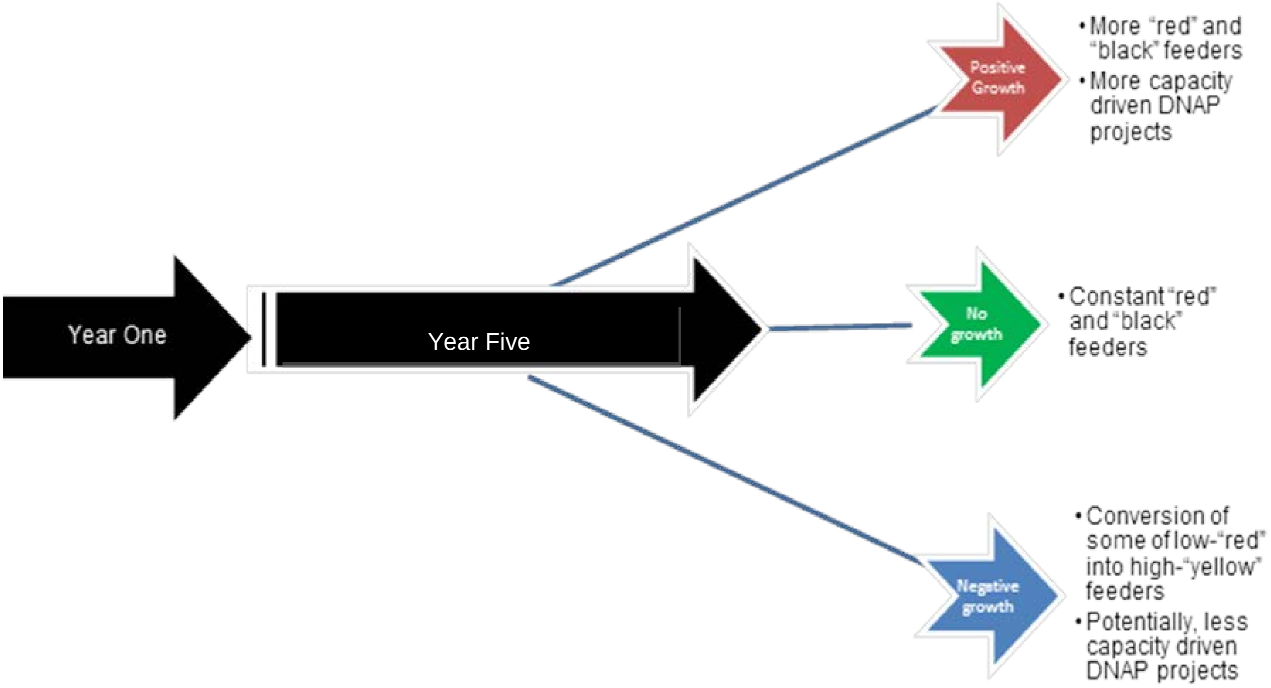

Figure 8: Correlation between Distribution Feeder Forecasting and Distribution Network Augmentation Plan (DNAP)

It is useful to examine the correlation between system maximum demand growth and distribution network load forecasting. Mild ambient temperatures reduce the average summer day maximum demand in some of the regions at the system level. However, due to the dynamic nature of distribution networks, load growth on individual distribution feeders is a function of a variety of predictable and unpredictable factors. In addition, the intensity of negative load growth on urban feeders already operating within red (>75%) and black (>100%) utilisation must be in order of more than 10% on annual basis to reflect any major changes in overall utilisation levels.

The Planning or RWR stage commences after the DNAP has been submitted. In this stage the Network Planning group allocates loads based on distribution feeder specifics, temperature corrections and known demographic and econometric factors. At the distribution feeder level, equal consideration is given to natural ('organic') load growth, block loads, planned load transfers, development of new distribution networks, temperature correction (based on 50PoE and 10PoE) and demographic and econometric planning. Demographic and econometric planning requires understanding of the local town development zones, type, time and level of developments, economic drivers, water supply specifics, as well as ADMD parameters for all planning zones.

The following factors are also considered:

- analysis of distribution feeder peak times (automated filtering of normal peak loads)
- correlation between temperature, wind, solar radiation and peak loads
- temperature correction on residential feeders
- feeders with significant photovoltaic penetration
- mid-day time load drops resulting from the increase in photovoltaic generation
- integration of demographic/town planning schemes from the regional city councils.

The final outcome is a distribution feeder load forecasting table (Figure 9) with two compound growth figures, seasonal limiting underground and overhead planning criteria '4 into 3' (0.75 x NCC, PoE50) rating limitation (for simplicity, shown as N-1) and ten-year forecast for SD (summer day) and WN (winter night) as two most dominant limiting periods. In addition to the bottom-up approach, the RWR load forecasting summary includes top-bottom substation growth rates to identify the most critical feeders in the studied distribution network.

System Configuration		Growth Rates		Rating				Current	Forecast 10Yrs									
		1-2yrs	3-10yrs	Cable Section	Season	Rating (A)	N-1	2013 / 2014	2014 / 2015	2015 / 2016	2016 / 2017	2017 / 2018	2018 / 2019	2019 / 2020	2020 / 2021	2021 / 2022	2022 / 2023	2023 / 2024
SOTO - South Toowoomba 66/11kV Zone Substation	Elser Street	2.25%	2.25%	SD	UG	511	383	293	300	306	313	320	327	335	342	350	358	366
					OH	314	236											
				WN	UG	540	405	293	300	306	313	320	327	335	342	350	358	366
					OH	433	325											
	Corsett / Hoey Street	0.90%	0.90%	SD	UG	493	370	293	295	298	301	303	306	309	312	314	317	320
					OH	694	521											
				WN	UG	521	391	293	295	298	301	303	306	309	312	314	317	320
					OH	758	569											
	Hoeper Street	0.70%	0.70%	SD	UG	455	341	85	85	86	87	87	88	88	89	90	90	91
					OH	314	236											
				WN	UG	485	364	85	85	86	87	87	88	88	89	90	90	91
					OH	433	325											
	Smithfield	3.65%	3.65%	SD	UG	421	316	210	217	225	233	242	251	260	269	279	289	300
					OH	502	377											
				WN	UG	421	316	210	217	225	233	242	251	260	269	279	289	300
					OH	541	406											
	South Street	0.70%	0.70%	SD	UG	421	316	262	264	266	268	269	271	273	275	277	279	281
					OH	502	377											
				WN	UG	421	316	262	264	266	268	269	271	273	275	277	279	281
					OH	541	406											
	West Street	1.00%	1.00%	SD	UG	421	316	302	305	308	312	315	318	321	324	327	331	334
					OH	314	236											
				WN	UG	421	316	302	305	308	312	315	318	321	324	327	331	334
					OH	433	325											
	Alderley Street	1.10%	1.10%	SD	UG	421	316	151	184	186	188	190	192	194	196	198	200	203
					OH	502	377											
				WN	UG	421	316	151	184	186	188	190	192	194	196	198	200	203
					OH	541	406											
	Non Coincidental Substation Total (Amps)			Transfer Capacity (MVA)	Capacity (MVA)	N-1 (MVA)	SD	1,595	1,650	1,675	1,701	1,727	1,753	1,780	1,808	1,836	1,865	1,895
							WN	1,595	1,650	1,675	1,701	1,727	1,753	1,780	1,808	1,836	1,865	1,895
	Non Coincidental Substation Total (MVA)						SD	31.3	32.4	32.9	33.4	33.9	34.4	34.9	35.5	36.0	36.6	37.2
							WN	31.3	32.4	32.9	33.4	33.9	34.4	34.9	35.5	36.0	36.6	37.2
	Diversity Factor						SD	1.01	0.99	0.99	0.99	0.99	0.99	0.99	0.99	0.98	0.98	0.98
							WN	1.01	0.99	0.99	0.99	0.99	0.99	0.99	0.99	0.98	0.98	0.98
	Substation Forecast Total	1.42%	1.42%	0.0	34.5	23.0	SD	31.7	32.1	32.6	33.1	33.5	34.0	34.5	35.0	35.5	36.0	36.5
				0.0	34.5	23.0	WN	31.7	32.1	32.6	33.1	33.5	34.0	34.5	35.0	35.5	36.0	36.5

Figure 9: The RWR Load Forecasting Summary

3.6 Security criteria

Ergon Energy's security criteria has undergone significant changes over the last ten years. Appendix A discusses the nature and drivers of these changes while the 'Security Criteria' document provides supporting information and details on these changes and outcomes.

In March 2014, the Queensland Government wrote to Ergon Energy to:

- remove the policy obligation for Ergon Energy to have and comply with N-X planning standards from 1 July 2014
- create a new policy obligation for Ergon Energy to transition to an 'economic' customer value based approach to reliability from 1 July 2014 onwards
- created a new requirement for Ergon Energy to submit safety net measures for regulatory approval under the Electricity Act 1994 (Qld) in order to manage outage risks to customers in the transition to an economic approach to reliability from 1 July 2014.

As a result, Ergon Energy has developed new security criteria, requested by the Queensland Government, which has two components:

- a component that is based on a VCR-based approach for reliability based investment; and
- a safety net component, to ensure a basic level of network security, covering mandatory investment.

The safety net component is now a requirement of Ergon Energy's Distribution Authority.

3.6.1 Safety Net

The safety net is used to provide an upper limit to customer outage times that could occur as a consequence of a single credible contingency event on Ergon Energy's network.

Ergon Energy had regard for the credible and non-credible contingency events in clause 4.2.3 of the NER:

> Without limitation, examples of credible contingency events are likely to include:
>
> (1) the unexpected automatic or manual disconnection of, or the unplanned reduction in capacity of, one operating generating unit; or
>
> (2) the unexpected disconnection of one major item of transmission plant (e.g. transmission line, transformer or reactive plant) other than as a result of a three phase electrical fault anywhere on the power system.
>
> A 'non-credible contingency event' is a contingency event other than a credible contingency event. Without limitation, examples of non-credible contingency events are likely to include:
>
> (1) three phase electrical faults on the power system; or
>
> (2) simultaneous disruptive events such as:
>
> (i) multiple generating unit failures
>
> (ii) double circuit transmission line failure (such as may be caused by tower collapse).

These definitions suggest that the focus of the safety net should be low probability, high impact events such as those experienced in Ergon Energy's sub-transmission network.

3.6.2 Application to Sub-transmission Network

The sub-transmission network is the focus of the safety net given that it is concerned with low-probability, high-impact events. Based on network risk assessment outcomes, expected restoration times and assuming 50% PoE loads, the corresponding Regional Centre and Rural/Remote outage magnitudes and maximum allowable durations are shown below in Table 4.

Table 4: Safety Net maximum outage magnitudes and durations

Category	Safety Net – Load not supplied and maximum restoration times following a credible contingency	
	Regional centre	Rural/Remote
(1)	Less than 20 MVA after 1 hour	Less than 20 MVA after 1 hour
(2)	Less than 15 MVA after 6 hours	Less than 15 MVA after 8 hours
(3)	Less than 5 MVA after 12 hours	Less than 5 MVA after 18 hours
(4)	Fully restored within 24 hours	Fully restored within 48[20] hours

[20] 48 hours refers to the time required to restore supply using a transportable substation in rural locations. As per the Queensland Electricity Code Guaranteed Service Level (GSL), no group of customers should be off supply for more than 24hours during this 48 hour restoration time.

Major customers (>1.5MVA) with 'N' connection agreements are assessed as able to be shed under the Safety Net, should a trigger event occur. The load of these customers is therefore not considered in the load off-supply for the purpose of the safety net evaluation.

3.6.3 Application to Distribution Network

The safety net refers to total customer impact and therefore does not specifically split between sub-transmission and distribution. However, restoration of lost supply assumes that Ergon Energy maintain adequate transfer capacity via distribution feeders.

While the sub-transmission N-1 component of the security criteria has been relaxed, the distribution security criteria remains at 75% maximum utilisation under system normal. This is to both help manage Minimum Service Standards (MSS) impacts at a distribution level and to manage load transfer.

For urban distribution feeder planning, an investigation will be triggered when the 50% PoE load exceeds 75% of the normal cyclic capacity (NCC) rating of the feeder. However, construction is not scheduled until a risk assessment indicates that augmentation is warranted. This is a prudent approach to planning distribution network augmentations, as annual variability in demand means that the feeder may not continue to exceed 75% of the NCC rating after the investigation has first been triggered.

For rural distribution feeders the load should not exceed 90% of the NCC.

3.6.4 Corrective actions

The standard network corrective actions and responses that form the basis of Table 4 are:

- automatic or remote (SCADA) restoration – 15-30 minutes
- field switching to transfer load – 4 hours urban, 6 hours rural
- repair of overhead sub-transmission or backbone feeder – 6 hours urban, 8 hours rural
- deployment of generation – 12 hours urban, 18 hours rural
- deployment of mobile substation – 24 hours urban, 48 hours rural.

These restoration times assume a maximum travel time to the affected site. The longer restoration times proposed for rural areas reflect the additional travel required to move people and plant from the primary locations, such as stores, typically located in the major regional centres. Ergon Energy currently has three transportable substations, or Nomads, located in Townsville, Rockhampton, and Toowoomba.

Load restoration will follow documented feeder management plans such that supply to critical infrastructure (typically hospitals, water, sewerage, communications, essential services) and high impact customers (high cost and/or high socio-economic impact) is restored prior to low impact customers (typically domestic customers).

Ergon Energy is required to maintain a range of additional capabilities to ensure restoration of supply within the Safety Net limits. These capabilities include:

- further development and integration of Real-time Capacity Monitoring System
- development of Demand Response/Load Curtailment options
- mobile generators to support timely restoration of supply for priority customers and to support the safety net targets
- mobile substations to support single transformer substations
- documented contingency plans
- adequate contingency spares, including through joint Energex and Ergon Energy initiatives.

3.6.5 Value of Customer Reliability (VCR) based investment

Energy at risk modelling is a tool that can be used to optimise the timing of augmentation projects and prioritise projects. This methodology calculates the probability weighted cost of unserved energy. This value can then be compared against the annualised capital costs of the augmentation project. The VCR values adopted by Ergon Energy are based on the Charles River Associates (CRA) Final Report to VENCorp in 2008 and are shown in Table 5. The CRA study was conducted in Victoria only. To validate the results for Queensland two alternative studies were conducted, both confirming that the figures are reasonable. Refer to further detail in the 'Reliability Investment Guideline, Ergon Energy/Energex Joint Reference Document '. The AER, in its Service Target Performance Incentive Scheme (STPIS), has based its incentive rates on the average VCR figures from the CRA (2007) study. Hence it is expected that using the CRA VCR figures for both STPIS and network planning should result in network performance consistent with reliability targets.

The key steps in calculating the VCR for a specific area are as follows:

- Examine a load duration curve of the demand on the substation or feeder to determine the number of kWh or MWh the load is above either the NCC rating under system normal conditions or above the N-1 rating under contingency conditions. This represents the load at risk and is illustrated in Figure 10 below. This assessment is typically done on an annual basis but it could also be done on a seasonal basis, if required.

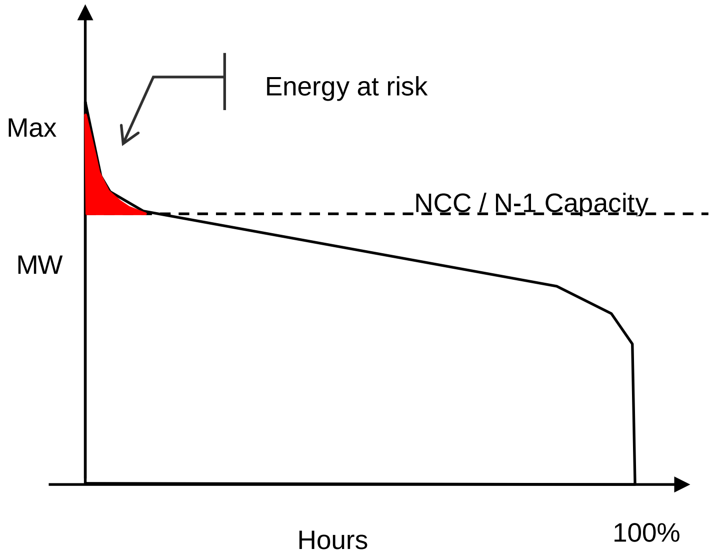

Figure 10: Illustration of energy at risk

- For N-1 constraints, the MWh energy at risk should be weighted by the probability of the N-1 event coinciding with the forecast maximum demand and the estimated repair time. Industry and/or where available, company specific outage rates should be used.
- The Value of Customer Reliability (VCR) is expressed as a $/MWh value based on the category of load supplied. Below, Table 5 details the values that Ergon Energy uses to calculate the value of energy at risk per annum. These dollar values were determined in analysis undertaken by the consulting firm CRA. The table shows that as load grows the energy at risk, and therefore the value of energy at risk, increases.

Table 5: VCR for Ergon Energy (Nominal $'s of the day)

Category	Annual VCR $/MWh
CBD	$95,700
Urban	$47,850
Rural	$47,850
System	$47,850

Below, we provide two illustrative examples of how the VCR can be applied.

Example 1

A single 33 kV feeder rated with an NCC rating of 10 MVA is forecast to supply a maximum demand of 10.5 MVA forecast over the next year:

- Based on the feeder load duration curve, the energy at risk is forecast to be 3MWh.
- The load comprises of 80% rural and 20% urban giving a VCR = (0.8 x $47,850) + (0.2 x $47,850) = $47,850 per MWh of energy at risk.
- The value of the energy at risk = 3 MWh x $47,850 = $143,550.

Example 2

A 2 x 25 MVA substation has an N-1 capacity of 28.75 MVA and is forecast to supply a maximum demand of 32 MVA over the next year:

- Based on the substation load duration curve, the energy at risk is forecast to be 60 MWh.
- The probability of an N-1 event has been assessed as a one in ten-year event i.e. 0.1 per annum.
- The repair/replacement time has been assessed as six months i.e. 0.5 years.
- The load comprises of 80% urban and 20% CBD giving a VCR = (0.8 x $47,850) + (0.2 x $95,700) = $57,420 per MWh of energy at risk.
- The value of the energy at risk = 50 MWh x 0.1 x 0.5 x $57,420 = $172,260.

The calculated value of energy at risk calculated in these examples is then compared against the annualised capital cost of the solution to address the network constraint. This element of the planning process is set out in Boxes 7-10 in Figure 11 below.

4. Current period outcomes at a category level

This section examines why Ergon Energy's CIA capital expenditure in the current regulatory control period differed from the forecasts that it presented to the AER in its regulatory proposal (and revised regulatory proposal) as well as the AER's own capital expenditure allowance in its distribution determination. It also explains how Ergon Energy has incorporated learnings about these differences into its capital expenditure forecasts for the next period.

4.1 Ergon Energy's regulatory proposal and AER's distribution determination

Table 6 details Ergon Energy's CIA capital expenditure forecast in its regulatory proposal and revised regulatory proposal and the AER's allowance in its distribution determination for the current period.

Table 6: AER and Ergon Energy's Corporation Initiated Augmentation (CIA) capital expenditure forecast (Direct costs, $m real 2014-15)

	2010-11	2011-12	2012-13	2013-14	2014-15	Total
Regulatory Proposal	219	282	335	392	449	1677
Revised Regulatory Proposal	224	295	354	413	465	1751
AER Determination	200	194	239	285	327	1244

The AER did not accept the CIA capital expenditure forecast that Ergon Energy presented in its Regulatory Proposal for the current regulatory control period. The AER's draft Distribution Determination stated that it considered that Ergon Energy's planning documentation did not reconcile to its forecast and that Ergon Energy had overestimated its maximum demand forecast by one to two years. Accordingly, the AER reduced Ergon Energy's CIA capital expenditure allowance by the equivalent of 18 months, or 30%.

Ergon Energy argued in its Revised Regulatory Proposal that the AER's reduction in CIA capital expenditure was not justified because its capital expenditure forecast could in fact be reconciled to its planning documentation. Further that there were flaws in the demand forecast that the AER used; the AER overstated the sensitivity of the capital expenditure forecast to deferred demand; and the AER wrongly assumed a linear relationship between capital expenditure and demand, which was inconsistent with regulatory precedent.

The AER did not accept Ergon Energy's revised CIA capital expenditure forecast in its Revised Regulatory Proposal. In particular, the AER's final Distribution Determination indicated that it considered that there were deficiencies in Ergon Energy's business cases, project unit costing and sub-transmission network augmentation planning documentation. The AER made significant adjustments to Ergon Energy's CIA capital expenditure by changing the timing of projects' delivery and by retaining its 18-month (30%) demand forecast adjustment. This resulted in a $636 million (total cost, 2009-10 real dollars) reduction in CIA capital expenditure over the current five-year period, which equates to $507 million (direct costs, 2014-15 real dollars).

4.2 Performance against the AER's Corporation Initiated Augmentation (CIA) allowance

Table 7 below compares Ergon Energy's actual and estimated CIA capital expenditure for the current regulatory control period with the AER's CIA capital expenditure forecast.

