APPENDIX 4.3

Unmodelled repex: Business cases for “other” repex

PUBLIC

Energex

Reactive Asset Replacement Program

Asset Management Division

energex

positive energy

Energex

Reactive Asset Replacement Program 2015/16 - 2019/20

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Version control

Version	Date	Description
1	1/07/2015	Submitted

Energex Limited (Energex) is a Queensland Government Owned Corporation that builds, owns, operates and maintains the electricity distribution network in the growing region of South East Queensland. Energex provides distribution services to almost 1.4 million domestic and business connections, delivering electricity to a population base of around 3.2 million people.

Energex’s key focus is distributing safe, reliable and affordable electricity in a commercially balanced way that provides value for its customers, manages risk and builds a sustainable future.

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Executive Summary

Where unanticipated failures of critical network assets occur, Energex must replace these assets to maintain safety or meet the guaranteed service levels required in its statutory distribution authority (security standard). Proactive asset replacement and maintenance programs are unable to prevent one hundred percent of critical failures.

Energex has historically experienced early/mid-life failures on critical assets due to inherent defects or deficiencies in the design, materials selection or manufacturing process of the asset.

The purpose of this document is to outline the required expenditure for the replacement of unpredicted critical asset failures over the 2015/16 – 2019/20 period. This expenditure is not accounted for in the modelled REPEX programs.

Energex has a historical spend on reactive replacement averaging around $5 million per annum. Given the increasing average age of particular asset classes across 2015/16 to 2019/20 and a number of emerging and ongoing safety and reliability issues due to problematic equipment, this requirement is forecast to continue during the 2015/16 – 2019/20 regulatory control period.

Energex's revised proposal will result in Energex accepting an increased level of risk surrounding unanticipated asset failures but will provide a reduction of $13.9 million over 5 years from its original proposal.

$m, 2014/15	2010/11	2011/12	2012/13	2013/14	2014/15	Total
Historical reactive replacement spend	3.0	3.6	8.1	8.0	2.7	25.4

$m, 2014/15	2015/16	2016/17	2017/18	2018/19	2019/20	Total
Energex Proposal	6.2	8.2	7.8	8.2	8.4	38.9
Energex Revised Proposal	5.0	5.0	5.0	5.0	5.0	25.0

Contents

1 Introduction

The purpose of this document is to outline the required expenditure for the replacement of unmodelled/unpredicted asset failures over the forthcoming 5 year period. This is not accounted for in the modelled REPEX programs.

When network assets fail and cannot be repaired or decommissioned, Energex must replace them to ensure continuity of supply to customers. This proposed expenditure for reactive replacements is required for these unpredicted asset failures, and is based on projected costs for capital replacement of plant which fails in service short of the expected service date.

The drivers for this expenditure program consist of two main factors, end of life asset failures and early/mid-life failures which are often linked to issues with a particular asset type/manufacturer. This business case provides background to the historical reactive spend, details some specific case studies, and forecasts future expenditures under this program.

Changes from the original proposal

The original proposal to the AER for the works covered here was for **$38,894,444** (direct costs).

In their draft determination, the AER has made it clear it expects Energex to operate with a higher level of risk. Accordingly, the program has been reviewed and a number of items allowing for replacement of assets which have failed diagnostic testing criteria have been removed. These assets are now planned to be managed by other risk mitigation approaches. Energex has negotiated with some manufacturers to undertake repairs and share the costs for known problematic assets. These costs will now instead be managed under the OPEX program. This information was unavailable at the time of the initial submission.

In other cases where such repairs are not possible, Energex must adopt an alternative strategy for managing the risk of each asset which may include a Condition Based Risk Management (CBRM) analysis or a run to failure strategy. Note that for assets which are proactively managed under the CBRM approach, Energex cannot prevent one hundred percent of critical failures.

This program provides a means of prudently managing unplanned failures which necessitate asset replacement.

The revised proposal presented here outlines a required expenditure of $25 million over the 2015/16 – 2019/20 period. The required expenditure is listed below and is broadly in line with historical spend on the replacement of assets that fail unexpectedly as shown in Figure 1.

$m, 2014/15	2010/11	2011/12	2012/13	2013/14	2014/15	Total
Historical reactive replacement spend	3.0	3.6	8.1	8.0	2.7	25.4

Table 1: Historical Reactive Replacement Spend

$m, 2014/15	2015/16	2016/17	2017/18	2018/19	2019/20	Total
Energex Proposal	6.2	8.2	7.8	8.2	8.4	38.9
Energex Revised Proposal	5.0	5.0	5.0	5.0	5.0	25.0

Table 2: Expenditure Summary

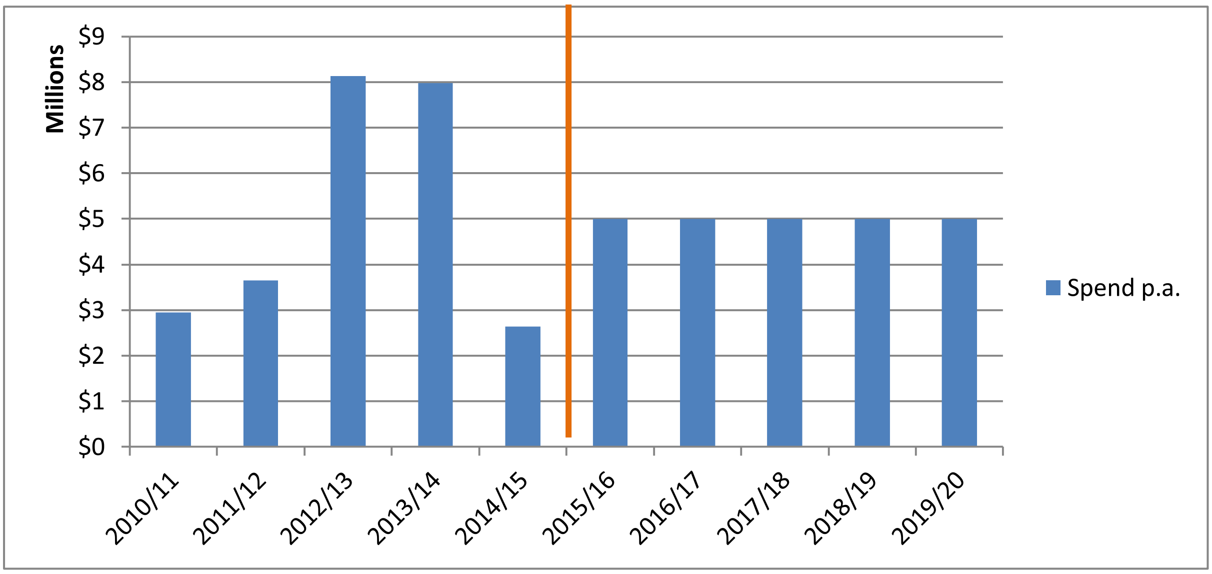


Figure 1: Historical Reactive Spend and Proposed Expenditure for Upcoming Regulatory Period.

2 Drivers

When network assets fail and cannot be repaired or decommissioned, Energex must replace them to ensure continuity of supply to customers. The drivers for this program consist of two main factors; (1) unplanned end of life asset failures and (2) early/mid-life failures which are often linked to defective equipment associated with a particular asset type/manufacturer or the operating environment.

Energex has assets which follow the traditional “bathtub” curve shown in Figure 2 which depicts the conditional probability of failure (hazard rate) over the age of a population of assets. Initially there is a bedding-in period, during which any manufacturer faults, unforeseen problems etc., can cause asset failures. This then flattens out to random failures over the mid-section of the lifetime of the assets. The failures experienced are typically at a lower, constant rate, and occur in spite of proactive maintenance programs. Replacement of early and mid-life asset failures experienced over the upcoming 5 year period for all subtransmission assets are to be covered by the proposed reactive replacement expenditure. When asset populations move towards the end of life, they experience increasing failure rates. These end of life assets are planned to be replaced under the modelled REPEX expenditure; however if they fail short of their expected replacement life they are replaced under the reactive expenditure.

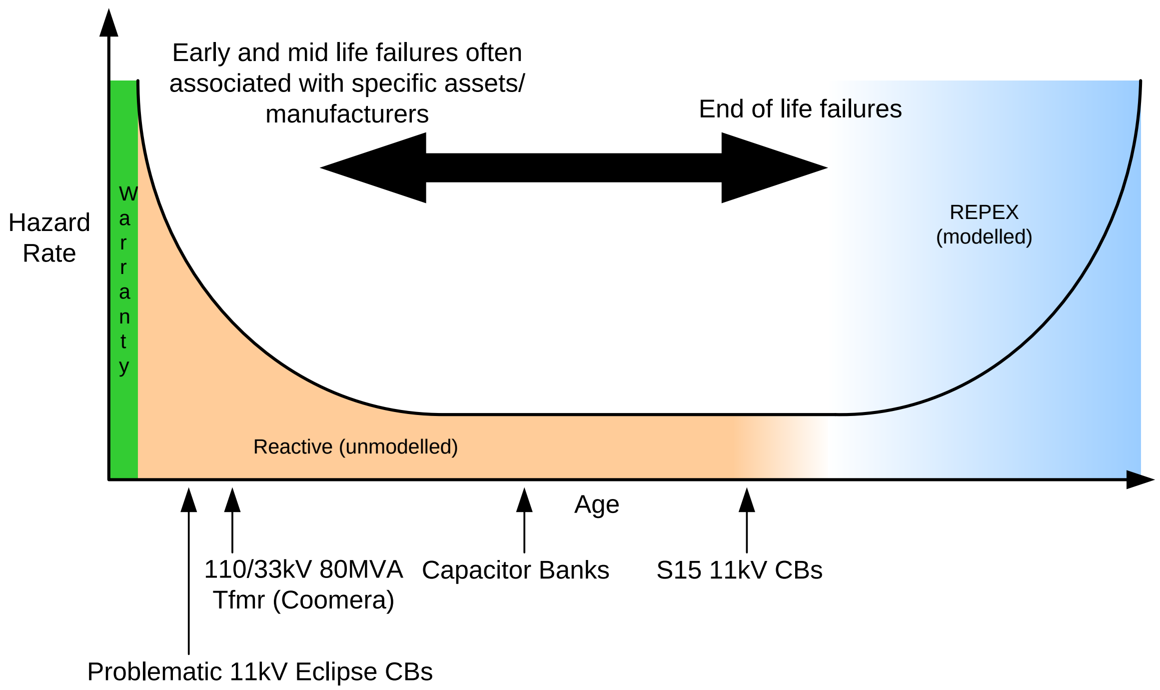


Figure 2: Representation of When Specific Failures are Expected During Asset Population Life

Energex has experienced significant unpredicted asset failures. For example, the [redacted] outdoor type 11kV circuit breakers are failing at 44 to 47 years of age; this up to 10 years short of their expected mean economic life of 54 years. The Hawker Siddeley Eclipse circuit breakers are experiencing significant degradation across ages of 1 to 15 years, indicating significantly reduced lifespan expectation compared to their mean economic life of 54 years. The Coomera 110/33kV 80MVA transformer failed at 7 years of age mainly due to high sulphur oil content. This is 46 years short of the expected economic mean life of 53 years.

Energex has found early failures on a number of assets, primarily due to defects arising from the design, materials selection and manufacturing process. Even with due diligence in the procurement process there will always be items of plant whose failure modes do not present until later in their life and could not be foreseen. Failures will occur during the life cycle of the asset and even with the CBRM program, Energex cannot achieve one hundred percent success with proactively replacing end of life assets.

2.1 Historical Asset Failures

To support the basis for the reactive replacement program for the upcoming regulatory period, the historical cost of asset failures have been recorded and detailed in Figure 3 and Figure 4 below. In the upcoming regulatory period, it is expected that the failures will occur at a similar rate (averaged over the 5 year period) for the range of network assets. The cost to replace a particular number of failed assets forms the basis of the projected required reactive replacement expenditure.

The spread of historical spend as shown in Figure 3 is “irregular” or uneven, but is expected given the nature of a reactive expenditure is to replace assets that fail unexpectedly.

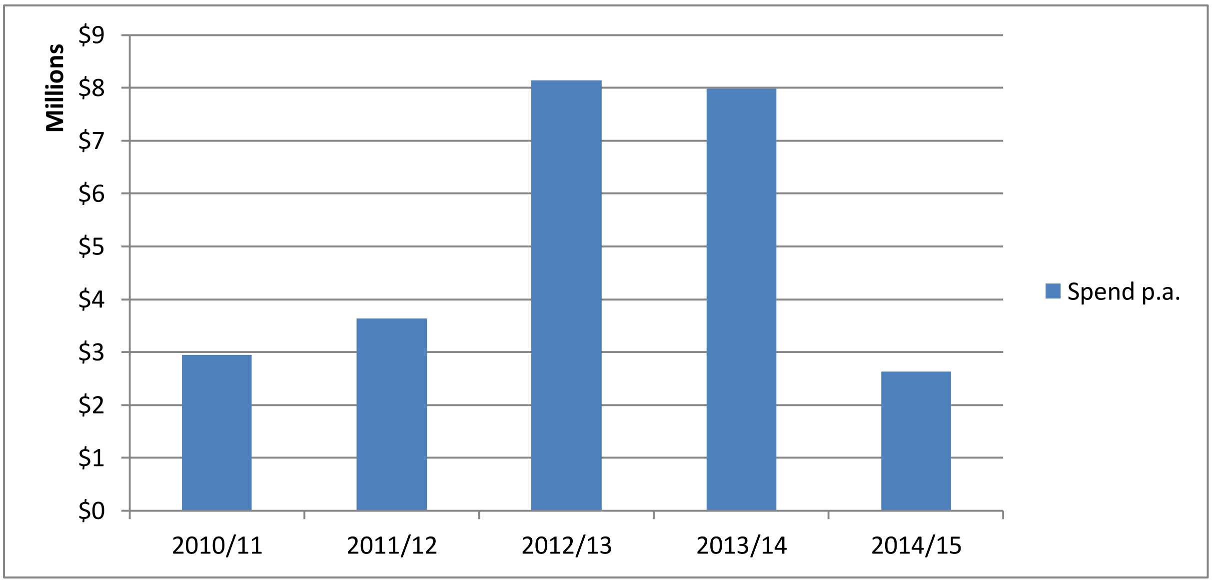


Figure 3: The historical spend for the previous regulatory period

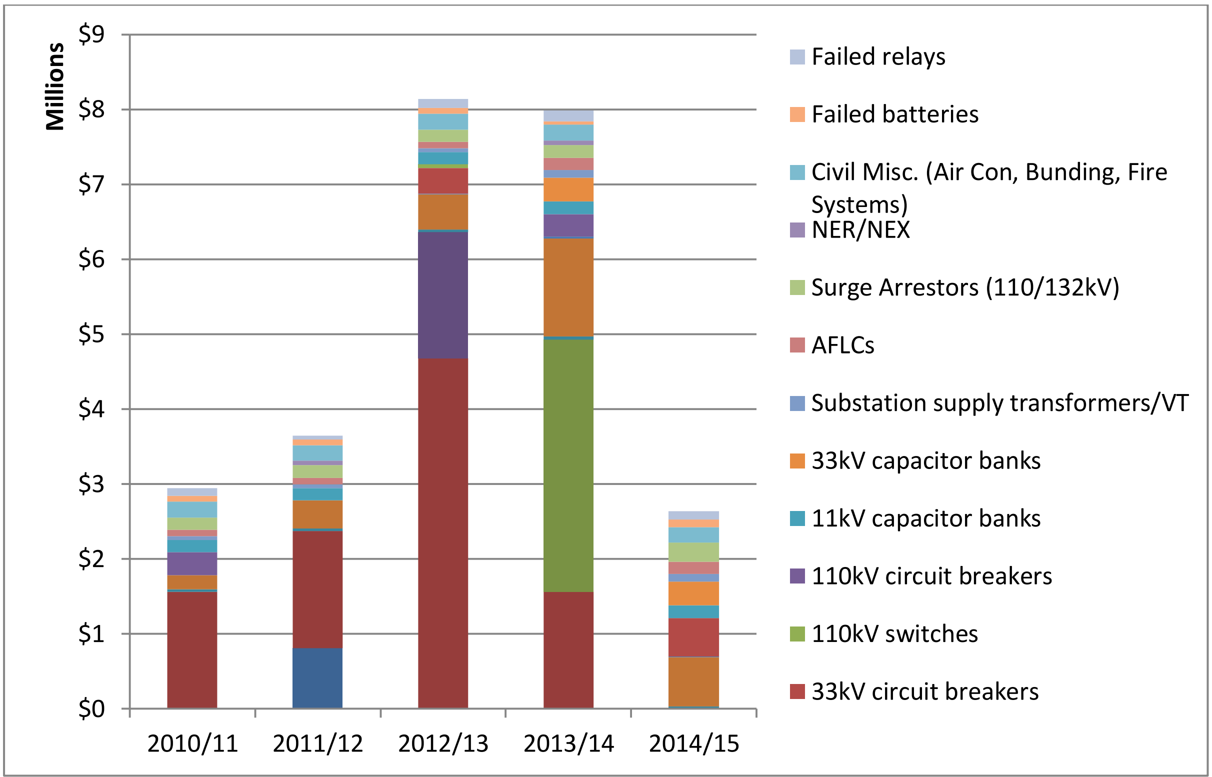


Figure 4: Breakdown of Failures by Asset Type

Figure 4 and Table 3 outline the breakdown of 19 different types of subtransmission assets that have failed in the previous regulatory period including the number of assets which have failed. This gives an indication of the problematic asset types that are experiencing premature failures on the Energex high voltage and subtransmission network.

Asset	Quantity				
	2010/11	2011/12	2012/13	2013/14	2014/15
33kV UG cables	0	1	0	0	0
33/11kV 15-25MVA transformers	1	1	3	1	0
110/11kV 30MVA transformers	0	0	0	2	0
110/33/11kV 120MVA transformers	0	0	1	0	0
11kV switches (AB & RMU)	2	2	2	2	2
11kV circuit breakers	2	4	5	14	7
33kV switches	0	0	1	2	1
33kV circuit breakers	0	0	2	0	3
110kV switches	0	0	1	0	0
110kV circuit breakers	1	0	0	1	0
11kV capacitor banks	1	1	1	1	1

33kV capacitor banks	0	0	0	1	1
Substation supply transformers/VT	1	1	1	2	2
AFLCs	1	1	1	2	2
Surge Arrestors (110/132kV)	2	2	2	2	3
NER/NEX	0	1	0	1	0

Table 3: Historical Failure Numbers of Plant Requiring Full Replacement

2.2 Emerging and Ongoing Issues

Energex has observed increasing failures and poor test results in specific fleets of equipment within the previous regulatory period. This indicates an increased degradation rate and shortened life for these particular assets. Some of these emerging issues have already been translated into failures, and are included in the historical spend for reactive replacement of assets.

As the drivers for reactive asset replacement are related to individual cases, they have been separated as follows for the past 5 and future 5 years. Table 4 is a record of assets which are presenting safety and reliability issues, and not a record of assets replaced. Many of the items are being monitored closely, or repaired, whilst some require full replacement. In this discussion, “failure” can be either be conditional (failed diagnostic tests/checks) or functional (catastrophic or no longer *actually* functions). This data provides evidence for the expected future failure rates of assets.

Asset type	Population	Past condition failures	Past function failures	Predicted condition failures	Predicted function failures
Hawker Siddeley Eclipse insulation	1,680	20	0	10	2
Hawker Siddeley Eclipse mechanical issues	1,680	50	0	50	2
[redacted]	130	15	4	4	2
Hawker Siddeley Horizon	120	13	0	10	2
11kV Capacitor banks	385	10	35**	10	15**
33kV Capacitor bank CBs & plant	40	17	4	23	5**
Transformer corrosive Sulphur (110kV	*148	100	1	0	2
Transformer corrosive Sulphur (33kV)	*228	166	0	0	3
Ageing OCB diagnostic failures (all kV)	1113	45	2	40	5
[redacted] RMU oil leaks	900	0	3	5	5
[redacted] bushing failure	35	4	4	5	5
VV Tap changers	150	1	1	4	3

* From the population identified as being at risk from corrosive sulphur (1998-2007)
** Circuit breaker or entire capacitor bank

Table 4: Historical and Predicted Numbers of Specific Asset Conditional and Functional Failures

Note that for each asset type in Table 4 the predicted conditional and functional failures are due to the failure mechanisms described below. Further details and evidence for these predicted failures are given in Appendix A.

2.2.1 Hawker Siddeley Eclipse 11kV Circuit Breaker Insulation

The Energex population of Eclipse 11kV circuit breaker (CB) switchgear comprises approximately 1,680 units. Since 2012 Energex has become aware of an issue in which the high voltage (HV) insulation deteriorates to a potential failure point – this has been identified by high partial discharge (PD) testing values. The failure is related to the design and quality of an earthed stress control screen on the surface of the insulation. Several instances have been found by other industry users where this layer has degraded to a state which has led to catastrophic failures. It is reasonable to expect that if this degradation is unrectified, it will lead to a complete failure and any ensuing fault may destroy large parts of the switchboard and present a significant safety risk to any personnel in the vicinity.

2.2.2 Hawker Siddeley Eclipse 11kV Circuit Breaker Mechanical Issues

Since January 2015 Energex has experienced 6 separate failures of circuit breakers during commissioning in which the vacuum interrupters were found to be open circuit in one phase.

Investigations and discussion with the manufacturer has revealed that the problem is due to a defect in the magnetic actuator drive train which leads to loss of travel in one phase. No detection of the defect is available and there is risk of failure of the circuit breaker until repaired. There are two consequences to this event; the first is the loss of a phase during closing in normal/fault reclose operation which will lead network reliability and power quality issues due to current flow in only two phases. In some cases a protection operation could result in the loss of the entire substation load. There is additional risk of catastrophic vacuum interrupter failure and switchboard damage during closing/reclosing onto high faults currents. This can lead to significant repair costs and insurance claims (from equipment damage and loss of supply).

A second emerging issue is that the Eclipse CB has exhibited delayed or slow opening on occasions. The impact of delayed opening is consequential damage to plant due to extended fault currents.

2.2.3 [redacted] 11kV Circuit Breaker Failures

Following a number of catastrophic failures, it was discovered [redacted] switchgear was suffering from a series of design and installation issues that could lead to degradation and eventual failure. Following several such failures, all [redacted] switchgear is being PD scanned on a regular basis to identify and monitor at risk sites and a retrofit procedure was developed to remove the PD trigger factors hence reducing the risk of failure.

Failure of the HV insulation can present a safety risk to any personnel in the substation at the time of the event. Despite these remedial actions, there still remains a risk in a population in which it is not possible to continuously condition monitor all assets within a time frame that could guarantee failure free performance through the asset life. This is especially prevalent in designs with polyurethane insulation which when the insulation reaches a critical point the time leading to failure can be extremely rapid.

2.2.4 Hawker Siddeley Horizon 33kV Circuit Breaker with Defective Earth Stress Control Screen

Energex has a number of 33 kV Horizon CBs which have a serious defect on the earthed stress control screen. Energex undertook a PD scan of all Horizon CBs and found that a large portion of the Energex population is suffering this defect. Energex is currently negotiating with the manufacturer to implement a suitable retrofit procedure. Until this is undertaken, regular PD scanning will be used to reduce this risk, however this does not guarantee failure cannot occur. A failure of the HV insulation will result in the loss of the asset and can present a safety risk to any personnel in the substation at the time of the event.

2.2.5 11kV Capacitor Banks and Circuit Breakers damaged by restrikes, vermin or wear-out.

Energex has approximately 365 modular capacitor banks on the 11kV network. These are custom made units comprising the capacitor cans, reactors, vacuum circuit breaker and associated control gear. The designs have varied over the years and the main item which is varied is the 11kV CB (where Energex has installed [redacted] [redacted] or [redacted]). In the past 5 years we have seen approximately 40 capacitor bank/CB failures due to insulation degradation, failed vacuum interrupters (restriking or worn out) or vermin ingress. In most cases the most economic option is to replace either the CB or the entire capacitor bank.

2.2.6 33kV Capacitor Bank and Circuit Breakers damaged by restrikes

Energex has experienced a number of failures associated with switching capacitor banks with ageing vacuum CBs. It is well known in the industry that when switching capacitive load the CBs are prone to substantial overvoltage generation due to prestriking, reignition and restriking. In the past 10 years Energex has experienced at least four catastrophic plant failures that can be directly attributed to vacuum CBs. Also as the CB ages and the contacts suffer damage due to pre-striking (especially switching back-back) the probability of restrike and significant overvoltage increases. When it is identified that they are no longer performing as required it is necessary to replace ageing capacitor bank CBs to minimise plant damage and outage. In some cases the vacuum CB is part of an indoor GIS switchboard and an additional outdoor CB is required to perform the switching.