Table 7: Ergon Energy's actual, and the AER's forecast, Corporation Initiated Augmentation (CIA) forecast (Direct costs, $m real 2014-15)

	2010-11	2011-12	2012-13	2013-14	2014-15	Total
AER Determination	200	194	239	285	327	1,244
Actual/Estimate	100	118	103	106	116	543
Variance – Actual v Determination	-50%	-39%	-57%	-63%	-65%	-56%

The reasons for the underspend fall into four categories: changes in external conditions compared to forecasts; changes to government-set standards; initiatives undertaken by Ergon Energy, and changed expectations from Ergon Energy's owners, the Queensland Government.

4.2.1 External conditions

Peak Demand growth in this regulatory control period has been lower than expected at the time the regulatory determination was made due to several factors. As a result, the need for network Augex has been reduced.

Since mid-2009, Queensland has experienced subdued economic growth, largely due to the impact of the GFC. At the time the determination was being made, the effects of the GFC on the Queensland economy were uncertain and it was difficult to determine what the ultimate impact on demand growth in the Ergon Energy supply area would be. It has since become clear that the GFC reduced demand for new customer connections, including subdivisions, and delayed mining activity, which has been later and flatter than previously indicated by industry and government. As a result, network Augex is significantly lower than expected prior to the start of this regulatory control period.

Weather events have also impacted on the maximum demand forecasts for this regulatory control period. Cyclone activity over summer periods has moderated temperatures and disaster events (described in more detail below) have resulted in load (especially mining load) being removed from the network during periods when peak demand could be expected to occur. Some coal mines in the Bowen basin had to cease operating during these periods as a result of excess water in their mining pits. Over the remainder of this regulatory control period Ergon Energy forecasts peak demand to increase, but at a level well below the AER forecast.

Ergon Energy's ability to deliver planned programs of work during this regulatory control period has been severely impacted by sustained levels of cyclonic activity:

- Cyclone Tasha in 2010 resulted in flooding and a disaster declaration for Dalby, Theodore, Emerald, Bundaberg, Central Highlands, Northern Burnett and Woorabinda.
- Cyclones Anthony and Yasi in early 2011 impacted on over 600,000 square kms of our service area from the Cassowary Coast to Mt Isa and resulted in loss of supply to some 220,000 customers.
- Oswald caused extensive flooding in the Burnett River region and on the Darling Downs in January 2013.
- Cyclones Dylan (January 2014) and Ida (April 2014) both impacted coastal areas of northern Queensland.

Significant resources needed to be redeployed from the normal works program to perform repairs in the affected areas following these major disasters. Both the redeployment of resources and the disruption of access to work sites because of the disaster conditions had a negative impact on delivery of augmentation projects.

During this regulatory control period a large number of customers have installed photovoltaic energy systems at their premises, which have been connected to the network. This has significantly impacted the need for augmentation in some areas. In locations where the load peak occurs during the middle of the day to early afternoon the peak demand has been moderated or reduced which has also reduced the overall need for Augex in those locations.

As well as peak demand, overall energy consumption is lower than expected at the time the regulatory determination was made and this is expected to be sustained over this regulatory control period. The reasons include impact of higher electricity prices, the impact of energy conservation/demand management programs, government-run programs such as Climate Smart and insulation, and increased use of solar hot water systems. Installation of photovoltaic systems may not have directly reduced customer energy consumption as such, but importantly, has reduced the amount of energy transported to customers from the distribution network.

4.2.2 Changes to Standards since the start of the control period

Within this regulatory control period, there have also been substantial changes to network security standards arising out of the ENCAP review and a more recent review of security standards to move to a less deterministic approach underlined by a safety net for customers.

The ENCAP review approved revised security criteria associated with the security of supply for zone substations and distribution feeder maximum load levels. For zone substations, a relaxation of the security standard was applicable for those substations that had a mixed but predominately residential load category. N-1 security standard was stipulated where loads were greater than or equal to 15MVA, whereas the previous threshold was 5MVA. Where the load category was mixed but had significant commercial and industrial load, the threshold remained at 5MVA for the provision of N-1 security standard. For urban category distribution feeders, the maximum load level was increased from 67% of NCC, or '3 into 2', to 75% of NCC, equivalent to a '4 into 3' target security level. The review also mandated an economic cost/benefit approach to be taken in more rural areas where cost of augmentation would be high compared to marginal increases in reliability.

Based on feedback from customers that the cost of energy was more important to them than further improvements to security of supply Ergon Energy was proactive in further reviewing the security of supply standards with a view to reducing augmentation costs while ensuring an acceptable minimum standard of reliability, and times for restoration of supply outages are maintained. As a result, there was a further relaxation in security of supply standards made by the government on 1 July, 2014 with a new non-deterministic standard based on the value of energy at risk as a result of a contingency. This was underpinned by a Safety Net requirement, which ensures there is a reasonable upper limit paced on the time customers can expect to be without supply following a contingency in the distribution network.

Each change to the security standard has resulted in the level of Augex being reduced in order to maintain compliance with the standard.

4.2.3 Ergon Energy initiatives

Ergon Energy has been undertaking an increasing level of demand management projects during this regulatory control period to prove the approach is successful and, if so, to optimise expenditure on augmentation. This has deferred the need for augmentation at a number of targeted sites to well beyond the end of this regulatory control period. Additionally, Ergon Energy has been undertaking a project with the other Queensland DNSP, Energex, to identify areas where a common approach to standards and procedures could provide efficiency gains. This project has delivered efficiency improvements which have reduced the augmentation program during this and future regulatory control periods.

Ergon Energy undertook a review of its capital and operating expenditure in August and September 2012. This was following the completion of the second year of the regulatory control period. The review came after ENCAP recommendations were made public, after a 10.5% fall in consumption in 2010-11 and a decline in peak demand. The fall in consumption was thought to be due to seasonal conditions and changes in customer behaviour as evidenced by increasing solar photovoltaic and solar hot water connections, Home Energy Saver Audits and insulation programs. These latter changes in behaviour were expected to be sustained. The fall in peak demand compared to forecast was viewed more cautiously and thought to be due to the GFC and seasonal conditions. However, the expectation was that peak demand was easing but with the potential for future volatility.

4.2.4 Shareholder Expectations

In March 2012, a new government was elected in Queensland. The new Queensland Government brought with it a focus on electricity prices, cost of living pressures on Queensland families and fiscal repair (i.e. reducing the state deficit and returning to surplus over the medium term). As a government-owned corporation, the change in government bought with it changes in shareholder expectations for Ergon Energy.

In particular, shareholding Ministers wrote to Ergon Energy on 6 September 2012 and stated the following expectations of Ergon Energy to:

- position itself so that in the next regulatory control period, the network price for electricity will not increase greater than the CPI
- generate savings to the capital program that will limit growth in debt levels
- ensure efficiency savings are balanced against ongoing delivery of safe, secure and reliable services to appropriate technical conditions.

These changes to the shareholding Ministers’ expectations were implemented within Ergon Energy.

Shareholder expectations with respect to the network price were consistent with Ergon Energy’s existing Strategic Direction document, which set out Ergon Energy’s strategic goal of having average network prices rise at or less than CPI by 2020 and 1% less than CPI by 2025. This strategy was set because the affordability of electricity was (and continues to be) a major contributor to customers' perceptions of Ergon Energy providing value for money.

4.3 Effect on current period expenditure

The Somerville (ENCAP)[21] review conducted at the end of 2011 indicated savings[22] in augmentation of at least $249 million during this regulatory control period would result from the change in the security criteria at that time and a further $300 million reduction as a result of reducing forecast of peak demand (includes $110 million from Ergon Energy Demand Management programs). This corresponds to approximately $188 million and $226 million respectively in direct costs.

The change to the VCR/Safety Net approach to security criteria performed in 2014 has been forecast to reduce the level of augmentation by an additional $85 million ($64 million direct) for the remainder of this regulatory control period.

The reduction in actual and forecast peak demand (excluding demand management reductions) during this regulatory control period, as forecast in the ENCAP review, will result in an estimated reduction $190 million (approx. $143 million direct costs) in Augex.

The demand management program performed within Ergon Energy has resulted in an overall reduction in Augex of $322 million (approx. $243 million direct costs) during this regulatory control period.

Efficiency gains from joint workings have delivered savings in the augmentation program of $10 million (approx. $7.5 million direct costs) during this regulatory control period.

The remaining differences (<10%) between the original determination and actual outcomes relate to issues which are not able to be readily quantified.

The variations[23] to the original program are illustrated in Table 8 below.

Table 8: Current Period Expenditure Summary

Category	$ million[24] (estimated direct costs)
AER Determination	$1244
Actual Expenditure	$543
Difference	$701
Expenditure Reductions	
Category	**$ million 22 (estimated direct costs)**
Reduced Demand	$143
Demand Management	$243
ENCAP Security Criteria	$188
VCR/Safety Net Security Criteria	$64
Joint Workings Efficiencies	$7.5
Sum of Variations	$645.5

[21] Electricity Network Capital Program (ENCAP) Review 2011, from Queensland Govt. web site
[22] In nominal $'s of the day
[23] Ergon Energy estimate of Direct Costs by excluding on-costs where appropriate.
[24] Source from Table 1 and 7

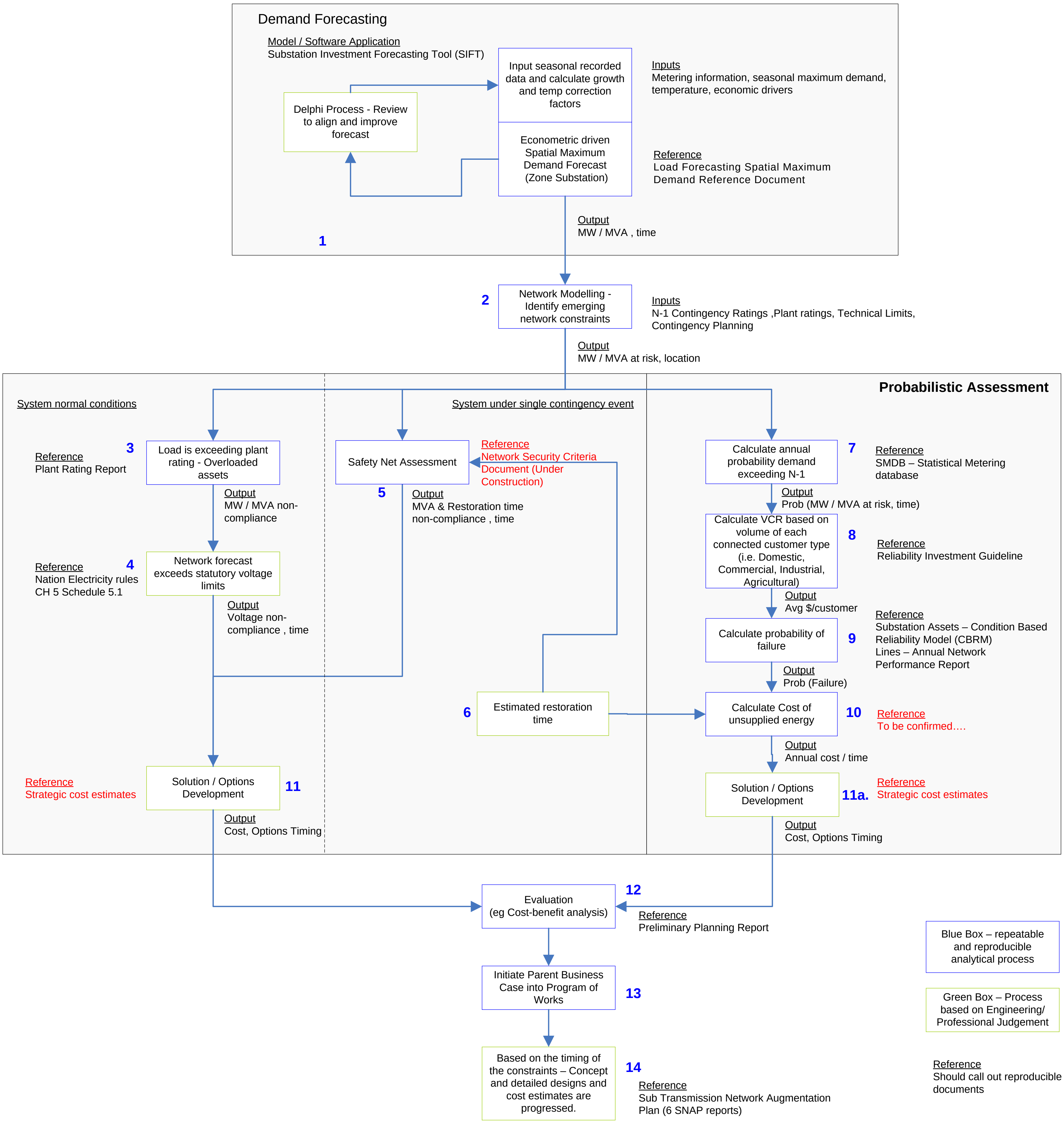

Figure 11: Sub-transmission Corporation Initiated Augmentation (CIA) capital expenditure forecasting methodology

5. Expenditure forecasting method – Sub-transmission

This section explains and justifies the method that Ergon Energy has used to forecast its CIA capital expenditure for the next regulatory control period for its sub-transmission network.

The remainder of this section explains and justifies the methodology by reference to the numbered stages in Figure 11. The methodology is consistent with normal industry practice for augmentation planning where loading on network elements is forecast; the rating of network elements is established; constraints as a result of loading and non-compliance with security criteria are identified; and the most cost effective solutions to resolve identified constraints are developed and submitted for approval through project governance processes.

5.1 Stage 1 – Demand forecasting

The purpose of this stage is to prepare a reconcilable system and spatial maximum demand forecast for a ten-year horizon. The system maximum demand is a single (i.e. system-wide) value, while the spatial maximum demand is prepared for each zone substation or bulk supply point. Ergon Energy also prepares a forecast for energy and customer numbers over the same period; however these are not used for the sub-transmission plan.

The system and spatial maximum demand forecasts, particularly the spatial forecasts, are key determinants of Ergon Energy's localised CIA capital expenditure programs.

The forecasts are prepared using a number of inputs, including:

- actual seasonal maximum demand
- gross state product at the system level
- gross regional product, demographics, and industry composition at the spatial level
- actual loading rates and temporal data
- actual temperature and weather information
- internal information about network operations, including switching events
- metering information, comprising of statistical metering, metering at connection points (from the AEMO) and SCADA information (which is used for collecting demand information where there are no meters).

The maximum demand forecasts are estimated using the Substation Investment Forecasting Tool (SIFT). This is a joint Ergon Energy and Energex internally-developed tool, which produces demand forecasts by supply point. The SIFT tool relies on the input of seasonally recorded data for the extrapolation of econometric data over the ten-year forecast period.

The maximum demand forecasts are then reviewed through the Delphi process, whereby subject matter experts assess the reasonableness of the forecasts. In particular, they check for any obvious misalignment of the spatial network forecasts. Where appropriate, adjustments are made to reflect local economic conditions.

The outputs of this forecasting approach are:

- econometric driven spatial maximum demand forecast by substation for MW, MVA and time – this therefore forecasts when maximum demand will occur within a year at each bulk supply point
- system-wide energy and customer numbers – these are used for calculating pricing and are provided to transmission network service providers. However, they are not directly used for sub-transmission CIA forecasts. They are used as indictors for the distribution forecasts (which is discussed below)
- seasonal MW and MVA.

Refer to the 'Load Forecasting Spatial Maximum Demand reference' document.

5.2 Stage 2 – Network Modelling

The purpose of network modelling is to undertake technical analysis of the sub-transmission network under system normal and N-1 conditions at times of peak demand. This will identify where and when physical constraints may arise and the conditions that may cause them. Through the network modelling analysis, it is possible to identify the areas of the sub-transmission network, which will be constrained under particular system conditions, for example, when one item of plant is not operating for a period. This analysis is used to identify the need for augmentation, and the nature of the plant that is required.

The key inputs to the network modelling include:

- the N-1 contingency ratings – these are what the system is capable of supplying under normal conditions and with one item of plant out of service, either at a feeder level or a zone substation level
- plant ratings – these are the line ratings and substation ratings (and components) that define the maximum load that plant can supply under normal and contingency conditions (i.e. where one item of plant is out of service). There is a difference between plants' continuous rating (i.e. nameplate) and a cyclic rating (i.e. plant can supply higher loads under a normal cyclic rating and under long term and short term emergency cyclic ratings)25
- voltage limits, as specified in Schedule 5.1 of Chapter 5 of the NER, which sets out voltages to be maintained at the sub-transmission level of the network. These are consistent with maintaining voltages at the distribution level within the limits specified in the Electricity Act 1994 (Qld)
- other technical limits – these may be investigated in a small number of cases and works recommended if necessary. This would include constraints arising as a result of the following technical characteristics exceeding allowable limits – harmonics, flicker and/or fault capacity of the plant.

The overriding assumption of the network analysis is that the network will remain as it is today, with only currently approved projects (i.e. beyond the Gate 3 stage of Ergon Energy's internal business case process) being factored into the capacity of the network.

Ergon Energy undertakes its network analysis using the DINIS[26] tool, which models and analyses the performance of present and planned distribution configurations under a range of operating conditions. It identifies whether each item of plant's rating is met or exceeded at times of peak

[25] The plant rating report is used to document plant ratings.

[26] The DINIS tool is a proprietary commercial power system analysis package used by many DNSPs and engineering consultants to model and analyse the performance of present and planned distribution network configurations under a range of operating conditions.

demand under normal and contingency conditions and establishes the magnitude of the overload or constraint for the year being modelled given the relevant demand forecast.

The key outputs of the network modelling stage are:

- MW and MVA at risk by location over the next ten years (the duration of the risk is analysed later in the process)
- spreadsheet output – produced from the results of the DINIS analysis.
- predictions of constraints due to load exceeding ratings or other technical limits being exceeded under System Normal or with one item of plant out of service.

5.3 Deterministic assessment

Ergon Energy uses two methods of forecast assessment – a deterministic process and a probabilistic process. They are separate, mutually exclusive processes – Ergon Energy does not assess the same projects using the two different assessment techniques. It first undertakes an assessment under System Normal Conditions (i.e. Stages 3, 4 and 11 below), then assesses the system under Single Contingency Event conditions (i.e. Stages 5 and 6 below) and finally under the probabilistic assessment (i.e. Stages 7 to 11A below) as a check to ensure compliance (or not) under each of these processes.

5.4 Stage 3 – Load exceeding plant rating

This stage determines if any item of plant is overloaded under System Normal Condition, having regard for the Normal Cyclic Ratings, loading limits, and network modelling outputs determined in Stage 2, in order to identify required actions. This stage does not involve new analysis in itself, but rather identifies where plant is overloaded under System Normal Conditions. Spreadsheets are developed that document load against plant rating to identify which assets are overloaded under System Normal Conditions. For this analysis, the Normal Cyclic Rating of the relevant plant and the 50% probability of exceedance (50 PoE) load forecast are used. This is presented as MW and MVA non-compliance.

5.5 Stage 4 – Network forecast exceeds statutory voltage limits

Again assuming System Normal Conditions, this stage determines when voltage limits and statutory regulations are exceeded, having regard for the Normal Cyclic Ratings, loading limits, and network modelling outputs determined in Stage 2 above, in order to identify required actions. Again, as with Stage 3, this does not involve new analysis in itself, but rather identifies where voltage limits are exceeded under System Normal Conditions. A spreadsheet compares voltage levels with voltage limits and identifies where and when limits are exceeded under System Normal Conditions.

5.6 Stage 5 – Safety net assessment

The safety net details the maximum times that Ergon Energy can have a customer without supply in the case of one item of plant being out of service. The times have been determined by Ergon Energy and approved by the Queensland regulator. The safety net is detailed in the ‘Security Criteria’ document and section 3.6.1 of this document.

In order to determine if the safety net will be violated, Ergon Energy assesses the maximum demand forecasts from Stage 1, the network constraint forecasts from Stage 2, and the estimated restoration times discussed in Stage 6.

The assessment flags where Ergon Energy needs to take action to avoid customers being off supply for longer than the specified safety net time. This then allows Ergon Energy to identify if additional capacity or action is required to meet safety net supply and restoration time limits.

Options analysis is then undertaken to establish the options available to restore supply to customers, given the current network configuration. As a result, Ergon Energy establishes where and when action is required to meet future supply requirements.

Breaches of this safety net are documented in the 'Sub-transmission Network Augmentation Plan' (SNAP) project list, and in the 'DARP'.

5.7 Stage 6 – Estimated restoration time

Ergon Energy estimates the time to restore supply to customers when an outage occurs by using engineering and professional judgement to explore all current options. Current options that may be explored include mobile substations (Nomads), network switching, temporarily replacing items of plant, mobile generation, and the use of spare items of plant. No augmentation or restoration processes are undertaken at this stage – only non-permanent options are explored.