2.2.7 Transformer Corrosive Sulphur Oil

Over a period of 10 years, Energex purchased power transformers that utilised [redacted] Nytro 10GBN insulating oil and it has been demonstrated that this oil has proven corrosive tendencies as per the IEC & ASTM D 1275 test methods. A result of this corrosive sulphur is the formation of silver and copper sulphide deposition on conductor components. The risk with formation of silver sulphide is that of reduced dielectric strength of the insulating oil, or the formation of solid sulphide deposits on silver surfaces such as tap changer selector contacts.

When these deposits are disturbed or detached usually due to tap changer operation, there is a serious risk of electrical flashover and this failure mode is believed to be responsible for the destruction of a large power transformer (110kV, 80MVA) at our Coomera (SSCMA) substation. This asset was a write off and had to be replaced at a cost of $2.15 million (this includes indirect costs).

Energex has around 520 power transformers that have been tested for presence of corrosive sulphur in their oil. To minimise the risk of failure, Energex is proposing to add metal passivator to power transformers containing corrosive oil and replace when indicators indicate the risk of failure is imminent. Energex proposes to develop a condition monitoring technique for the testing of power transformer for indicators of prospective failure due to corrosive sulphur. Based on these indicators, Energex will prioritise the bulk replacement of corrosive oil with non-corrosive oil

Even when these measures are implemented, there is still a risk of catastrophic failure of the power transformer.

2.2.8 [redacted] Ring Main Unit Oil Leaks

An issue has been found with [redacted] oil ring main units (RMUs) in which a substantial oil leak develops. The operation of an 11kV RMU without the correct oil level is a serious safety risk to the operator.

Inspection programs and restrictions have been implemented to alert operators to this risk. There is no repair option as the entire RMU has to be removed and extensively dismantled to repair; hence replacement is the most economic option. The replacement program is driven by identifying affected units as found during inspection or by operators performing routine switching.

2.2.9 [redacted] 11kV Circuit Breaker Bushing Failure

In the past 2 years Energex has experienced 4 catastrophic failures of [redacted] outdoor CB bushings.

Such failure of a porcelain bushing is very violent and in each of the 4 failures, porcelain shards were ejected several metres across the substation yard, thereby presenting a serious safety risk to operators, and in some installations, the public. For short term operator safety all [redacted] CBs have been fitted with plywood barriers to reduce the impact of a catastrophic failure.

Taking into account the age of the CB (44-47 yrs.) and the fault rating of 13.1kA is less than the typical fault levels on the network, the safest and most economical course of action is to replace with a new CB.

2.2.10 Transformer Tap Changers

In the past 5 years Energex has experienced 2 failures of [redacted] tap changers displaying the same failure mode. In the diverter switch a spiral pin sheared in the drive which will allow the slow transition of the diverter switch. This can leave the transition resistor in-circuit for an unacceptable time leading to failure. In the last example the diverter suffered a catastrophic failure which resulted in the asset being written off and requiring replacement.

There have also been a number of gearbox alignment problems. No total loss failures have occurred from this problem but it is a risk to the transformer or tap changer.

2.2.11 [redacted] Ring Main Units Defective Isolator Mechanism

Energex operates a large population of [redacted] 11kV RMUs. In a recent issue, a design fault on a mechanical switch allowed the contacts to over-travel into an indeterminate position between OFF & Earth, which then initiated an internal arcing fault. This fault led to the destruction of the asset. To rectify this, a large high risk batch was rectified (1,000) and the entire population, which can still fail, is required to be operated with an over-travel arresting device (mounted on the front panel). The objective of the device is to limit travel of the mechanical switch and this will allow the unit to survive, and can then be repaired.

However, as the over-travel arrestor is an administrative control and is therefore not fail safe. Operators can fail to use the device and any malfunction will result in an arcing fault and destruction of the RMU, which will need to be replaced.

2.2.12 Ageing Oil Circuit Breaker Diagnostic and Service Failures

The Energex network has a large population of older oil circuit breakers (OCB) and they are approaching end of life. To ensure the safety of operators and the public, these OCBs are part of a strict maintenance and diagnostic test regime in which critical measurements such as IR, DLA and PD are measured. When these parameters exceed values in the acceptance criteria, the CBs are required to be replaced as soon possible. Failure to replace these OCBs in a timely manner may significantly increase the risk of catastrophic failure. The failure of oil switchgear has been attributed to serious injuries and even fatalities in certain cases.

3 Options

When network assets fail and cannot be repaired or decommissioned, Energex must replace them to ensure continuity of supply to customers. Without the funding to replace failed assets, Energex will be unable to provide an appropriate level of safety and reliability for the network.

Proactive asset replacement programs (i.e. REPEX) will not prevent one hundred percent of asset failures. Assets will fail either because they have reached end of life prematurely or because they have failed early or mid-life due to a design issue, quality/manufacturing issue or operating condition/environmental exposure. Energex has a demonstrated historical spend on reactive replacement of averaging around $5 million per annum. This presents as significant safety and legislative risk on the network if left unaddressed.

When an asset fails either conditionally or functionally, each case is considered on an individual basis. Options to ensure ongoing customer service which also mitigate safety and legislative compliance risks are assessed to select the most cost effective remedial solution. Energex will monitor defective and degraded assets identified and apply appropriate mitigation solutions including replacement to minimise the risk. This is in line with our commitment to the community, customers and staff to remain a responsible and safe operator of the South East Queensland electricity distribution network, as well as our legislative compliance requirements. These risks are managed and mitigated to As Low As Reasonably Practicable (ALARP).

In their draft determination, the AER has made it clear it expects Energex to operate with a higher level of risk. Accordingly, the program has been reviewed and a number of items allowing for replacement of conditionally failed assets have been removed; these assets are planned to be managed by other risk mitigation approaches to levels that are ALARP.

When any asset fails an assessment is undertaken as to whether the asset must be decommissioned, repaired or replaced:

Option	Description
Do Nothing	In the cases that the failed asset is deemed unnecessary, it shall be decommissioned. This proposal does not take these failures into account.
Repair failed asset	In the cases that the asset is deemed necessary and repairable, non-capital works shall be arranged to repair the asset. This proposal does not take these failures into account, or allow for the cost of repairs, as this is an operating expense.
Replace asset	In the cases that the asset is deemed necessary, non-repairable, and must therefore be replaced, a capital project must be raised to replace the failed asset. This proposal allows only for replacement of assets in this category and does not take assets which can be decommissioned or repaired into account. Neither does it allow for the cost of repairs, as this is an operating expense.

Table 5: Options to Address Risk

4 Proposed Works

It is recommended that Option 3 Replace Asset be implemented for the programs of work in the 2015/16 – 2019/20 regulatory period to maintain an acceptable level of safety and reliability of the network.

The flow chart depicted in Figure **5** demonstrates the process that is followed upon failure of an asset:

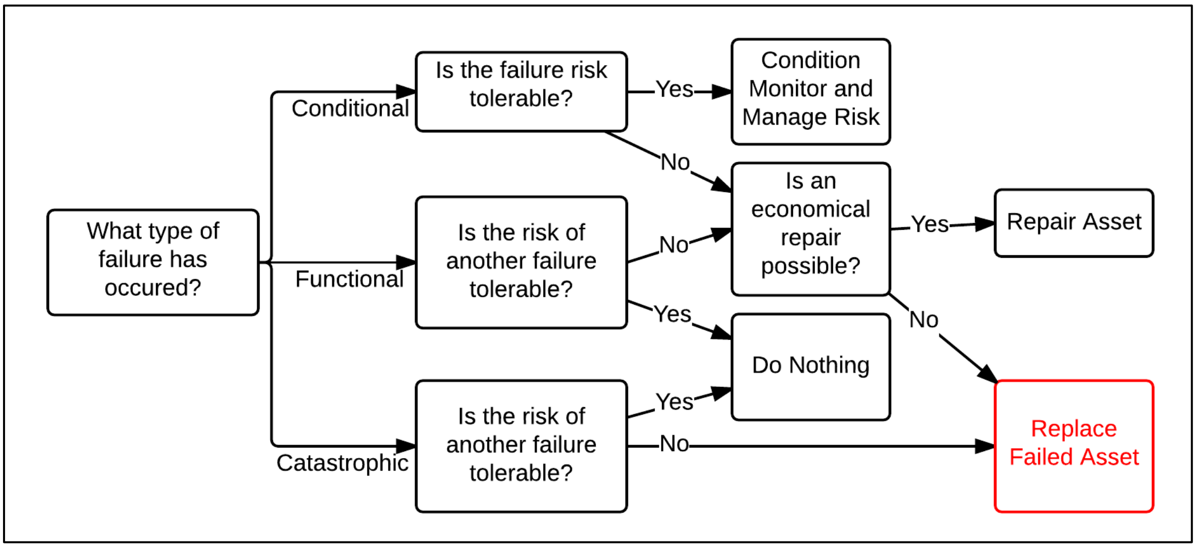


Figure 5**: Failed Asset Assessment Process**

5 Required Expenditure

The required expenditure for the reactive replacement program is listed below. The basis for this expenditure is the average historical spend on failed asset replacement over the last 5 years. This level of expenditure is considered prudent to maintain over the 2015/16 – 2019/20 period in light of Energex current population of assets and the issues being exhibited.

$m, 2014/15	2010/11	2011/12	2012/13	2013/14	2014/15	Total
Historical reactive replacement spend	3.0	3.6	8.1	8.0	2.7	25.4

Table 6: Historical Reactive Replacement Spend

$m, 2014/15	2015/16	2016/17	2017/18	2018/19	2019/20	Total
Energex Proposal	6.2	8.2	7.8	8.2	8.4	38.9
Energex Revised Proposal	5.0	5.0	5.0	5.0	5.0	25.0

Table 7**: Energex Proposal and Revised Reactive Spend**

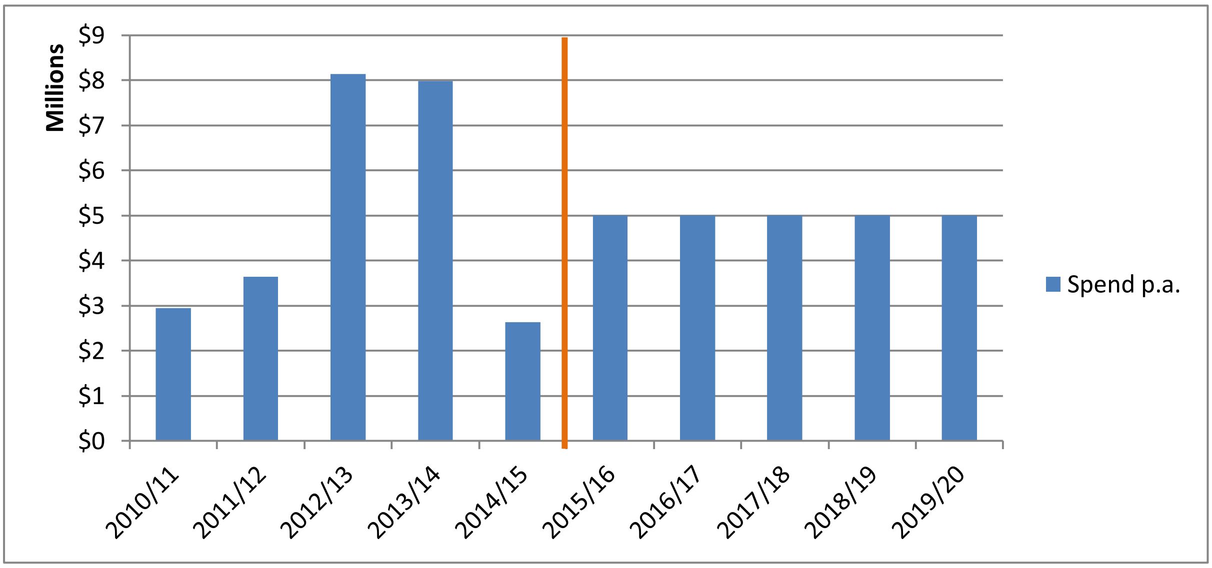


Figure 6: Energex Proposed Reactive Program Expenditure

6 Recommendations

It is recommended that Option 3 Replace Asset be endorsed for inclusion in the programs of reflected in Energex's revised regulatory proposal for the 2015/16 – 2019/20 regulatory period.

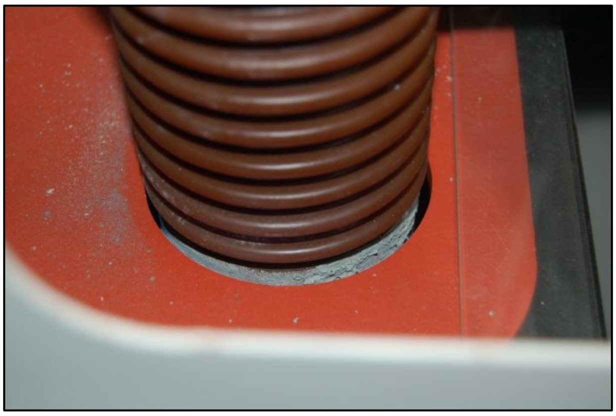
Appendix A – Evidence of Failures

Note that the cases outlined below are specific cases of asset failures, and not every asset failure has been documented. The specific asset failures described below are considered to be important due to either their large populations or large financial, legislative compliance or safety impacts.

11 kV Hawker Siddeley Eclipse CB Insulation Degradation

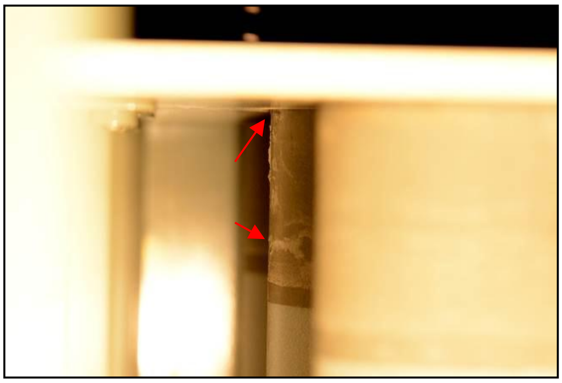
Following investigations at a number of sites, several potentially concerning PD related defects have been identified in the Eclipse switchgear. All Eclipse CBs were PD scanned to identify at risk sites and some invasive inspections and repairs have been carried out. At this stage in the investigation, a suitable and comprehensive retrofit procedure has not been developed to remove the PD trigger factors, hence reducing the risk of failure. Failure of the HV insulation can result in a catastrophic failure and present a safety risk to any personnel in the substation at the time of the event. Regular PD scanning will be used to monitor and mitigate this risk.

SSMGL CB1022 badly detached screen

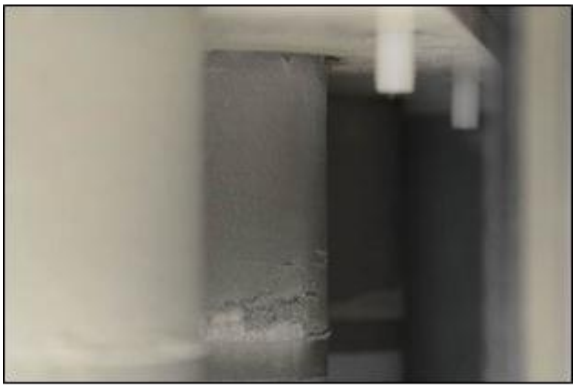


SSMGL CB1022 screen detachment in air gap

However, in 2012 two panels were found at a substation (SSMGL) to be in very bad condition such that if not rectified immediately failure would have been very likely to fail. Further inspections and tests have shown that PD activity and associated degradation has been found in more than one aspect of the design albeit in very small quantities. To understand the extent of the problem, Energex initiated an on-line PD scanning program of all Eclipse CB panels across the network.

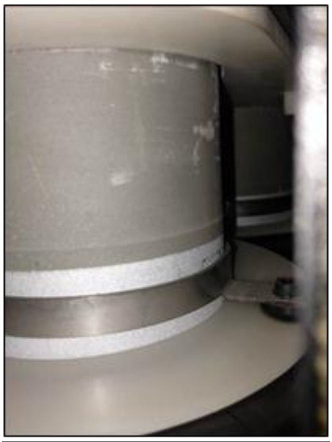


SSALY CB1082 screen damage



SSALY CB2042 screen detachment

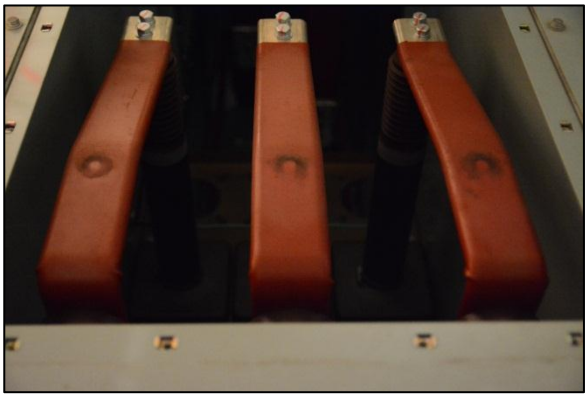
All CBs have been tested on-line for PD and a very small proportion (1-3%) are exhibiting evidence of ultrasonic PD at system voltage.



Damaged screen SSLYT CB1022

Damaged screen SSLYT CB1T32

PD on nylon screws SSLYT CB1022



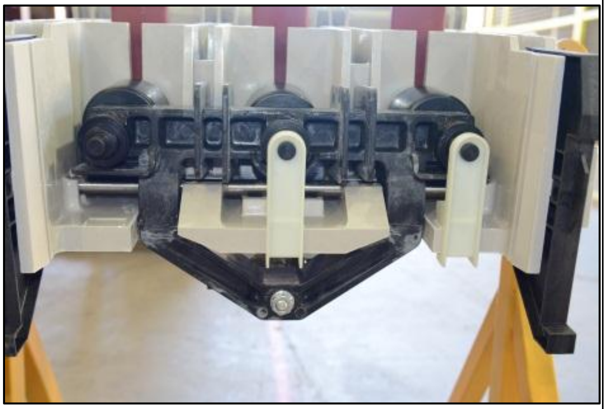
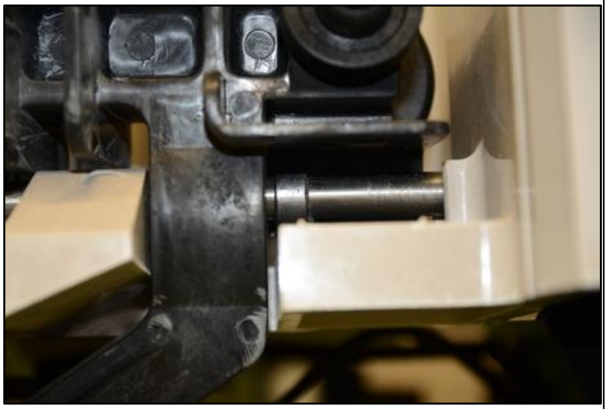
Damage on bus below nylon screws SSLYT CB1T32

PD has been linked to catastrophic insulation failure in other in Eclipse switchgear. As the occurrence of PD can be very dependent on the environment, it cannot always be detected at the time of asset inspection thus leading to risk of dielectric failure at some later time. The impact of such a catastrophic failure will depend on the fault level and duration and may lead to the complete destruction of one or more complete CB panels and adjacent equipment. A number of photographs are included from several sites where defective insulation has been discovered.

A Full technical report is available (TR-14-02 v7) detailing the engineering issues, likely failure modes and recommendations.

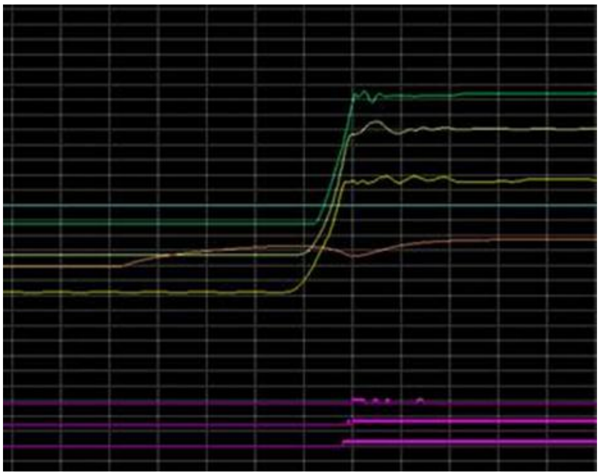
11 kV Hawker Siddeley Eclipse Mechanical Issues

The dislodging of the bearing in the Eclipse CB can be attributed to the design and manufacture of the drive shaft. The consequence of this is that the drive to the three vacuum interrupters is unbalanced and one of the outer phases does not close. In the case of a bearing failure, the loss of travel is approximately 5mm which means the CB is only just open when in the closed position. In a faulty CB the contacts will be open circuit in phase after closing, but during the closing stroke they will overtravel and make momentary contact through a small bounce period. This can be seen in the diagram below in which the first phase (with a dislodged bearing) is bouncing during closing for approximately 15ms. In this time current will be initiated and the interrupter will attempt interruption at each rebound open. As this will occur during the initial making at the time the DC component may be high, the CB may actually fail during this time. Such a failure could result in the welding of the interrupter or actual physical failure resulting in an external arcing event within the CB cubicle.

	
Eclipse drive shaft bottom view	**<u>Bearing fallen out onto drive shaft</u>**

The manufacturer has declared there was a design change in 2010, it is not yet known if this issue affects only post 2010 or all units. Energex has installed approximately 1,000 CB pre 2010 and approximately 600 post 2010.

To date Energex has experienced six complete failures spread across years of manufacture (YOMs) 2010-2013. All recently installed equipment (non-commissioned and in-project) has been inspected from YOM 2010-2014 and we have found from 214 CBs inspected that 73 CB had bearings that were displaced or had fallen out.



Closing contact bounce with displaced bearing

In the earth position, the CB cannot be used as a system earth if there is doubt as the integrity of the CB status when closed. This will result in a serious safety consequence and thus the CB cannot be used as intended as an earthing device until repaired.

As the failure is mechanical, it is logical to assume that the number of operations will contribute to risk of failure. From the failures seen so far, the number of operations is relatively low and in some cases, much less than similar units in service from the same YOM. This makes prediction very difficult based on operations. No in-service failures have been reported, however, the probability of a unit failing in service is very high based on the evidence to date. The defect cannot be detected and the risk of failure is high until the CB is repaired. We have not sampled any CBs from the pre 2010YOM.

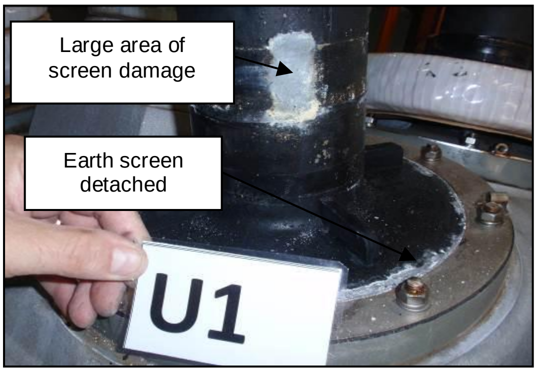
The slow or delayed opening is a recently evolving issue. Recently, (May 2015) a UK NEDERS report was released discussing further defects on the Eclipse CB, and this was due to the impact of tight machining tolerances and the adverse effect of high battery voltage on the magnetic actuator. The consequence of a delayed or slow CB will be the consequential damage to associated plant from an uncleared short circuit or an arcing fault.

33 kV Hawker Siddeley Horizon Circuit Breakers with Defective Stress Control Screen

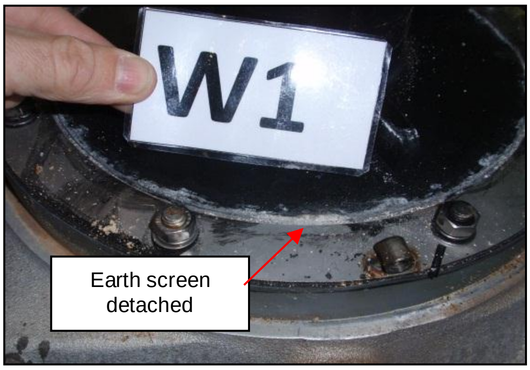
Over a 12 year period Energex has installed approximately 120 Horizon 33kV CBs across the network.

It has been recently demonstrated that a problem related to the defective stress control screen on the bushing leads to PD in the vicinity of the CTs.

Energex conducted a survey (in 2013) which detected PD activity in 16 CBs on the Energex network, from which 2 have been inspected and serious HV insulation degradation was found. Such degradation may ultimately lead to either CT or catastrophic insulation failure. Photos of the two inspected units are shown below



SSDRA CB3T22 screen degradation



SST11 CB3C12 screen degradation

This problem is not limited to Energex and exchanges of information have occurred between South Australia Power Networks (SAPN) in Australia and Western Power Distribution (WPD) in the UK. NEDERs notices, presentations and UK Power Network documents have publicly released information relating to these events.

Hawker Siddeley UK has acknowledged this latest development and has indicated that the problem was related to the use of an unsuitable screening material pre Jan 2011. They also stated that they did not monitor the electrical parameters of the screen during routine production of the CB.

Further tests are required to understand if the problem affects the entire Energex population and if Energex is required to minimise the risk of catastrophic failure with an appropriate rectification & repair program.

- A full technical report (TR-14-01 v1) is available detailing the engineering issues, likely failure modes and recommendations;

11kV Capacitor Banks and Circuit Breakers damaged by restrikes, vermin and wear-out

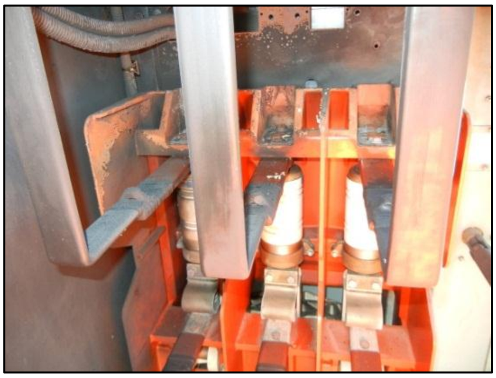
Energex has approximately 365 modular capacitor banks on the 11kV network. These are custom made units comprising the capacitor cans, reactors, vacuum circuit breaker and associated control gear. The designs have varied over the years and the main item which is varied is the 11kV CB (where Energex has installed [redacted] or [redacted]). In the past 5 years we have seen approximately 40 failures of capacitor bank/CBs due to insulation degradation, failed vacuum interrupters (restriking or worn out) or vermin ingress. In most cases the most economic option is to replace either the CB or the entire capacitor bank.

SSLYT [redacted] CB flashover

SSRLB [redacted] flashover

SSTPT [redacted] CB flashover

SSCLM [redacted] vacuum bottle failure



SSBDT[redacted] CB flashover

SSKBN[redacted] vacuum bottle failure

[redacted] RMU oil leaks

An issue has been found with [redacted] series oil RMUs in which the tank may leak oil, usually after invasive maintenance. This problem was brought to the attention of Energex after several leaking units were discovered by Ergon Energy. Energex has conducted checks and has found some leaks from a small quantity of RMUs. Investigations have suggested that the leak only occurs in later models in which a change of gasket design with less fixings is not providing an effective seal. Evidence has shown that the unit may be more susceptible to leaking after switching operations during maintenance without oil in the tank. The practice of switching without oil has been ceased but it is not known how many units may leak in the future as a result of these conditions.

As the leak is usually from the bottom of the unit, inside the HV cable boxes, it is not easy to check for this leak other than checking the oil level on the sight glass. Operating restrictions are in place to manage this and prevent energised operation without oil. Once a leaking unit is discovered, it cannot be repaired either onsite or economically in the workshop and the only viable action is to replace the unit with a new SF_6 insulated RMU. At this time there is no accurate data to forecast the numbers affected or the likely locations.

For the above RMU, inspection programs and restrictions have been implemented to alert operators to this risk. The variables that cause the RMU to leak have no geographical pattern and hence potential failures cannot be predicted on this basis. The replacement program is driven by identifying affected units as found during inspection or by operators performing routine switching.

11 kV [redacted] Switchgear Failures

This case outlines issues that may lead to premature failure of [redacted] 11kV [redacted] withdrawable indoor switchgear. Since 1995 Energex has installed approximately 130 [redacted] 11kV [redacted] circuit breakers and there have been 4 disruptive failures. Throughout the investigation, several other panels were found to be in very bad condition such that if not rectified failure would have been very likely. Further inspections and tests have shown that PD activity and associated degradation has been found in more than one aspect of the design which is attributed to factors such as; poorly placed BIL barriers that can lead to PD and Damp and poorly sealed cable trenches. Also air conditioning in the switch room can generate condensation in the cable box/CT chamber and lead to tracking across the insulation.

To date all CBs have been tested on-line for PD and a rectification program has commenced to resolve the problems outlined above. The success of the modifications can only be evaluated after several years of failure free operation.

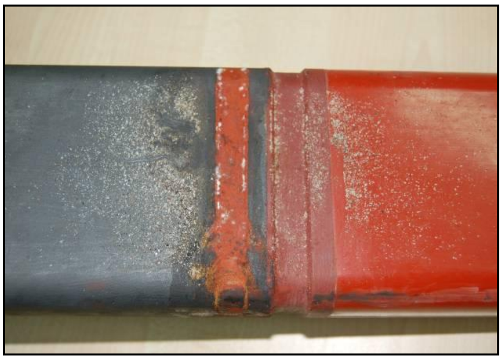
Following modification, the apparatus is subject to offline PD tests but as the occurrence of PD can be very dependent on the environmental conditions, it cannot always be detected at the time of asset evaluation thus leading to risk of dielectric failure at some later time. The impact of such a catastrophic failure will depend on the fault level and duration and may lead to the complete destruction of one or more complete CB panels and adjacent equipment.

A series of technical reports (TR-08-04, TR-11-01 and TR-12-03) detailing the engineering issues, likely failure modes, recommendations and type tests on the modified design is available.

SSBTA Problematic high stress air gap

SSCPC Degraded bushings

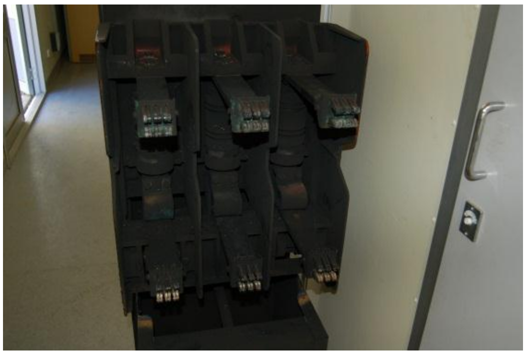
SSCVL Damaged earth screen



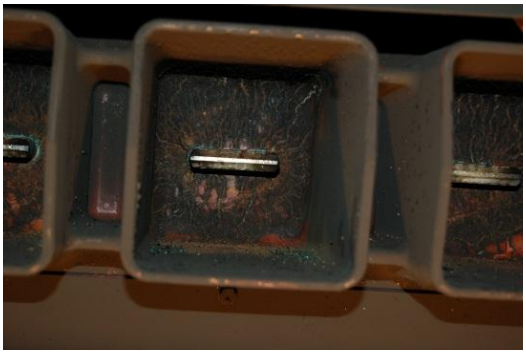
SSCVL Close up of earth screen damage

SSGVN Degraded joints

SSRBA degraded joints



SSMFD Catastrophic CB failure

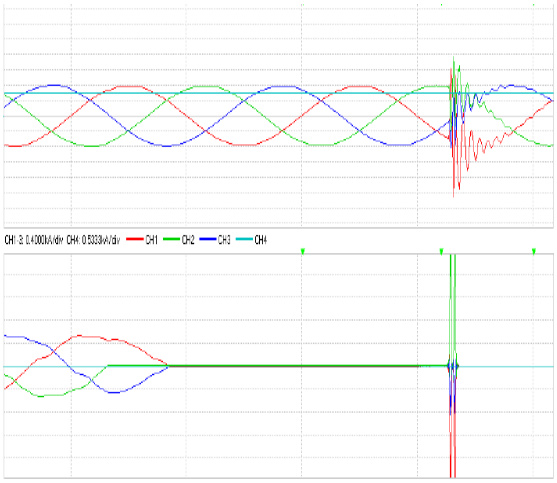


SSMFD Catastrophic CB failure

33kV Capacitor bank and Circuit breakers damaged by Restrikes

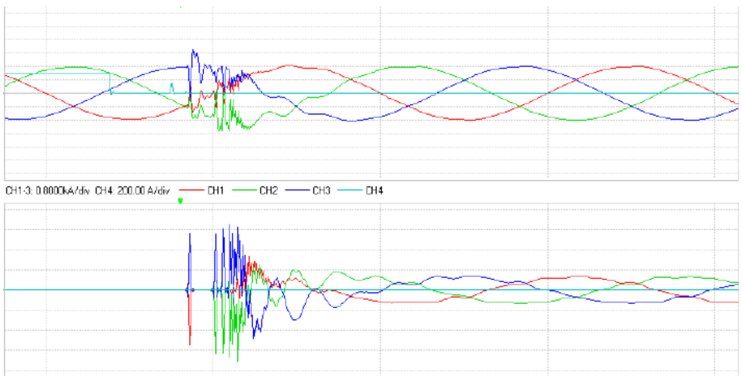
Following a study of the 33kV capacitor banks CB on the network (table below); it was found that several vacuum type CBs are being damaged (or causing damage to associated plant) from significant overvoltages due to prestriking, reignitions and restriking.

Energex has installed surge arresters adjacent to the CB to limit overvoltages, but as we have experienced insulation failures at sites with surge arresters, this demonstrates that arresters alone may not be sufficient to guarantee protection against overvoltages generated by capacitor switching operation. These incidents can lead to catastrophic plant failure which will pose a safety and network security risk.

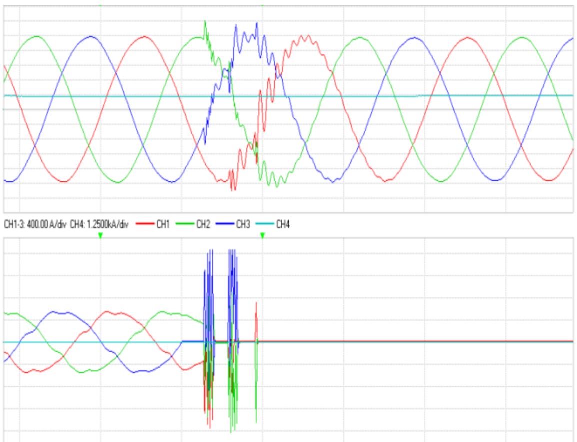


SSRVW Late restrikes on [redacted]

SSIPS Flashover in TRF cable box



SSLBS Multiple prestriking on [redacted]



SSBBS Multiple restrike activity on HS Horizon

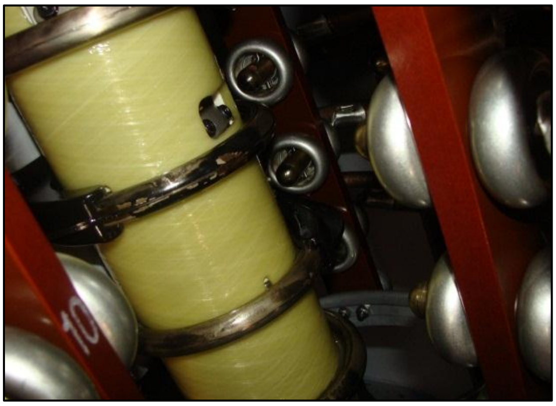
The overvoltages due to switching with vacuum CBs may damage the connected apparatus (capacitor banks, transformers), and with regular switching of the CB, damage can occur again and again! A replacement option would be to utilise a more appropriate CB for the routine switching of the capacitor bank such as a puffer type SF_6 CB or other device designed for capacitor switching which is less likely to cause switching problems. In a restriking event at substation SSRVW, a cable box on a transformer at and adjacent substation SSIPS simultaneously suffered a flashover. Another case was the complete destruction of the capacitor bank at substation SST108 during a restriking event.

 **Failure of capacitor bank at SST108**	 **Capacitors from SST108**

Corrosive sulphur oil in Power Transformers

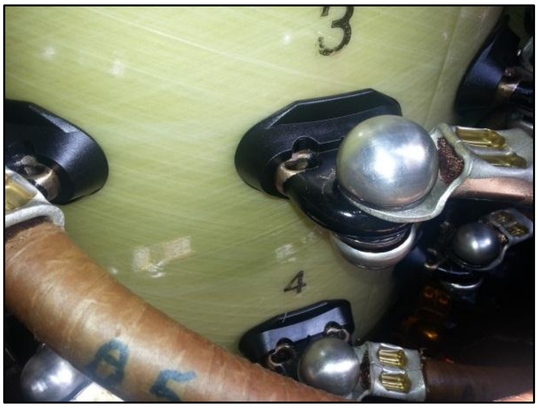
In November 2012, an 80 MVA power transformer, TR52854 (TR6 at Coomera) failed catastrophically, with an internal fault leading to the displacement of the three windings. The windings were damaged and required rewinding. The presence of corrosive sulphur compounds in the oil was identified by the transformer and on load tap changer (OLTC) manufacturers as a predisposing condition to the failure. In the case of this transformer the corrosive sulphur oil reacted with silver on the contact tips within the OLTC selector forming a coating of conductive silver sulphide. This lowered the dielectric strength of the oil and insulation breakdown occurred.

SSCMA winding damage



SSCMA silver sulphide deposits

A detail investigation of power transformers at AFD-Archerfield, VPK-Victoria Park and LBS-Lytton Bulk Supply Substations have shown significant evidence of corrosive sulphur in the transformer oil and are at a high risk of failure.



Silver sulphide deposits SSVPK

Silver sulphide deposits SSVPK

Corroborative evidence was sought by checking similar transformers and samples were taken on all transformers. The presence of silver sulphide was confirmed by analysis on transformers manufactured between 1998 and 2007. Energex has embarked on a program of oil passivation, prioritised by higher rated power transformers. Of this program, 34 off 110 kV transformers and 108 off 33 kV transformers are scheduled for completion in 2014/15 with the remaining 142 off 33 kV transformers programmed for completion in 2015/16. Energex will also be completing internal inspections, cleaning and refilling oil in 9 power transformers each year until 2019/20 in units where oil passivation alone is not sufficient to manage the risk.

While the same problem exists in the 33kV power transformer fleet, the risk of failure is lower as there is no tap changer components inside the main tank, thus a failure would most likely be inside the selector/diverter chamber.

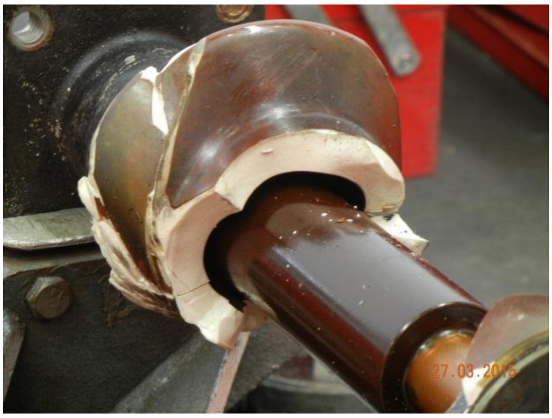
[redacted] bushing failure

In the past 2 years Energex has experienced 4 catastrophic failures [redacted] outdoor CBs. This particular model of CB is an indoor withdrawable OCB that has been modified to fit inside a cubicle, with outdoor porcelain bushings on the top to facilitate connection to overhead open busbar type 11kV substations. The failure arises when the small volume of insulating oil in the top of the bushing is lost resulting in moisture ingress. As the bushing core is paper based insulation and thus hygroscopic, water absorption over time leads to catastrophic insulation failure.

Destruction of bushings at SSLDR

SSLTN Destruction of bushings

Such failure of a porcelain bushing is very violent and in each case porcelain shards are ejected several metres across the substation yard thereby presenting a serious safety risk to operators and the public. For short term operator safety all [redacted] CB have been fitted with plywood barriers to reduce the impact of a catastrophic failure.



SSLTN shattered bushing

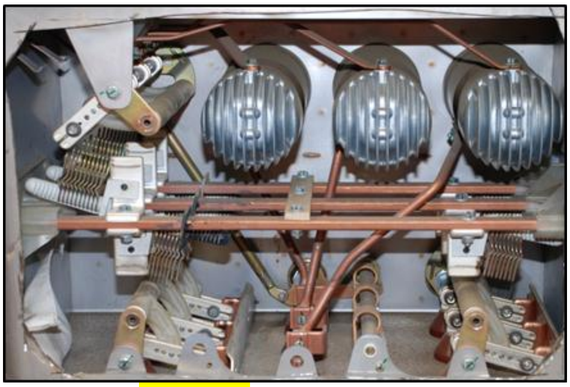
SSLTN tracking due to water ingress

Taking into account the age of the CB (44-47 yrs.) and the fault rating of 13.1kA is less than the typical fault levels on the network, it is not economically viable to repair the bushings. The only safe course of action is to replace with the new CBs.

[redacted] RMU Operating Switch Failures

Energex operates a population of approximately 8,500 [redacted] 11kV RMUs. On several occasions, a design fault on a mechanical switch allowed the contacts to overtravel into an indeterminate position between OFF & Earth, which initiated an internal arcing fault. This situation is dangerous to operators and also destroys the asset. To rectify this, a large high risk batch was rectified (1,000) and the entire population, which can still fail are required to be operated with an overtravel arresting device (mounted on the front panel). This objective of the device is to limit travel of the mechanical switch and this will allow the unit to survive, and can be repaired.

Overtravel resulting in indeterminate position



Rear of [redacted] with overtravel arcing

However, as the arrestor is an administrative control, operators can fail to use the device and any malfunction will result in an arcing fault and destruction of the RMU, which will need to be replaced.

Ageing Oil Circuit Breaker diagnostic and service failures

Within the past 3 years, Energex has experienced 2 significant failures of oil circuit breakers. The failure of an OCB is a significant safety event which usually involves the release of a large volume of oil that can be dangerous to the operator or the public.

SSLTN 11kV OCB failure exterior

SSLTN 11kV OCB failure internal view

Failure to replace these OCBs in a timely manner may significantly increase the risk of catastrophic failure. The failure of oil switchgear has been attributed to serious injuries and even fatalities in certain cases.

The photographs above from substation SSLTN show an 11 kV OCB that actually cleared a fault, but in doing so, suffered internal structural damage. During the reclose dead time (20s) the CB flashed over on the live side bushings inside the oil tank and failed catastrophically, ejecting oil from the enclosure.

The second failure involved an outdoor live tank 110kV OCB at substation SST114 (refer photos below). During routine switching on an adjacent device the operator heard discharging sounds from within and the unit was immediately isolated. Until examination severe tracking damage was found inside the porcelain chamber. Despite regular maintenance, this CB had become unserviceable, most likely due to moisture ingress thus affecting the integrity of the internal insulation.

SST114 110kV OCB failure exterior

SST114 110kV OCB failure exterior

PUBLIC

Energex

Obsolete Protection Scheme Replacement Program

Asset Management Division

energex

positive energy

Energex

Obsolete Protection Scheme Replacement Program 2015/16 - 2019/20

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1/7/15

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Version control

Version	Date	Description
1	1/07/2015	Submitted

Energex Limited (Energex) is a Queensland Government Owned Corporation that builds, owns, operates and maintains the electricity distribution network in the growing region of South East Queensland. Energex provides distribution services to almost 1.4 million domestic and business connections, delivering electricity to a population base of around 3.2 million people.

Energex's key focus is distributing safe, reliable and affordable electricity in a commercially balanced way that provides value for its customers, manages risk and builds a sustainable future.

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Corporate Communications
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Executive Summary

Energex seeks to continue to deliver sustainable outcomes for customers and business without compromise to existing safety or legislative compliance requirements. Effective protection systems for the high voltage network are a vital link in the provision of a safe and compliant network. Protection systems detect and disconnect faults from the power system, for example when electrical equipment fails or an incident occurs causing powerlines down on the ground. Reliable operation of protection schemes is vital to mitigating these risks, with failure of a protection system to do so resulting in unsafe conditions until the public or staff notify Energex of an incident and power is switched off.

The purpose of this document is to establish a prudent expenditure forecast for replacement of Obsolete Protection Schemes over the forthcoming 5 year period. This is not accounted for in the modelled REPEX programs.

The objectives for this program are to:

- Mitigate safety risks to staff and the community to As Low As Reasonably Practicable (ALARP);
- Provide for continued operation of the high voltage network in accordance with protection system requirements in the National Electricity Rules; and
- Minimise the likelihood of plant damage by improving capability for effective clearance of high voltage faults

During the 2010 - 2015 period Energex replaced obsolete protection schemes by aligning work with primary electrical plant upgrades and replacements. This represented an efficient and cost effective method of mitigating the risks associated with the obsolete protection schemes. The approach to managing obsolete protection scheme replacements is required to change for the 2015/16 – 2019/20 period. The remaining obsolete schemes on the network are not aligned with primary plant replacements in the reduced forward capex program and are therefore represented as a focused stand alone REPEX program.

In the interim determination the AER stated Energex had taken a conservative risk approach. In response Energex has revised this program to target only high priority protection scheme replacements which address safety risks and/or legislative compliance outcomes. Obsolete schemes mitigating customer impact risks have been removed with Energex to tolerate increased risk of customer outages as a result, with the exception of the highest customer impact risk related with the 2018 Commonwealth Games.

The following table provides a summary of the revised investment required being $24 million over the five year period.

$m, 2014-15	2015/16	2016/17	2017/18	2018/19	2019/20	Total
Energex proposal	15.2	13.3	11.6	11.8	11.8	63.7
Energex revised proposal	4.0	4.5	5.0	5.0	5.5	24.0

Contents

1 Introduction

The purpose of this document is to outline the required expenditure for the 2015/16 - 2019/20 regulatory period for the replacement of obsolete protection schemes in order to effectively manage the risk exposure of the distribution network while operating safely and reliably.

A protection scheme is considered obsolete when it:

- exposes the public and personnel to safety risks that are not as low as reasonably practicable and could be reasonably addressed by replacing or upgrading the protection scheme required under the *Work Health and Safety Act* (2011) Cth.
- does not meet minimum performance requirements under the National Electricity Rules (NER) and where a lack of compliance also results in:
  - a safety risk that is not as low as reasonably practicable; or
  - a risk of causing collateral plant damage because of non-operation or slow clearing times; or
  - a risk of increasing the severity of damage to the faulted item resulting in escalated repair costs; or
  - a design that does not meet industry practice
- presents a corporate risk due to a high value of customer reliability

The obsolete protection scheme program seeks to establish a secondary systems repex strategy reducing the risk exposure of existing protections schemes to meet revised levels of risk tolerability. This aims to ensure that the secondary system facilitates a safe and reliable primary system providing operational flexibility under today's network load conditions.

Obsolete Protection Scheme Replacement Program			
Section	**Scheme Deficiency**	**Key Drivers**	**Expenditure $m, 2014-15**
3.1.1	Two Phase Supply Connections	Safety	2.90
3.1.2	110kV Communications Diversity	Compliance & Plant Damage	0.60
3.2	110kV/132kV Bus Bar Protection	Customer Impact Risk	0.60
3.3	33kV Feeder Protection	Safety	0.20
3.4	33kV Bus Bar Protection	Safety	3.10
3.5.1	High Impedance Dual Winding Transformers	Compliance & Plant Damage	2.60
3.5.2	Circuit Breaker Fail schemes for Delta Primary Transformers	Compliance & Plant Damage	3.80
3.6	Communications Diversity for Transformer Ended Feeders	Safety & Compliance	2.90
3.7	High Impedance Distribution Transformers	Safety	1.90
3.8	11kV Busbar Protection	Safety	5.50

Table 1: Obsolete Protection Scheme Replacement Program

As the distribution network ages, life cycle management of equipment is critical. When failure rates increase, there is an increased reliance on the protection system to detect and isolate faults. Protection schemes provide a risk control measure for operating equipment closer to its retirement age by utilising digital relays they offer faster fault detection and can minimise the fault energy exposed to the aging equipment. Therefore, if the primary system is nearing end of life where failure rates begin to increase and the protection scheme does not meet operating requirements, the risk of a catastrophic failure increases.

The Energex network has shifted from facilitating uni-directional powerflow to bi-directional powerflow integrating multiple levels of distributed generation. This has coincided with a desire to operate equipment closer to its limits, achieving efficiency and drive down capital expenditure. These changes have resulted in the traditional design of secondary systems falling short of the operational flexibility sought by the primary operating strategy. In order to ensure that the network has been operated safely with existing protection schemes, load restrictions have been placed on primary equipment by the secondary system. This does not present good engineering practice and limits the utilisation of plant items. This program assists in lifting these limitations.

In reconsidering the obsolete scheme program, Energex has identified further program items that can be removed on the basis of risk mitigation techniques.

An example of the increased risk strategy we have employed in the revised proposal is the removal of the neutral earthing resistor (NER) program. The risk is associated with removing an NER from service that is shared by multiple transformers, to conduct maintenance. During this period the step and touch potentials on the CMEN network increase and expose the public to above allowable levels described in ENA Earthing Guidelines (EG-0) and AS7000. Maintenance is critical to ensure that there is no open circuit, effectively removing the earth reference from the network. Energex reviewed its maintenance procedures to facilitate a lower risk profile. This includes, working at night to reduce public exposure, applying temporary protection settings to ensure fast clearing time, and utilising 11kV load transfers to alternate substations. While this does not reduce the risk to the level proposed by the obsolete program, in adjusting our risk approach these controls are considered acceptable to manage, and have met the safety requirement of being as low as reasonably practicable. This has facilitated the prudent avoidance of $1.31 million (2014/15) in upgrading to individual neutral earthing reactors per transformer.

2 Drivers

The main drivers of this program fall across two (2) categories, safety and legislative compliance.