Guidelines provide information about the time to deploy the temporary restoration options. However, the circumstances of each outage need to be examined to determine if these restoration times can be achieved, and how this is best done. The location of the fault relative to staff and spare plant can be important considerations – this is particularly significant given the large geographic area that Ergon Energy supplies. Ergon Energy prepares contingency plans by substation by high risk items of plant to ensure estimated restoration times can be achieved consistently.

As noted above, the restoration times feed into the safety net assessment in Stage 5 of the deterministic approach (and into the calculation of the cost of unsupplied energy by contingency event for the probabilistic approach).

5.8 Stage 11 – Solution/options development (Deterministic assessment)

So far in the above stages, Ergon Energy has not established long term options to address the identified constraints. This occurs in this stage.

This stage involves developing options to meet requirements under either System Normal or N-1 contingency conditions. The purpose is to determine the action that Ergon Energy needs to take to respond to the violations identified in Stages 3, 4 and 5 above. Engineering and professional judgement is used to develop the potential options and to determine their scope. This requires a detailed knowledge and understanding of Ergon Energy's network and of the constraints.

Options are analysed on a constraint-by-constraint basis, often with multi-element options considered, establishing a range of alternative solutions, both network and non-network or a combination of both may be proposed, with different timing and costs. The purpose of these options can be to remove the constraint, reduce the restoration time for a relevant constraint or reduce the level of risk associated with the constraint. The options identified are reflected in an Investigation Report, also known as a Preliminary Planning Report. At this stage no evaluation is undertaken of the different options identified.

5.9 Probabilistic Assessment

Illustrative examples of the probabilistic assessment described in the following sections are found in Section 3.6.5.

5.10 Stage 7 – Calculate annual energy at risk as a result of exceeding N-1

The purpose of this stage is to predict how long demand will exceed N-1 capacity (i.e. the number of hours for the number of days each year) by substation or sub-transmission feeder (it is noted that supply capacity may be limited to one or more substations if a sub-transmission feeder is out of service). As a result, this analysis determines the capacity of the network with one item of plant out of service. In order to do so, this analysis uses:

- the statistical metering database, which provides half-hourly data at each substation in the network. This assists in identifying when N-1 has been exceeded, and for how long
- the load at risk by location from Stage 2, above
- N-1 contingency ratings, also discussed above in Stage 2.

The outputs of this analysis are the energy at risk (MWh) by time, network component and contingent conditions. These are documented in a Probabilistic Assessment Spreadsheet.

5.11 Stage 8 – Calculate VCR (Value of customer reliability)

In this stage Ergon Energy determines the dollar VCR for plant, which is the economic value of a unit of unreserved energy. This reflects the value that customers place on an outage, measured in dollars per MWh for each type of customer (commercial, industrial, urban, rural etc.). These dollar values are sourced from the 'Reliability Investment Guideline, Ergon Energy/Energex Joint Reference Document'. They were determined in analysis undertaken by the consulting firm CRA.

Ergon Energy determines the applicable VCR by determining the weighted average of all VCR, having regard for the types of customers that are connected to the supply point.

The relevant VCR values are reflected into the Probabilistic Assessment Spreadsheet.

5.12 Stage 9 – Calculate the probability of failure

This stage involves identifying how often Ergon Energy expects an item of plant to fail. Information about plant failure rates is sourced from:

- CBRM models, which contains information about the age and condition of substations and the probability of plant failure for specific items of plant
- the Annual Network Performance Report, which contains information about the probability of line failures
- industry standard failure rates for plant where a failure rate has not otherwise been established (i.e. new sub-transmission feeder).

The numerical probability of asset failure is reflected into the Probabilistic Assessment Spreadsheet.

5.13 Stage 6 – Estimated restoration time

This stage involves the same activity as is described in Stage 6 above in section 5.7.

5.14 Stage 10 – Calculate the cost of unsupplied energy

This stage involves calculating the total cost of unsupplied energy at a particular supply point, by determining the product of the outputs of Stages 7, 8 and 9, which is then applied to the estimated restoration time from Stage 6. This determines the annual cost of unsupplied energy (i.e. the economic cost to customers, not Ergon Energy) of a contingency event at each supply point. This is then also reflected into the Probabilistic Assessment Spreadsheet.

5.15 Stage 11A – Solution/options development (Probabilistic assessment)

As for the equivalent stage of the deterministic assessment, Ergon Energy has not so far in the process established long term options to meet future demand under this probabilistic assessment. This occurs in this stage.

The key inputs into the solutions/options development are:

- the outputs of Stages 7-10, above
- strategic cost estimates, which are used to establish the cost of each option being examined, as based on standard Ergon Energy cost units embedded in the Ellipse tool
- strategic planning assessments which detail how the network will be configured in the long term (25 years) so that shorter term development can be consistent with what will be required into the future. This is performed by using regional council development plans and land use studies to determine where and how the network may need to be developed in the longer term
- engineering and professional judgement by Ergon Energy staff.

Options are analysed on a constraint-by-constraint basis, often with multi-element options considered, establishing a range of alternative solutions, both network and non-network or a combination of both may be proposed, with different timing and costs. The purpose of these options can be to remove the constraint, reduce the restoration time for a relevant constraint or reduce the level of risk associated with the constraint. The options identified are reflected in an Investigation Report, also known as a Preliminary Planning Report. At this stage no evaluation is undertaken of the different options identified.

5.16 Stage 12 – Evaluation

This evaluation stage applies to the solutions/options that have been developed under both the deterministic assessment and the probabilistic assessment.

Ergon Energy undertakes cost benefit analysis (by net present value) of the identified options. The Business Case Tool is used to compare options and to identify a preferred option. All of the information used in this assessment is drawn from the above analysis.

The output of this evaluation stage is the preferred option to address the identified constraints, including details of costs and timing.

5.17 Stage 13 – Initiate parent business case

Ergon Energy reflects preferred option identified in Stage 12 into a Parent Business Case. This could include multiple options to address the identified constraint, such as demand management, temporary augmentation response or a permanent augmentation response.

Child business cases are developed to address each step in the program.

The end result of this process is a program of works that identifies the optimal response to the identified network constraints.

5.18 Other issues

Ergon Energy also notes that:

- A regulatory investment test is required for all augmentation works requiring capital over $5 million.
- Some expenditure may be required to facilitate expenditure being undertaken by Powerlink. These can be considered as non-optional and as consequential projects to facilitate transmission investment. The overall work for these projects will be subject to the Regulatory Investment Test for Transmission and is co-ordinated as part of the Joint Planning Process as detailed in the NER.
- The 'DAPR' draws information from the demand forecasts, network modelling and constraints, and the program of works in the parent business case.

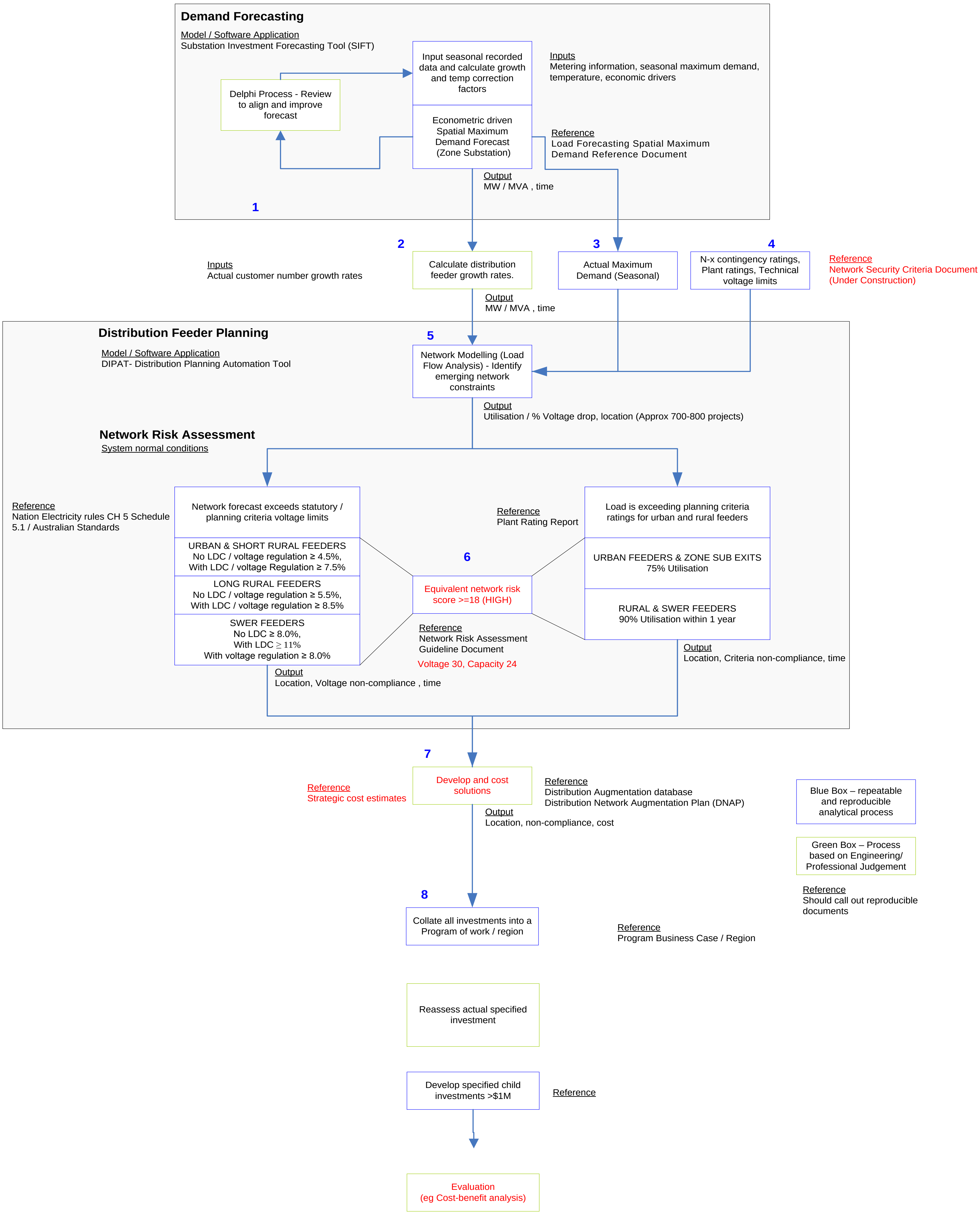

Figure 12: Distribution Corporation Initiated Augmentation (CIA) capital expenditure forecasting methodology

6. Expenditure forecasting method – Distribution

This section explains and justifies the methodology that Ergon Energy has used to forecast its CIA capital expenditure for the next regulatory control period for its distribution network.

The remainder of this section explains and justifies the methodology by reference to the numbered stages in Figure 12. The methodology is consistent with normal industry practice for distribution augmentation planning, where there is loading on distribution network elements is forecast. The rating of network elements is established and modelling of the network is performed; constraints as a result of loading and non-compliance with security criteria are identified and risks associated with the constraints are assessed; and the most cost effective solutions to resolve identified constraints that present an unacceptable risk are developed and submitted for approval through project governance processes.

The Distribution Network Augmentation Plan (DNAP) expenditure category relates to the capital works that are needed to meet the augmentation requirements of Ergon Energy's distribution network assets based on existing constraints and future demand forecasts. Distribution network assets include high voltage (HV) and low voltage (LV) distribution feeders and Single Wire Earth Return (SWER) schemes, distribution substations and all other related distribution equipment typically operating with nominal voltages under 33kV (in one of the Ergon Energy's regions 33kV is also considered as distribution network nominal voltage).

The dominant drivers of DNAP program in the regulatory control period 2015-20 relate to the existing constraints of Ergon Energy's distribution networks, and managing future growth and penetration of photovoltaic systems. The DNAP includes augmentation plans for HV feeders, SWER schemes and distribution transformers.

The main characteristic of the DNAP 2015-20 program is that it is structured into five main categories (See Figure 13 and Table 9). For comparison, the DNAP for regulatory control period 2010-15, and before 2010, included only two programs – specified DNAP and Unspecified/Un-modelled augmentation.

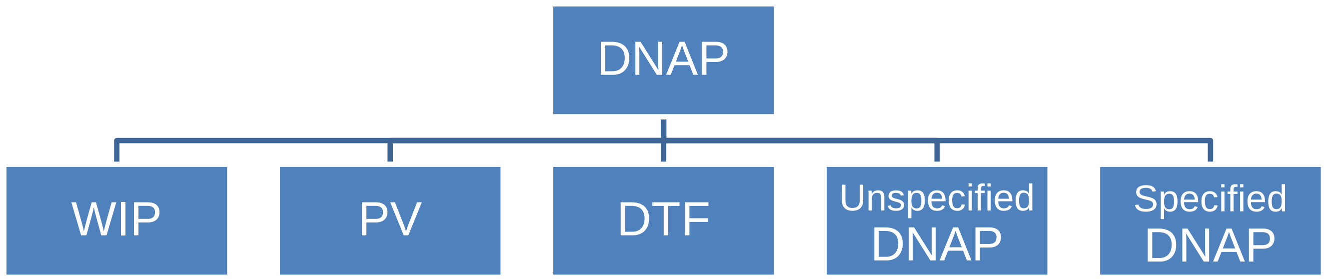

Figure 13: Structure of DNAP Program

Table 9: Distribution Network Augmentation Plan (DNAP) Expenditure Category Totals

DNAP Expenditure Category Totals for 2015-2020 (Direct Costs in 2012/13 $)	
Work in Progress	$ 42 million
Photovoltaic (PV)	$ 41 million
Distribution Transformers	$ 8 million
Unspecified DNAP	$ 80 million
Specified DNAP	$136 million

Specified DNAP projects address known capacity and voltage related problems on the distribution network (distribution feeders and SWER schemes). They are regionally modelled, reviewed, risk assessed, estimated, and specified. Specified DNAP projects combine conventional and 'non-conventional' network options, including demand management (e.g. embedded generators and power factor correction) and new technologies (Battery Energy Storage Systems - GUSS systems and HV STATCOMs). Some of the DNAP projects consider real-time data recording on specific network assets like overhead conductors and underground cable exists.

In comparison to previous regulatory control periods, which focused only on cable exits and first overhead sections out of zone substations, ALF studies now provide a detailed assessment of existing and future constraints of all sections of line across distribution feeders. Because of modelling the entire distribution network, for the first time the DNAP 2015-20 includes augmentation recommendations after considering limitations, loading profile and associated risks on the entire distribution feeder. Consequently, a number of distribution feeder constraints have existed during the present regulatory control period but will not be able to be addressed until the 2015-2020 regulatory control period.

Another feature of the DNAP program for 2015-20, which differs from the present regulatory control period, is the integration of SNAP 'child' projects recommending installation of new distribution feeder circuit breakers (CB) at zone substations in the DNAP structure. As the new CBs relate to establishment of new distribution feeders (DNAP 'parent' project), it was logically decided to transfer these projects from SNAP to DNAP.

Unspecified (also known as Reactive/Un-modelled) Augmentation is based on historical spend for the 2009-2013 period. This augmentation is required to address 'operational' constraints and issues seen in Ergon Energy's LV network which are not anticipated, forecasted or planned. Reactive/Un-modelled Augmentation requirements have been forecast by looking at historical spend and reducing this to account for potential overlaps with other program areas.

Distribution Transformer Augmentation (DTF) is a program developed to proactively upgrade distribution transformers with a level of utilisation exceeding their emergency capacity. The program estimate is based on analysis of utilisation levels of the entire population of Ergon Energy's distribution transformers (consisting of more than 90,000 transformers) by applying data about energy consumption, nameplate rating, ADMD and load category.

The DNAP 2015-20 has also undertaken proactive planning of photovoltaic connections and capital network planning of LV systems that was not performed for previous regulatory control periods. The number of photovoltaic/Inverter Energy System (IES) connections is expected to increase, however the rate of new connections is unclear. To cover this uncertainty, three different uptake scenarios have been created, modelling the number of potentially affected networks (Figure 14). Modelling of present number of IESs and the distribution of these systems throughout each region has been proportional to the density of customers. It was therefore determined that the change in numbers of connections in each region will continue as it is currently projected until there is a uniform distribution of systems throughout the entire Ergon Energy network. In combination with this and the economics of the DNAP, a low photovoltaic projection has been applied regionally in the development of the photovoltaic investment category.

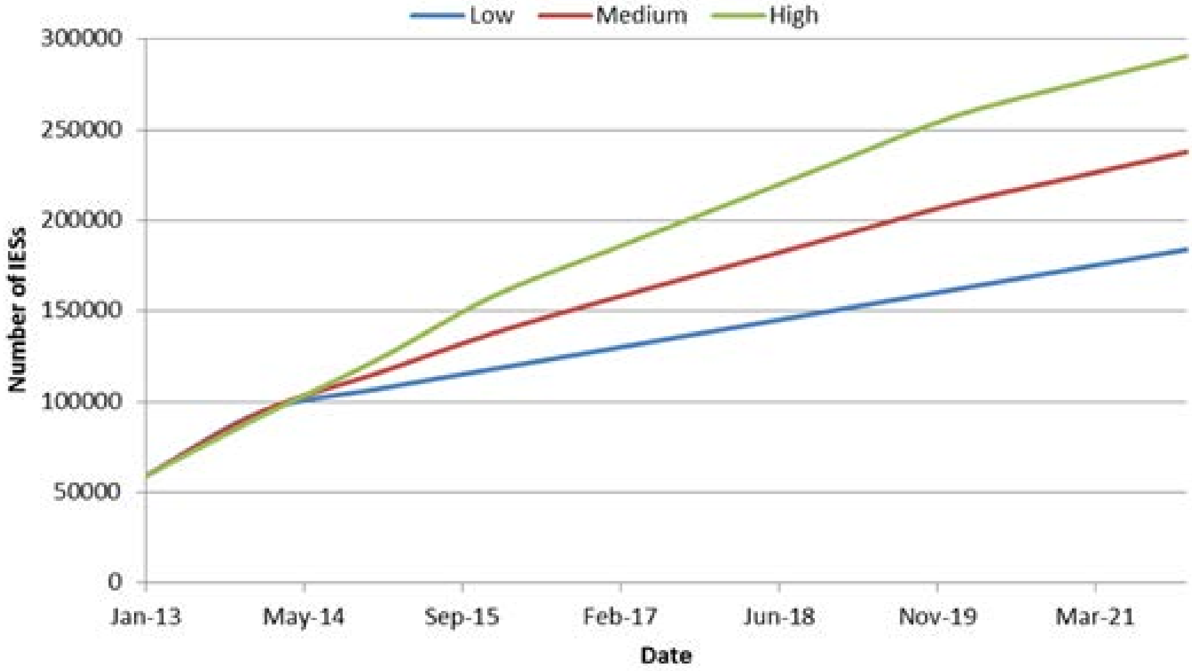

Figure 14: Projected numbers of PV/IESs in the Ergon Energy Network (2013-21)

Another specific (and certain corporate risk) is that in 2015-20 the sub-transmission augmentation program has been significantly reduced as a result of changes detailed above. All DNAP child projects associated with the sub-transmission augmentation projects have also been removed, so during 2015-20 the distribution network will need to partially manage risks (such as the reduction in ability to transfer load during network contingencies) associated with the removal of these projects.

A large contribution to capital expenditure in the regulatory control period 2015-20 is the number of DNAP carryover projects, also known as Works in Progress (WIP). It is expected that approximately 75 WIP projects initiated in the final months of 2014-15, will be completed in the early months of 2015-16, the first financial year of the 2015-20 regulatory control period.

In addition to the direct positive impact on future utilisation of Ergon Energy's distribution network, all capacity driven DNAP projects maintain the reliability of the distribution network. Voltage regulation projects rectify quality of supply issues. These 'additional' benefits are very important considering reduced investment for improving reliability performance of Ergon Energy's networks. In addition, many DNAP projects improve the age profile of Ergon Energy's assets, by replacing older network. With 47 planned new feeders and additional capacity, the DNAP programs are of vital importance for the future connection and development of Ergon Energy's distribution network, significantly contributing to the operability and flexibility of the network.

6.1 Stage 1 – Demand Forecasting

The same demand forecast analysis is used as the basis for the distribution CIA capital expenditure forecast as is described above for sub-transmission. The main distinctions however, are that the distribution forecasts:

- make greater use of customer numbers
- investigate regional growth in greater detail.

Professional engineering judgements are made about whether maximum demand growth or customer demand growth at the zone substation level provides the most appropriate basis for determining the distribution CIA capital expenditure forecast.

6.2 Stage 2 – Calculate distribution feeder growth rates

Ergon Energy uses the information in stage 1 to determine a zero to five year, and five to ten year average annual growth rate for maximum demand and customer numbers. The demand forecasts for zone substations are used to forecast demand at the distribution feeder level. This is done by planning engineers with on-the-ground knowledge, using engineering judgement to assess whether or not the growth in individual feeders is likely to be consistent with the related zone substation.

The results of this stage are therefore a zero to five year and five to ten year percentage MVA per annum growth rate. These growth rates are reflected into the Current State Assessment (CSA) of the DFD.