2.1 Safety

The guiding principle of the *Work Health and Safety Act*, is 'that all people are given the highest level of health and safety protection from hazards arising from work, so far as reasonably practicable'. To meet this principle while operating the distributions network, the obsolete protection scheme program seeks to:

- Ensure protection schemes can detect all credible fault conditions reducing the probability that an unsafe situation will remain with a power source connected.
- Ensure protection clearing times are sufficiently prompt to reduce the energy released under fault conditions, reducing the likelihood of:
    - catastrophic failure of equipment
    - ignition of a fire
    - collateral damage including airborne debris
- Ensure that appropriate protection schemes given remote fault indication to a controller to prevent inadvertent remote energisation of substation faults reducing the risk exposed to personnel.

2.2 Legislative Compliance

There are protection system performance standards in Chapter 5 of the *National Electricity Rules* (NER), outlining protection system obligations for a DNSP. Many of the obsolete schemes that are proposed to be replaced over the 2015-2020 period address shortfalls in compliance to the following sections of the NER:

- To ensure primary system faults are detected and isolated by providing sufficient primary and backup protection systems S5.1.9(c)
- To ensure fault clearing times for the 110kV and 132kV network are met in accordance with Table S5.1a.2 where applicable.
- To ensure fault clearance by a protection scheme for any fault type while there is a failure of a single communications scheme, in accordance with S5.1.9(d).
- To ensure that there is a breaker fail system or a similar backup protection system that disconnects a fault such that is does not cause collateral damage S5.1.9(f)
- To ensure fault clearance while preventing consequential plant damage on the 33kV and 11kV network, in accordance with S5.1a.8(a)(3) and Table S5.1a.2.

Energex has assessed the above compliance areas in conjunction with the prudency measures designed in the NER under sections S5.1.9(j), (n), (o).

In addition, the *Electrical Safety Regulation* 2013 (Qld), section 196 requires that high voltage lines are to be protected by a protection system that can be relied upon to operate.

3 Supporting Analysis and Risk

This section provides the reasons and supporting information driving the inclusion of the Obsolete Protection Scheme program in the submission. It will seek to highlight the risk management techniques already being employed, those that are proposed and defining the scope of works where the risk has not been reduced to as low as reasonably practicable. It also examines key case studies, largely from the Energex network, that highlight safety and corporate risks that have led to the inclusion in the 2015-2020 submission.

3.1 110kV/132kV Feeder Protection

3.1.1 Two Phase Supply Connections

There is a safety risk to the public on 110kV traction supply feeders where under certain conditions, live conductors could be on the ground without any protection scheme capable of detecting and isolating the unsafe condition. This arises in transformer ended feeder installations and radially supplied feeders. This type of fault is referred to as a backfed earth fault. There will be a zero sequence voltage source at the point of fault but minimal current flow due to the lack of earth reference. Existing protection schemes will not operate for this fault.

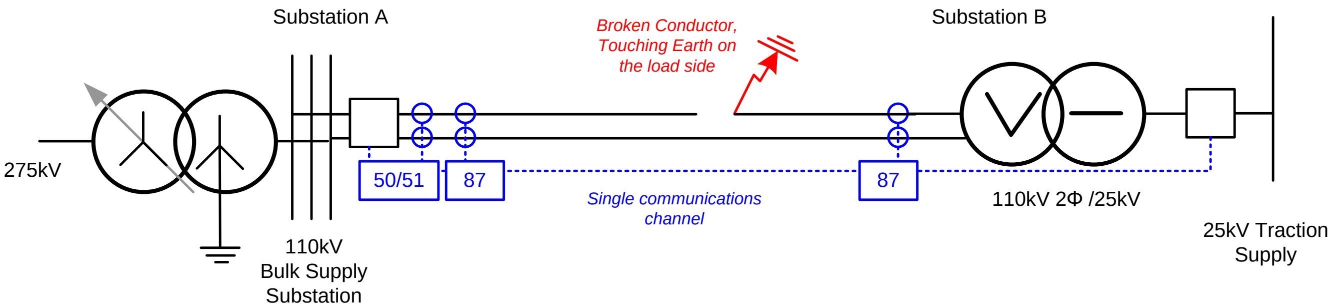


Figure 1: Backfed earth fault diagram that cannot be detected with existing protection schemes

This highlights a shortfall in compliance to the system standards outlined in Schedule 5.1 of the NER, as there is no primary nor backup protection system that can detect this type of short circuit fault. This fault will remain undetected and will not be automatically disconnected in contravention with S5.1.9(c), (d), S5.1a.2 of the NER. This type of fault is considered a credible contingency event on a two-phase transmission line[1].

Energex also has a responsibility under the Electrical Safety Regulation 2013 (Qld)[2], to ensure that a high voltage line is protected by a protection system that can be relied upon to operate. The regulation also incorporates appropriately recognised electricity supply industry standards. In AS2067, it provides that Electrical equipment shall be effectively and safely disconnected by protective devices in the event of a fault occurring.[3] The current protection scheme neither addresses requirements under the Safety Regulation nor under AS2067 because this type of fault will not be disconnected.

There are safety consequences resulting from not disconnecting this type of fault. A fire can be ignited from the arcing caused by the broken conductor, even at the low current that this

[1] *National Electricity Rules*, S5.1.2.1(a).
[2] *Electrical Safety Regulation* 2013 (Qld), s196.
[3] AS2067 - *Substations and high voltage installations exceeding 1 kV AC*, 7.2(b).

type of fault presents. In a report prepared for the Victoria Government's Work Safe department[4] it was concluded that, under certain conditions 4.2A of current at 12.7kV can ignite a fire almost instantaneously, within 10ms). The probability of ignition directly relates to the arc duration, which is the protection system fault clearance time, refer to Figure 2. This is important when considering a backfed earth fault on the 110kV network in question as it is not disconnected by any protection scheme.

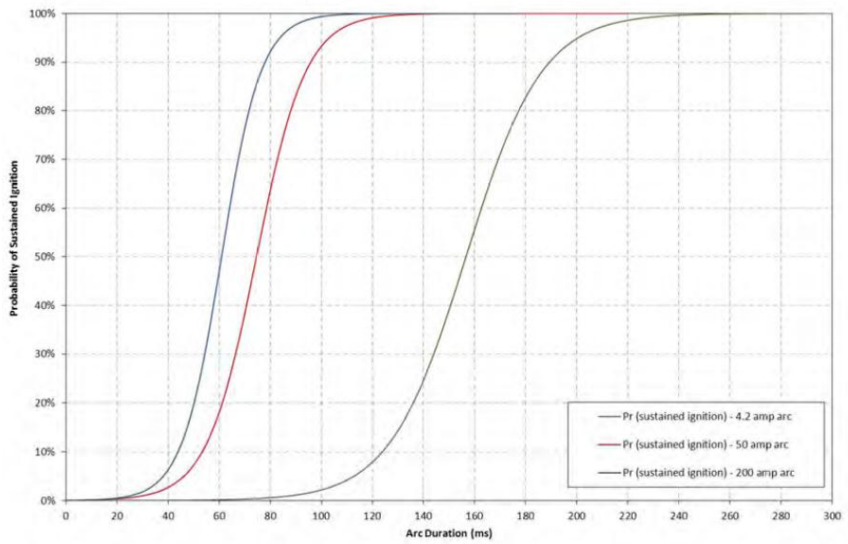


Figure 2: Ignition probability against arc duration for 12.7kV network with 4.2, 50 and 200 amp arcs at 45°C and 10 kph wind speed for hay/straw at 5% moisture[5]

This type of fault on the transmission network, that can lead to fire ignition, can occur when a shackle connection to a pole fails, vegetation damage to conductors, corrosion on insulator strings or lightning strikes. The current failure rate is in the order of 10^{-4}-10^{-5}. Notwithstanding this failure rate across the total population in Energex, the nine feeders with this risk have or are beginning to enter the later portion of the asset management life cycle.

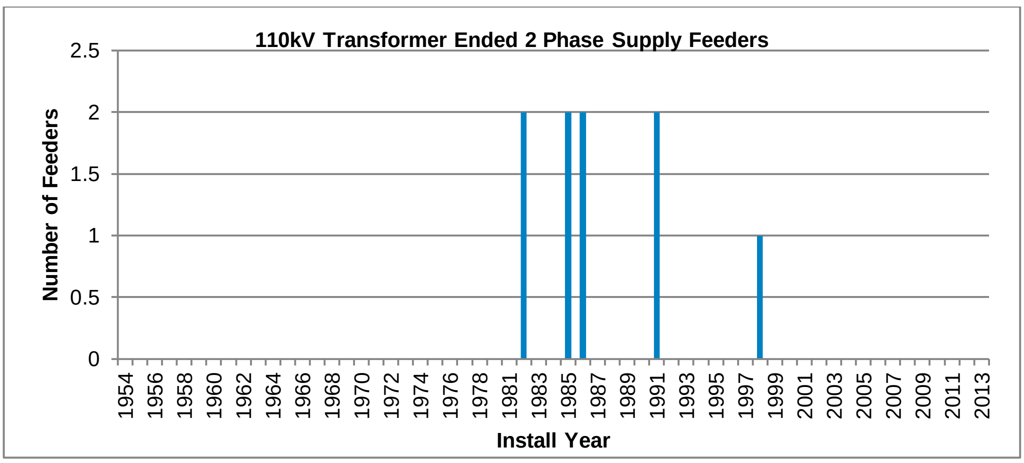


Figure 3: Age Profile of 110kV Transformer Ended 2 Phase Supply Feeders

[4] Coldham, Czerwinski, Marxsen (2011), *Probability of Bushfire Ignition from Electric Arc Faults*, HRL Engineering Materials, Accessed at http://www.esv.vic.gov.au/Portals/0/About%20ESV/Files/RoyalCommission/HRL%20final%20report.pdf

[5] Ibid.

These feeders take routes that in some cases directly pass over community areas such as parks, and over properties. In addition, due to the alignment of these feeders to rail easements, many of the feeders have a large proportion of shackle connections which increases the probability of failure when compared to the Energex typical straight sectioned easement transmission feeder.

Figure 4: Exposure of 110kV Feeder over residential properties and community parks.

There have been no reported incidents of the fault in question at 110kV, however a similar scenario has occurred previously on the 33kV 3–phase transformer ended feeder, which presents the same technical difficulties for a protection scheme. This fault was not disconnected until a customer rang the emergency line.
A risk assessment has been conducted to consider the risk that this presents to the company under the network risk framework.

Category	Risk Scenario	Consequence	Likelihood	Risk Score
Safety	A broken conductor caused by a failed shackle connection, on a 110kV feeder supplying a 2 phase ungrounded load with the conductor falling to the ground on the load side of the feeder, which falls on a person, fence, car or ignites a fire and causes multiple fatalities.	6	2	12 (Moderate Risk)
Legislated Requirements	A compliance audit leading to the identification of the lack of protection to detect and isolate a fault on the 110kV network leading to the regulator issuing an improvement notice. A connected registered participant connected at this voltage level notifying the regulator leading to the regulator issuing an improvement notice.	5	3	15 (Moderate Risk)

Table 2: Risk Assessment – 2 Phase Supply Connections

In order to reduce the safety risk to as low as reasonably practicable, and the Legislative Risk from Moderate Risk, it is proposed to address the protection scheme deficiencies by employing an engineering control measure. This involves the installation of voltage transformers as close to the terminals of the connected transformer as possible, employing an undervoltage scheme to detect this type of fault. The undervoltage protection is then required to send a trip signal to the source substation to isolate the fault. This relies on a communications path.

Option 1 (Preferred) – Communications & VT

Option 1 addresses the limitations by providing a primary and backup protection scheme that utilise diverse communications, such that the protection scheme can withstand a single protection system outage while maintaining supply to the network. This is the most cost effective option to address the risks. It is proposed to:

- Install an All Dielectric Self Supporting (ADSS) communications path in a diverse path from the existing route
- Install digital protection relay schemes to utilise diverse communications paths
- Install two single phase Voltage Transformers
- Implement an undervoltage protection scheme to detect a backfed earth fault

Option 2 – Parallel Connection

This option involves installing bus work and a bus section circuit breaker at the load substation. This provides an alternate path for fault current to flow, and therefore allows existing protection schemes to be utilised to detect all earthfaults. The main disadvantage of this scheme is that where there are dual circuit connections, they are largely connected using two different phases. This is done to balance the network and minimise the negative sequence source. Therefore, in most cases to achieve this, the third phase would need to be constructed from the source to the load substation. This then becomes cost prohibitive and is the basis from which the option is discounted.

- Install a 110kV bus section circuit breaker and associated bus work
- Install 2 km (per feeder) of single phase 110kV overhead conductor.

Option 3 – Do nothing (Derogation)

This option involves no changes to the protection system, and instead seeking derogation from the AEMC from the protection system performance criteria in Schedule 5 of the National Electricity Rules. This is not recommended due to the safety risks that are not addressed by this option.

3.1.2 110kV Communications Diversity

The protection system performance standards required to be met under Schedule 5 in the NER, specify fault clearance times for the 110kV/132kV network both in the primary protection system and the backup protection system. These times must still be met with a single protection scheme out of service, or the loss of a communications path. There are three areas of the 110/132kV network that cannot withstand an outage of a communications scheme due to a lack of a second diverse path.

One of the regions that currently does not meeting the requirements is to the west of the South East Queensland network. This network provides supply to the Lockyer Valley and surrounds in addition to providing a contingency supply to parts of the Ergon Network in Toowoomba. The length of the three 110kV feeders of concern, range from 20km to 39km.

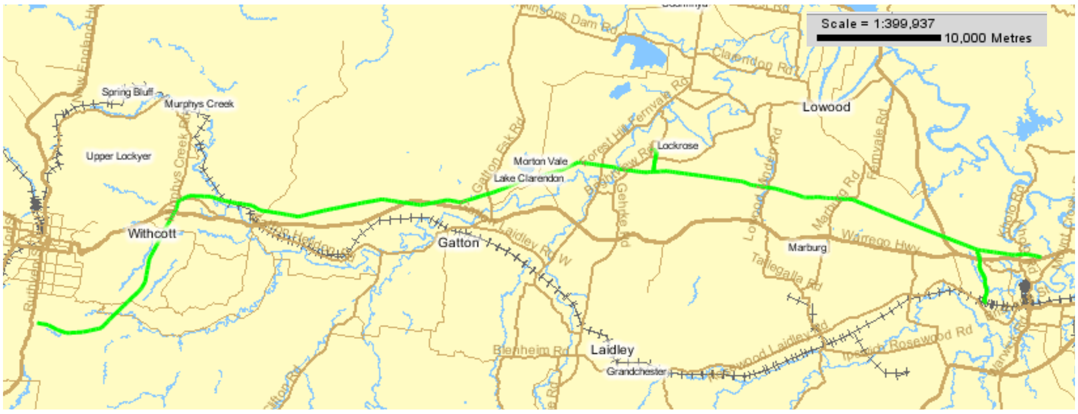


Figure 5: Geographical location of the 110kV feeders without communications path diversity

This part of the network is not heavily meshed at any voltage level, therefore there are no other established diverse communications paths available via the existing network. Many of the existing links are via the overhead earth wire or via microwave link. The consequence of losing a single communications path and consequentially being required to de-energise a 110kV line due to not having sufficient protection coverage is more severe than in other areas of the network as there are fewer contingency network arrangements at the lower voltages to support the load.

It is proposed to improve the communications diversity in this region by installing a new major microwave site that provides infrastructure to improve the communications diversity on no less than three 110kV feeders. This may also provide a benefit for the communications on the 33kV and 11kV network once established. This provides a cost effective way of managing multiple shortfalls in NER compliance due to the communications network.

Option 1 (Preferred) – Microwave Link
This option presents the most cost effective to address the multiple site issues with a single communications installation. This microwave link will provide an important mesh point in the network.

- Establish a major Microwave Link site with visibility to existing sites in the region
- Install Microwave equipment at the respective substations
- Uncouple existing single points of failure at existing microwave sites

Option 2 – Optical Fibre
This option is the most technically desirable, however the most expensive, to address the communications issues. This has been discounted a viable investment option as it does not present sustainable practice in the remote part of the South-East Queensland Network

- Install three separate dedicated optical fibre communications paths
- Install associated optical fibre patch panels at each substation

Option 3 - Do nothing (Derogation)
This option involves no changes to the protection system, and instead seeking derogation from the AEMC from the protection system performance criteria in Schedule 5 of the National Electricity Rules. This is not recommended due to the safety risks that are not addressed by this option.

The other 110kV network that has been highlighted as requiring diverse communications network is for the feeders that supply the Australian Trade Coast incorporating critical industrial customers and parts of the Brisbane Airport Industrial Park.

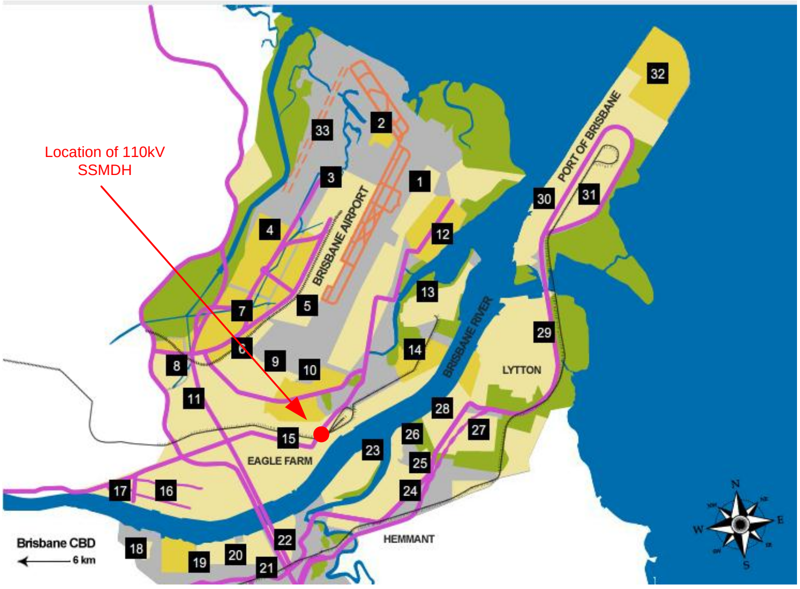


Figure 6: Australian Trade Coast Precinct Map showing the location of the 110kV substation with an obsolete protection scheme

The existing 110kV supply is via two 110kV cables approximately 6.5km in length that are connected in a transformer ended feeder arrangement. This protection scheme relies on two pilot cables that are 33 years old. Consistent with the Pilot Cable Refurbishment program, pilot cables near their retirement age around at 45 years. Therefore it is prudent to ensure that there are alternate communications paths in order to ensure that the primary network can still be operated until the secondary equipment can be repaired or replaced.

Option 1 (Preferred) – Existing Optical Fibre
This option involved the installation of secondary systems to utilise existing communications infrastructure.

- Utilise existing optical fibre communications path
- Install associated optical fibre patch panels at each substation
- Install optical fibre compatible relays

Option 2 – Do Nothing (Derogation)
This option involves no changes to the protection system, and instead seeking derogation from the AEMC from the protection system performance criteria in Schedule 5 of the National Electricity Rules. This is not recommended due to the safety risks that are not addressed by this option.

One area of network identified as not being able to withstand a communications outage is the 110kV network supplying islands off the South East Coast of Queensland, including Stradbroke Island and Russell Island. Duplicate diverse communications paths to these geographically challenging locations are not economically feasible.

Figure 7: Geographic map showing the 110kV feeder route supplying Stradbroke and Russell Islands

Following feedback from the AER on the original proposal, Energex has taken a risk based approach to manage communications outages in this part of the network and is relying on the economic basis allowed under the NER in section S5.1.9(j) to define that it is not practical nor economic to achieve the standards required in Table S5.1a.2. This displays prudency in the engineering design of the protection and communications networks and the asset management techniques being employed across this challenging part of the 110kV network.

3.2 110kV/132kV Bus Bar Protection

It is an industry practice to provide bus bar protection on all 110/132kV substation bus bars. The industry practice has been reflected in the performance criteria in Schedule 5 of the NER, where the protection scheme clearing time should be 120 milliseconds by the primary scheme and 430 milliseconds for the backup scheme[6]. An effective bus bar protection scheme isolates a bus fault and latches to ensure that the scheme is not remotely energised with personnel in the substation and indicates to an operator a zone where the fault occurred to aid in restoration of load from alternate supplies and to inform test activities post-fault.

At a key Gold Coast 110kV/11kV substation there is an obsolete protection scheme on two 110kV buses and four 110kV feeders. Under normal and contingency operating conditions the clearing time requirements of the NER are met, however there is limited discrimination and does not provide sufficient fault information for a controller to diagnose a fault effectively or efficiently to restore supply safely. This is limiting the operational flexibility to manage

[6] *National Electricity Rules*, ss S5.1a.8(b), S5.1a.8(d), S5.1a.2.

faults in the surrounding 110kV network potentially leading to a significant delay in the restoration of load.

The SSBBH substation was originally converted from an outdoor 33kV/11kV substation in 1985 to a 110kV/11kV substation. At the time, the site was particularly constrained as supply had to be maintained while converting the substation. This limitation meant that there was no room in the substation for 110kV circuit breakers. Even with modern disconnecting circuit breakers, it will be a challenge to upgrade this site without additional land which is unlikely to be available. Therefore operational management techniques need to be employed to circumvent primary substation works while balancing the risks associated with the site and the surrounding network.

The limitation of this network is that under a fault condition there is a lack of protection zones discrimination that provide a remote operator enough information to begin restoring the network in the most efficient manner. It relies heavily on primary testing practices to identify faults before re-energising equipment. This presents a significant risk of additional cost and time in restoration activities. Whilst the existing protection and SCADA design provided the most efficient design to minimise investment in the secondary system given the technology available at the time, it no longer represents good practice. This design would have also considered the load magnitude and criticality at the time of construction, and as the Gold Coast region has rapidly developed over the last 30 years, and this no longer reflects the customer expectations in the area.

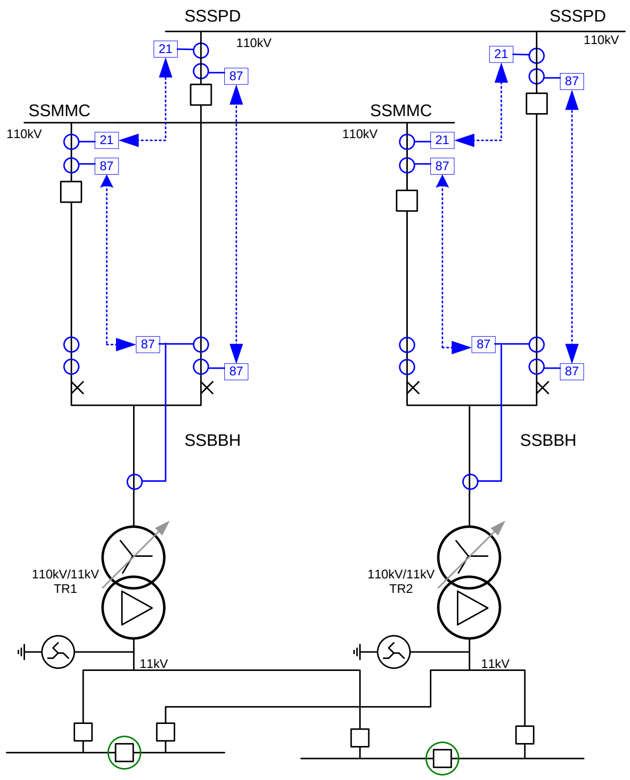


Figure 8: Gold Coast 110kV network showing obsolete protection schemes limiting primary system flexibility

There are two 110kV feeders per bus that are supplied from adjoining bulk supply substations, the cables are laid adjacent in the same route to each substation, sharing marshalling areas and pits. There is a primary network limitation, where a single cable fault on either F826 of F827 could cause collateral damage to the adjacent conductor. Likewise for F919 and F918. All four feeders are 35 year old, and in particular F826 and F827 are oil filled cables. Asset modelling has projected that F827 will reach end of life in 10 years, and F826 in 20 years. This difference is being driven by poor sheath test results on F827, which indicates that there is widespread damage to the cable. This presents a primary fault risk as we approach the useful life of the cables.

There is a reasonable probability that if one of the cables fails, that the adjacent feeder in the same route with minimum separation will also sustain damage. An incident in Auckland - New Zealand saw multiple transmission cables damaged from a single fault.

Figure 9: Penrose Substation – New Zealand 2014 – fire and damage following an oil filled cable fault within a substation[7]

An outage on any of the feeders supplying SSBBH, rely on communications assisted protection schemes to isolate the fault remotely. As these schemes cannot ascertain whether there is a transformer fault, or a bus bar fault at SSBBH, all protection is latched to ensure safety such that an operator cannot remotely place the network in an unsafe arrangement without sending a crew to site and identifying the exact issue causing the protection operations. The worst case fault for this network is a fault on of F818 or F819 as load cannot be restored to the respective transformer at SSBBH without primary testing for the 110kV switchgear at SSBBH. Therefore the worst case scenario would be a failure of F818 or F819 causing a fault on the other because they are laid in the same route. This would render the whole site de-energised until primary test are conducted.