6.3 Stage 3 – Actual maximum demand

In this stage, Ergon Energy sources from its historic records, the actual maximum demand, based on its half hourly demand for individual feeders with switching removed. This data is also reflected in the CSA database.

6.4 Stage 4 – N-X contingency ratings

In this stage, Ergon Energy sources details of the ratings of the distribution plant, being the technical voltage limits and plant ratings. The ratings of distribution feeders are reflected into CSA database.

6.5 Stage 5 – Network Modelling

As for sub-transmission, network modelling of the distribution network is used to undertake technical analysis of the distribution system in order to identify emerging network constraints. It relies on the information gathered in Stages 2 to 4, above.

The Distribution Integrated Planning Automation Tool (DIPAT) is used to perform load flow analysis to identify emerging network constraints. Each individual line segment in the distribution is analysed, and those with high utilisation or voltage drop by location are then identified and examined (This does not include exit cables, which are analysed using a manual look up in the database to compare ratings to projected demand).

The key output of this network modelling is the identification of line segments with high utilisation and voltage drops by location.

6.6 Stage 6 – Network risk assessment

The purpose of this stage is to assess the risk of voltage and loading constraints on the distribution network. High risk constraints are then addressed through the distribution augmentation process.

A network risk assessment is undertaken with respect to the criteria of Network Health and Safety, Environment, Reliability and Capacity when there is a risk/limitation/constraint of the Ergon Energy Network and a works program or project is proposed.

Each risk scenario based on a specific risk driver/area of concern or interest based on identified risk factors is documented with the following information:

1. Scenario of concern including the chosen consequence of interest or concern
2. Risk Data Sheet including risk drivers, risk factors, strategic estimate, other controls in place
3. Assessed likelihood
4. Risk level calculations and details regarding any new or changed risk treatment measures.

Risk analysis includes analysing risks, choosing consequences, assessing likelihood and applying Risk Assessment Consequence and Likelihood Matrix (Figure 15).

Risk Analysis 6x6 multiplication R = C x L		Consequence					
		1	**2**	**3**	**4**	**5**	**6**
Likelihood	**6**	6	12	18	24	30	36
	5	5	10	15	20	25	30
	4	4	8	12	16	20	24
	3	3	6	9	12	15	18
	2	2	4	6	8	10	12
	1	1	2	3	4	5	6

Figure 15: Risk Assessment Consequence and Likelihood Matrix

The Risk Tolerability scale (Figure 16) that Ergon Energy has adopted for evaluation of semi-quantitative risk scores relies upon the following key risk principles:

Exposure to risks identified as intolerable must cease immediately, and the risk clearly communicated to the business.

For risks identified as intolerable for which exposure is still required and necessary, there is no limit to the resources and effort required to bring it into the tolerable range. There may need to be interim measures put in place to lower the risk while desired works are implemented.

There is no such thing as 'negligible' or 'zero' risk, and hence all risks identified should be managed (for very low risks this could be a simple as a periodic review).

For risks in the tolerable range, the aim is to reduce all network risks to As Low as Reasonably Practicable (The ALARP principle, as represented by the ALARP range in the risk tolerability scale).

Risk may remain in the ALARP range if it is shown further risk reduction is impracticable or requires action grossly disproportionate in time, trouble and effort to the reduction in risk achieved.

There is no barrier to allowing a particular risk to rise within the ALARP tolerable range, provided it is demonstrated that is the best outcome for the business, is supported by detailed risk assessments, and has the appropriate level of approval.

The periodic review frequency needs to be calculated and set according to foreseeable frequency of changes of significant risk factors. These frequencies must be recorded and flagged in the appropriate Risk Register.

	RISK TOLERABILITY CRITERIA, ACTION & APPROVAL REQUIREMENTS						
	RISK SCORE		RISK LEVEL		RISK TOLERABILITY CRITERIA & ACTION REQUIREMENTS		
					POSITION	METHOD	DETAILS
	30	36	Intolerable (stop exposure immediately)				
Tolerable Range	25	29	Very High	ALARP (Risk in this range managed to "as low as reasonably practicable")	EGM Asset Management	Quarterly Report + One Page Summaries	Each project to be supported by the project data sheet, network risk assessment and a one page executive summary (provided by RAM). EMT Report to be provided at discretion of EGM Corporate Risk Register to be updated Periodic Review Required.
	18	24	High		Asset Management Team	Quarterly Report + Project Details	Each project to be supported by the project data sheet & network risk assessment. RAM ensures project details available for review by accountable AMT Manager. Periodic Review Required.
	11	17	Moderate		Regional Asset Manager	Quarterly Report + Works Request	Each project to be supported by the project data sheet & network risk assessment. Project Instigator assigns WR to RAM which includes Project Data Sheet & Network Risk Assessment. Periodic Review Required.
	6	10	Low				
	1	5	Very Low	No Approval Required			

Figure 16: A Risk tolerability scale for evaluating Semi-Quantitative risk scores

6.6.1 Risk assessment of capacity and voltage constrained feeders

Applying Ergon Energy's risk assessment methodology and the process shown in Figure 17 and Figure 18, all DNAP projects have been assessed based on their level of constraint and risk scored.

C Scale	Distribution feeders			Distribution feeders or plant	
	Voltage for Urban & Short Rural	Voltage for Long Rural	Voltage for SWER	Utilisation Level - Urban feeder & all ZS feeder exits	Utilisation Level - Rural/SWER feeders
	C	D	E	F	G
6	No LDC- ≥8.0% voltage drop, LDC-≥11.0% voltage drop	No LDC- ≥9.0% voltage drop, LDC-≥12.0% voltage drop	No LDC- ≥12.0% voltage drop, LDC- ≥15.0% voltage drop, Voltage Regulation= 12%	≥100%	≥100%
5	No LDC- ≥6.5% voltage drop, LDC-≥9.5% voltage drop	No LDC- ≥7.5% voltage drop, LDC-≥10.5% voltage drop	No LDC- ≥10.5% voltage drop, LDC- ≥13.5% voltage drop, Voltage Regulation- ≥10.5%	≥95%	≥95%
4	No LDC- ≥5.0% voltage drop, LDC-≥8.0% voltage drop	No LDC- ≥6.0% voltage drop, LDC-≥9.0% voltage drop	No LDC- ≥9.0% voltage drop, LDC- ≥12.0% voltage drop, Voltage Regulation- ≥9.0%	≥85%	≥90%
3	No LDC- ≥4.5% voltage drop, LDC-≥7.5% voltage drop	No LDC- ≥5.5% voltage drop, LDC-≥8.5% voltage drop	No LDC- ≥8.5% voltage drop, LDC- ≥11.5% voltage drop, Voltage Regulation- ≥8.5%	≥75%	≥90%, within 1 year
2	No LDC- ≥4.0% voltage drop, LDC-≥7.0% voltage drop	No LDC- >5.0% voltage drop, LDC->8.0% voltage drop	No LDC- ≥8.0% voltage drop, LDC- ≥11.0% voltage drop, Voltage Regulation- ≥8.0%	≥66%	≥90%, within 2 years
1	No LDC- <4.0% voltage drop, LDC-<7.0% voltage drop	No LDC- <5.0% voltage drop, LDC-<8.0% voltage drop	No LDC- <8.0% voltage drop, LDC- <11.0% voltage drop, Voltage Regulation- <8.0%	<66%	≥90%, within 3 years

Figure 17: Risk assessment consequence scale (Likelihood scale at 50PoE)

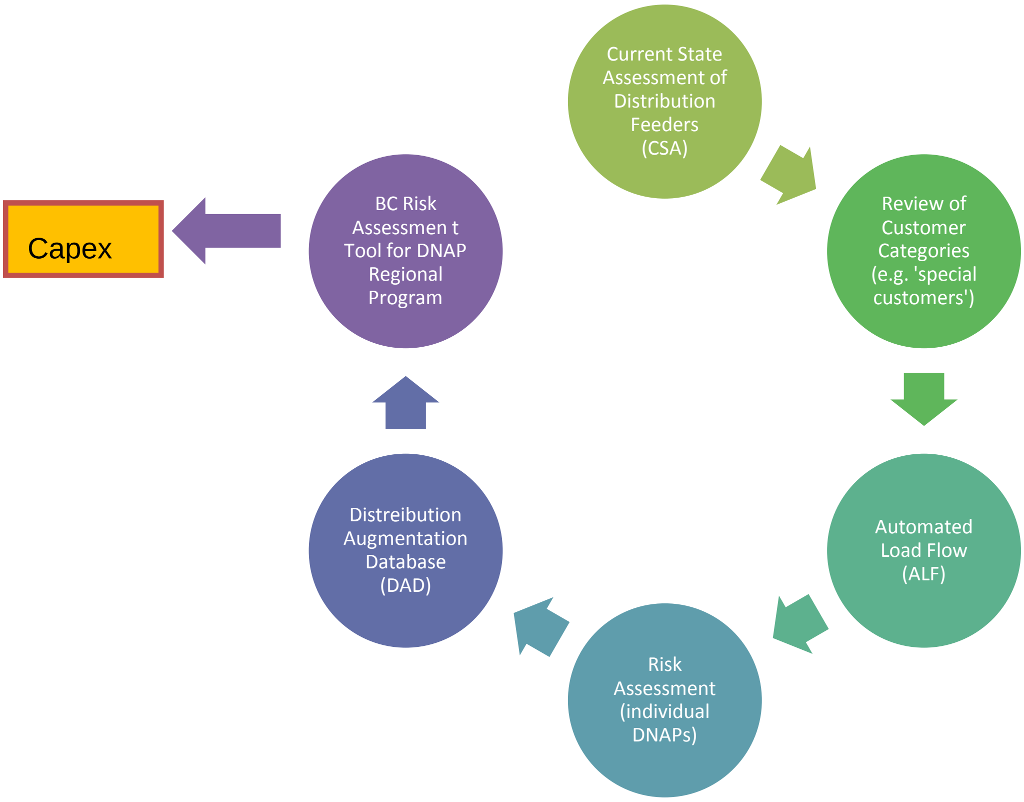

Figure 18: Risk assessment process of specified Distribution Network Augmentation Plan (DNAP) projects

The risk scores that have been used to qualify projects for the DNAP program of work are as follows:

- Capacity >=24 (Very High to Intolerable Risk removed)
- Voltage >=30 (Intolerable Risk removed)

These risks scores will result in the following outcomes:

- Capacity >=24 – Short term maximum utilisation levels for urban feeders of 85% (50PoE)
- Capacity >=24 - Maximum utilisation levels for rural feeders of 90% (50PoE)
- Voltage >=30 - Voltage drop (50PoE)
  - Urban 3.5% (max 6.5%, voltage at risk 3%)
  - Rural 4.4% or 7.0% with Load Drop Compensation (LDC)(No LDC max 7.5%, voltage at risk 3.1%, if possible to use LDC in rural areas voltage at risk 0.5%)
  - SWER 7.5 or 10% with LDC (No LDC max 10.5%, voltage at risk 3.0%, if possible to use LDC voltage at risk 0.5%)

6.6.2 Loading constraints and utilisation levels

Ergon Energy distribution networks have historically been operated as a 66% ('3 into 2') configuration with recent network criteria extending this to 75% ('4 into 3'). Increasing the utilisation increases the duration and number of customers affected during a contingency event as there is reduced transfer capacity.

For urban distribution feeder planning, an investigation will be triggered when the 50% PoE load exceeds 75% of the NCC rating of the feeder. However, construction is not scheduled until the loading reaches 85%. This is a prudent approach to planning distribution network augmentation, as annual variability in demand means that the feeder may not continue to exceed 75% of the NCC rating after the investigation has first been triggered. Using this criteria, more than 170 DNAP projects originally planned have been removed from program for the regulatory control period 2015-20.

This level of utilisation will result in some medium sized substations being unable to maintain supply to all customers during a contingency or operational requirement if more than one feeder is removed from service during a peak load period. This means during a single feeder contingency any additional planned work would require generation or customer outage.

Increasing utilisation long term will increase the heating internally and between adjacent cables. This will reduce the life expectancy of the cable and if the cable has been overloaded (a common historical occurrence) this may lead to failure. This heating will also de-rate the cables due to thermal dry out and temperature sharing. This will require close monitoring.

As lines will be normally loaded close to the rating (typically limited by statutory clearances) increased utilisation will increase the likelihood of exceeding clearances during 10PoE high load events.

Other risks associated with increasing the peak utilisation of urban feeders are:

- It is likely to result in a lower level of reliability
- An increased number of voltage and power quality complaints
- A reduction in the ability of the distribution network to assist with sub-transmission network failures.

There are different planning criteria for rural and SWER feeders on the basis that reliability consequences of a loss of feeder are less severe. Typically, these feeders will not have ties between them so Ergon Energy must ensure there is no overloading of feeders. Ergon Energy uses a planning criterion based on 90% utilisation of the feeder. This gives it a 10% safety limit (buffer) if above forecast maximum demand occurs. Any feeder at risk of exceeding the loading constraint is included in the distribution augmentation database. This database contains information about the loading constraints, the risk, and where potential projects may be required to address them.

6.7 Stage 7 – Develop and cost solutions

The purpose of this stage is to identify Ergon Energy's response to the identified constraint and to determine the project cost. This stage is effectively undertaken in conjunction with stage six as identifying the constraint and solution and then costing of the project, are all undertaken simultaneously.

Projects are recorded in the following four documents, which reflect the different stages of the augmentation forecasting process, from project identification to approval:

- Distribution augmentation database. This is developed in Stage 6, above
- 'Distribution Network Augmentation Plan' (DNAP) – this is a database of all projects, including carryover projects from previous regulatory control periods, which may not necessarily make it through to the approved program. New projects are sourced from the distribution augmentation database, and include all projects which would ideally be completed, given no constraints
- the approved works plan in Artemis 7. This captures projects that have formally been approved for delivery

- 'Distribution Annual Planning Report' (DAPR) – This document covers two years of projects on the distribution network, and identifies potential projects to address constraints. Solutions are typically discussed in general terms, and do not explore every solution or potential solution in detail.

Ergon Energy ensures that the solutions developed for distribution network constraints result in prudent and efficient outcomes by the following governance processes:

- Lean standard estimates are used in business cases for projects in the DNAP when they are being developed for approval;
- Gated business cases are used to ensure deliverability and minimise the risk of changes to estimates;
- The Network Investment Review Committee (NIRC) and Investment Review Committee (IRC) review and question business cases prior to approval;
- Post project reviews are conducted should there be any material variance in outcomes.

6.8 Stage 8 – Collate all investments into a program of work

In this stage, Ergon Energy collates the projects that are selected to be delivered into a program of works, based on priority of funding availability and risk level. They are then reflected into regional business cases.

6.9 Other issues

This section has explained the building blocks for developing the regional business cases for the distribution program. In addition, Ergon Energy has an 'unspecified' component of the distribution program business case. This unspecified component relates to managing issues such as customer voltage complaints, small urgent works, pole removals and overloaded distribution transformers. The timing for this 'unspecified' component is determined on a 'find as we go approach'. It is not based on the above forecasting modelling analysis but rather on a projection of the historical level of expenditure for this kind of activity.

In addition, there is a program business case for IESs/photovoltaic supplies (Shown as IES expenditure in Table 13, and documented in 'Distribution Network Impacts of Photovoltaic Connections to 2020'). This is justified based on the level of uptake of photovoltaic and the related voltage issues that they generate at the distribution network level. To date, due to a lack of remote monitoring equipment, voltage regulation issues have largely been identified through customer complaints. In the 2015-20 regulatory control period Ergon Energy will continue to roll out a comprehensive Power Quality Monitoring Program to identify such issues in a proactive manner and propose timely and targeted augmentation works in response. Forecast capital expenditure for the 'Power Quality Monitoring Strategy' is described in the 'Forecast Expenditure Summary Reliability and Quality of Supply 2015 to 2020' document.

7. Demand Management

Ergon Energy expects to invest $60.5 million in demand management over the 2015-2020 regulatory control period targeting a reduction in demand of 80MVA. This section summarises activities, strategies, risks, drivers and operation of demand management throughout Ergon Energy's network.

Ergon Energy considers demand management to be a key strategic capability for supporting the proposed reducing capital works forecast for the 2015-2020 control period, forecast to decline during 2015-2020 from $118 million in 2015 to $83 million in 2020. This reduced capital works program will be achieved by increasing the risk levels in the network and is not possible without the forecast risk mitigation support from demand management activities. The capital works program is forecast to be reduced by approximately $100 million in real terms over the regulatory control period due to the support from the $60.5 million demand management program.

This reduced investment in network assets from a combination of dynamic planning and demand management supports Queensland government initiatives such as The 30 Year Electricity Strategy and Queensland Plan as well as Ergon Energy's target of maintaining electricity price increases below inflation.

Ergon Energy's current demand management program consists of five main functions, which involve a range of activities that are evolving as part of the Effective Market Reform (EMR) strategic program. They are:

1. Committed works – existing programs with an ongoing operational component beyond the 2014-2015 financial year
2. Planned programs – programs that are forecast to commence in the regulatory control period 2015-2020
3. Smart Network – innovative use of new technologies in managing demand
4. Demand Management Innovation Allowance (DMIA)
5. Program management – the ongoing management and maintenance of the programs.

The forecast demand reduction targets in Table 10 highlight growth in the demand management program consistent with forecast decreasing capital expenditure over the 2015-2020 regulatory control period.

Table 10: Demand Reduction Targets

Additional Demand Targets	2014-15	2015-16	2016-17	2017-18	2018-19	Total
Broad-based, Smart Network Programs	3.3	2.5	3	3.5	4	**16.3**
Safety net risk mitigation	2	2.4	3.4	4.2	4.6	**16.6**
Network Constraint targeted programs	9	8.1	10.5	9.4	10.2	**47.2**
Total Additional Demand	**14.3**	**13**	**16.9**	**17.1**	**18.8**	**80.4**

Ergon Energy's commitment to demand management is demonstrated by Ergon Energy's existing 2010-2015 demand management program[27], which has had significant successes such as:

- Successfully aiding in the forecast deferral of $243 million of capital investment
- Delivery of the regulatory control period demand reduction target of 122MVA, 12 months ahead of schedule and under budget
- Contracting of demand via market engagement methodologies
- The first use of Ergon Energy's Demand Response Incentive Map (DRIM) and Trade Ally Network (TAN) market mechanisms to support market enablement.

In addition to these business as usual activities, changes to the network security criteria have provided additional drivers to support the use of demand management. The change from a largely N-1 security criteria to the VCR/Safety Net approach enables higher levels of risk to be tolerated within the network encouraging increased value from existing assets and increasing the need for risk mitigation using demand management. Ergon Energy's forward forecast capital expenditure reflects the use of demand management in supporting higher levels of risk with a reduced network augmentation program.

In consideration of the new planning methodologies and customer needs Ergon Energy are embarking on a program of EMR. The EMR program aims to enhance the linkages between network infrastructure capacity, network planning, demand management, market capabilities and customer choice by:

- Market Enablement – enabling the market access to timely, appropriate information on the value of demand via appropriate market channels.
- Dynamic Planning – forecasting and planning to further integrate customer demand capabilities into network planning analysis.
- Product Management – development and enablement of product solutions for demand management, including new customers and new customer loads.
- Market Engagement – use of third parties, aggregators, retailers and energy service suppliers to develop relationships with customers for the supply of demand services.
- Business Capability – greater implementation of intelligent devices in the distribution network for both measurement and control

A detailed review of demand management in Ergon Energy is provided in the 'Demand Management Overview 2015-2020' report.

[27] see Demand Management Outcomes Report 2013/14 for a detailed review of the program to date

8. Expenditure forecasts and outcomes for next period

This section details Ergon Energy's forecasts for its CIA capital expenditure for the next regulatory control period that it is proposing that the AER approve.

8.1 Expenditure forecasts for next regulatory control period

Table 11 provides a detailed breakdown of Ergon Energy's CIA capital expenditure forecasts for the next regulatory control period[28].

Table 11: Corporation Initiated Augmentation (CIA) capital expenditure forecast (Direct costs, $million real 2014-15)

	2015-16	2016-17	2017-18	2018-19	2019-20	Total
Distribution	69	64	64	63	63	323
Sub-transmission	49	53	51	20	21	193
Total	118	117	115	83	83	516

This table shows that:

- Ergon Energy is proposing to reduce CIA Capital Works during the 2015-20 regulatory control period.
- The first years of the regulatory control period are characterised by a larger percentage of works in progress.
- The proposed expenditure is in line with the load forecast for the network.
- The level of expenditure proposed achieves an acceptable balance between risk, reliability and the expressed expectations of customers.
- The proposed level of CIA Capital expenditure for the 2015-20 regulatory control period is below the estimated level of expenditure for this regulatory control period.

To assist it to assess the efficiency of Ergon Energy's proposed capital expenditure for CIA; the AER has published an Augex model. The purpose of the Augex model is to enable the AER to perform high-level analysis of Ergon Energy's expenditure to determine what areas of its planned augmentation may require further analysis.

The model uses Ergon Energy's historical expenditure levels, historical added capacity volumes, project details and samples to forecast expenditure from the present to the end of the next regulatory control period. Ergon Energy has derived the various planning parameters that are inputs into the AER's Augex model and used it to forecast augmentation costs for the 2015-20 period for several growth scenarios. Ergon Energy has then compared the outputs of the model with its proposed augmentation capital expenditure. The results of this comparison are presented in Section 8.3 of this document.

[28] Escalated for CPI only and excludes input price escalations and overhead as per the CAM.

8.2 Explanation of expenditure forecasts

8.2.1 Sub-transmission Augmentation

The proposed sub-transmission Augex for the 2015-20 regulatory control period is shown in Figure 19. This graph illustrates expenditure on projects in progress at the end of the 2010-15 regulatory control period and the expenditure on new projects commenced during the 2015-20 regulatory control period. Projects in progress are those, which have received, or are expected to receive before the AER's Final Determination, approval from Ergon Energy's NIRC or IRC and for which funds are considered to be committed.

Each of the investment committees' (NIRC and IRC) have charters that govern the process, the meeting and the delegation approvals. Refer to the 'Network Investment Review Committee (NIRC) Charter dated July 2014' and the 'Investment Review Committee Charter dated July 2014'

In the 2015-20 regulatory control period Ergon Energy has proposed capital expenditure for 23 existing (total $39.7 million) and 31 new (total $143.6 million) projects at the sub-transmission level. All new projects have been planned based on forecast loads associated with the low economic forecast for Queensland. Individual projects with cash flows and details of the driver of need are provided in the 'SNAP' spreadsheet.

Sub-transmission augmentation projects are based on five different drivers:

- VCR has justified the augmentation – in this case the value of load at risk exceeds the cost of augmentation
- Safety Net violation has justified the augmentation – in this case the project is required to ensure the times for restoration of load specified in the Safety Net (and Ergon Energy's distribution authority) are not breached
- Technical compliance: Exceedance of plant rating; non-compliance with NER; non-compliance with legislation
- The project is required to complement an upgrade of the transmission network by Powerlink Queensland or to satisfy the requirements of connection agreement with Powerlink Queensland – these projects result from the joint planning activity mandated by the NER.
- The project is a strategic acquisition of property to ensure future augmentation may proceed in the relevant area in future regulatory control periods at which time it may have become problematic to obtain the required property to allow the augmentation to proceed when justified.

Overall expenditure in each of the categories for the 2015-2020 regulatory control period is provided in Table 12 below (Direct cost in 2012-13 $).

Table 12: Sub-transmission Expenditure Categories

Expenditure Category	2015-16
VCR	57,053,199
Safety Net	33,424,944
Technical Compliance	61,368,935
Powerlink	26,922,722
Property Acquisition	4,517,002

Figure 19 shows the annual expenditure profile for the sub-transmission augmentation works. The first year of the 2015-20 regulatory control period shows the main expenditure is on projects that are already in progress with this transitioning to new projects over the next two years. Expenditure on new projects is reduced to below $20 million for the last two years of the regulatory control period.

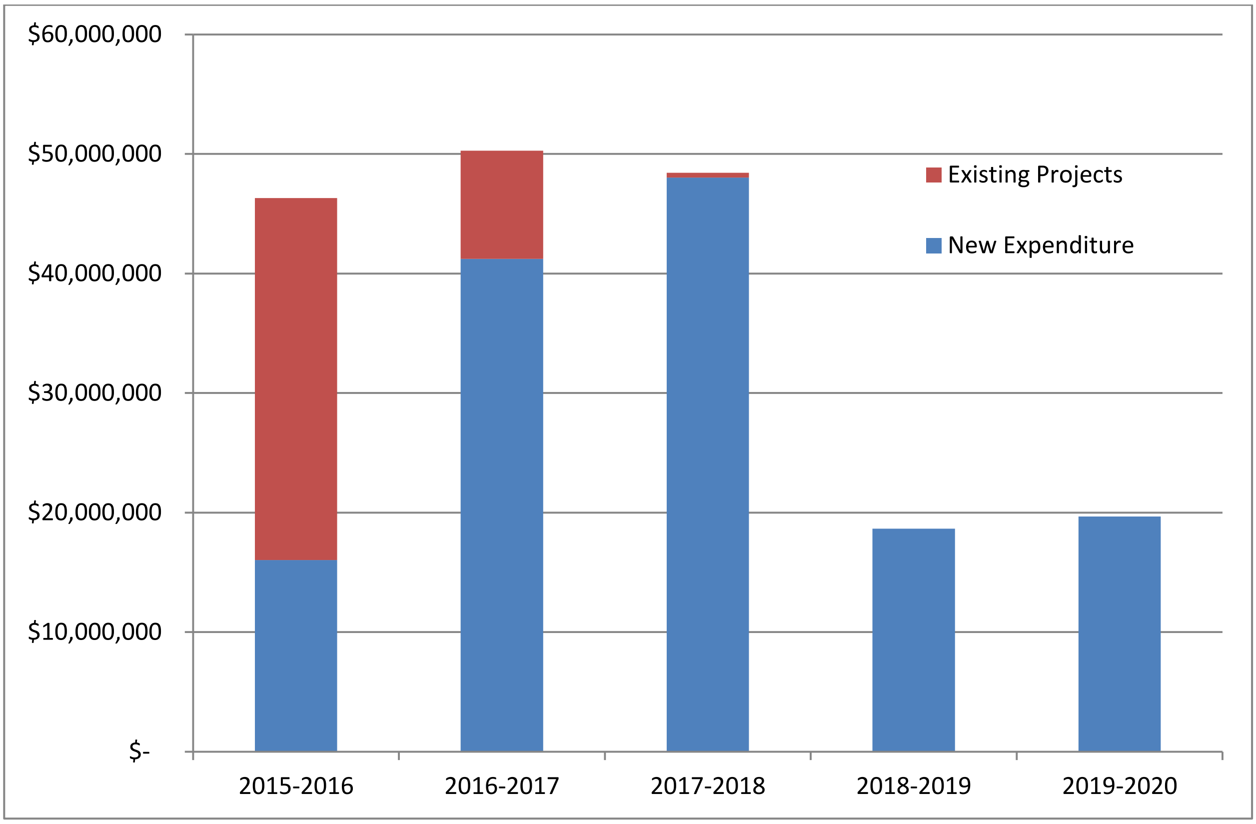

Figure 19: Sub-transmission expenditure profile (Expenditure per Financial Year)

The projected energy at risk for Urban, Rural and Long Rural zone substations based on the forecast program of works and load growth is provided in Figure 20. Energy at risk is the energy supplied in excess of the N-1 capacity of zone substations, if one element of the network was out of service and the load exceeded the capacity of the remaining in-service network this amount of energy would not be able to be supplied to customers without some mitigation works being performed.

This graph shows the energy at risk in all categories remaining relatively constant throughout the regulatory control period. This indicates that the level of performance of the sub-transmission network is being maintained, or slightly reduced, but not improved, throughout the next regulatory control period. Energy at risk is a suitable metric to reflect customer outcomes from the sub-transmission network as this area is characterised by infrequent but high consequence events hence maintaining a consistent overall level of energy at risk should maintain performance to customers at existing levels.

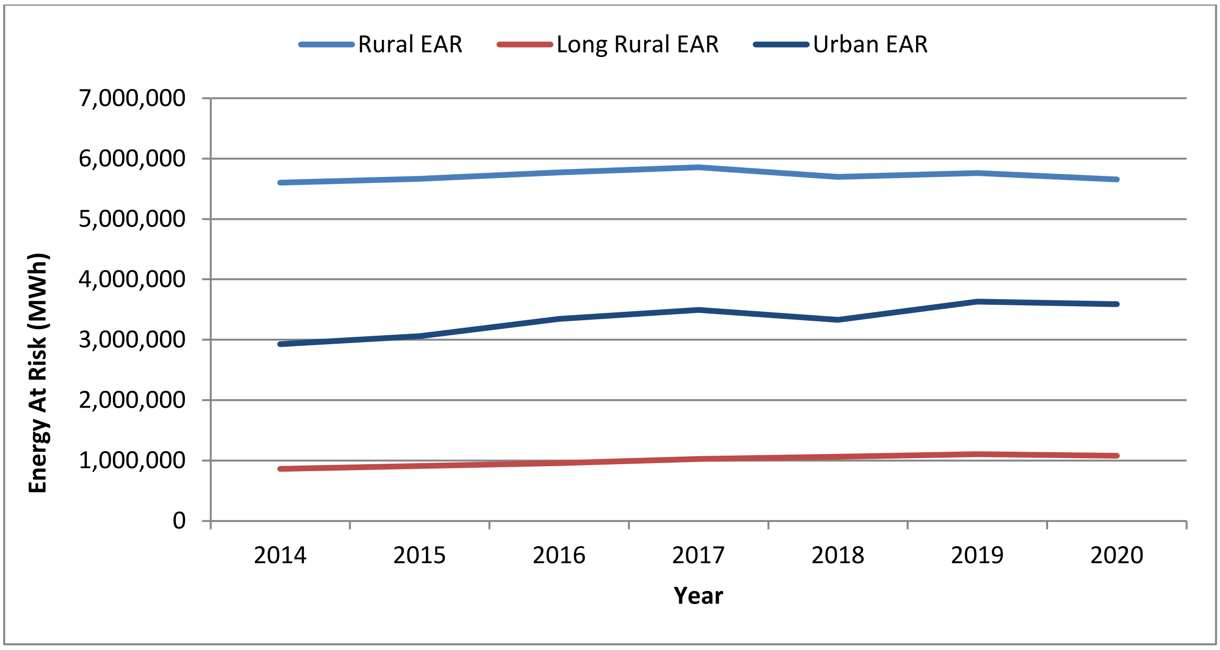

Figure 20: Projected Energy at Risk

8.2.2 Distribution Augmentation

In the 2015-20 regulatory control period, Ergon Energy has proposed expenditure of $306.5million at a distribution network level. Individual projects with annual cash flows are provided in the 'DNAP' spreadsheet.

The expenditure can be further classified into specific programs and geographic regions and this is provided in Table 13 below (Direct cost in 2012-13 dollars).

Table 13: Distribution Network Augmentation Plan (DNAP) expenditure categories

Distribution Transformer	**$8,440,602**
Distribution Network Augmentation Plan Central Region – AER Submission	$3,592,070
Distribution Network Augmentation Plan Northern Region – AER Submission	$2,726,686
Distribution Network Augmentation Plan Southern Region – AER Submission	$2,121,846
IES	**$40,606,608**
Distribution Network Augmentation Plan Central Region – AER Submission	$13,816,252
Distribution Network Augmentation Plan Northern Region – AER Submission	$7,986,857
Distribution Network Augmentation Plan Southern Region – AER Submission	$18,803,500
Modelled	**$135,527,283**
Distribution Network Augmentation Plan Central Region – AER Submission	$49,000,058
Distribution Network Augmentation Plan Northern Region – AER Submission	$42,754,458
Distribution Network Augmentation Plan Southern Region – AER Submission	$43,772,767
Reactive/Unmodelled	**$80,210,262**
Distribution Network Augmentation Plan Central Region – AER Submission	$26,948,112
Distribution Network Augmentation Plan Northern Region – AER Submission	$25,357,703
Distribution Network Augmentation Plan Southern Region – AER Submission	$27,934,448
WIP	**$41,672,343**
Distribution Network Augmentation Plan Central Region – AER Submission	$15,343,926
Distribution Network Augmentation Plan Northern Region – AER Submission	$2,819,031
Distribution Network Augmentation Plan Southern Region – AER Submission	$23,509,387
Grand Total	**$306,457,098**

In Ergon Energy's classification, based on the level of capacity constraint, distribution feeders are either classified as black (maximum demand or MD is >100% of feeder NCC), red (for urban feeders level of utilisation is >75%), yellow (50-75%) and green (<50%).

Voltage constrained feeders are classified as red and yellow based on voltage drop criteria. In general, voltage drop on red feeders exceeds 5% (urban), 6% (rural) and 9% (SWER).

Based on 2012 analysis there were capacity constraints on 212 distribution feeders (19.8%, mostly urban, Figure 21) including SWER schemes.

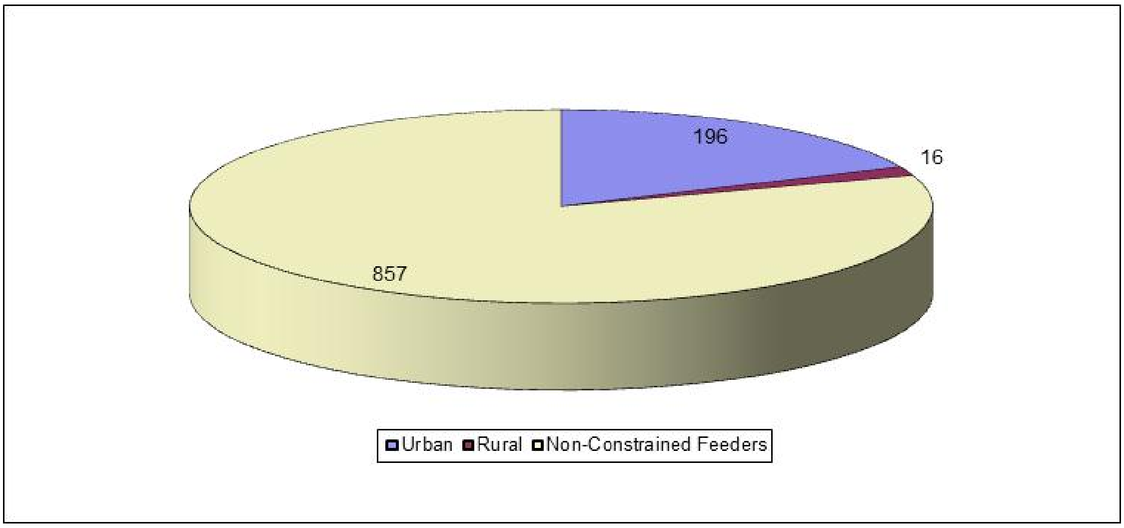

Figure 21: Summary of Distribution Feeder capacity Constraints (No of Constraints)

Voltage regulation constraints affected a total of 264 distribution feeders (24.7%) including SWER schemes. This is shown in Figure 22. Voltage constraints may relate to over or under voltage issues. In addition, there are 314 distribution feeders and SWER schemes nearing capacity constraint and 138 distribution feeders and SWERs nearing voltage constraint. Voltage constraints result in the voltage supplied to customers falling outside of statutory levels and can affect the safe operation of customer's connected electrical equipment.

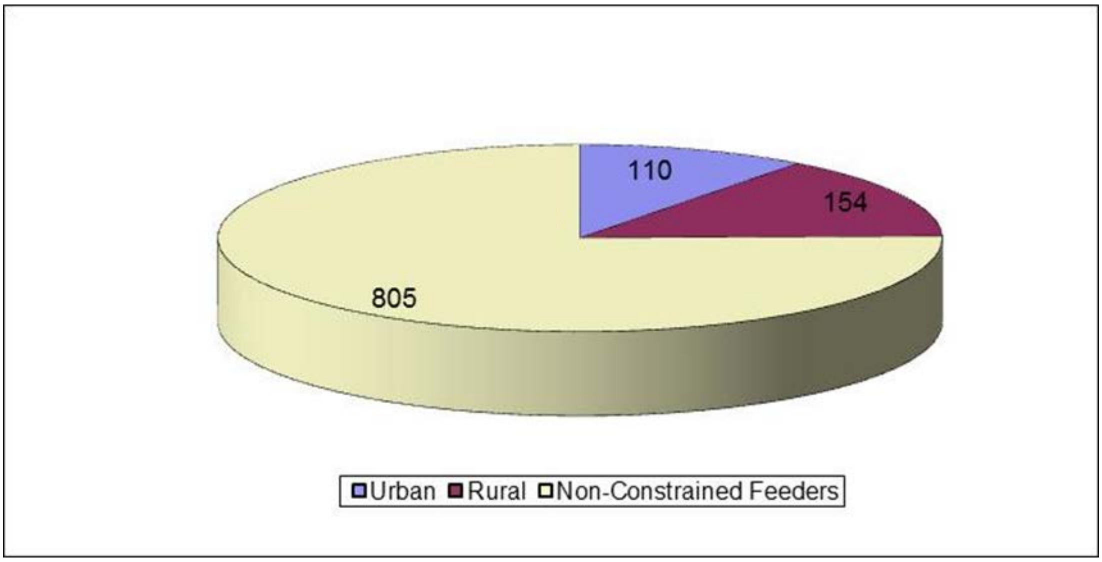

Figure 22: Summary of Distribution Feeder Voltage Constraints (No of Constraints)

Figure 21 and Figure 22 summarise capacity and voltage constraints recorded on distribution feeders and SWER schemes since 2006. Also, based on five and ten-year forecasting data, these graphs present the expected population of distribution feeders and SWER schemes, which will operate outside of planning and security criteria and voltage regulation standards in 2017 and 2022, in the case of 'Do nothing' option. Hypothetically, if there is minimum or no load growth, there will be approximately 200 distribution feeders with capacity constraints and more than 350 feeders with voltage-regulation problems. However, as the standard annual customer connection rate in Ergon Energy is approximately 9,000 to 10,000, it is expected that on an annual basis new connected load on distribution feeders will consequently be between 22 and 27 MVA increasing the maximum demand at the distribution level.

It should be noted that the historical numbers of constraints presented in these figures are based on the feeder underground cable exits, initial overhead sections and SWER isolators, and distribution substations utilisation and worst-case downstream voltage regulation zones of the network. However, for the 2015-20 regulatory control period, for the first time the development of the 'DNAP' has applied an assessment process across all feeder sections based on the current and ten-year load forecast (ALF Process). As a result, a number of feeder sections downstream from zone substations have been identified with capacity or voltage constraints and have been included in the 'DNAP'.

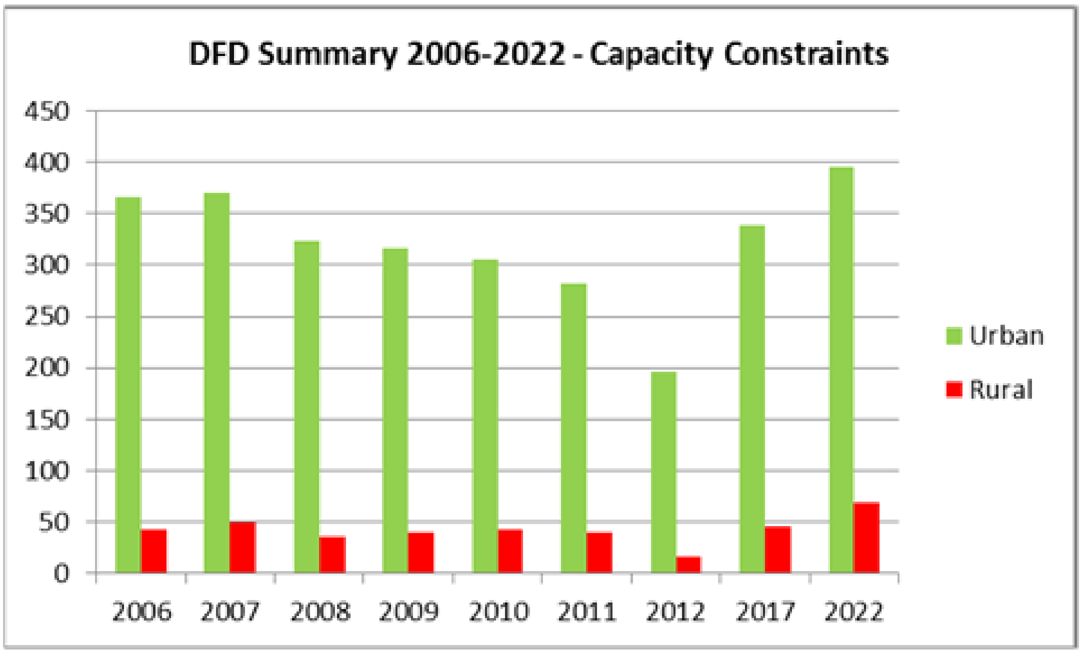

Figure 23: Distribution Feeder Database (DFD) – Capacity Constraints (No of Constraints per Year)

Between 2006 and 2012, Ergon Energy has proactively managed the Network Security Criteria applicable to these assets resulting in changes during the period. Ergon Energy has also reviewed and ultimately improved its overhead lines plant rating criteria.

The decrease in constraint numbers is evident in 2008 and 2012 for both urban and rural feeders. The 2012 constraint reduction primarily resulted from application of a new security criteria (increasing maximum utilisation from 66% to 75%). Additionally in 2012 the new plant rating criteria resulted in the ratings of overhead lines being increased between 5% and 25%.

Key changes to the Urban Planning Criteria changes include the following:

- 66% maximum utilisation in years 2006, 2007, 2010, and 2011
- 75% maximum utilisation in years 2008, 2009 and from 2012
- From 2012 new Ergon Energy climate zones and new overhead plant rating criteria were introduced.