In the lead up to, and during the 2018 Commonwealth Games, this substation will provide the supply for the

- Gold Coast Convention and Exhibition Centre which will host the main media centre throughout the games along with the Netball and Basketball events.
- Broadbeach Bowls Club hosting the Lawn Bowls.
- Broachbeach and southern parts of Surfers Paradise which will provide high density accommodation for the duration of the games.
- Attractions such as the Casino, Pacific Fair Shopping Centre and Dining Precincts.

If an outage was to occur during the Commonwealth Games, the limit in operational flexibility due to the existing protection schemes presents a significant customer impact risk due to outage periods in restoring the primary network. This will reflect poorly on Energex and Queensland's infrastructure due to the intense exposure to international media during this period. Under normal load conditions an outage on any one of the four feeders that this issue is present for, would be an operational challenge as the high density of the load and location with respect to the coast presents significant limitations in providing alternate supply arrangements. This becomes even more difficult during peak load times which are expected

[7] Further footage of fire available at http://www.nzherald.co.nz/electricity/news/video.cfm?c_id=187&gallery_id=145876&gal_objectid=11338075.

during this event. As such, this risk is unable to be managed operationally during this period.
While the value for customer reliability (VCR) is tolerable during normal operation periods, the Commonwealth games places new variables in a VCR equation. There should be an escalated VCR attributed to this network for this period, however it is very difficult to quantify due to the vast difference in circumstances compared to those surveyed in the AEMO 2014 report.[8]

The replacement of the protection scheme will provide greater information to a network operator remotely, will aid in guiding restoration works. This will form part of a risk mitigation plan during the Commonwealth Games.

Option 1 (Preferred) – Upgrade Protection Systems
This option does not limit the outage exposure that this substation design presents, however it addresses how quickly an operator can interpret protection indications to assist in fault finding and load restoration post-fault. This is an investment based on a risk management technique rather than an elimination control measure for the risks. It is the solution that balances the risk and cost efficiently until primary network investment is required.

- Install a bus zone relay
- Reconfigure the existing feeder differential schemes to provide better scope of the unit protection
- Replace the electromechanical differential relay, with a feeder management relay providing overcurrent protection and waveform capture.
- Provide SCADA infrastructure to remotely monitor all protection indications
- Install a second battery for the 110kV protection panels.

Option 2 – Replace 110kV switchgear
This option provides the engineering control measure that attempts to eliminate the risks identified completely. This involves significant capital investment and may involve the acquisition of further land to facilitate the works.

- Install 110kV switchgear (4x feeder, 2 x transformer and 1 bus section circuit breakers)
- Install duplicate 110kV protection schemes providing unit protection that mirrors the new primary configuration.
- Install a second battery for the 110kV protection panels.

Option 3 – Do Nothing
Operationally managing the risk of customer outages is not feasible for this situation given the increased levels of demand and the high availability requirements for the Commonweath Games 2018. The do nothing option is therefore rejected from consideration.

[8] AEMO, 2014, '*Value of Customer Reliability Review – Final Report*'.

3.3 33kV Feeder Protection

The Energex 33kV network has a highly meshed topology. The advantages of this type of network include the ability to avoid momentary loss of supply to customers when a feeder is disconnected, provide a contingency supply arrangements to substations and is an efficient way of designing a network. There are four feeders in the 33kV network that are considered to have an obsolete protection scheme. These present either a safety risk to the public or a business risk due to consequential damage on the network.

One of these feeders provides a supply in the metropolitan south region of the network. It currently has a single electromechanical overcurrent relay protecting the 40MVA rated feeder. The primary protection clearing time is approximately 1 second and the backup protection clearing time is approximately 2 seconds. This feeder is run normally open at one end, with an automatic change over scheme if the alternate supply was lost. When this feeder is closed it provides a mesh point between supply connections. The existing protection at the source substation does not have the functionality to install a high set setting or any communications capability,

The concern for this feeder is that there are spans of this feeder that traverse a major interstate 6 lane carriageway, the Pacific Motorway (M1), which carries high volumes of domestic vehicles as well as being rated as a multi-combination dangerous goods route. This presents a safety risk to the public if the feeder was to experience a fault and fall over the motorway. This also presents significant difficulty in accessing the area to make safe and to repair any damage.

Figure 10: F419 crossing over the Pacific Motorway (M1)

The risk of failure of overhead conductors and associated equipment such as bridges and clamps increases as the fault current and clearing time of protection systems increases. The safety risk that this presents is not considered to be as low as reasonably practicable as high speed protection on this type of asset is expected by the community and the industry. An upgrade of the protection scheme reduces the risk and avoids the more significant capital expenditure to relocate the motorway crossing or to underground the supply.

Option 1 (Preferred) - Digital Protection
This option installs a digital communications assisted protection scheme to provide near instantaneous clearance of faults inside its zone of protection. This reduces the safety risks associated with a falling conductor.

- Establish a communications path between the two substations
- Install a digital communications assisted protection scheme

Option 2 - Underground Cable
The option provides and engineering elimination of the risk that is driving the protection scheme upgrade by replacing the existing overhead line that traverses the motorway. This option is technically complex due to restrictions in underboring the motorway and presents a significant capital investment.

- Replace the existing overhead line traversing the motorway with an underground cable.

Option 3 – Do Nothing
This option has been rejected as the safety risks are not as low as reasonably practicable where the above options provide reasonably practicable solutions.

3.4 33kV Bus Bar Protection

3.4.1 Installation of 33kV Bus Bar Protection

It is an industry practice to provide bus bar protection on all 33kV substation bus bars. In Schedule 5 of the NER, there are no defined protection clearing times specified however, there is an overarching principle provided in Table S5.1a.2 that the clearing times should be fast enough to prevent plant damage. An effective bus bar protection scheme isolates a bus fault and latches to ensure that the scheme is not remotely energised with personnel in the substation and indicates to an operator a zone where the fault occurred to aid in restoration of load form alternate supplies and to inform test activities post-fault.

Without bus zone protection there is a safety risk to the public that a fire is ignited in the faulted equipment due to the slow clearing time of the protection, and a safety risk to personnel from the protection scheme clearing the fault not being a latched relay such that a bus fault can be remotely reenergised with crews in the substation yard.

In 2011, there was a catastrophic failure of a 33kV/415V station transformer at a zone substation which sprayed and ignited oil up to 15 metres from the failed unit and resulted in a large fire, damage to third party property and damage to other plant items in the substation. Queensland Fire Services were alerted and attended site to extinguish the fire. Queensland Police personnel also attended site to control traffic and public access to the site[9].

[9] Video footage of the resulting fire was captured by a bystander and can be viewed at: https://youtu.be/ExFnIHGbf7w?list=ULExFnIHGbf7w

Figure 11: Station Transformer TR8 exploded and expelled 400L of hot insulating oil igniting spontaneous fires

Figure 12: Ignited oil sprayed approximately 10m from the transformer, across the foot path onto the Vehicle

The investigation report highlighted that a contributing factor to the severity of the damage was the slow detection and isolation of the fault. The corrective action plan identified that high speed bus zone protection could have reduced the severity of the damage caused by limiting the electrical energy released during the fault.

There are 16 33kV buses, across 12 substations that currently do not have bus bar protection, that we are proposing to install high speed (<100ms clearing time) protection to reduce the energy release under fault conditions. An important aspect of this upgrade is installing latched output relays. This provides an engineering control measure to ensure that equipment that has been subjected to fault is not accidentally re-energised remotely. The incident referred to in 0 also provides history surrounding the risk associated with not latching these protection functions and the personnel risk this presents.

Option 1 (Preferred) – Bus Zone
This option installs a low impedance bus zone, unit protection scheme using existing current transformers.

- Install a low impedance bus zone scheme

Option 2 – Bus Blocking
This option utilises existing digital relays, or installs digital relays, that provide a blocking input to a bus multitrip relay. These schemes are effective as they do not require an additional CT on the existing switchgear however, there have been mal-operations and non-operations under certain conditions within Energex, therefore it is not recommended where a bus zone scheme can be installed.

- Replace electromechanical relays and standardise digital relays on outgoing feeders
- Install a bus blocking scheme

Option 3 – Do Nothing
This option has been discarded as the safety risks are not as low as reasonably practicable where the above options provide reasonably practicable solutions.

3.4.2 Upgrade of 33kV Busbar residual unit scheme schemes

Historically, in order to provide a cost effective form of unit protection for a bus bar, a two-wire scheme was implemented. This avoided the cost of additional relays and wiring, however it comes with a limitation that it would only detect unbalanced faults. Phase to phase and three phase faults are not detected.
Most phase to phase bus faults occur on outdoor installations usually occurring due to wildlife (e.g. Snakes). On indoor switchgear phase to phase faults are less common however can occur where the switchgear is not phase segregated. In particular the risks associated with two wire schemes is that it will not detect balanced faults and clearance of the fault can rely on remote substations, with clearing times in excess of switchgear ratings. This then places stress on the switchgear and can lead to consequential damage of equipment and presents a safety risk to anyone in the substation, and in cases such as in 3.4.1 the public is also exposed.

Option 1 (Preferred) – Upgrade to 4-wire scheme
This option upgrades the existing two-wire scheme to incorporate all phases in a 4-wire scheme.

- Install a 4-wire bus zone scheme

Option 2 – Bus Blocking
This option utilises existing digital relays, or installs digital relays, that provide a blocking input to a bus multitrip relay. This scheme is not recommended as it is not the lowest cost option and presents additional complexity in the protection scheme that can cause mal-operations and can cost more to maintain over its life.

- Replace electromechanical relays and standardise digital relays on outgoing feeders
- Install a bus blocking scheme

Option 3 – Do Nothing
This option has been discarded as the safety risks are not as low as reasonably practicable where the above options provide reasonably practicable solutions.

3.5 Transformer Protection

3.5.1 High Impedance Dual Winding Transformers

High impedance dual winding transformers are used on the 110kV/11kV network to provide a cost effective way of providing a high capacity supply using a single transformer unit while managing fault levels. The difficulty with protecting these assets is that faults in the LV winding, cable connections or the circuit breaker are not capable of being detected from the HV side of the transformer without significantly limiting the load capacity of the transformer.

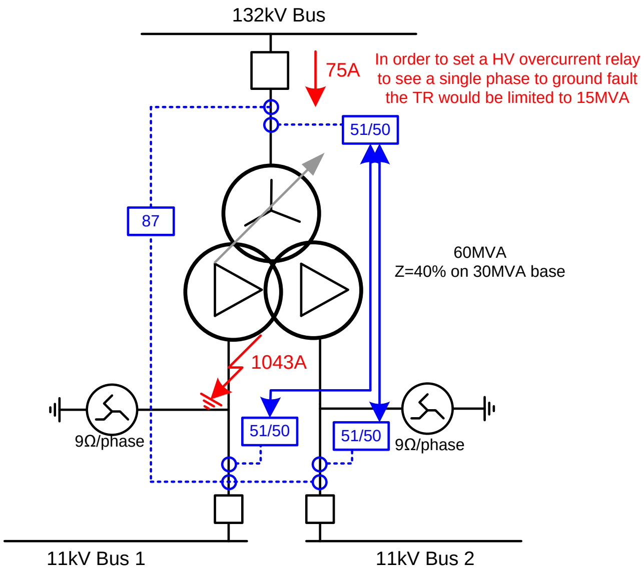


Figure 13: Existing deficiencies in the protection scheme for dual winding transformers

In most cases, the existing scheme has utilised a single transformer differential relay along with a communications assisted overcurrent scheme using load encroachment principles to increase the load carrying capacity. This overcurrent scheme has been deemed as obsolete due to limitations in its speed of operation and sensitivity. The scheme is extremely sensitive to load characteristics, fault impedance and communications and uses these elements in a blocking scheme under load conditions.

The existing overcurrent load encroachment scheme is limited in sensitivity and speed by the load variability, which at times can be extreme and is also impacted by the penetration of solar on the network. This variability also includes the use of 11kV capacitor banks and their interaction with the transformer tap changer to manage power quality on the network. This has a flow on affect to the sensitivity of the load encroachment settings, as it must withstand step changes in all these variables. There are fault conditions where this scheme may block for an internal fault in the transformer, therefore having a sole reliance on the single transformer differential scheme for the detection and isolation of the fault.

One of these installations has shown only a 50% availability over a 24 hour period due to the load variability. The consequence of the 50% availability is that if there is a fault with some fault impedance that occurs during a high load period, the relay will not operate. This creates a safety risk in not disconnecting the fault that could lead to the ignition of oil under certain conditions. It also highlights a shortfall in compliance against s5.1.9(d) of the NER as the site cannot withstand and outage of the differential protection scheme. The other 50% of the time, the relay believes that the load is not within a 'normal load region' and therefore does not block the overcurrent setting on the HV side of the transformer. This could lead to maloperation during high load periods.

High speed protection should act reliably for all transformer faults and to minimise the risk associated with oil ignition for a bushing fault, it can also minimise the damage to the transformer, leading to the transformer being repaired rather than being replaced after an internal fault. In order to achieve this risk mitigation, particularly for the ignition of oil, protection systems should be designed with fault clearing times of approximately 100 milliseconds; accounting for less than 30ms for the relays to detect the fault and 45 to 60ms for the circuit breaker to isolate the faulted equipment from all sources.

In 2012 there was an a transformer fault initiated in the on load tap changer of a 110kV/33kV transformer. This fault was detected and isolated from all sources by the protection scheme in approximately 120ms. Despite the fast clearing time there was still damage caused to the winding of the transformer. However as the damage was limited and the auxiliaries of the transformer were still intact, allowing the transformer to be re-wound at a lower cost than being replaced. Arguably, had the protection not isolated the fault as quickly as it had, there could have been more damage sustained to the transformer. If there been a reliance on a load encroachment blocking scheme under this fault the consequences could have greater.

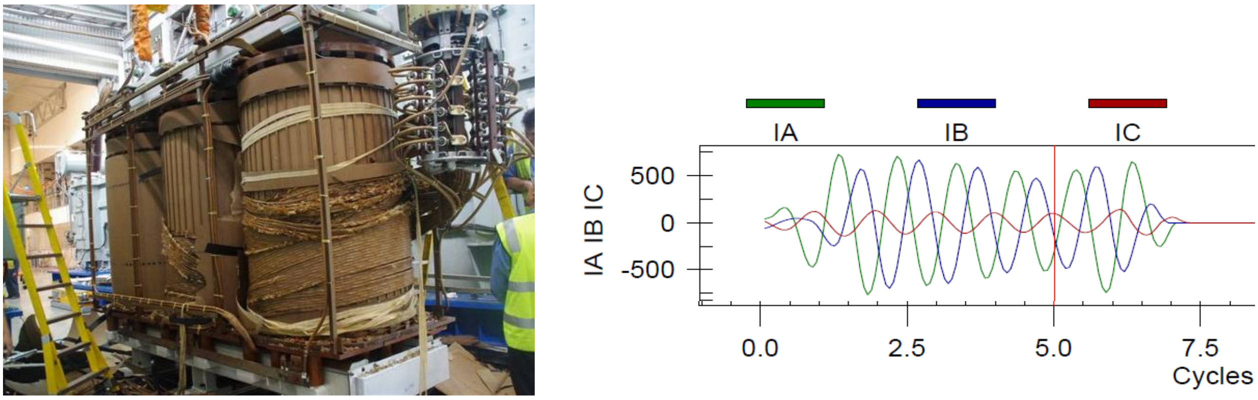


Figure 14: 110/33kV Transformer winding damage after a fault and corresponding waveform capture from the protection relay disconnecting the fault in 120ms.

Another consideration in replacing this scheme is how maintenance intervals are managed on the secondary system while maintaining supply to the network. While the overcurrent scheme can be taken out of service at regular maintenance intervals while relying on the transformer differential relay, the same cannot be said in order to maintain the transformer differential relay. The overcurrent scheme is not relied upon to provide the same level of sensitivity and speed of operation, particularly with crews in the vicinity of the switchgear and the transformer. In order to overcome this, protection permits that alter different schemes at the substation are changed in order to provide protection for the duration of the maintenance activities. This increases operation costs in providing protection settings, secondary systems works on site and network switching activities.

The replacement of the overcurrent load encroachment scheme with a transformer management scheme:

- Allows the transformer to have effective protection with any single protection element out of service, providing compliance under S5.1.9(d) of the NER
- Removes the reliance on a load encroachment blocking scheme
- Removes the risk of mal-operating under load conditions
- Removes load limits imposed by existing protection schemes.
- Can potentially reduce the consequence and repair costs of transformer faults
- Simplifies the protection scheme and settings

- Reduces operational costs during secondary systems maintenance activities.

This obsolete scheme upgrade represents approximately a 4% investment with respect to the cost of a transformer to provide the above improvements, offering a prudent investment that future proofs the network asset to handle more diverse and onerous load conditions.

Option 1 (Preferred) - Transformer Management Relay
This option removes the reliance on an overcurrent scheme to protect the transformer, therefore provides high speed duplicate transformer protection which will no longer provide a load restriction on the transformer.

- Replace Overcurrent Load Encroachment scheme with a transformer management scheme (Utilise existing current transformers)

Option 2 - Do nothing - Load Encroachment
This option relies on the existing scheme overcurrent load encroachment scheme to operate reliably and effectively for a transformer fault. This does not effectively manage the deficiencies in the existing scheme and does not reduce, or eliminate the risks.

- Rely on existing protection schemes

3.5.2 Circuit Breaker Fail schemes for Delta Primary Transformers

Energex 33kV/11kV power transformers are a Delta-Star configuration (Dyn11). The neutral is impedance earthed via resistor or a reactor limiting the earth fault current to approximately 2kA, providing a non-effectively earthed network. This design limits the step and touch potential exposed to the public in a Common Multiple Earthed Neutral (CMEN) network to meet limits imposed by the ENA EG-0[10], and AS7000:2010[11]. However this presents a challenge in protecting these transformers with the previous protection schemes.

Previous design standards across the network relied on a single transformer differential relay and overcurrent schemes on the high voltage and low voltage sides of the transformer. As the HV overcurrent relay had to see through the transformer and protect for faults in the secondary transformer winding or on the cable connection to the switchgear, circuit breaker failure (CBF) functionality was not installed and instead the backup protection scheme was relied upon. Likewise for a HV circuit breaker fail, the remote source was relied upon to detect this scenario. This has largely met the network requirements to date however as higher capability is sought from primary network assets to defer capex investment, the sensitivity of remote relays to detect these conditions is no longer feasible without limiting the primary network.

[10] ENA EG-0, *Risk Based Earthing Guideline*.
[11] AS7000:2010, *Overhead Line Design*.

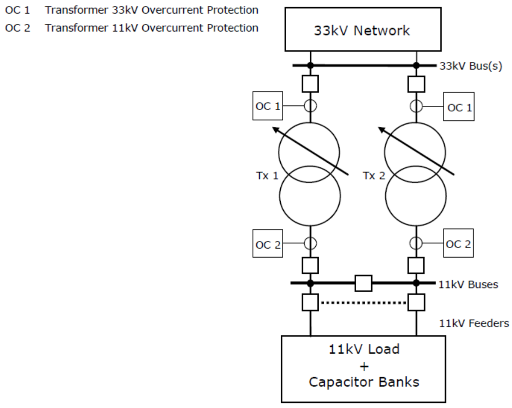


Figure 15: Existing protection design for 33/11kV transformers.

Without specific circuit breaker fail protection, distinct from backup protection, under current and future load requirements of the transformers it is not possible to adequately detect a breaker fail with the upstream protection device to isolate a fault. Not only does this reduce the backup coverage, but the primary protection coverage is sacrificed in order to accommodate an increase in load. This presents a safety and plant risk. The safety risk and consequently the plant risk that this presents is related to the increase in probability that for a transformer fault that there will be an ignition of the insulating oil causing a fire. As discussed in 3.5.1 there is a plant risk where there is a delay in fault detection and isolation and can have larger plant damage. In addition, due to the slow clearing times from remote substations, consequential damage can also occur to switchgear being exposed to through fault currents for durations in excess of their rating. The protection system should be designed such that no damage is caused to plant other than the faulted item[12].

There are also requirements in Schedule 5 of the NER that places a performance obligation on the protection system to ensure that there is a breaker fail system or a similar backup protection system that disconnects a fault such that is does not cause consequential damage other than the faulted element[13]. Therefore as the load is increasing in the network and rendering the existing method of meeting this requirement inadequate, a dedicated breaker fail system is now required.

In addition to the relays currently not having CBF functionality, this program also addresses where the HV overcurrent relay has only been implemented on two out of the three phases. This scheme still effectively detects all types of faults on the LV side of the transformer, however, depending on the phase installation of the relays (usually A and C phase), the scheme is required to be set half of an equivalent three phase setting due to the influence of the delta winding on LV faults. This is also causing load limitations on the network to provide sufficient coverage to meet Schedule 5 requirements.

Therefore the intent of this obsolete scheme program is to remove the dependence on overcurrent protection as a backup protection system to allow for a circuit breaker fail condition protecting a 33kV/11kV power transformer. It is proposed to install a digital relay capable of doing three phase circuit breaker failure. Where remote sites are required to provide the CBF functionality, communications links are relied upon.

[12] *National Electricity Rules*, Table S5.1a.2.
[13] *National Electricity Rules*, S5.1.9(f).

Option 1 (Preferred) - CBF on HV and LV
This option includes the installation of circuit breaker failure (CBF) functionality on the HV and LV of the transformer to remove reliance on an overcurrent backup protection scheme. This eliminates load restrictions to provide sufficient protection and provides compliance to the NER. There are cost efficiencies in replacing the HV and LV relays at the same time, to save on project overheads and in particular aligns network switching and outages.

- Install a digital, 3 phase overcurrent, earth fault and CBF relay on the HV and LV of the transformer
- Install intertripping to remote substations where fault isolation is conducted remotely

Option 2 - CBF on LV only
This option includes the installation of CBF functionality only on the LV of the transformer as it is the most load prohibitive setting. This reduces the population of relays that are replaced however introduces complexities in altering existing circuitry to old relays to accommodate the new functionality. This option improves NER compliance however, there will be sites where compliance is not achievable without CBF functionality in the HV relay.

- Install a digital, 3 phase overcurrent, earthfault and CBF relay on the LV of the transformer

Option 3 - Do Nothing – Existing Backup Protection
The do nothing option relies on the existing overcurrent schemes providing backup protection for a CBF. This limits the load carrying capacity of equipment, thereby accelerating expenditure requirements for primary equipment upgrades. This option has therefore been rejected as being less cost effective and as it also does not reflect industry best practice.

3.6 Communications Diversity for Transformer Ended Feeders

The obsolete scheme program for transformer ended feeders relates to the reliance on communications systems to detect and isolate faults. If the communications path is out of service the feeder and transformer are not effectively protected for faults. Previous protection techniques have utilised overcurrent and negative sequence elements at the source end to see through the delta winding to the LV winding of the transformer, however due to the impedance earthing of these transformers this has not been very effective scheme.   Typically these schemes have limited sensitivity and slow clearing times (>1s) and in particular under circuit breaker fail conditions or an outage of the communications link, faults on the HV network may not be detected by the LV protection. Under a communications failure, the fault clearing times are normally in excess of the through fault rating of the transformer, switchgear and line accessories. This presents a safety risk as it increases the probability that a conductor will fall on the ground and that a transformer fault results in the ignition of the oil due to slow protection clearing times.

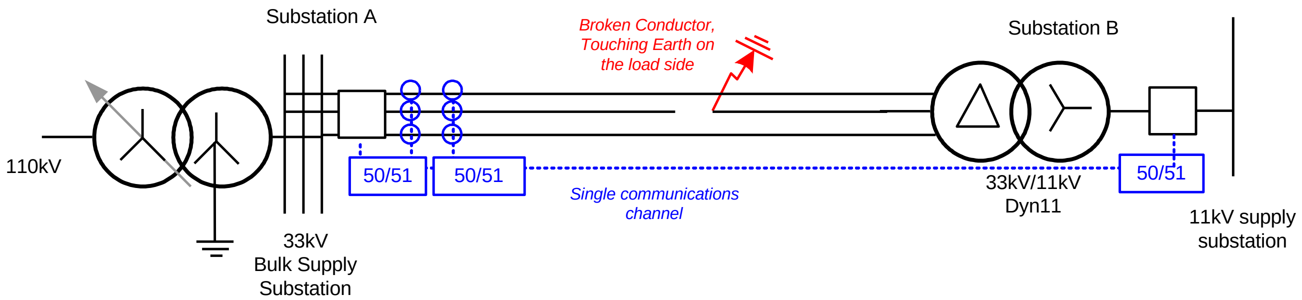


Figure 16: Obsolete transformer ended protection scheme

As with sections 3.5.1 and 3.5.2, there are protection system performance requirements that are required to be met under the NER. Specifically for transformer ended feeders the existing scheme cannot withstand an outage of the communications scheme, s5.1.9 (d), and there is no mechanism without intertripping schemes to withstand a circuit breaker failure, s5.1.9 (f).

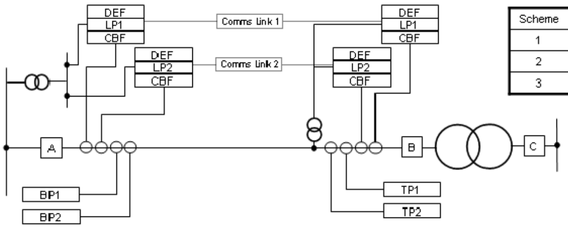
This scheme also has a similar protection system limitation to that described in 3.1.1, where there is a lack of primary protection scheme that can detect a back-fed earth fault, where there is a broken conductor and it falls to the ground on the load side of the feeder. This is in contravention to S5.1.9(c), (d), S5.1a.2 of the *NER*, s196 *Electrical Safety Regulation* 2013 (Qld) and AS2067. This has been assessed as presenting a moderate risk to the business.

Category	Risk Scenario	Consequence	Likelihood	Risk Score
Safety	A broken conductor on a 33kV transformed ended feeder or radial feeder with the conductor falling on the ground on the load side of the feeder, which falls on a car and a person attempts to exit the car, or a bystander going to help and they receive a shock leading to electrocution causing multiple fatalities.	6	2	12 (Moderate Risk)

Table 3: Risk Assessment – Transformer ended feeder

There has been at least one example of this fault occurring within the Energex network. In the late 1990's there was a backfed earth fault that remained undetected on a 33kV metropolitan feeder in a residential area. The fault was only identified after a customer reported the conductor on the ground sparking. This then required operator intervention to isolate the feeder.

The preferred protection scheme on new transformer ended installations:



Scheme	LP1	LP2
1	Line Diff	Line Diff
2	Line Diff	Distance
3	Distance	Distance

Protection Label	Protection Description
BP1 / BP2	Bus Protection 1 / 2
TP1 / TP2	Transformer Protection 1 / 2

Protection Element Trip Matrix

Protection Label	Protection Description	End A Trip	End B Trip	End A CBF Start	End B CBF Start	End A Backup CB(s)	End B Backup CB(s)	End A Auto Reclose	End B Auto Reclose
LP1 End A	Line Protection 1 End A	✓		✓				✓	
LP1 End B	Line Protection 1 End B		✓		✓				✓
LP2 End A	Line Protection 2 End A	✓		✓				✓	
LP2 End B	Line Protection 2 End B		✓		✓				✓
DEF *	Directional Earth Fault	✓	✓	✓	✓				
CBF 1 End A	Circuit Breaker Fail 1 End A					✓			
CBF 1 End B	Circuit Breaker Fail 1 End B						✓		
CBF 2 End A	Circuit Breaker Fail 2 End A					✓			
CBF 2 End B	Circuit Breaker Fail 2 End B						✓		

Figure 17: Current Protection design for newly constructed transformer ended feeders

The aim of this program is to bridge the gap between the risk and compliance issues with the current scheme while utilising the existing equipment efficiently and reduce the risk to as low as reasonably practicable. Therefore the proposed upgrade does not go to the extent of protection coverage expected for new installations.

It is proposed to equip the protection scheme with a second diverse communications path. 90% of the feeders have an existing diverse communications path available either via the optical fibre network or the pilot wire network. By establishing a second communications path, using existing protection relays and installing an additional intertrip relay and associated circuitry, it will provide the most economic investment to improve the existing protection scheme, without requiring significant capital investment. The network will then be able to withstand an outage of the communications scheme without the need to deenergise the primary equipment or applying temporary protection settings.

Option 1 (Preferred) – Digital Relay
This option establishes duplicate tripping mechanisms for the existing protection relays and establishes a voltage protection scheme for the detection of back fed earth faults.

- Enable a second diverse communications path
- Install a second form of intertripping
- Install a 33kV voltage transformer as close of practicable to the transformer.
- Install a overvoltage protection scheme

Option 2 (Alternate Preferred) – 33kV Recloser
This option can be implemented where substation site constraints limit the installation of voltage transformers. It involves the installation on an overhead feeder and automatic circuit recloser that has neutral displacement protection functionality in its controller. This should be installed as close to the load substation as possible, if not inside the substation fence. This option presents a slightly higher cost to option 1 due to the overhead construction works that will need to occur to facilitate the installation of the ACR.

- Install a 33kV automatic circuit recloser
- Enable neutral displacement protection in the control device
- Install a fibre optic communications path from the ACR to the load substation
- Enable a second diverse communications path
- Install a second form of intertripping

Option 3 – 33kV bus
This option involves considerable primary switchgear however, alleviates the requirement for duplicate communications schemes and by creating an alternate supply there is no requirement for the detection of back-fed earth faults. This is largely constrained by site space requirements.

- Install 3 x 33kV circuit breakers and associated bus work

Option 4 – Do nothing
This option has been rejected as the safety risks are not as low as reasonably practicable where the above options provide reasonably practicable solutions.

3.7 High Impedance Distribution Transformers

Historically on the Energex network high impedance 11kV/0.415kV transformers were utilised in order to limit the fault current that was exposed to LV customer switchboards. Energex has identified deficiencies in the existing design of installations utilising a fuse as the protective device for the transformer. The fuse does not provide sufficient protection for the low voltage side of the transformer due to the high impedance and the load carrying capability of a 1500kVA transformer.

The ENA Low Voltage Protection Guidelines highlights “that typical arc resistance can typically restrict the current to about one third of its prospective level” [bolted fault]; and that “Almost all naturally occurring and accidental faults on the LV busbar type systems are arcing type faults that are self-sustaining or re-striking and are extremely destructive and hazardous. ‘Burn downs’ of complete switchboards have occurred as well as injuries and fatalities.”[14]

Energex has adopted a risk based approach to fuse selection by using the following guidelines:

- Clearing a bolted LV fault within 1 second ; and
- Clearing an impedance fault, equivalent to 60% of the bolted fault, within 20 seconds.

There has been a safety risk raised where we have a 1500kVA transformer, of approximately 9% impedance being protected by a 100A fuse. Under favourable fault levels the clearing time of the fuses is approximately 3.8 seconds for a bolted fault and approximately 30 seconds for a fault representing 60% of the bolted fault level. At the installation with the lowest fault level the clearing time of the fuse is 8 seconds for a bolted fault and 170 seconds at 60% of the bolted fault level. Therefore both fuse selection criteria cannot be met for these installations. This also raises a significant business risk due to the consequential damage to third party property. Energex has recently experienced the consequence highlighted by the ENA where incorrect fuses have contributed to a safety event.

In 2013 there was a significant incident on the network that resulted in a fire. There was extensive fire damage to the customer’s switchroom and an adjoining factory building. A contributing factor to the severity of this incident may have been the installation of the incorrect HV fuses in the associated RMU allowing fault conditions to exist for a significantly longer time frame, 20 minutes for the 100 amp fuses compared to possibly 8 minutes for 40 amp fuses.

As the 100 amp fuses did operate approximately 20 minutes after the fire originated, it is then possible that the fire caused a phase to phase fault with the fault current momentarily rising in the range of 300 to 600 amps to cause the operation of the 100 amp RMU fuses.

[14] 2006, ENA DOC 014 - *ENA Low Voltage Electrical Protection Guidelines*, Appendix B, B2, p20.

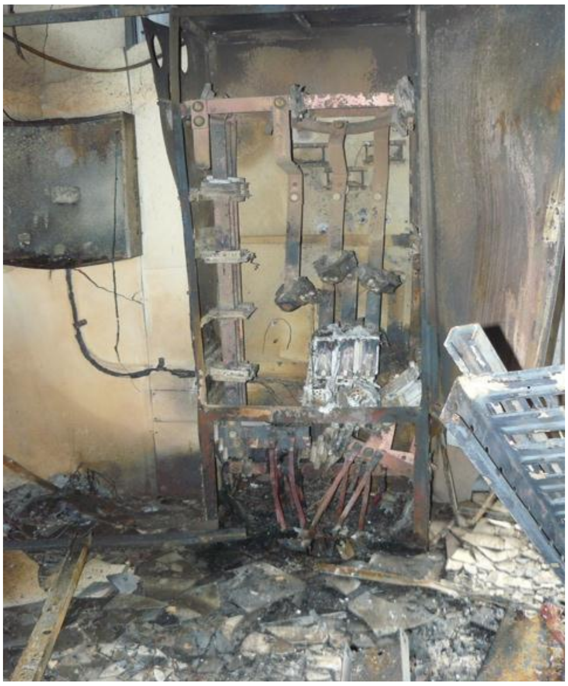


Figure 18: Entry point of LV cables to customer's switchboard following an incident in the Energex Network

Category	Risk Scenario	Consequence	Likelihood	Risk Score
Safety	Failure of a fuse to disconnect an LV fault connected via a high impedance transformer causing a significant fire that results in multiple fatalities	6	2	12 (Moderate Risk)
Business Impact	Failure of a fuse to disconnect an LV fault connected via a high impedance transformer causing a significant fire that results in property damage leading to compensation and significant media coverage leading to damage to corporate reputation.	3	2	6 (Low Risk)

Table 4: Risk Assessment High Impedance Transformers

Option 1 – Replace Fuse

This is the most cost effective way of managing the risk however it limits the load carrying capacity of the transformer and therefore is only capable of being deployed at low load sites.

- Install a full range, aerial expulsion drop out fuse (EDO) in series with the existing backup range RMU fuse where connected to the overhead network
- Implement a load monitoring program

Option 2 – Replace Transformer

This option is the technical solution that reduces the risk most significantly, however is more expensive than option 1. This option is considered the preferred option where a load limit of 80A cannot be achieved or where the customer switchboard connected to the site is not rated to the higher fault level.

- Replace the high impedance transformer with a low impedance transformer

Option 3 – Protection Relays

This option is the highest cost option and also presents significant technical complexity. For these reasons it should only be considered if option 1 and 2 cannot be employed due to site constraints.

- Install protection class CT's on existing switchgear
- Install an alternate protection relay scheme to detect faults

Option 4 – Do Nothing

This option has been rejected as the safety risks are not as low as reasonably practicable where the above options provide reasonably practicable solutions.

It is proposed to address the population of high impedance transformers using a combination of Options 1 to 3. This will provide for a cost effective way to address each individual site considering site specific limitations. This program will reduce the safety risk from moderate risk to low risk, and deemed to be as low as reasonably practicable.

3.8 11kV Bus Bar Protection

3.8.1 Installation of 11kV Bus Bar Protection

There are three categories of 11kV feeder protections schemes that are considered to be obsolete where there is no high set functionality available in the existing relay protecting

1. 11kV oil circuit breakers with a fault level over 4kA
2. 11kV vacuum circuit breakers with a fault level over 10kA
3. 11kV circuit breakers connected to capacitor banks

As oil breakers are phased out of the distribution network, a key management strategy of their end of life cycle operation is ensuring that there is a fast operating, reliable protection system that can detect and isolate a fault condition. The failure mode of switchgear is dependent on the energy released during a fault, i^2t. While the protection scheme will not prevent an internal fault occurring, the protection scheme may reduce the severity of the consequences of the fault.

There are four main phases to an internal arcing fault.[15]

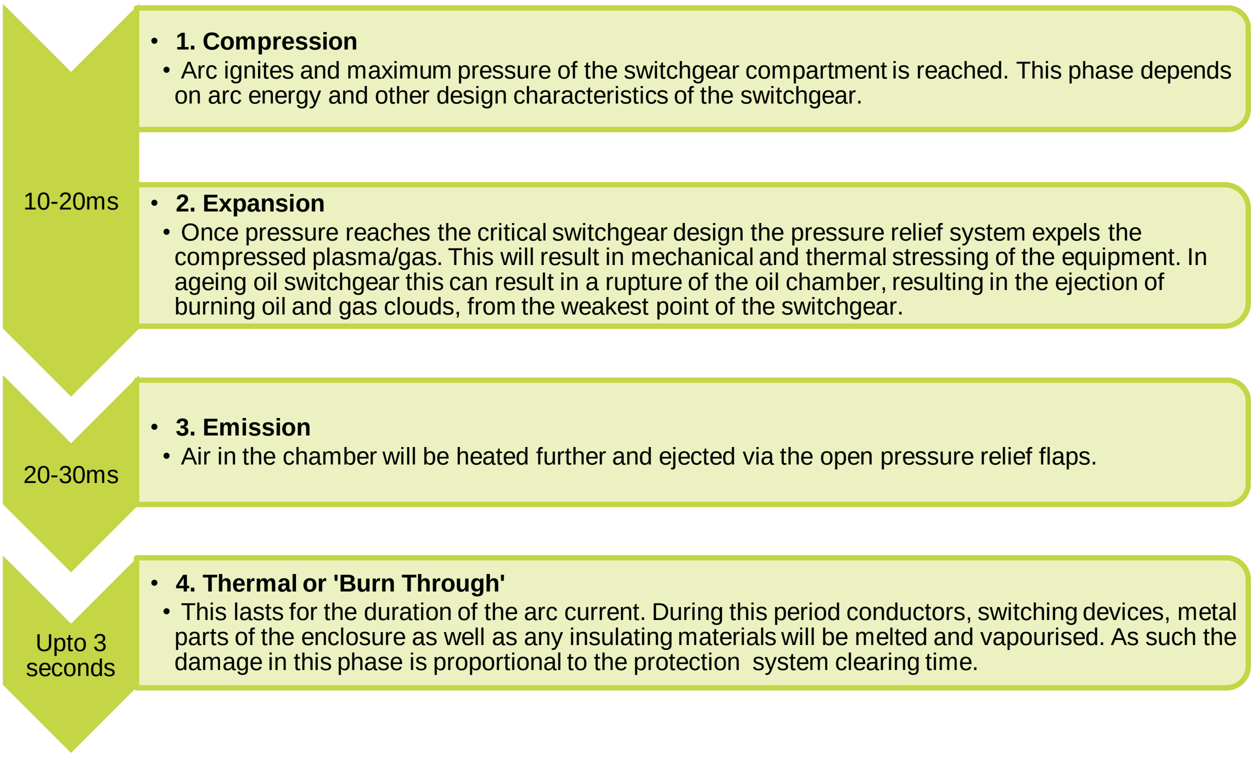


Figure 19: Stages of an internal arc fault in oil switchgear

Previous switchgear contracts and in particular existing oil switchgear does not meet the internal arc rating requirements under AS62271-200[16]. Therefore while the risk of causing

[15] Blakeley, Richard, 2013, *Internal Arc Safety in New and Existing Switchgear*, Electrical Safety & Power System Protection Forum.

[16] AS62271-200, 2003, High-voltage switchgear and controlgear Part 200: A.C. metal-enclosed switchgear and controlgear for rated voltages above 1 kV and up to and including 52 kV.

death or serious injury to persons and major damage to plant and buildings in the vicinity of the failed equipment due to the first three stages of an arcing fault cannot be reduced by the protection scheme, the severity of the incident can be reduced by shortening the fourth stage of the arcing fault.

For example some of the oil switchgear is Reyrolle LMT, this switchgear was designed with no requirement or standard for switchgear Internal Arc withstand, so these switchboards are not equipped with any internal arc pressure relief or arc containment. In the event of a failure of the high voltage insulation or other fault leading to the inception of an arc, the operator would not be protected.[17]

Therefore it is proposed to install high speed 11kV digital protection relays on these installations in order to reduce the consequence should an internal fault occur. Energex has taken a sustainable approach and only proposed to address those installations that are above 4kA in fault level.

In addition to addressing this exposure with oil switchgear, which presents a higher risk due to the susceptibility of oil to fire, it has also been highlighted that non-arc contained switchgear that does not used oil as the insulating medium also presents similar risks from conductors, switching devices, metal parts being melted and vaporised. For these installations an approach of ensuring high speed protection is installed on those circuit breakers that are in excess of 10kA in fault level.

This strategy also ensures that the through fault current seen by the power transformers is reduced. Investment in the secondary system ensures that the life of the power transformer does not degrade the expected life of the asset. In addition, the faster protection clearing time also provides a benefit for downstream equipment. In particular it minimises conductor clashing and consequential damage caused by operating overhead mains over their thermal rating. This also limits the mechanical stress on bridges and clamps which are often the cause of secondary faults on the network caused by the fault current of the initial fault.

In 2014, there was a catastrophic failure of an 11kV circuit breaker that potentially exposed emergency crews to the release of uncontrolled high voltage electrical energy and debris associated with the explosive failure. The initial fault resulted in both the primary and backup protection operating to isolate the fault, as the fault was on the bus side of the circuit breaker. As the substation did not have bus zone protection installed, there was no latching functionality on the tripping mechanisms prohibiting a controller re-energising the damaged equipment. This allowed this misdiagnosis of the fault and returned the plant to service believing it was a fault outside the substation. This led to an uncontrolled explosion, which occurred while field crews were onsite. In this case no personnel were injured however they were placed in an unsafe environment.

[17] Ibid.

Figure 20: Extent of damage insitu

Figure 21: Extent of damage to all 6 bushings of the failed circuit breaker

The investigation report highlighted that a contributing factor to the severity of the damage to the circuit breaker and bushings was the slow operation of the protection schemes (Approximately 3 seconds at a magnitude of 11kA). Another contributing factor was that the protection schemes allowed remote re-energisation without confirming the existence of a substation fault.
The corrective action plan from the safety investigation highlighted that a latching bus zone relay would have ensured the fault was correctly diagnosed and not re-energised remotely without confirming damage onsite and would not have exposed emergency crews to the explosive risk when attending c to investigate.

If an internal bus bar fault was to occur on an 11kV bus without high speed bus protection, clearing times can be in the order of 1-3 seconds, and in cases no circuit breaker fail protection has been installed (considered obsolescence in section 3.5.2.)

Option 1 (Preferred) – Bus Zone
This option balances the technical capability of a bus zone scheme and the cost of addressing the safety risk. This option installs a low impedance or high impedance bus zone, unit protection scheme using existing current transformers.

- Install a bus zone scheme

Option 2 – Frame Earth Fault
This option requires the switchgear to be insulated from the ground, normally on epoxy tracks, with a CT around a single earth connection. This provides only unbalanced protection, and should only be used on phase segregated switchgear where the probability of balanced faults is low. This will only be a cost effective option where the switchgear is already insulated, otherwise is likely to be cost prohibitive.

- Test existing insulation installation
- Install Frame Earth Fault relay and latching multitrip relay.

Option 3 – Bus Blocking
This option utilises existing digital relays, or installs digital relays, that provide a blocking input to a bus multitrip relay. These schemes are effective as they do not require an additional CT on the existing switchgear however, there have been mal-operations and non-operations under certain conditions within Energex, and therefore it is not recommended where a bus zone scheme can be installed.

- Replace electromechanical relays and standardise digital relays on outgoing feeders
- Install a bus blocking scheme

Option 4 – Fault Level Reduction
This option seeks to reduce the fault level energy that the switchgear will be exposed to under a fault condition. This relies on opening bus section breakers so that only a single transformer feeds a bus and reduces the fault level. This means that most of the auxiliary equipment needs to be duplicated. This is only possible where there are no existing customers that have a parallel supply.

- Install additional capacitor banks
- Install additional audio frequency load control equipment
- Install auto-changeover automation scheme
- Run the 11kV bus split

Option 5 – Faster Settings and PPE
This option utilises existing protection schemes until the switchgear is replaced but it accelerates the replacement of switchgear. To reduce the fault energy it relies on reducing the protection grading to downstream devices to facilitate faster fault clearance time and the implementation of full arc flash rated PPE for any crews attending substation.

- Regrade all 11kV feeders allowing minimal grading between devices
- Deploy category 4 (40 cal/cm^2) arc flash hazard personal protective equipment
- Accelerate replacement of switchgear

Option 6 – Do Nothing
This option has been rejected as the safety risks are not as low as reasonably practicable where the above options provide reasonably practicable solutions.

3.8.2 Upgrade of 11kV Busbar residual unit schemes

As with the 33kV scheme highlighted in section 3.4.2, previous protection standards provided bus bar protection via a two-wire scheme, only providing residual protection for unbalanced fault conditions. This leaves the switchgear vulnerable to phase-to phase and three phase faults. While modern switchgear is largely phase-segregated and the probability of these types are faults are remote, older switchgear was not segregated and the probability of these faults is higher.

There are nine indoor substations that have non-phase segregated busbars that only have a two-wire bus protection scheme installed. Should a balanced fault occur at these substations there is a reliance on the overcurrent schemes on the transformer to detect and isolate the fault. In these installations there is no circuit breaker fail protection (considered obsolescence in section 3.5.2.). Therefore to provide a backup protection system there is a reliance on the HV overcurrent relay of the transformers. This then places a load carrying capacity limit on the transformer due to the sensitivity required to detect this type of fault. Primary protection clearing time would be in the order of 1-2 seconds and backup protection in the order of 2-3 seconds.

It is therefore proposed to upgrade these schemes to either a 4-wire bus zone scheme or install frame earth fault protection. The solution will depend on site considerations and what option presents the most economical approach. This provides a risk mitigation approach to operating this switchgear in the later part of the asset management life cycle before being replaced.

Option 1 (Preferred) – Bus Zone Upgrade
This option installs the secondary wiring and associated relays to convert a 2-wire scheme into a 4-wire scheme.

- Install a 4-wire bus zone scheme

Option 2 – Bus Blocking
This option utilises existing digital relays, or installs digital relays, that provide a blocking input to a bus multitrip relay. These schemes are effective as they do not require an additional CT on the existing switchgear however, there have been mal-operations and non-operations under certain conditions within Energex, and therefore it is not recommended where a bus zone scheme can be installed.

- Replace electromechanical relays and standardise digital relays on outgoing feeders
- Install a bus blocking scheme

Option 3 – Do Nothing
This option has been rejected as the safety risks are not as low as reasonably practicable where the above options provide reasonably practicable solutions.

4 Options

4.1 Impact of Doing Nothing

The do nothing approach fails to mitigate the articulated safety and legislative risks, resulting in continued risk exposure for Energex at these levels and increasing over time. This outcome is not tolerable to Energex, with untreated risks not considered to be As Low As Reasonably Practicable (ALARP). It also results in elevated risk of plant damage and customer outages.

4.2 Option 1 – Original Submission with Replacements per Current Design Standards

Option 1 is per the original Energex submission which addressed obsolete protection schemes by replacing schemes to the current design standards.
Table 5 below outlines expenditure required for Option 1 being $63.7 million over 5 years.

The Obsolete Protection Scheme Program – Option 1						
$m, 2014-15	**2015/16**	**2016/17**	**2017/18**	**2018/19**	**2019/20**	**Total**
Expenditure	15.2	13.3	11.6	11.8	11.8	**63.7**

Table 5: Option 1 Obsolete Protection Scheme Expenditure

4.3 Option 2 – Address Safety and Legislated Risks using a site by site approach

Option 2 requires Energex tolerate increased risk of customer outages by determining schemes that must be managed operationally. Significantly this approach requires operational control measures for some instances such that the schemes below may been managed without capital expenditure in the 2015/16-2019/20 period:

- Neutral resistor earthed substations
- Three-ended feeders without a communications assisted scheme
- Instantaneous sensitive earth fault relays
- Substations without any disturbance recording capability
- Neutral sensitive earth fault schemes on transformers sharing a single neutral earthing resistor
- Upgrading existing auxiliary supply equipment at zone substations
- Communications investments, including that referred to in section 3.1.2.

The Customer Outage risk associated with supply security for the 2018 Commonwealth Games is also addressed as part of this option.

Table 6 outlines expenditure required for Option 2 being $24 million over 5 years. The slightly increasing annual expenditure reflects incorporation of scheme replacement works with other capex project works early in the regulatory period. As the period continues there are less capex projects that address obsolete schemes, therefore an increasing reliance on secondary systems focused projects.

The Obsolete Protection Scheme Program – Option 2						
$m, 2014-15	**2015/16**	**2016/17**	**2017/18**	**2018/19**	**2019/20**	**Total**
Expenditure	4.0	4.5	5.0	5.0	5.5	**24.0**

Table 6: Option 2 Obsolete Protection Scheme Expenditure

4.4 Option 3 – Replacement of Safety Risk Items Only

Option 3 presents the program of Obsolete Protection schemes that only address the highest safety risks that expose personnel and the general public. It does not reduce all safety risks to as low as reasonably practicable.

It addresses the following obsolete protection schemes and represents the minimum investment required to address the highest risk schemes:

- 110/132kV Feeder protection
- 33kV Bus Bar Protection
- Communications Diversity for Transformer Ended Feeders
- High Impedance Distribution Transformers
- 11kV Busbar Protection
- 33kV Feeder protection

The disadvantage of this option is that it does not address compliance, plant damage and customer impact risks associated with:

- 110/132kV Bus Bar protection
- Transformer Protection
- Duplicate DC Supply at Bulk Supply Substations
- 11kV Feeder Protection on non-oil filled switchgear
- In addition to those schemes removed between Option 1 and Option 2.