The impact of new connections is of critical importance in understanding future feeder constraints. The annual connection of premises has increased from a historical low point in 2011 of approximately 9,100 to a 2013 level of approximately 10,900. This is shown in Figure 24. Overall, this is well under the ten-year average of 13,650 premises comprising approximately 5,000, 4,100, and 4,550 connections respectively for Northern, Central, and Southern regions. Currently 3,430, 4,940, and 2,530 connections are made in the respective regions.

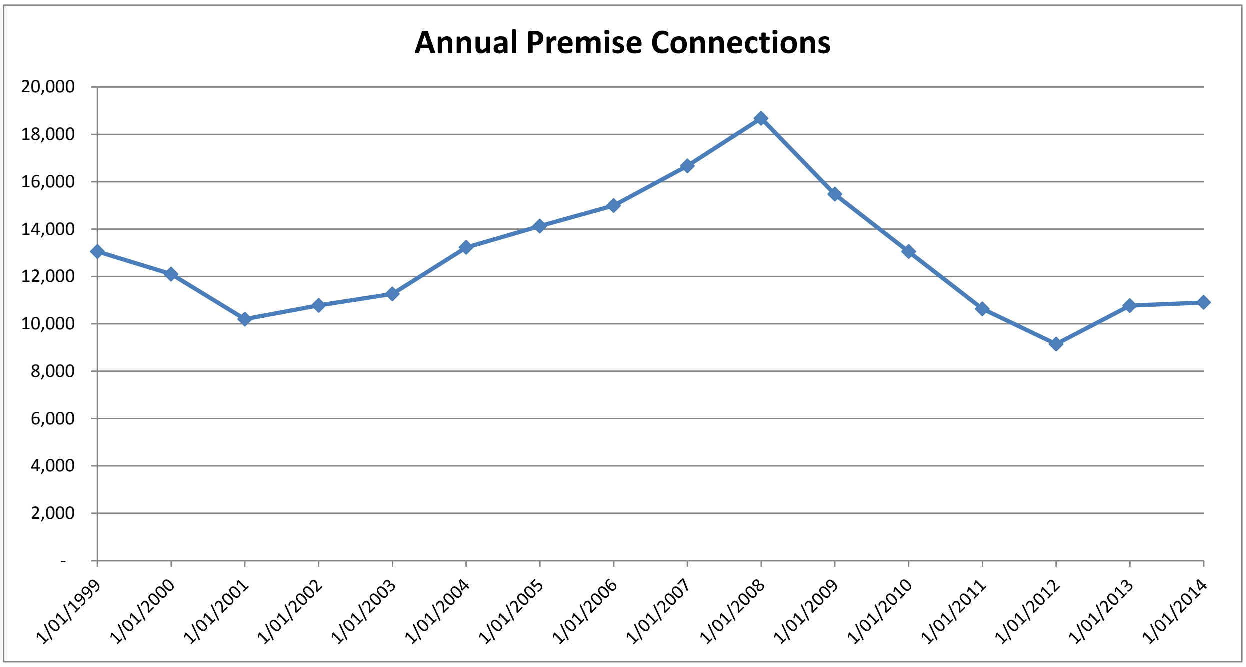

Figure 24: Ergon Energy Annual Premise Connections (excluding isolated communities) (No. of Premise Connections per Year)

An important factor for the distribution network is the impact of connected photovoltaic systems on distribution feeder constraints. To understand this subject, it is necessary to analyse feeder constraint levels (i.e. if feeder utilisation is 'black', 'high red', 'medium red' or 'low red'), load profile, time of maximum demand and penetration levels of photovoltaic systems on particular feeder. Based on our studies of a number of feeders with typical residential load profile in the Hervey Bay region, there is no evidence of reduced peak demand on distribution feeders as a result photovoltaic systems. Also, on one of the studied feeders voltage stability has been affected by higher photovoltaic penetration. The voltage regulation standard also impacted the number of voltage constraints which are shown in Figure 25. These again were in 2012 as part of the changes to the Network Planning Criteria.

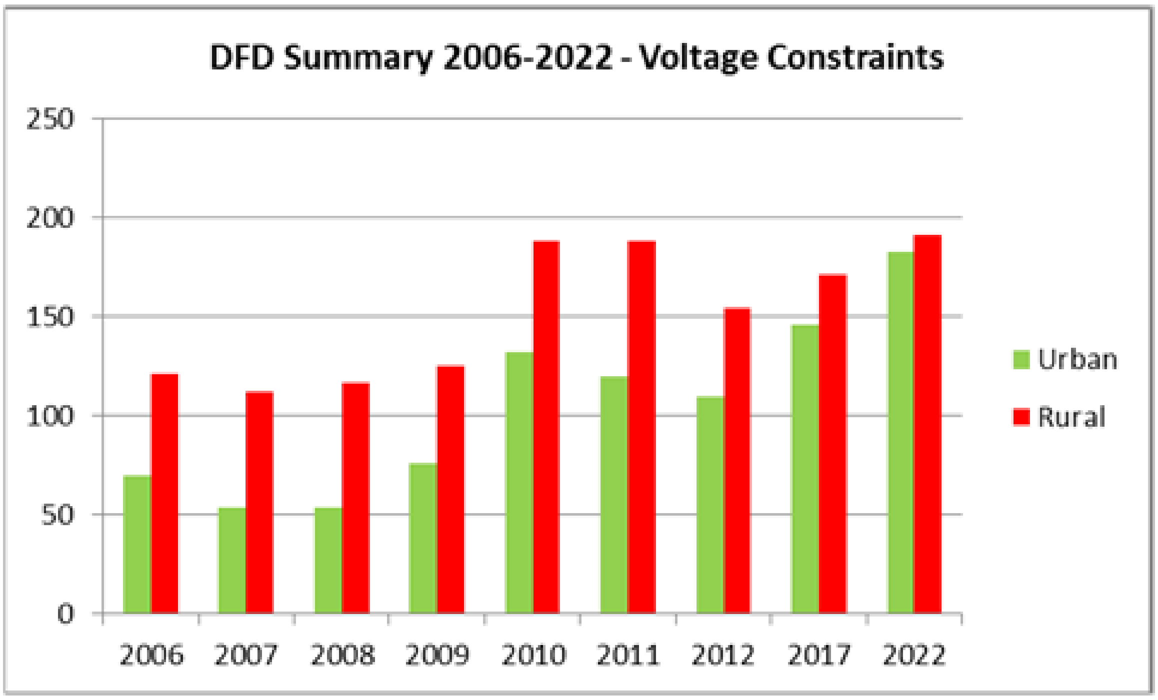

Figure 25: Distribution Feeder Database (DFD) – Voltage Constraints (Constraints per Year)

In 2012, the SWER Isolating and Distribution Transformer Plant Rating were increased in the following categories:

- >135% domestic
- >115% commercial
- >100% industrial
- >120% SWER isolating transformers.

In addition to this the SWER Voltage Regulation Criteria was also changed as stated below:

- >12% in years 2006-09
- >9% in years from 2010.

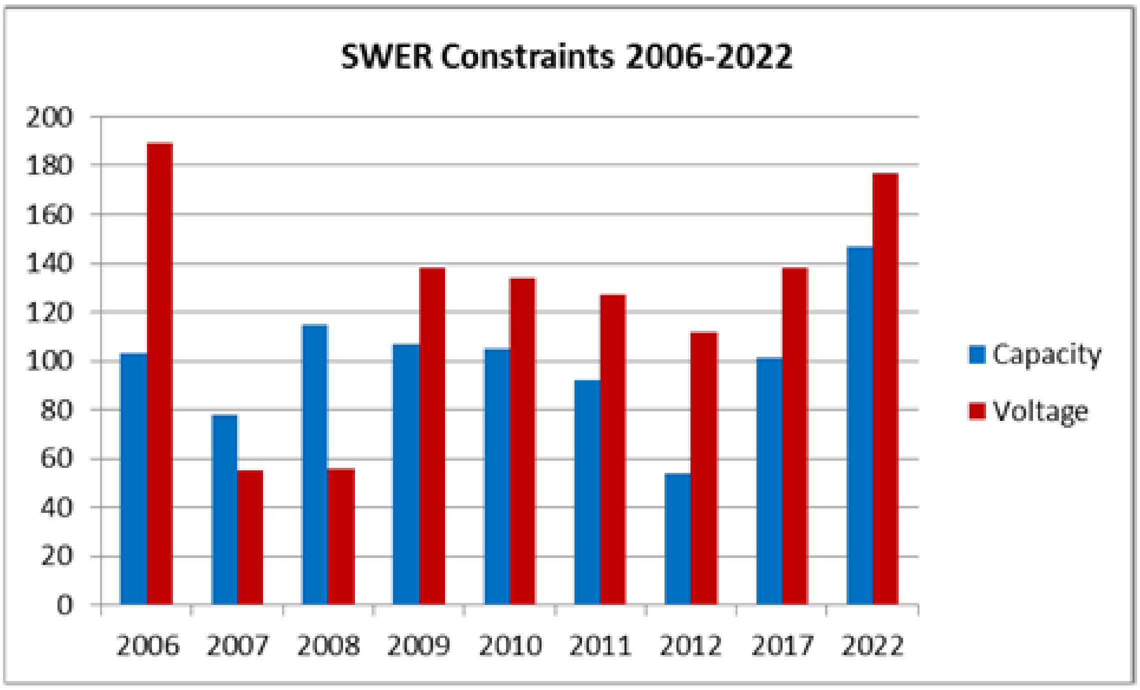

Figure 26: SWER Scheme Constraints (Constraint types per Year)

Change in the constraint level over the time is a combination of five factors:

1. change in the urban capacity criteria and voltage regulation standards
2. implementation of the new climate zones and new plant rating criteria
3. augmentation works being completed and ultimately providing more capacity
4. forecasted load growth
5. applied design temperature assumptions to underground cable and overhead line conditions.

Typically, new feeders are established as part of new zone substations (sub-transmission works sub component) in growing areas. It is expected, that owing to the reduction in the security criteria for sub-transmission assets the number of future constraints in the distribution network will increase.

Without augmentation, expectation is that the level of distribution feeder underground cable capacity constraints will increase from 145 to 286 over the period until 2022-23.

8.3 Augmentation Expenditure (Augex) Model Output

The AER has recommended the use of the Augex model to estimate the volume of capital expenditure, by category, calibrated on historical expenditure.

Consistent with the views of many other DNSPs and various independent consulting firms that have examined aspects of the Augex model, Ergon Energy notes that the Augex model has a number of limitations and potential flaws that prevent the model from being used for the purpose intended by the AER. The purpose of this attachment is to highlight a number of the concerns that Ergon Energy has regarding use of the Augex model.

For information on the Augex model inputs, please refer to the Submission RIN (Regulatory Information Notice), the related Basis of Preparation (BoP) document and Schedule 1 responses that are submitted separately to this document and give a more detailed description of a number of the model compilation and assumptions.

8.3.1 Challenges in model application

Modelling a complex, multi-billion dollar business such as Ergon Energy is very challenging. While Ergon Energy supports the attempt by the AER to use models such as Augex to inform and help guide the investigation and analysis of regulatory submissions, Ergon Energy cautions against the AER placing undue weight on such simple models for determining or comparing the Augex requirements of DNSPs.

As the AER notes in its November 2013 edition of the Augmentation Model Handbook: 'like other benchmarking techniques we [the AER] are applying, benchmarking through the Augex model may need to consider the environmental factors not allowed for within these assumptions'.

Ergon Energy engaged Heugin Consulting to do a benchmark review based on the information submitted to the AER in the Category Analysis (CA) RIN and to assess the impact of 'environmental' and other factors on assessing the relative performance of DNSPs. The report 'Ergon Energy Benchmarks – Category Analysis'[29] forms part of Ergon Energy's 'How Ergon Energy Compares' suite of documents. The Huegin report, and the 'How Ergon Energy Compares' document shows the challenges in defining and working with benchmark values across Australian DNSP's with differing networks and customer requirements. As can be seen from this material, and recognising the inherent limitations of benchmarking as an indicator of efficiency, depending on what variables are considered depends on whether Ergon Energy is able to be portrayed as one of the best or worst performing DNSP's in Australia based on a particular or single performance attribute or characteristic. This issue needs to remain a key consideration when assessing models such as Augex against the augmentation expenditure proposed in our regulatory proposal.

Page 8 of the Heugin review under Augex comments that *'The correlation between utilisation rate and customer growth rates and augmentation expenditure per km is fairly weak.'* This remains a concern given the dependence of the Augex model on these parameters as demonstrated by the use of them as inputs to determine augmentation thresholds and timing.

8.3.2 Ergon Energy specific considerations

As 'How Ergon Energy Compares' demonstrates, Ergon Energy operates a very different network to most Australian DNSP's in the National Electricity Market (NEM), typified by small customer numbers, long network distances, large geographical spread of network and subsequent low network densities. With 7% of the total NEM customer base, Ergon Energy's network area is 44% of the total area covered by the networks that form part of the NEM. Ergon Energy operates the lowest density network in Australia which has a large impact on how the network is designed, managed and operated. It is a largely overhead and radial network which includes one of the largest SWER networks in Australia.

Given the network topology described above Voltage Management is a key challenge for Ergon Energy. Voltage regulation constraints (over or under voltage) affected a total of 264 distribution feeders (24.7%) including SWER schemes. In addition there are 138 (13%) distribution feeders and SWERs nearing voltage constraint over the regulatory control period. Voltage constraints result in the voltage supplied to customers falling outside of statutory levels and can affect the safe operation of customer's connected electrical equipment.

Voltage constraints are not considered by the Augex model as it is predominantly based around capacity. Voltage is partially considered in the utilisation factor at time of augmentation in the model, but this is not considered accurate in the case of Ergon Energy's sparse and diverse network. Of the

[29] Huegin Consulting, Ergon Energy Benchmarks – Category Analysis' supported by 'How Ergon Energy Compares'

proposed distribution Augex proposal $54 million of the specified program is specifically related to voltage driven constraints, which is not appropriately captured in the Augex model. This concern has also been noted by the NSW DNSPs and detailed in the submission documentation by Essential Energy:

> *'The difficulty in applying the AUGEX model at the 11/22kV level of the network arises because of the difficulty that many DNSPs do not separate project financial data in a sufficiently detailed manner to enable distinctions to be made between the various types of expenditure and as a result, the accuracy of expenditure modelling is questionable.*
>
> *For some DNSPs augmentation to overcome voltage constraints represents a major part of their augmentation program. Modelling of these types of augmentation is complex, with capacity factors varying according to the location of the constraint on a feeder. The benchmarked variable of cost per MVA capacity added is highly variable in these situations, rendering benchmarking comparisons invalid.*
>
> *For these reasons care must be taken by the AER when considering AUGEX outputs for this level of the network.'*

8.3.3 Factors impacting historical expenditure

The Augex model relies heavily on historical spend, which is appropriate assuming the following conditions are met:

- That the expenditure and sample size is significant enough in each category to be averaged
- The expenditure has been recorded consistently and accurately by the DNSP over time and in a manner that fully and completely addresses the qualifications, limitations and guidance notes issued by the AER in terms of how the model is to be used
- That the expenditure is consistent during the regulatory control period, and not impacted by external factors
- That the expenditure incurred has dealt appropriately with the issues that developed during the regulatory control period, such that the state of the network at the beginning and end of a period are consistent and all relevant exogenous factors or major regulatory/security criteria/licence condition changes have been accounted for.

While the Augex model does appear to operate in some respects in accordance with some of the conditions described above, the adjustments and allowances made by the model to accommodate the above conditions are very basic despite the fact that they can have a very significant impact on the expenditure that occurred during a period. This is discussed in more detail below.

The model assumes that the volume of work completed during the historical period is equal to that which was required to address the relevant constraints during the forecast period. Carry-over of works between periods would be a requirement above the Augex forecast. In the case of Ergon Energy's regulatory submission this requirement for carry-over expenditure from the 2010-15 regulatory control period accounts for a total of $84 million, being comprised of $44 million of Distribution expenditure and $40 million of Sub-transmission expenditure.

Ergon Energy has focused strongly on the use of non-network alternatives such as Demand Management to reduce load and manage cost in the network. The demand management program performed within Ergon Energy was very successful, and has resulted in an overall reduction in Augex of $322 million (approx. $243 million direct costs), during this regulatory control period. In most cases demand management results in a deferral, not total removal of the capital expenditure. In addition to demand management, project need and timing is influenced heavily by the load forecast.

The success of the demand management program has resulted in several deferrals, some of which are able to be maintained as demand management solutions in the 2015-20 regulatory control period, but some of which will have risk and load increasing to a point that triggers network augmentation. The impact of this on the Augex model is similar to that of carry-over expenditure, as expenditure within the existing regulatory control period has been suppressed but projects may still be required in the following period.

The other challenge when considering historical spend are the projects that comprise the capital works program. Each category of investment from LV (415 V three-phase) to sub-transmission is managed differently and this has an impact on expenditure during the regulatory control period. Sub-transmission expenditure historically requires the largest portion of funding and comprises a smaller number of higher complexity and higher cost projects than those projects in other categories. This means that the consistency and stability of spend depends on the network requirements and hence projects underway during the relevant regulatory control period.

Sub-transmission investment is typically described as ‘blocky’ rather than ‘granular’. Sub-transmission project requirements and hence expenditure may stretch over three to five financial years and so it is very challenging to capture this effectively over a 5 year regulatory control period. At the other end of the scale is LV network expenditure, which is comprised of a higher volume of simple augmentation projects. These are not forecast specifically and are managed as an unspecified program as the most efficient management approach. For this reason project specific data may not be captured, and evaluation and categorisation of these projects can only be estimated. In general the Augex model is felt to apply better to the LV network than the sub-transmission network. In the case of the distribution network in Ergon Energy, small changes related to voltage management or increases in rural constrained locations can result in large swings in augmentation requirements, making it very difficult to generalise with a model such as Augex.

8.3.4 Changes in network management

Any change in the security criteria also has an impact on the results of the Augex model. While the total combined sub-transmission and distribution funding recommended from the model is representative, the proportional allocation between categories will need to change as a result of the changes in the security criteria. The present security criteria, requires a stronger focus on distribution network security compared to sub-transmission and as a result has changed the percentage allocation of funding between the categories. In brief this is because distribution transfer is required to support a reduced level of sub-transmission redundancy and because retention of distribution utilisation is critical in managing end-customer reliability outcomes. This should not impact the total expenditure forecast from the model but will impact the allocation of funding between categories.

The impact on the Augex model workings of Ergon Energy’s recent change in security criteria in July 2014, and other changes in security criteria as Ergon Energy transitioned away from the EDSD established N-1 criteria have not been fully assessed by Ergon Energy at this time, however, Ergon Energy considers that any consideration of the Augex model output by the AER without properly allowing for the impact of this change must be treated with extreme caution. Similar observations were made by the NSW DNSPs on changes in their licence conditions. An extract from the AER submission from Essential Energy Attachment 5.4 states the following:

> *‘An example of the type of external influence that renders the use of calibration to historic expenditure levels invalid can be seen in the Design, Reliability and Performance licence conditions imposed on the NSW DNSPs by the NSW government in 2007. These licence conditions imposed a requirement to provide N-1 security on most sub-transmission assets by 30 June 2014. Achieving this required significant levels of expenditure. As this level of supply*

security has now been achieved and this requirement has been removed from our licence conditions from the start of the next regulatory control period, augmentation expenditure will be significantly reduced in future compared to the past and calibrating expenditure forecasts to historic levels will produce meaningless results.'

The other challenge between regulatory control periods could be the proportion of investment between Urban/Rural areas. This has impacts in terms of the required cost for augmentation, with urban centres often requiring more undergrounding of feeders, additional traffic management requirements, as well as higher property acquisition costs than equivalent rural substations.

At this stage a detailed analysis of the overall differences and/or inter-relationships implied by the Augex model of historical to forecast Urban/Rural spend has not been conducted but this issue is included for noting. Ergon Energy notes that the AER recognises in the handbook for the model that while *'… urban distribution feeders are classified separately from rural feeders, partly because of these perceived differences … benchmarking via some other metric that captures transportation distances may also be required to normalise for these effects'.*

A significant change from the previous regulatory control period is the increased penetration of IES on the Ergon Energy Network. Ergon Energy has the highest average size of customer IES coupled with the lowest network density, resulting in a number of network challenges. The Augex model does not consider the impact of step changes in network requirements such as this between regulatory control periods, as it calibrates a historical expenditure model to future growth forecasts. The mass take up of IES in the form of Solar photovoltaic is such a step change and has resulted in a number of issues in the LV and Distribution networks. The requirements for network upgrades associated with IES are discussed separately in the document 'Distribution Network Impacts of Photovoltaic Connections to 2020' and require a total of $41 million to manage.

Ergon Energy's analysis of the Augex model suggests that at a practical level the model oversimplifies the impacts of this technology on the network. Photovoltaic technology will potentially change the utilisation profile and growth rate of the network over time. Ergon Energy's understanding is that at this stage, the Augex model can only accommodate a single demand growth rate figure and assumes that the utilisation profile will remain constant over time, which could significantly compromise the accuracy of any estimation.

8.3.5 Model calibration

The Augex model parameters were calibrated based on historical expenditure levels and augmentation patterns. Because of the inability of the Augex model to function with zero or negative growth rates across the entire program of work, sub-categories were created to represent high and low growth parts of the network. Because of the negative growth rates on the low growth parts of the network, no expenditure could be forecast for these elements with the Augex model.

The unit cost calculations were based on historical 'as commissioned' or project close expenditure, as per the requirements outlined in the AER augmentation model handbook. No threshold of materiality was used in this historical expenditure, as applying such a threshold would no longer be representative of the total historical Ergon Energy augmentation related expenditure. Table 2.4.6 in the Reset RIN requested 'as incurred' expenditure for the historical (and forecast) periods, which will be different to the expenditure used to generate the unit cost estimates. Ergon Energy feels that project close expenditure better represents the spend in categories where cost is incurred across multiple years, such as in sub-transmission augmentation projects.

The resulting Augex forecast (Table 14) only pertains to predicted expenditure on those parts of the network that are experiencing demand growth and it is only relevant to compare results with those projects which are being performed in the next regulatory control period due to emerging, growth related, constraints. The following components of the augmentation submission are not included in or forecast by the Augex model:

- Carry-over expenditure -The model assumes that the volume of work completed during the historical period is equal to that which was required to address the relevant constraints during that period. Carry-over of works between periods would be a requirement above the Augex forecast. Carry-over from the 2010-15 regulatory control period accounts for a total of $84 million being comprised of $44 million of Distribution and $40 million of Sub-transmission expenditure for projects not completed within one regulatory control period.

- Voltage related expenditure - voltage constraints are not considered by the Augex model as it is predominantly based around capacity. Voltage is partially considered in the utilisation factor at time of augmentation in the model, but this is not considered accurate in the case of Ergon Energy's sparse and diverse network. Of the proposed distribution Augex proposal $54 million of the specified program is specifically related to voltage driven constraints.

- Solar photovoltaic/IES Impacts- the Augex model does not consider the impact of step changes in network requirements between periods, as it calibrates a historical expenditure model to future growth forecasts. The mass take up of customer IESs in the form of Solar photovoltaic is such a step change and has resulted in a number of issues in the LV and Distribution networks. The requirements for network upgrades associated with IES are discussed separately in the document 'Distribution Network Impacts of Photovoltaic Connections to 2020' and require a total of $41 million to manage.

The change in the security criteria also has an impact on the results of the Augex model. While the total combined Sub-transmission and Distribution funding recommended from the model is representative, the proportional allocation between categories will need to change as a result of the changes in the security criteria. The present security criteria requires a stronger focus on Distribution security compared to Sub-transmission and as a result a change in the percentage allocation of funding between the categories. In brief this is because Distribution transfer is required to support a reduced level of Sub-transmission redundancy and because retention of distribution utilisation is critical in managing end-customer reliability outcomes.

Table 14: Augex Model Output Projected expenditure (Direct costs, $million real 2012-13)

	2016	2017	2018	2019	2020	Total
Sub-transmission lines	23.0	22.8	22.6	22.5	22.4	**113.3**
Zone substations	37.7	37.4	37.2	37.1	37.1	**186.5**
Distribution feeders	11.6	11.6	11.7	11.7	11.8	**58.3**
Total	**72.3**	**71.8**	**71.5**	**71.3**	**71.3**	**358.1**

Note: Table excludes WIP, Voltage related expenditure, or Step change impact of photovoltaic connections.

Table 15: Comparison of Augex Model to Proposed Augmentation (Direct costs, $million real 2012-13)

Comparison of Augex to Proposed Augmentation						
Year	**2015-16**	**2016-17**	**2017-18**	**2018-19**	**2019-20**	**Total**
Augex Output	$72	$72	$72	$71	$71	**$358**
Total Augmentation	$112	$111	$109	$79	$79	**$490**
WIP, Voltage and PV	$68	$39	$24	$23	$23	**$176**
Total Augmentation (less WIP, Voltage and PV)	$43	$73	$85	$56	$57	**$314**
Augex – Augmentation Variance	**$29**	**-$1**	**-$14**	**$16**	**$15**	**$45**

Table 14 above shows the output of the Augex model. Table 15 provides a comparison of the output from the Augex Model and Ergon Energy's proposed Augex.

The model estimates a total augmentation requirement of $358 million (Direct Costs) compared to our proposed 2015-20 regulatory submission of approximately $490 million (Direct Costs 2012-13 $). The inclusions and exclusions of this model were discussed above and exclude carry-over expenditure, voltage related expenditure and Solar photovoltaic impacts, totalling $176 million of additional requirement. Removing this expenditure from the comparison our 2015-20 proposal total expenditure is approximately $314 million compared to a modelled forecast requirement of $358 million, showing that our proposal is approximately $45 million or 12.5% less than forecast by the Augex Model and demonstrating a significant commitment to limiting investment to manage customer price increases.

Based on the above analysis and other DNSP reviews of how the Augex model operates, Ergon Energy considers that at its highest, the Augex Model may usefully be used only as a partial test as to the efficiency or prudency of the company's augmentation program as a whole.

In this regard, Ergon Energy echoes the following conclusion reached by the joint Networks NSW review of the Augex Model:

> *'…care must be taken to understand the investment context, environmental and political influences, as well as the underlying principles of network design and data capture before a model of this type can be used to substitute for detailed and appropriate expert interrogation of individual projects and their drivers.'*

9. Meeting Rules' Requirements

This section draws on the material in the previous sections to explain and justify Ergon Energy's CIA capital expenditure forecast against the capital expenditure objectives and criteria in clause 6.5.7 of the NER.

It therefore outlines why the AER should approve this capital expenditure forecast as part of its distribution determination for Ergon Energy's next regulatory control period.

9.1 The capital expenditure objectives

The NER set out the objectives that Ergon Energy's proposed capital expenditure for the next regulatory control period must satisfy. Clause 6.5.7(a) states:

> *A building block proposal must include the total forecast capital expenditure for the relevant regulatory control period which the Distribution Network Service Provider considers is required in order to achieve each of the following (the capital expenditure objectives):*
>
> *(1) meet or manage the expected demand for standard control services over that period;*
>
> *(2) comply with all applicable regulatory obligations or requirements associated with the provision of standard control services;*
>
> *(3) to the extent that there is no applicable regulatory obligation or requirement in relation to:*
>
> *(i) the quality, reliability or security of supply of standard control services; or*
>
> *(ii) the reliability or security of the distribution system through the supply of standard control services,*
>
> *to the relevant extent:*
>
> *(iii) maintain the quality, reliability and security of supply of standard control services; and*
>
> *(iv) maintain the reliability and security of the distribution system through the supply of standard control services; and*
>
> *(4) maintain the safety of the distribution system through the supply of standard control services.*

Standard Control Services is the name given to those services that Ergon Energy provides by means of, or in connection with, its distribution system, and for which the costs incurred by Ergon Energy in doing so are generally recovered through distribution use of service tariffs paid by all, or most, customers. SCSs are grouped into five categories: network services, connection services, metering services, ancillary network services and public lighting services The Standard Control Services that Ergon Energy provides to customers are set out in the 'AER's Framework and Approach – Ergon Energy and Energex 2015-2020' paper.[30] The proposed CIA expenditure relates to network services.

[30] AER, Framework and Approach – Ergon Energy and Energex 2015-2020, April 2014, p 51.

Ergon Energy believes that its proposed capital expenditure for CIA in the next regulatory control period achieves the objectives as follows:

- Meeting and managing expected demand for standard control services, as required by clause 6.5.7(a)(1), is one of the predominant objectives of Ergon Energy's proposed CIA expenditure, the nature of which is described in Section 3 of this document. Ergon Energy's CIA expenditure is driven by increased customer activity and maximum demand, which, if left uncontrolled, can constrain network assets. CIA expenditure is necessary as it enables Ergon Energy to take action to prevent these constraints from impacting the customer. Without Ergon Energy's proposed CIA expenditure, Ergon Energy would not be able to meet the expected demand for standard control services over the 2015-20 regulatory control period. The way in which Ergon Energy forecasts its CIA expenditure is primarily based upon a forecast of expected maximum demand, an assessment of network conditions under the expected demand against technical limits and the selection of the most cost effective solution that enables Ergon Energy to remedy the constraint and hence meet the demand. These processes are summarised in Section 5 and 6 of this document.
- The CIA capital expenditure that Ergon Energy proposes is necessary to comply with all applicable regulatory obligations or requirements associated with the provision of standard control services, as required by clause 6.5.7(a)(2).

  As described in Section 3.2, Ergon Energy is subject to regulatory obligations imposed by several statutory instruments at a state and at a federal level. Key legislation includes, but is not limited to, the *Electricity Act 1994 (Qld)* and the *National Electricity Rules.* Together, these instruments require Ergon Energy to ensure adequate, economic, reliable and safe supply of electricity to its customers and propose expenditure to manage expected demand for standard control services and hence electricity. How Ergon Energy determines the level of reliability to be supplied is largely driven by the 'economic' value of customer reliability and the Safety Net Measures, which are set out in the 'Security Criteria' document and in Ergon Energy's Distribution Authority. Additionally, Ergon Energy is required to maintain voltage levels at the sub-transmission and distribution levels within statutory limits.

  The methods that Ergon Energy has used to determine its CIA expenditure, and the resulting works that Ergon Energy proposes to undertake, are intended to discharge Ergon Energy's obligations under these and other statutory instruments. For further details on how Ergon Energy's statutory obligations inform its forecast CIA expenditure refer to Ergon Energy's sub-transmission and distribution network augmentation plans, relevant business cases, 'DARP' and the Network Planning Process Document. These and other supporting documents are set out in Appendix C and in turn form the basis for the forecast CIA expenditure set out in Section 8.1.
- The CIA expenditure that Ergon Energy proposes is necessary to maintain the quality, reliability and security of supply of standard control services, and hence the reliability and security of the distribution system, as required by clause 6.5.7(a)(3).

  Maintaining the quality, reliability and security of supply of standard control services as required by clause 6.5.7(a)(3), is one of the predominant objectives of Ergon Energy's proposed CIA expenditure. As described in relation to sub clause (2), the purpose of Ergon Energy's Security Criteria and the Safety Net Measures contained in Ergon Energy's Distribution Authority is to require Ergon Energy to maintain reliability and security of supply for all of its customers at all times. Ergon Energy's methodologies for forecasting expenditure for sub-transmission and distribution augmentation are designed to satisfy these obligations, and the resultant capital expenditure that Ergon Energy proposes is therefore necessary to maintain reliability and security of supply of standard control services and hence the distribution system over the 2015-20 regulatory control period.

Similarly, to maintain the quality of standard control services, Ergon Energy uses risk-based methodologies to ensure that voltage and other power quality indicators remain within operating and statutory limits. Based on the forecast maximum demand and the continuing increase in the penetration of solar photovoltaic systems, CIA expenditure to address voltage constraints and other power quality issues is necessary to maintain power quality at historical performance levels in the next period.

- The CIA expenditure that Ergon Energy proposes is required to maintain the safety of the distribution system through the supply of standard control services, in accordance with clause 6.5.7(a)(4). Ergon Energy has obligations under the *Electrical Safety Act 2002* (Qld) to inspect, test and maintain works, and a duty to ensure that its works are electrically safe and are operated in a way that is electrically safe. Under the *Work Health and Safety Act 2011* (Qld), Ergon Energy must ensure, so far as is reasonably practicable, that the fixtures, fittings and plant are without risks to the health and safety of any person. Additionally, Ergon Energy is subject to enforceable orders issued by the Queensland Electrical Safety Office in response to identified safety risks.

  To discharge these obligations, Ergon Energy must ensure that network assets do not exceed plant ratings, voltage limits or other technical limits that may compromise the safety of the distribution system. The established planning processes and practices in Section 5 and 6 that Ergon Energy has used to develop its capital expenditure forecast assist in the identification and prevention of such unacceptable risks. Ergon Energy's CIA expenditure and the resultant capital works that Ergon Energy proposes to deliver are therefore necessary to maintain the safety of the distribution system in accordance with Ergon Energy's regulatory obligations.

9.2 The capital expenditure criteria

Clause 6.5.7(c) states:

> *The AER must accept the forecast of required capital expenditure of a Distribution Network Service Provider that is included in a building block proposal if the AER is satisfied that the total of the forecast capital expenditure for the regulatory control period reasonably reflects each of the following (the capital expenditure criteria):*
>
> > *(1) the efficient costs of achieving the capital expenditure objectives;*
> >
> > *(2) the costs that a prudent operator would require to achieve the capital expenditure objectives; and*
> >
> > *(3) a realistic expectation of the demand forecast and cost inputs required to achieve the capital expenditure objectives.*

Clause 6.5.7(e) goes on to state:

> *In deciding whether or not the AER is satisfied as referred to in paragraph (c), the AER must have regard to the following (the capital expenditure factors):*
>
> > *(1) – (3) [Deleted]*
> >
> > *(4) the most recent annual benchmarking report that has been published under rule 6.27 and the benchmark capital expenditure that would be incurred by an efficient Distribution Network Service Provider over the relevant regulatory control period;*
> >
> > *(5) the actual and expected capital expenditure of the Distribution Network Service Provider during any preceding regulatory control periods;*

(5A) the extent to which the capital expenditure forecast includes expenditure to address the concerns of electricity consumers as identified by the Distribution Network Service Provider in the course of its engagement with electricity consumers;

(6) the relative prices of operating and capital inputs;

(7) the substitution possibilities between operating and capital expenditure;

(8) whether the capital expenditure forecast is consistent with any incentive scheme or schemes that apply to the Distribution Network Service Provider under clauses 6.5.8A or 6.6.2 to 6.6.4;

(9) the extent the capital expenditure forecast is referable to arrangements with a person other than the Distribution Network Service Provider that, in the opinion of the AER, do not reflect arm's length terms;

(9A) whether the capital expenditure forecast includes an amount relating to a project that should more appropriately be included as a contingent project under clause 6.6A.1(b);

(10) the extent the Distribution Network Service Provider has considered, and made provision for, efficient and prudent non-network alternatives; and

(11) any relevant final project assessment report (as defined in clause 5.10.2) published under clause 5.17.4(o), (p) or (s):

(12) any other factor the AER considers relevant and which the AER has notified the Distribution Network Service Provider in writing, prior to the submission of its revised regulatory proposal under clause 6.10.3, is a capital expenditure factor.

Therefore, Ergon Energy must demonstrate that its proposed capital expenditure reasonably reflects the criteria in clause 6.5.7(c) by reference to the factors in clause 6.5.7(e).

9.3 How Ergon Energy's capital expenditure reasonably reflects the criteria

The capital expenditure that Ergon Energy proposes to meet the objectives, in accordance with clause 6.5.7(a), reasonably reflects the criteria set out in clause 6.5.7(c) as follows.

9.3.1 The efficient and prudent costs of achieving the objectives

Ergon Energy has had regard for the AER's interpretation of prudency and efficiency in assessing whether Ergon Energy's capital expenditure reasonably reflects sub clauses (1) and (2) in this Summary. In the Explanatory Statement to the Expenditure Forecast Assessment Guidelines the AER stated that:

> *'We consider that efficient costs complement the costs that a prudent operator would require to achieve the expenditure objectives. Prudent expenditure is that which reflects the best course of action, considering available alternatives. Efficient expenditure results in the lowest cost to consumers over the long term. That is, prudent and efficient expenditure reflects the lowest long term cost to consumers for the most appropriate investment or activity required to achieve the expenditure objectives.'*[31]

As set out in Sections 5 and 6, Ergon Energy has developed objective methodologies to model the number and location of the network constraints, based upon reasonable and robust demand

[31] Australian Energy Regulator, Expenditure Forecast Assessment Guideline for Electricity Distribution, November 2013, p 12.

forecasts, to establish prudent volumes of CIA activity to address expected constraints at the sub-transmission and distribution levels. Each methodology that Ergon Energy uses enables Ergon Energy to determine the most prudent action to be taken, at the most appropriate time, having regard for the objectives, which its expenditure must satisfy. These actions primarily result in a specified project or a program of works to address a specific need and are set out in the ‘Sub-transmission Network Augmentation Plan’ and the ‘Distribution Network Augmentation Plan’. CIA expenditure also includes an unspecified component which is discussed in Section 6.9, which Ergon Energy considers to be prudent because it is based upon a projection of similar historical activity that Ergon Energy expects to undertake to fully meet the objectives set out in clause 6.5.7(a) of the Rules. Ergon Energy’s decision making processes, and the way in which they achieve prudent outcomes, are demonstrated throughout its corporate policies, protocols, standards, Network Planning Reports and associated supporting documentation and business-as-usual governance processes.

To develop an efficient cost base Ergon Energy has adopted a robust methodology to estimate the unit costs of projects and programs of works, based on a combination of historic and estimated costs. These costs, and how they are developed, are described in the summary paper titled ‘Capital Expenditure Forecast Unit Cost Methodologies Summary 2015 to 2020’. Ergon Energy applies unit costs to the projects and programs, based on forecast volumes of work to be delivered, to determine an efficient forecast level of CIA capital expenditure.

Ergon Energy considers its capital expenditure to be both prudent and efficient because not only are its unit costs efficient, Ergon Energy applies those efficient costs to the prudent actions it proposes to undertake so that its total CIA expenditure is both prudent and efficient.

9.3.2 A realistic expectation of the demand forecast and cost inputs required to achieve the objectives

Ergon Energy has significantly improved its demand forecast methods in response to concerns raised by the AER in the previous regulatory determination. The forecasting approach that Ergon Energy has used is based on a comprehensive, independently verified methodology which has been applied to obtain a robust and realistic expectation of the demand forecast, because:

- Ergon Energy has developed an independent system maximum demand methodology that can be used to reconcile spatial forecasts at the zone substation level;
- Ergon Energy has developed a methodology that allows for variation in key economic, demographic, appliance and weather factors; and
- Ergon Energy now applies a weather normalisation process to its forecasting process.

These and other factors that demonstrate how Ergon Energy’s demand forecast is realistic are discussed in Section 3.5 of this document.

Ergon Energy adopts a realistic expectation of the cost inputs required to achieve the objectives by developing unit costs that are based on a reasonable and robust estimation methodology. This methodology excludes inefficient costs when evident, includes only those costs to do the task and presents a transparent set of escalations (where applicable) owing to contractor and mobilisation costs in establishing direct costs. Mobilisation and contractor costs are assessed and applied on a per-project basis based on costs incurred by similar projects in the current period. For further details see the ‘Capital Expenditure Forecast Unit Cost Methodologies 2015-2020’.

9.3.3 Having regard for the factors

Ergon Energy's proposed capital expenditure reasonably reflects the prudent and efficient costs of achieving the objectives by having regard for the factors in clause 6.5.7(e) as follows:

- In relation to sub clause (4), in September 2014 the AER decided to delay the release of its first benchmarking report under clause 6.27 until late November 2014, one month after the submission of this Regulatory Proposal. As a result Ergon Energy has not been able to use it to inform its capital expenditure forecasts. Nevertheless, using the same publicly-available information that will be used to develop the AER's benchmarking report, Ergon Energy commissioned an independent report to enable it to compare its performance and other network service providers, having regard for the unique qualities of Ergon Energy's network. This is prudent because Ergon Energy has quite unique cost drivers which should be considered when benchmarking performance. For further details refer to the 'How Ergon Energy Compares' document.
- In relation to sub clause (5), Ergon Energy has set out, in Tables 1 and 2 of this Summary, its actual capital expenditure during the previous regulatory control period (2005-10) and actual and expected capital expenditure in the current regulatory control period (2010-15). To accompany this information, in Section 4, Ergon Energy has explained the actual and expected capital expenditure by reference to the allowance approved by the AER (and, for the 2005-10 regulatory control period, the QCA) and the endogenous and exogenous factors that have contributed to any variance from the AER's allowance.

  Where its current period expenditure has deviated from the AER's allowance, Ergon Energy has explained this by reference to drivers and circumstances that support the prudency and efficiency of the level of capital expenditure that was actually incurred. This demonstrates the robustness of Ergon Energy's system of investment review controls, which ensures that Ergon Energy's capital expenditure is continuously assessed for prudency and efficiency.
- In relation to sub clause (5A), Ergon Energy has conducted a comprehensive program of customer engagement to identify the concerns of electricity consumers and ensure that its proposed capital expenditure addresses those concerns. The results of Ergon Energy's engagement, and how they have informed its forecast CIA expenditure, are set out in this summary document and in the document entitled 'Informing Our Plans, Our Engagement Program'. Despite the slowing growth in overall network demand, Ergon Energy's network exhibits a diversity of demand profiles, many of which are continuing to grow. The CIA expenditure that Ergon Energy proposes is necessary to maintain existing levels of reliability to accommodate a variety of customer profiles and economic conditions, as expected by our customers.