As this program does not address all risks identified in the obsolete schemes, reactive expenditure would increase as would work to address compliance audits. This option does not meet the expectations of a distribution authority operating a safe and reliable network.

The table below outlines expenditure required for Option 3 being $16.5 million over 5 years.

The Obsolete Protection Scheme Program – Option 3						
$m, 2014-15	**2015/16**	**2016/17**	**2017/18**	**2018/19**	**2019/20**	**Total**
Expenditure	2.5	3.0	3.5	3.5	4.0	**16.5**

Table 7: Option 3 Obsolete Protection Scheme Expenditure

5 Proposed Works

To ensure Energex continues to deliver sustainable outcomes for customers and business without compromise to existing safety or legislative compliance requirements, it is proposed to implement Option 2 to address the identified safety and legislative risks.

6 Required Expenditure

The obsolete protection scheme replacement program requires expenditure of $24 million in the 2015/16 – 2019/20 regulatory period, consistent with Option 2.

Obsolete Protection Scheme Replacement Program						
$m, 2014-15	**2015/16**	**2016/17**	**2017/18**	**2018/19**	**2019/20**	**Total**
Expenditure	4.0	4.5	5.0	5.0	5.5	24.0

Table 8: Option 2 Obsolete Protection Scheme expenditure

7 Recommendations

It is recommended that Option 2 be endorsed for inclusion in the programs of work and reflected in Energex's revised regulatory proposal for the 2015/16 – 2019/20 regulatory period.

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Energex

Replace Distribution Ageing Cable Terminations Program

Asset Management Division

energex

positive energy

Energex

Replace Distribution Ageing Cable Terminations Program 2015/16 - 2019/20

Reviewed:

Tim Hart

Group Manager Asset Life Cycle Management

Endorsed:

Peter Price

Executive General Manager Asset Management

Version control

Version	Date	Description
1	1/07/2015	Submitted

Energex Limited (Energex) is a Queensland Government Owned Corporation that builds, owns, operates and maintains the electricity distribution network in the growing region of South East Queensland. Energex provides distribution services to almost 1.4 million domestic and business connections, delivering electricity to a population base of around 3.2 million people.

Energex's key focus is distributing safe, reliable and affordable electricity in a commercially balanced way that provides value for its customers, manages risk and builds a sustainable future.

Group Manager
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GPO Box 1461
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Executive Summary

In line with Energex's key objectives of maintaining safety, legal compliance and sustainable investment, the distribution cast iron cable termination replacement program will enable Energex to:

1. Provide safe outcomes to the community, staff and contractors,
2. Comply with the Code of Practice - Works under Electrical Safety Act 2002.

Energex has 4104 distribution cast iron cable terminations in service with an average age of 57 years. The expected life of cast iron cable terminations is 30 years. Energex is experiencing approximately 29 explosive in service failures of these assets per year, resulting in safety risks to the public, Energex personnel and a corresponding customer outage. Funding for mitigation of this risk is not accounted for in the modelled REPEX programs.

During the 2010/11 – 2014/15 regulatory control period, Energex replaced cast iron cable terminations on failure. Due to the ageing population and resultant increasingly high safety risk, the asset strategy for cast iron cable terminations has shifted from a reactive to a planned replacement approach.

In its revised proposal, Energex seeks a decreased level of funding from its original proposal, to replace cast iron cable terminations through a risk prioritised approach. The proposed program will initially target the 402 high risk sites within 150m of school zones to mitigate risk in high traffic areas in the case of catastrophic failure. A further 1309 sites will be scheduled and prioritised accordingly over the regulatory period, with the remaining sites deferred to the following period. High fault current sites will be targeted as the second priority. The revised replacement program will ensure all cast iron cable terminations are replaced by 2024/25.

The original proposal to the AER for the works for this program was for $32.7million ($2014/15 direct) with 2,964 replacements over the five year period based on a six year program.

The revised proposal presented here seeks an investment of $17.9 million ($2014/15) and a reduction in replacements to 1711 over the AER period 2015/16 to 2019/20. The remaining 2393 units will be scheduled to be replaced in the next regulatory control period.

The following table provides a summary of the revised proposed investment of $17.9 million ($2014/15 direct) over the 2015/16 – 2019/20 regulatory period.

$m, 2014/15	2015/16	2016/17	2017/18	2018/19	2019/20	Total
Energex Proposal	2.5	2.5	2.5	12.6	12.6	32.7
Energex Revised Proposal	2.2	2.2	3.5	5.0	5.0	17.9

Contents

1 Introduction

The purpose of this document is to outline the required expenditure for the replacement of problematic cast iron pot head cable terminations assessed as high risk and “end of life” over the 2015/16 – 2019/20 regulatory period.

This program is important due to the deterioration of dielectric material inside the chamber of ageing terminations resulting in failure or explosion of Cast Iron Pot Heads (CIPHs). A catastrophic explosion of a CIPH is considered a high safety risk to Energex. The risk of most concern is an explosion near schools and high pedestrian areas which result in serious injuries or fatalities to members of the public. To mitigate this risk, it is proposed to replace these units before failure over a 10 year period. There are a total 4104 CIPHs in service.

<u>Changes from the original proposal</u>

The original proposal to the AER for the works for this program was for $32.7million ($14/15 direct) with 2,964 replacements over the five year period based on a six year program.

Various options have been developed taking into account the problem specific risk assessment and program duration.

The revised proposal presented here outlines and expenditure of $17.9 milion ($14/15) and a reduction in replacements to 1711 over the 2015/16 – 2019/20 regulatory period. The remaining 2393 units will be replaced in the following regulatory period.

2 Drivers

CIPHs were installed in the 1950’s and 1960’s throughout the Energex network for overhead to underground terminations at all voltages. These units are considered to be obsolete and at or near end of life.

Ageing cable termination CIPHs generally consist of a hollow insulator and a metallic entrance sleeve (Figure 2). The terminal portion of the cable is inserted into the pot head through the entrance sleeve which is sealed to the cable surface and forms jointly with the hollow insulator an internal chamber surrounding the terminal section of the cable. The insulator is capped and a connector in electrical contact with the end of the cable protrudes out of the insulator cap. A dielectric material, such as hydrocarbon oil or asphalt, is used to fill the internal chamber.

Corrosion on the aged CIPH’s allow moisture ingress and the deterioration of dielectric material inside the chamber of ageing terminations. Tracking on the degraded insulating material can result in failure or explosion of the CIPH’s. The risk of most concern to Energex is an explosion of a CIPH near schools and high pedestrian areas which result in serious injuries or fatalities to members of the public. There are currently 402 sites falling within a

150m buffer of all school zones with significantly more located near shopping centres and other public locations.

Energex has issued a Safety Notice (refer Appendix 1) to restrict HV and LV live work in the vicinity of poles with metal clad underground terminations due to the risk of degraded insulation being compromised by inadvertent bridging movement. In situations where inadvertent movement of HV bridging cannot be avoided, crews are required to isolate the HV equipment using the Safe Access High Voltage (SAHV) process. This causes operational inefficiencies by increasing the time to undertake the tasks.

This proposed replacement program is in line with Energex's Network Asset Management Policy, Network Maintenance Protocol and Protocol for Refurbishment and Replacement. This program also complies with the Code of Practice - Works under Electrical Safety Act 2002.

3 Supporting Analysis

3.1 Asset Failure Rate

The recorded Ageing Cable Termination Pot Head failures are shown in Figure 1.

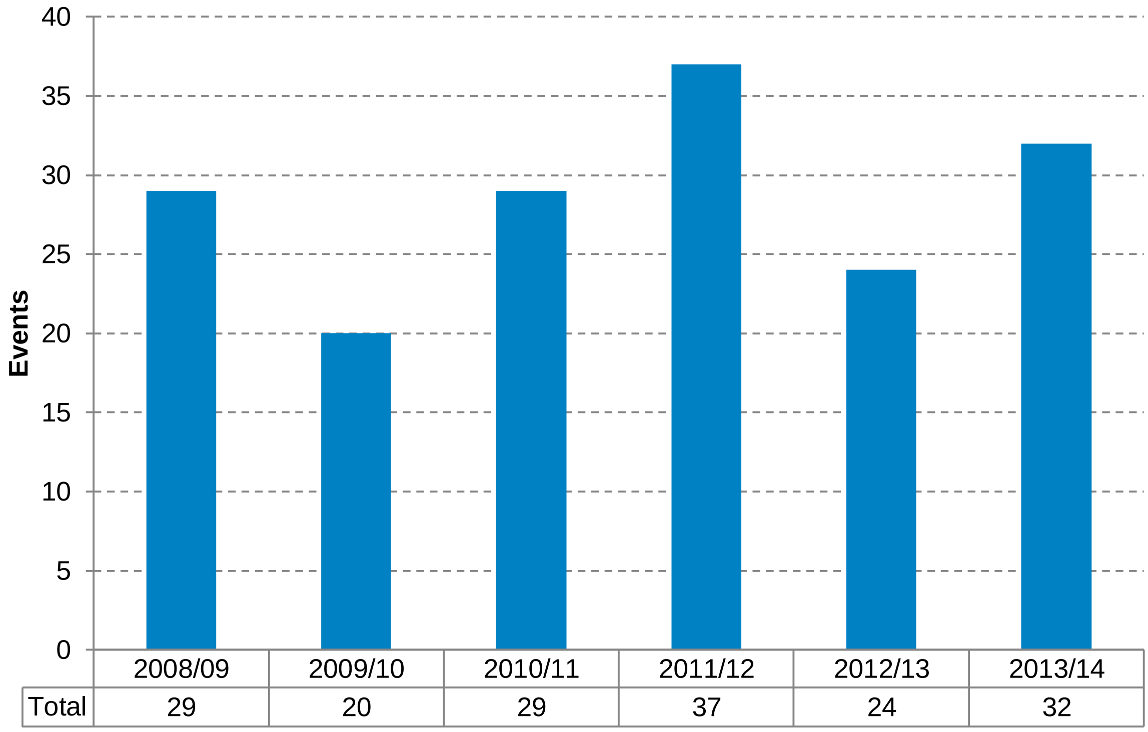


Figure 1 – Pot Head Failures per Financial Year

Based on these failure incidents, and given an estimated corrective replacement cost of $10,400 the overall unplanned expenditures over the years are given in Table 1.

	2008/09	2009/10	2010/11	2011/12	2012/13	2013/14
Failures	29	20	29	37	24	32
$m, 2014/15	0.30	0.21	0.30	0.39	0.25	0.33

Table 1 - Estimated Corrective costs for Termination Failures

3.2 Failure mode analysis

Corrosion of cast iron pot head casing causes water ingress resulting in insulation degradation leading to explosive failure and potentially serious injury/fatality to a member of the public or Energex personnel.

3.3 Recent Failures and Value of Customer Reliability (VCR) Impacts

Table 2 details recent network incidents (since December 2014) recorded for failed cable terminations showing customer and VCR impacts.

Outage Date	Site ID	Duration	Asset	Category	Customers	Total VCR $
16/12/2014	P497-C/CZ11	59.0	METRO SOUTH	URBAN	1647.0	106,960
17/12/2014	P51844-D	207.0	METRO SOUTH	URBAN	73.0	16,622
17/12/2014	P696637	60.0	SOUTH COAST	URBAN	176.0	11,616
18/12/2014	X384540	105.0	METRO SOUTH	URBAN	1.0	116
19/12/2014	P62102-D/CZ11	211.2	CENTRAL WEST	URBAN	583.0	135,416
27/12/2014	P411371	242.9	METRO SOUTH	RURAL	113.0	30,191
13/01/2015	DL1X29/CZ11	73.9	NORTH COAST	RURAL	2630.0	213,830
23/01/2015	P71097/CZ11	102.1	METRO NORTH	URBAN	312.0	35,045
29/01/2015	P43853-B/CZ11	33.7	METRO NORTH	URBAN	1643.0	60,892
14/02/2015	P639-I/CZ11	25.0	WESTERN	URBAN	112.0	3,080
19/02/2015	P10667-G/CZ11	76.4	METRO SOUTH	URBAN	1652.0	138,768
					Total	752,535

Table 2 - Outage Incidents - Cable Terminations

The average VCR cost for a failed CIPH is $68,400.

In addition, Energex has reported a total of 66 insurance claims paid as a result of failed cable terminations since 2005.

The photographs below show a cast iron 11kV pothead in service (Figure 2), one that has evidence of a pitch/fluid leak (Figure 3), the remnants of one that has suffered an explosive failure (Figure 4), and an example of leaking bitumen on an 11kV pothead (Figure 5).

Figure 2 - 11kV Pot Head In Service

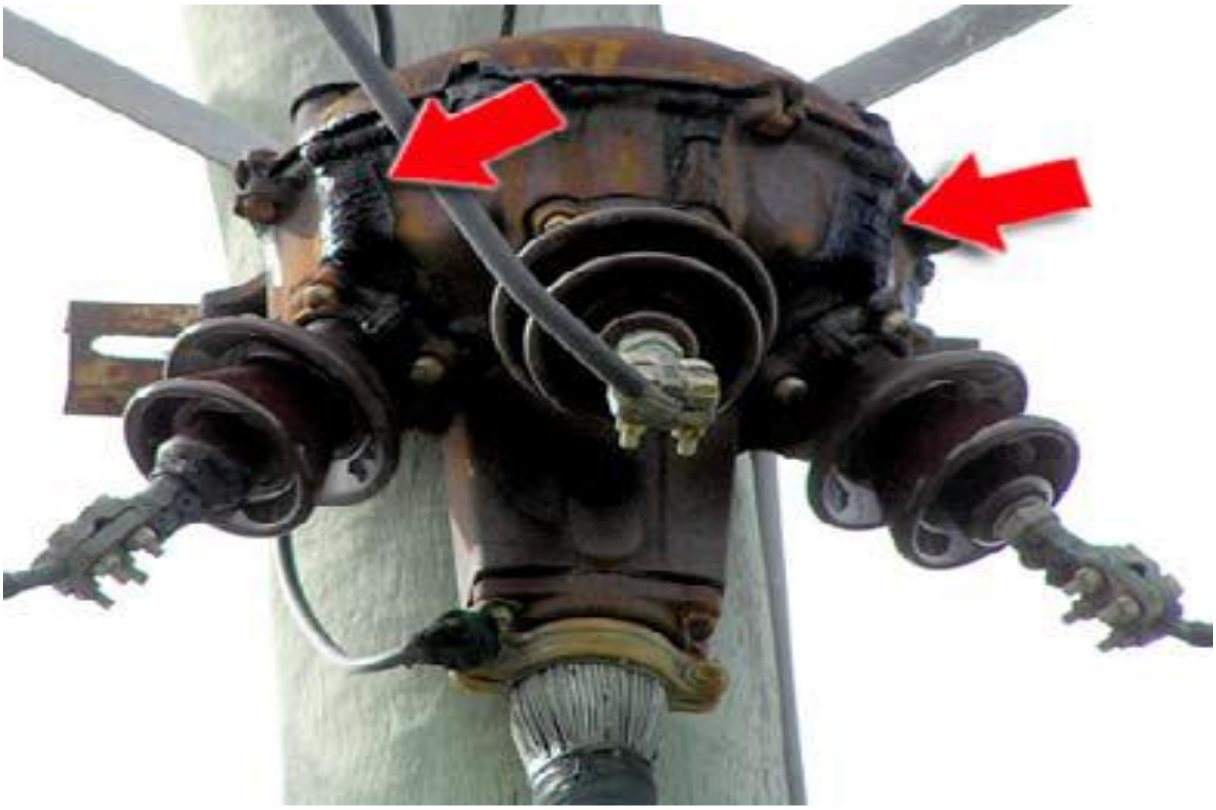


Figure 3 - 11kV Pot Head with fluid leaks

Figure 4 - Explosive Failure - 11kV Pot Head

Figure 5 - 11kV Pot Head Leaking Bitumen

3.4 Summary of case studies

A number of other Network Service Providers experiencing similar cast iron cable termination failure issues are proposing replacement programs, including the following:

- ActewAGL have experienced several 11kV cast iron cable termination failures which occurred in public places. These failures were catastrophic and metal debris dispersed up to 30 meters from the pole. ActewAGL undertook a risk based replacement program and have since removed all known 11kV cast iron sites. Similar failures have been experienced with their LV cast iron cable terminations and they are proposing an ongoing replacement program.

- Aurora's strategy is to have all high-risk cast iron potheads removed from the distribution network by 2017.

- Ergon Energy are proposing a Cast Iron Pot Head Replacement program as all cast iron pot heads are very old type cable terminations, rusted and allow moisture ingress. They cannot be condition monitored for oil degradation (and it would be uneconomic to do so if it were possible). Eventually the water/oil combination degradation will result in flashover, with catastrophic and sometimes explosive failure. The potheads are typically in urban and business centre locations frequented by the general population. These situations can present significant public safety risks.

- Jemena have a current five year proactive replacement strategy to replace all CABUS and metal clad box units.

4 Options

Several options to manage this cast iron pothead failure risk have been investigated.

4.1 Impact of Doing Nothing

The "do nothing" option, or failure to proactively replace ageing cable terminations, would result in an increasing likelihood of units failing catastrophically resulting in levels of safety, environmental, legislative and risk which are not considered to be as low as reasonably practicable. In the event of a failure, there is a high safety risk to public exposure to airborne porcelain shards, cast iron debris and hot bitumen. The high humidity and rainfall climatic conditions in South east Queensland poses a high likelihood of moisture ingress to these cast iron boxes. There are currently 402 sites falling within a 150m buffer of all school zones with significantly more located near shopping centres and other public locations. In addition, the restrictions to working live around metal clad terminations puts considerable limitations on other planned works. Failure to replace the CIPH will result in levels of safety, environment and network risk which are not considered as low as reasonably practicable.

Risk of the do nothing approach is quantified in the untreated risk scenarios in Table 3.

Risk	Risk Scenario	Consequence	Likelihood	Score
Safety	Insufficient program allocation for the replacement of Ageing Underground Cable terminations (eg Cast iron bitumen filled terminations). Based on recent evidence, there have been a number of explosive failures leading to third party damage. These terminations are particularly dangerous in high fault level areas because of their cast iron construction. Failure to replace these termination could lead to increased risk to public, staff and contractor safety	5	4	20 (High)
Environment	Insufficient program allocation for the replacement of Ageing Underground Cable terminations (eg Cast iron bitumen/gel filled terminations). Based on recent evidence, there have been a number of explosive failures leading to hot bitumen being released causing environmental impacts. These terminations are particularly dangerous in high fault level areas because of their cast iron construction. Failure to replace these terminations could lead to ongoing risk of environmental impacts.	2	4	8 (Low)
Customer Impact	Maintenance, inspection and capital replacement programs not undertaken for the period between 2015/16 – 2019/20 affecting an 11kV cable resulting in disruption to single large scale business or essential service.	3	4	12 (Moderate)

Table 3: Untreated Risk Assessment Summary – Ageing Cable Terminations

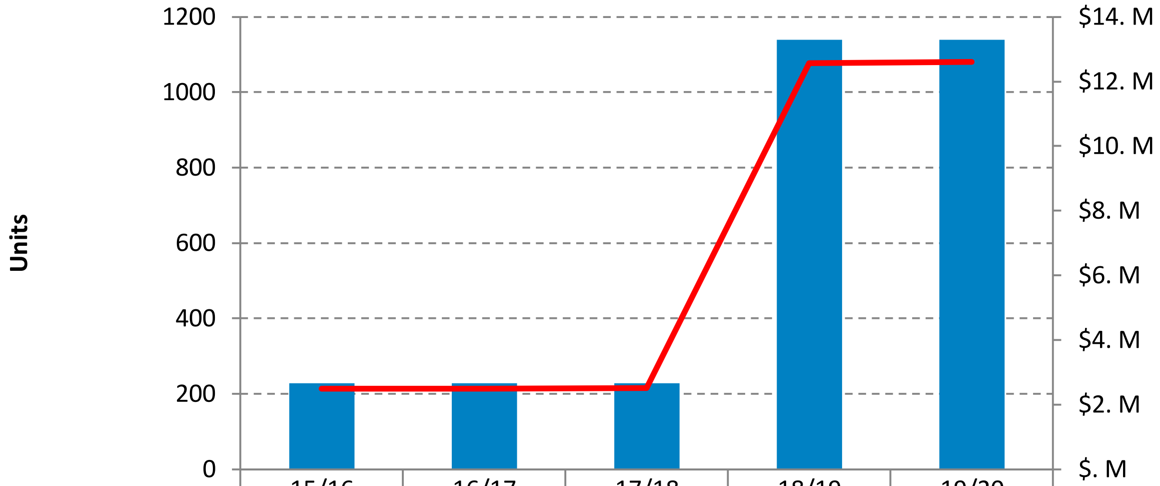
This Do Nothing option would call for continued risk exposure at these levels, with risks increasing over time and soon reaching intolerable levels. This outcome is not tolerable to Energex, with untreated risks not considered to be As Low As Reasonably Practicable (ALARP).

4.2 Option 1 – (Original) 6 Year Replacement Period

4.2.1 Summary

This option will completely phase out cast iron cable terminations over a six year period.

Energex proposed a six year replacement program as part of its original submission. The program was to commence in 2015/16 with completion in 2020/21. The initial focus of this program was completing high public risk areas and sites within the first three years. The submission then smoothed the remaining sites over a three year period. The overall phasing of this program took into account the need to balance the overall replacement program spend with the risk and financial resource requirements in Energex.



	15/16	16/17	17/18	18/19	19/20
Quantities	228	228	228	1140	1140
$ 14/15 Direct	$2.5 M	$2.5 M	$2.5 M	$12.57 M	$12.61 M

Figure 6 - Option 1 (6 Year Replacement Program)

4.2.2 Impact Analysis

The proposed replacement quantities initially proposed in the Energex submission represents an anticipated completion of all aged, problematic cable terminations by 2020/21.

Option 1 proposes to replace a total of 2,964 cable terminations in this regulatory determination period. The remaining 1,140 sites would then be scheduled over the following regulatory period with all sites completely phased out by 2020/21.

It is anticipated the replacement program represented in this option will reduce the unplanned replacements due to failure proportionally.

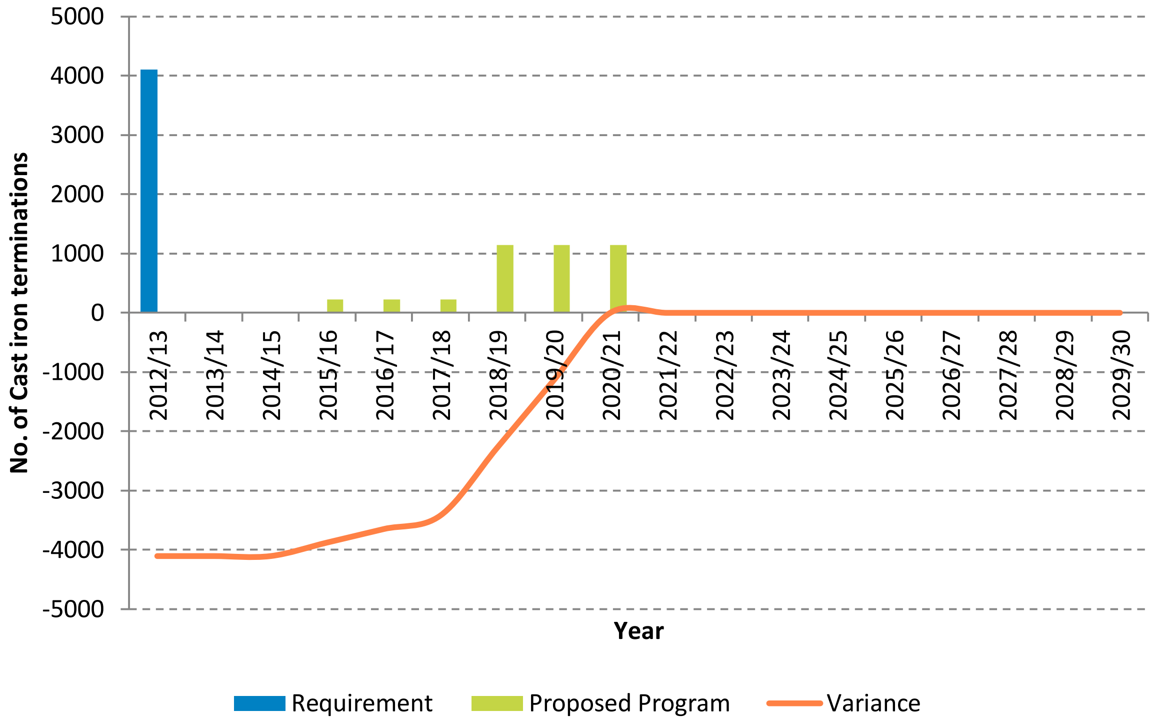


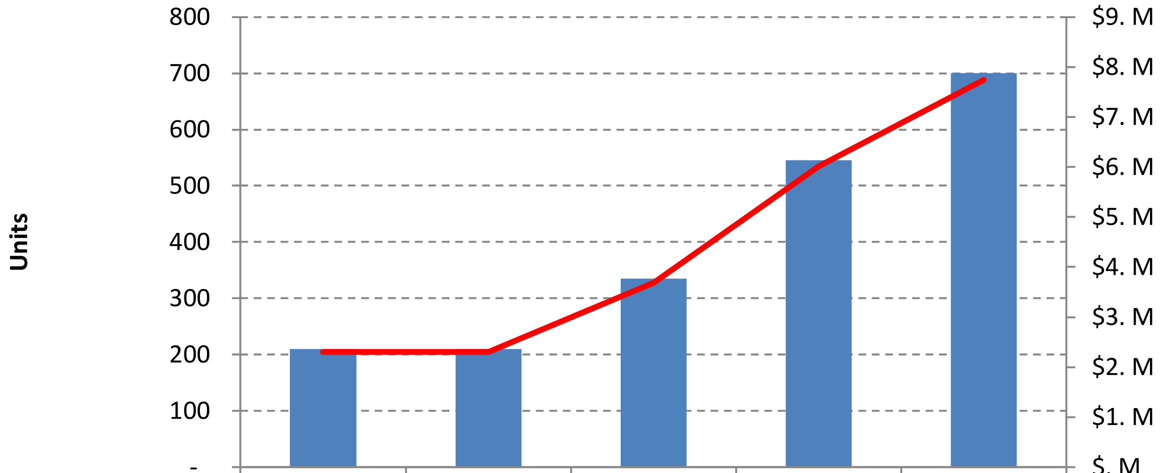
Figure 7 - Sustainability Chart - 6 Year Replacement Period

4.3 Option 2 – 7 ½ Year Replacement Period

4.3.1 Summary

This option will completely phase out cast iron cable terminations over a 7 ½ year period.