  However, Ergon Energy has also set out on a journey to change how it plans and operates the network so that Ergon Energy can achieve the best possible price for its customers. To this end Ergon Energy is rolling out 'smart' technologies that enable it to use the network it already has smarter, and adopting a role as market enabler to facilitate the emergence of new market participants that develop new economic and sustainable energy solutions. In turn this will empower consumers to seek the energy solution that is right for them - how their electricity is generated, where it is generated and how they wish to consume it. Further details on how Ergon Energy is proactively responding to the concerns of electricity consumers are found in relation to sub clauses (6) and (7) below and the document 'Informing Our Plans, Our Engagement Program'.

- In relation to sub clauses (6) and (7), the nature of CIA presents an opportunity to consider the relative prices and substitution possibilities of operating and capital expenditure via Demand management / Non Network alternatives. This enables Ergon Energy to meet demand for standard control services as prudently and efficiently as possible. Ergon Energy uses several methods to effectively manage network demand, which are set out in Section 7 of this document.
- In relation to sub clause (8), in forecasting its proposed CIA expenditure for the 2015-20 regulatory control period Ergon Energy has had regard to those incentive schemes set out in clauses 6.5.8A or 6.6.2 to 6.6.4 of the Rules as follows:
  - A Capital Expenditure Sharing Scheme (CESS) as contemplated by clause 6.5.8A is not in effect at the time of this regulatory submission;
  - A Service Target Performance Incentive Scheme (STPIS) supported by clause 6.6.2 of the Rules places a proportion of Ergon Energy's revenue at risk to incentivise Ergon Energy to maintain service standards above predetermined levels. Ergon Energy's CIA expenditure does not include expenditure to maintain these service standards as Ergon Energy's methodologies for forecasting CIA expenditure are driven by the application of network security criteria rather than by adverse performance against STPIS reliability and quality of supply targets. Ergon Energy notes that the changes to the Security Criteria that took effect on 1 July 2014 are expected to, over time, increase the number of constraints on sub-transmission assets and adversely impact reliability and quality of supply indicators. However, such impacts are not expected to occur until the end of the next period and beyond. Ergon Energy will monitor the emergence of any such impacts and it is expected that remedial works would be self-funded through the STPIS mechanism rather than funded by CIA expenditure. Ergon Energy's CIA expenditure is therefore not inconsistent with the application of the STPIS;
  - Ergon Energy is committed to facilitating the emergence of demand management solutions in its distribution system. The way in which cost-efficient demand management solutions form part of Ergon Energy's forecast CIA expenditure is described in Section 7 of this document. Clause 6.6.3 of the Rules however specifically relates to the Demand Management and Embedded Generation Connection Incentive Scheme (DMEGCIS) (previously the Demand Management Incentive Allowance) which the AER has proposed to continue to apply to Ergon Energy in the 2015-20 regulatory control period. The effect of the DMEGCIS is to encourage research and innovation in prospective demand management solutions rather than to lead to the immediate deferral of network Augex. Ergon Energy agrees with the AER's assertion in its 'Framework and Approach – Ergon Energy and Energex 2015-2020' that the DMEGCIS' focus on emerging solutions means that any benefits of the DMEGCIS 'may not be revealed until later periods'.32 As a result the application of the DMEGCIS does not have an impact on Ergon Energy's proposed CIA expenditure in the next period; and
  - A Small-scale Incentive Scheme as contemplated by clause 6.6.4 of the Rules is not in effect at the time of this regulatory submission.
- In relation to sub clause (9), Ergon Energy has robust procurement governance processes in place to ensure that contractual arrangements at all times reflect arm's length terms. These processes are described in detail in the 'Network Deliverability Plan'. It is noted that Ergon Energy's only subsidiary Sparq Solutions does not provide network services for CIA that would constitute 'direct' costs and which would thus form part of the expenditure proposed in Section 8.1.

[32] AER, Framework and Approach – Ergon Energy and Energex 2015-2020, April 2014, p 86.

- In relation to sub clause (10), as required by clause 5.17.4 of the Rules, Ergon Energy must apply the Regulatory Investment Test (RIT-D) (previously the Regulatory Test) for capital expenditure augmentation projects greater than $5 million. As part of this test, Ergon Energy must consider adopting non-network solutions where it is prudent and efficient to do so. The way in which Ergon Energy considers non-network solutions in augmentation planning is described in Section 7 of this document. Where the RIT-D process is enlivened, non-network alternatives delivered both internally and externally to Ergon Energy will be considered as required by the relevant provisions of the Rules. To ensure a robust number of solutions can emerge from the RIT-D process initiatives such as publishing a Demand Response Incentive Map (DRIM); implementation of a Trade Ally Network mechanism to encourage market enablement; and the EMR program are used to obtain realistic solutions that will deliver the required outcomes at the lowest possible cost.
- In relation to sub clause (11), Ergon Energy is required to develop a final project assessment report under 5.17.4(o), (p) or (s) as part of the Regulatory Investment Test for Distribution (RIT-D). Ergon Energy will apply the RIT-D to applicable projects in the 2015-20 period as required by the Rules. Ergon Energy notes that no capital expenditure projects have been subjected to the RIT-D to date and hence there are no relevant final project assessment reports for Ergon Energy to have regard to in proposing its CIA expenditure for the 2015-20 period.
- In relation to sub clause (12), Ergon Energy has not been notified of any other factor the AER considers relevant and has notified Ergon Energy is a capital expenditure factor.

10. Appendices

Appendix A. Evolution of Ergon Energy's security criteria

This Appendix explains the evolution of Ergon Energy's security criteria between 2004 and the present.

1. Electricity Distribution and Service Delivery (EDSD) review

The Independent Panel that undertook the 2004 EDSD review recommended to the Queensland Government that Ergon Energy apply new security of supply based on a deterministic, N-1 approach. It recommended that:

> Ergon Energy be required (unless otherwise agreed with major customers) to maintain N-1 on bulk supply sub stations and large zone supply substations (5MVA and above) and sub-transmission feeders. Critical HV feeders should also meet N-1 with the exception of those where Ergon Energy can provide satisfactory evidence that this does not put significant numbers of customers at risk.

The Queensland Government issued 'An Action Plan for Queensland Electricity Distribution' that adopted the EDSD Review's recommendations and, amongst other things required that:

> More conservative planning criteria – Energex and Ergon Energy will adopt more conservative planning assumptions, so that if assets fail across their systems they will have sufficient backup capacity to ensure customers don't lose supply. Energex and Ergon Energy will aim to achieve best practice security of supply for their systems by 2009-10. (Section 3)

Following the EDSD Review and the release of the Queensland Government's Action Plan, the Review Panel's consultant, Evans and Peck, worked with Ergon Energy to develop and agree appropriate security of supply standards that were necessary to give effect to the EDSD Report's recommendations.

These standards subsequently served as a cornerstone of Ergon Energy's network planning. They were reflected in its annual Network Management Plans, which described how Ergon Energy planned to meet the EDSD Report's security planning criteria. Ergon Energy used these criteria as the basis for preparing the expenditure forecasts that it included in its regulatory proposal to the AER for the current regulatory control period.

2. The 2011 Electricity Network Capital Program (ENCAP) review

In late 2011, following the AER's distribution determination for the current regulatory control period, the Queensland Government engaged another independent panel to revisit the findings of the 2004 EDSD review to ensure that its recommendations in terms of security and reliability standards still provided for a secure and reliable network at an efficient cost.[33] This became known as the Electricity Network Capital Program (ENCAP) Review.

The terms of reference for the ENCAP Review required it to examine reports provided by Ergon Energy on the delivery of the electricity network and to advise government on the appropriateness of any changes proposed by Ergon Energy to provide for a more efficient and cost effective delivery of a secure and reliable network.

33 Electricity Network Capital Program (ENCAP) Review, 2011, p 7.

The findings and recommendations of the ENCAP review supported a move away from the paradigm of the 2004 EDSD Review, on which Ergon Energy's regulatory proposal and the AER's distribution determination for the 2010-15 regulatory control period were based. Alternatives had become available that allowed for more efficient investment that better reflected the needs of customers in the economic climate at the time of the review. Some flexibility in the application of standards was now justified as understanding of the networks had improved.

The ENCAP review found that Ergon Energy had invested significant capital to pursue N-1 security standards and that this had resulted in significantly improved supply reliability. N-1 was still considered good industry practice but the Independent Panel took the view that there were more cost effective ways of achieving equivalent security standards, without requiring total duplication of assets. It also suggested that probabilistic planning should be considered.

In particular, the Independent Panel accepted Ergon Energy's recommendation to apply a cost-benefit approach to determining whether an augmentation should occur for remote locations and where the cost of achieving N-1 outweighs the reliability benefits gained.

Within this context, in the course of the ENCAP review, Ergon Energy identified potential net reductions of $724.5 million in its capital expenditure program from the AER's distribution determination, over the current regulatory control period. The IRP recommended to the Queensland Government that it accept the reductions identified by Ergon Energy and that they work together 'to precisely quantify the final amount of the identified savings'.[34]

The Independent Panel also observed that the savings in relation to customer and corporation initiated work were uncertain because they would be dependent on the pace of economic recovery. The Queensland Government subsequently endorsed the independent panel's findings and recommendations, although the capital expenditure reductions were later decreased from $724.5 million to $709 million on account of an increase in Ergon Energy's non-system capital expenditure relating to buildings. Table 16 illustrates that these savings arose principally in CICW and CIA. CIA was forecast to reduce by a total of $549 million[35] with $249 million as a result of the revised security standards and $300 million as a result a reduction on forecast peak demand.

Table 16: Reductions in total capital expenditure forecast – 2010-11 to 2014-15 ($million nominal)*

	AER Distribution Determination	ENCAP review variation
System Capital expenditure		
Asset Replacement	1,204	-20
Corp Initiated Augmentation	1,671	-549
Customer Initiated Capital Works	1,505	-206
Reliability and Quality Improvement	107	50
Other System Capital expenditure	364	
Total System Capital expenditure	**4,851**	**-725**
Total Non-System Capital expenditure	**670**	**16**
Total Capital expenditure	**5,521**	**-709**

[34] Independent Panel, Electricity Network Capital Program (ENCAP) Review, p 13.

[35] ENCAP Review Final Report on the Queensland Government web site, p 73.

* Excludes capital expenditure for streetlights and large customer connection alternative control services

As a result, the ENCAP review resulted in new security standards that defined the target network load limits based on delivering an equivalent N-1 level of security after accounting for a range of automatic and manual corrective actions. This standard reduced capital expenditure from the former EDSD criteria, while also maintaining an acceptable risk profile and delivering the acceptable customer security outcomes.

3. 2013 Independent review panel (IRP) on network costs report

In 2012, the Queensland Government began a process to reform the state's electricity sector to address rising electricity costs. This included engaging an IRP on Network Costs to investigate the impact of Queensland's electricity network on prices and to provide solutions for a secure and cost effective network. The IRP reported in 2013.

Among a wide ranging scope of recommendations, the IRP report addressed distribution planning and reliability standards.

The IRP considered that the security policy adopted in the 2004 EDSD resulted in excessive capital expenditure.

The IRP also found that while the ENCAP review had the effect of reducing the rate of growth of capital programs, explicit input-based security policy requirements should be removed. Instead there should be a focus on reliability outcomes that meet customer expectations, reflect engineering best practice and represent benchmark performance. Consistent with this alternative approach, the IRP found that responsibility for determining the security standards necessary to deliver reliable supply should be returned to the Boards of the DNSPs.

The IRP recommended that DNSPs should develop network security policies based on customers' expectations, the trade-offs between reliability and cost, delivery of reliability outcomes at least cost, and industry best practice.[36]

4. Queensland Government direction

The Queensland Government wrote to Ergon Energy in March 2014 indicating that it had decided to accept the direction of the recommendations of the IRP in relation to security standards. The Government:

- removed the policy obligation for Ergon Energy to have and comply with N-X planning standards from 1 July 2014 onwards
- created a new policy obligation for Ergon Energy to transition to an 'economic' customer value based approach to reliability from 1 July 2014 onwards and to detail this in its future 'DAPR'.
- created a new requirement in Ergon Energy's Distribution Authority to comply with approved 'Safety Net Measures' in order to manage increased outage risks to customers in the transition to an economic approach to reliability to apply from 1 July 2014 onwards.

The security criteria outlined in section 3.6 of this summary document describe Ergon Energy's response to this requirement.

[36] Independent Review Panel (IRP) on Network Costs 2013, Electricity Network Costs Review Final Report, p 42

Appendix B. Definitions, acronyms and abbreviations

The following abbreviations and acronyms appear in this summary document.

Abbreviation or acronym	Definition
ACS	Alternative Control Services
ADMD	After Diversity Maximum Demand
AEMO	Australian Energy Market Operator
AER	Australian Energy Regulator
ALARP	As Low as Reasonably Practicable
ALF	Automated Load Flow
Augex	Augmentation Expenditure
CB	Circuit Breaker
CIA	Corporation Initiated Augmentation
CICW	Customer Initiated Capital Works
CRA	Charles River Associates
CSA	Current State Assessment
DAPR	Distribution Annual Planning Report
DFD	Distribution Feeder Database
DMEGCIS	Demand Management and Embedded Generation Connection Incentive Scheme
DNAP	Distribution Network Augmentation Plan
DNSP	Distribution Network Service Provider
EDSD	Electricity Distribution and Service Delivery
EMR	Effective Market Reform
ENCAP	Electricity Network Capital Program Review
HV	High voltage
IES	Inverter Energy System
IRC	Investment Review Committee
IRP	Independent Review Panel
kV	Kilovolt
LDC	Load Drop Compensation
LV	Low voltage
MDI	Maximum Demand Indicator
MSS	Minimum Service Standards

Abbreviation or acronym	Definition
MW	Megawatt
MVA	Mega-volt amp
MWh	Megawatt Hour
NCC	Normal Cyclic Capacity
NEM	National Electricity Market
NER	National Electricity Rules
NIEIR	National Institute of Economic and Industry Research
NIRC	Network Investment Review Committee
PoE	Probability of Exceedance
PV	Photovoltaic
QCA	Queensland Competition Authority
RIN	Regulatory Information Notice
RWR	Recommended Works Request
SCADA	Supervisory Control and Data Acquisition
SCS	Standard Control Services
SIFT	Substation Investment Forecasting Tool
SNAP	Sub-transmission Network Augmentation Plan
STPIS	Incentive Scheme
SWER	Single Wire Earth Return
WIP	Works in Progress

Appendix C. References

1. Compliance Documentation

Name	Description
Codes of Practice	Codes of practice provide practical guidance for people who have electrical safety duties about how to achieve the standards required under the Electrical Safety Act 2002 (Qld) and about effective ways to identify and manage electrical safety risks.
Distribution Authority	Licence issued by the Queensland State Government to Ergon Energy pursuant to the Electricity Industry Act 1994 (Qld) to undertake electricity distribution activities in Queensland.
Electrical Safety Act 2002 (Qld)	The *Electrical Safety Act 2002* is the legislative framework for electrical safety in Queensland. The purpose of this Act is to prevent people from being killed or injured and property from being destroyed or damaged by electricity
Electrical Safety Regulation 2013	The Electrical Safety Regulation 2013 identifies specific ways to meet electrical safety duties under the Electrical Safety Act 2002 and establishes requirements for electrical work; licensing; installations; equipment; supply; safety management systems; cathodic protection systems; and incident notification and reporting.
Electricity Act 1994 (Qld)	State legislation governing the supply, distribution, sale and use of electricity in Queensland.
ISO55000 Asset Management Standard	An international suite of standards that provides guidance in asset management best practise and focuses on developing proactive lifecycle asset management system.
National Electricity Rules (NER)	Statutory instrument made under the National Electricity (South Australia) Act 1996 governing the National Electricity Market and the regulation of market participants including Ergon Energy.
National Electricity Rules (NER)	Statutory instrument made under the National Electricity (South Australia) Act 1996 governing the National Electricity Market and the regulation of market participants including Ergon Energy.
Work Health and Safety Act 2011 (Qld)	State Legislation governing the provision of a balanced and nationally consistent framework to secure the health and safety of workers and workplaces.

2. Strategic Documentation

Name	Description
Network Optimisation Asset Strategy	The Asset Strategy specifies objectives and outcomes that provide the link between the high-level aspirations and guiding principles articulated in the Asset Management Policy and the operational and tactical aspects within the asset management plans.
Power Quality Monitoring Strategy	This document provides a strategy for power quality monitoring of the network by: • building on and enhancing the current monitoring capabilities throughout the network • building capacity to monitor and report on the Momentary Interruption Frequency Index (MAIFI) • ensuring that Quality of Supply process is adequate and robust.

3. Supporting Documentation

Name	Description
'Distribution Annual Planning Report' (DAPR)	Ergon Energy's 'DARP' 2014-15 to 2018-19 presents the outcomes of a five-year distribution annual planning review, based on strategies and planning processes underpinning our approach and good practices in asset management.
Capital Expenditure Forecast Unit Cost Methodologies Summary 2015 to 2020	The purpose of this summary document is to explain and justify the methodologies applied by Ergon Energy to develop unit cost estimates for its Standard Control Services (SCS) and Alternative Control Services (ACS) for the next regulatory control period, 1 July 2015 to 30 June 2020.
Demand Management Outcomes Report 2013/14	Our Demand Management (DM) Outcomes Report provides annual results on our performance against the Demand Management Plan.
Demand Management Overview 2015-2020	This document comprises an overview of Ergon Energy's proposed Demand Management activities for the regulatory control period 2015 to 2020. As well as the targets and expenditure forecast, this document contains a summary of activities, strategies, risks, drivers and operation of Demand Management throughout Ergon Energy's network.
Distribution Network Augmentation Plan	This plan states the capital works that are required to meet the augmentation requirements of Ergon Energy's distribution networks in order to accommodate the normal load forecasts for the next 10 years. It forms the initial stage of the annual augmentation capital works program that is developed as part of the Ergon Energy capital budgeting process.
Distribution Network impacts of Photovoltaic connections to 2020	Review of the impact of photovoltaic connections to the distribution network and the expenditure required to address the resulting issues.
Forecast Expenditure Summary Reliability and Quality of Supply 2015 to 2020'	The purpose of this summary document is to explain and justify Ergon Energy's Reliability and Quality of Supply capital expenditure for the next regulatory control period, 1 July 2015 to 30 June 2020.
How Ergon Energy Compares	This document discusses benchmarking approaches across distribution networks and whether the cost to develop, operate and maintain the Ergon Energy network can easily be compared and contrasted with the industry average and peers. The document provides an appreciation of the way that the design and operation of Ergon Energy network has been shaped, over time, in direct response to both the needs of our customers and the challenges of our network area. Specifically, this documents seeks to highlight those significant drivers of cost that affect Ergon Energy more (or in a different way when compared to) other DNSPs.

Name	Description
Informing Our Plans, Our Engagement Program	The document, Informing Our Plans, Our Engagement Program, details the engagement program and the customer insights used to inform our Regulatory Proposal. It supports the document, An Overview, Our Regulatory Proposal and the main Regulatory Proposal.
Investment Review Committee (IRC) Charter dated July 2014	The document details the Charter and specifies the terms of reference and strategic and tactical oversight functions of the IRC.
Load Forecasting Spatial Maximum Demand reference	This document provides a high-level description of the methodology, processes, models, tools, and data used to develop summer and winter Spatial Maximum Demand forecasts for Ergon Energy.
Load Forecasting System Maximum Demand reference	This document provides a high-level description of the methodology, processes, models, and data used to develop summer and winter system maximum demand forecasts for Ergon Energy.
Network Deliverability Plan	The purpose of the Network Deliverability Plan is to describe Ergon Energy's consolidated works delivery strategy to ensure an efficient and successful delivery of the 2015 to 2020 work program.
Network Investment Review Committee (NIRC) Charter dated July 2014	The purpose of the NIRC is to facilitate the prudent and efficient management of all network related capital and operating expenditure of Ergon Energy in accordance with the Network Optimisation Plan.
Network Planning Process	This documents details the six distinct components in the network planning process.
Network Strategy and Planning Energy Demand Forecasting	This document details the energy demand forecasting process.
Reliability Investment Guideline, Ergon Energy/Energex Joint Reference Document	This guideline provides the investment criteria for assessing the economic worth of a network reliability improvement project. The economic value of reliability has been based on the value of losses incurred by the customer for interruption of electricity supply under the Australian Energy Regulator (AER) Service Target Performance Incentive Scheme (STPIS).
Security Criteria	The purpose of this document is to define Ergon Energy's Security of Supply/Network Planning Criteria. This criteria when combined with MSS targets, will underpin prudent capital and operating costs to deliver the appropriate level of service to customers.
Sub-transmission Network Augmentation Plan	This plan states the capital works that are required to meet the augmentation requirements of Ergon Energy's sub-transmission networks in order to accommodate the normal load forecasts for the next 10 years. It forms the initial stage of the annual augmentation capital works program that is developed as part of the Ergon Energy capital budgeting process.

4. Models

Name	Description
Augex Model	AER model of predicted Augmentation expenditure *Supporting documents provided:* • Augex_future model • Augex_past model