Energex has considered a 7 ½ year program with a focus on completing high risk areas and sites within the initial three years. The program will commence in 2015/16 with completion in 2022/23. The remaining sites are proposed to steadily increase until 2019/20, with a smoothed apportionment over the last four years of the program.



	15/16	16/17	17/18	18/19	19/20
Quantities	210	210	335	545	700
$ 14/15 Direct	$2.3 M	$2.3 M	$3.68 M	$6.01 M	$7.74 M

Figure 8 - Option 2 (7.5 Year Replacement Program)

4.3.2 Impact Analysis

The proposed replacement quantities put forward for the 7 ½ year program, represents an anticipated completion of all aged, problematic cable terminations by the end of the 2022/23 financial year.

Option 2 proposes to replace a total of 2,000 cable terminations over the current regulatory determination period (2015/16 - 2019/20).

The remaining 2,104 sites will then be scheduled over the following regulatory period with all sites completely phased out by 2022/23.

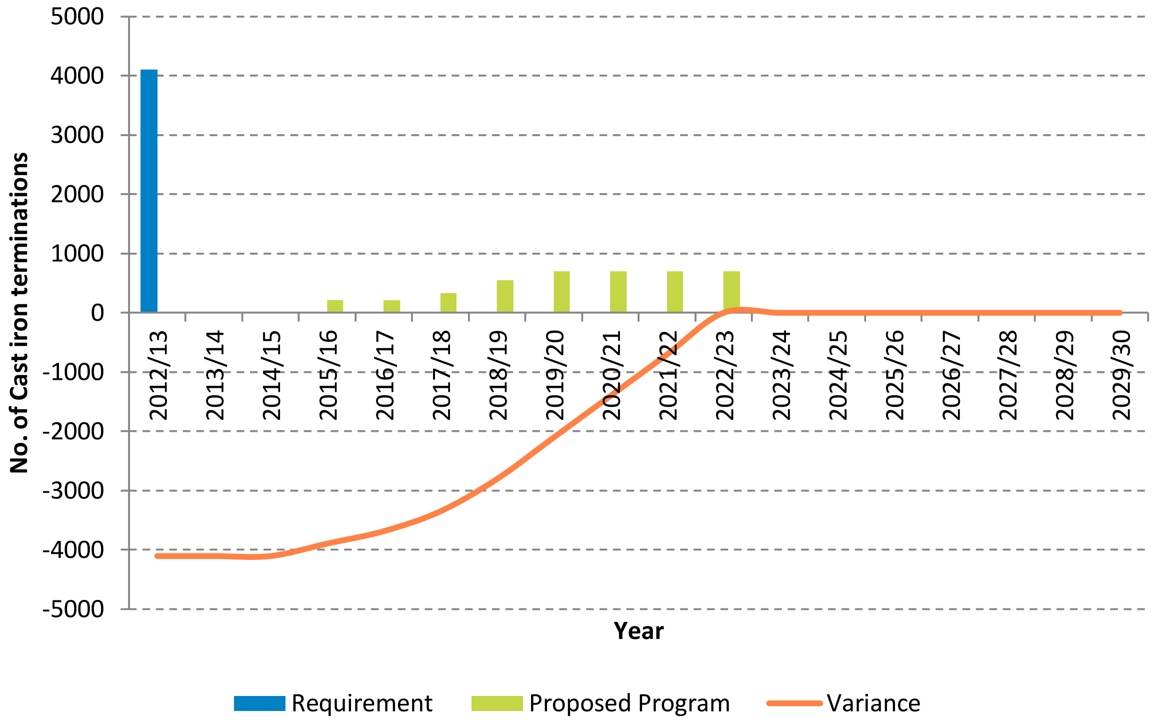


Figure 9 - Sustainability Chart - 7.5 Year Replacement Period

4.4 Option 3 – 10 Year Replacement Period

4.4.1 Summary

This option will completely phase out cast iron cable terminations over a ten year period.

Energex has considered a 10 year program with a focus on completing high risk areas and sites within the initial three years. The program will commence in 2015/16 with completion in 2024/25.

Replacement quantities increase progressively to 2018/19, and then stabilise through to program completion.

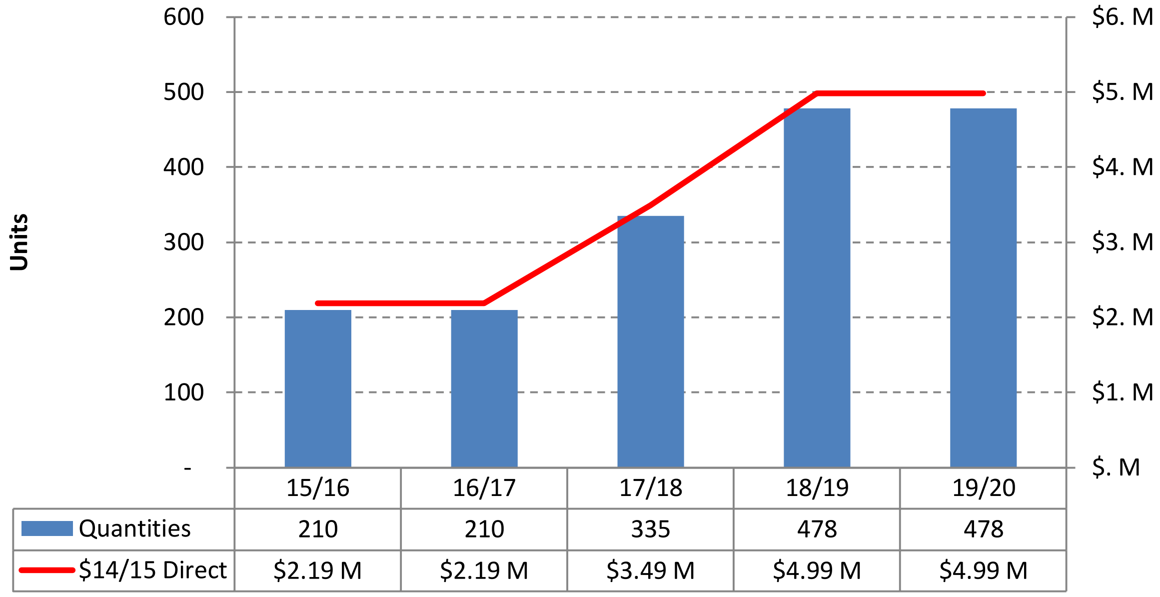


Figure 10 - Option 3 (10 Year Replacement Program)

4.4.2 Impact Analysis

The proposed replacement quantities put forward for the ten year program, represents an anticipated completion of all aged, problematic cable terminations by the end of the 2024/25 financial year.

Option 3 proposes to complete 1,711 over the current regulatory determination period (2015/16 – 2019/20). The remaining 2,393 sites will then be scheduled over the following regulatory period (2020/21 – 2024/25).

The sustainability of this program is considered the best option as it denotes a risk based approach to sites at high risk to public safety, aged asset life replacement and consideration to resource capability/constraints over the regulatory period.

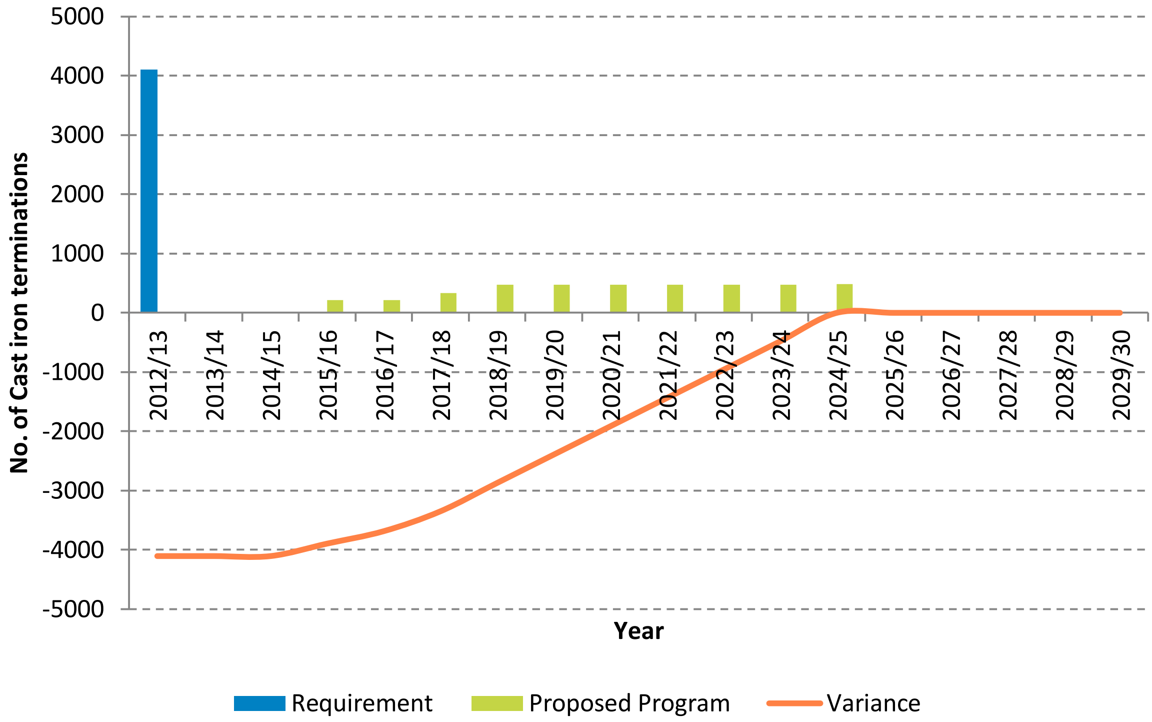


Figure 11 - Sustainability Chart - 10 year replacement period

5 Proposed Works

It is proposed to implement Option 3 to initially target the 402 high risk sites in the vicinity of 150m of school zones to mitigate risk to high traffic areas in the case of catastrophic failure. A further 1309 sites will be scheduled and prioritised accordingly over the regulatory period, with the remaining sites deferred to the following period. High fault current sites will be targeted as the second priority. Replacement quantities will steadily increase until all sites are completed by 2024/25.

The following table provides a summary of the treated risks. The replacement of ageing cable termination cast iron pot heads considered to be obsolete and at or near end of life will reduce the likelihood of failures.

Risk	Risk Scenario	Consequence	Likelihood	Score
Safety	Insufficient program allocation for the replacement of Ageing Underground Cable terminations (e.g. Cast iron bitumen filled terminations). Based on recent evidence, there have been a number of explosive failures leading to third party damage. These terminations are particularly dangerous in high fault level areas because of their cast iron construction. Failure to replace these termination could lead to increased risk to public, staff and contractor safety	5	2	10 (Low)
Environment	Insufficient program allocation for the replacement of Ageing Underground Cable terminations (e.g. Cast iron bitumen/gel filled terminations). Based on recent evidence, there have been a number of explosive failures leading to hot bitumen being released causing environmental impacts. These terminations are particularly dangerous in high fault level areas because of their cast iron construction. Failure to replace these terminations could lead to ongoing risk of environmental impacts.	2	2	4 (Very Low)
Customer Impact	Maintenance, inspection and capital replacement programs not undertaken for the period between 2015/16 – 2019/20 affecting a 11kV cable resulting in disruption to single large scale business or essential service.	3	2	6 (Low)

Table 4: Treated Risk Assessment Summary – Ageing Cable Terminations

6 Required Expenditure

Table 5 below outlines the required expenditure for Option 3, which is the preferred ageing cable termination replacement program (NAMP line CA47) in this business case. This option was selected as it provides a sustainable approach for addressing the identified limitations and managing risks to tolerable levels.

Description	2015/16	2016/17	2017/18	2018/19	2019/20
Expenditure $m, 2014/15	2.2	2.2	3.5	5.0	5.0
Quantity	210	210	335	478	478

Table 5: Proposed Program Expenditure

7 Recommendations

It is recommended that Option 3 be endorsed for inclusion in the programs of work and reflected in Energex's revised regulatory proposal for the 2015/16 – 2019/20 regulatory period.

Appendix 1 – Other Supporting Information

SAFETY Notice

Notice Number: SN-15-15
Issue Date: 07-05-15

Low Voltage Work in Proximity to 33/11kV Energised Metal Clad Underground Terminations

Background

Currently HV live work is not permitted in the vicinity of poles with metal clad underground terminations due to the risk of degraded insulation being compromised by inadvertent bridging movement. This could result in flashover of the insulation and destruction of the metal clad cable box.

Any substantial movement of the pole that results in similar bridge movement may also lead to the same result.

Personnel working on Energex assets in proximity to these terminations shall undertake a risk assessment to determine the potential for inadvertent HV bridge movement. If it is assessed that there is the potential for inadvertent bridge movement, work shall not proceed until the equipment is isolated as per SAHV requirements.

In general, on poles with energised metal clad underground terminations, LV tasks that do not alter the tip load by 1kN are acceptable; however the following LV tasks are not permitted;

- Re-conductoring
- Re- tensioning
- Broardband re-tensioning
- Shackle/termination crossarm replacement with tension changes

Currently Energex has a program to replace these units.


33kV Metal Clad U/G Terminations


11kV Metal Clad U/G Terminations

Action Required

1. Crews working on the LV network in proximity to 33/11kV Energised Metal Clad Underground Terminations are to undertake a risk assessment to determine the potential for inadvertent HV bridging movement prior to commencing work.

2. In situations where inadvertent movement of HV bridging cannot be avoided, isolate this equipment using SAHV process

3. All Process Owners to review relevant work practices and associated risk assessments with regard to the information contained in this Notice.

4. Managers and Coordinators must ensure that:
   a. This Notice is brought to the notice of relevant Workers and records kept of discussions with workers;
   b. A copy of this Notice is placed on all Safety Noticeboards;

For Enquiries: Tim Hart Asset Performance and Improvement Manager
Authorised by Group Manager Safety

PUBLIC

Energex

C&I Circuit Breaker Remote Control Program

Asset Management Division

energex

positive energy

Energex

C&I Circuit Breaker Remote Control Program 2015/16 - 2019/20

Reviewed:

Tim Hart

Group Manager Asset Life Cycle Management

Endorsed:

Peter Price

Executive General Manager Asset Management

Version control

Version	Date	Description
1	1/07/2015	Submitted
2		

Energex Limited (Energex) is a Queensland Government Owned Corporation that builds, owns, operates and maintains the electricity distribution network in the growing region of South East Queensland. Energex provides distribution services to almost 1.4 million domestic and business connections, delivering electricity to a population base of around 3.2 million people.

Energex's key focus is distributing safe, reliable and affordable electricity in a commercially balanced way that provides value for its customers, manages risk and builds a sustainable future.

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Executive Summary

Energex seeks to continue to deliver sustainable outcomes for customers and the business with no compromise to existing safety and legislative compliance. Effective switching devices such as remote control circuit breakers are vital elements in the provision of a safe and compliant network. The risk of explosive circuit breaker failure increases significantly during opening and closing operations. The manual operation of circuit breakers places field personnel in direct proximity to the circuit breaker during this period of heightend exposure which poses a high safety risk to personnel. The hazards are amplified when these are located in small enclosed environments such as Commercial & Industrial substation switchrooms.

The objective of this program is provide remote control operation to circuit breakers to remove the need for staff to be in proximity during operation hence mitigating the safety risks.

Installation of remote control capability on existing Commercial & Industrial circuit breakers is a cost effective and prudent investment to mitigating the safety risk to personnel. This program supplements existing programs to replace manually operated 11kV bulk oil filled circuit breakers that are in poor condition with remote vacuum circuit breakers.

The expenditure for this program is not accounted for in the modelled REPEX programs.

The revised program remains unchanged from the original proposal due to the safety risks associated with catastrophic failure of manually operated circuit breakers. However a review of the expenditure associated with the original program scope has determined a lower cost solution for installation of remote control.

The following table provides a summary of the required expenditure of $7.2 million over the 2015/16 – 2019/20 regulatory period.

$m, 2014/15	2015/16	2016/17	2017/18	2018/19	2019/20	Total
Energex Proposal	1.8	1.8	1.8	1.8	1.8	9.2
Energex Revised Proposal	1.4	1.5	1.5	1.4	1.4	7.2

Contents

1 Introduction

The purpose of this document is to outline the required expenditure for the installation and retrofit of 70 Commercial & Industrial (C&I) substation sites with remote control circuit breakers out of the 425 Energex owned C&I substation requiring remote control capability in the period 2015/16 – 2019/20.

This program will reduce the safety risk to personnel to as low as reasonably practical and provide improved operational flexibility during the period.

Changes from the original proposal

The original proposal to the AER for the C&I program was for $9.2 million over the 2015/16 – 2019/20 regulatory period. The revised program remains unchanged in scope and intent from the original proposal due to the safety risks associated with explosive failure of circuit breakers in C&I substations. A review of the costs associated with the original program has determined a more cost effective solution for remote control installation. The cost of the program has been revised to $7.2 million over the 2015/16 – 2019/20 regulatory period.

2 Drivers

Installation of remote control circuit breakers in substations was introduced in the early 1980s and has since become nationally accepted standard operating practice. Since then, Energex has been progressively implementing circuit breaker remote capability. Energex standards for bulk and zone substations have specified remote control circuit breaker capability since the mid-1990s, however circuit breakers in C&I substations have been traditionally installed with manual operated circuit breakers.

The Australian Standard AS62271.200 'High Voltage Switchgear and Controlgear – A.C. metal-enclosed switchgear and controlgear for rated voltages above 1kV and up to and including 52kV' states that distributors should adopt all measures to provide appropriate levels of safety protection to personnel. Installing remote control capability for circuit breakers mitigates the safety risk to personnel during circuit breaker operation.

Energex has progressively improved the safety of its circuit breakers in C&I substations by installing vacuum circuit breakers instead of oil breakers in newer sites. Energex's current standard for C&I substations requires remote control capability of circuit breakers. Remote control circuit breaker capability reduces the safety risk to personnel and also allows Energex to remotely de-energise the substation in the event of an emergency (e.g. flood).

During the current regulatory period, Energex have been replacing problematic circuit breakers in C&I substations to reduce the risk to personnel during circuit breaker operation. This program is only partially complete, still posing an increased risk to personnel. The proposed program for installation and retrofit of remote control circuit breakers in C&I substations includes both oil and vacuum breakers.

The safety risk associated with manually closing oil circuit breakers is related to the destructive impact of arc-faults which can cause oil explosions potentially harming personnel within the vicinity. Whilst vacuum circuit breakers can still fail catastrophically, there is no oil to ignite, which reduces some of the risk to personnel.

All pre-1981 contract switchgear in Energex's C&I substations neither has arc-fault containment nor vented capability, both of which reduce the impact of the fault on the operator. This increases the safety risk to personnel performing manual switching on these sites.

The improved operational flexibility of remote control circuit breakers will provide Energex greater flexibility during fault finding and major events such as floods where it is beneficial to manage C&I substations remotely.

Figure 1 and Figure 2 show a circuit breaker before and after failure during a manual operation.

Figure 1: Circuit breakers pre-fault of a manual operation (South Africa)

Figure 2: Circuit breakers post-fault of a manual operation (South Africa)

3 Options

3.1 Impact of Doing Nothing

The “do nothing” option or failure to install remote control on circuit breakers in C&I substations would result in a safety and legislative risks above levels considered to be as low as reasonably practicable (ALARP).

Risk of the do nothing approach is quantified in the untreated risk scenarios in Table 1.

Category	Risk Scenario	Consequence	Likelihood	Risk Score
Safety	Explosive failure of an oil manually operated circuit breaker within a C&I substation leading to multiple fatalities.	6	3	18 (High Risk)
Legislated Requirements	Explosive failure of a manually operated circuit breaker within a C&I substation harming a member of personnel leads to a breach in the obligations under AS62271.200.	5	3	15 (Moderate Risk)

Table 1: Untreated Risk Assessment Summary – C&I Non Remote Circuit Breakers

This Do Nothing option would call for continued risk exposure at these levels. This outcome is not tolerable to Energex, with significant safety and legislative risk risks not considered to be As Low As Reasonably Practicable (ALARP).

3.2 Option 1 – Install Remote Control Capability to 70 C&I Substation Circuit Breakers

3.2.1 Summary

This option proposes installation of remote control capability to 70 C&I substation sites with circuit breakers of both oil and vacuum type within Energex C&I substations. This solution requires installation of multiple Remote Terminal Units each with a communications network to multiple C&I substations. Energex is targeting 70 C&I substation sites which would address all higher priority sites and represents a more sustainable program due to resourcing and other priority works. The remaining 355 C&I substation sites will require the installation of circuit breaker remote operation in future regulatory periods.

3.2.2 Impact Analysis

The cost of installing remote control to C&I substations proposed under this option is much lower compared to installing a Remote Terminal Unit at each substation, known as a full SCADA build. This option is the most cost effective solution that will allow Energex to remotely operate circuit breakers in C&I substations and reduce the safety risk to personnel.

3.3 Option 2 – Install SCADA system to C&I substations

3.3.1 Summary

This option proposes to install a Remote Terminal Unit or full SCADA system at each C&I substation. This option allows for remote operation of the circuit breakers and detailed monitoring of each substation. Benefits of a full SCADA system compared to a remote control is improved operational flexibility.

3.3.2 Impact Analysis

The option to install a full SCADA system at each C&I substation would increase the cost of the install to approximately $200,000 per site. Although a full SCADA system would provide greater operational flexibility, a cost comparison of options does not justify the additional expenditure.

3.4 Option 3 – De-energise C&I circuit breakers before manual switching

3.4.1 Summary

This option proposes that Energex change its operating practices to disallow manual operation of circuit breakers that could result in an explosion. This would involve de-energisation before operation.

3.4.2 Impact Analysis

The option would have an intolerable impact to Energex customers as customer outages would be required to be organised for many routine operations. Energex would also incur significant impact from the effort required to coordinate these outages.

4 Proposed Works

It is proposed to implement Option 1 to install remote control capability to 70 C&I substation circuit breakers in the 2015/16 – 2019/20 period under this program. Option 2 represents a higher cost solution without significant additional benefit. Option 3 is rejected on the basis of significant impacts to customers reliability of supply.

Energex has prioritised the installation of remote control capability at C&I substations based on their age and condition. The remaining 355 C&I substation sites without remote control capability will require actioning in future regulatory periods.

Table 2 provides a summary of the treated risks.

Category	Risk Scenario	Consequence	Likelihood	Risk Score
Safety	Explosive failure of an oil manually operated circuit breaker within a C&I substation leading to multiple fatalities.	6	1	6 (Low Risk)
Legislated Requirements	Explosive failure of a manually operated circuit breaker within a C&I substation harming a member of personnel leads to a breach in the obligations under AS62271.200.	5	1	5 (Very Low Risk)

Table 2: Treated Risk Assessment Summary – C&I Remote Circuit Breakers

5 Required Expenditure

Table 3 outlines the required expenditure for Option 1, which is the preferred C&I circuit breaker remote control program in this business case.

Description	2015/16	2016/17	2017/18	2018/19	2019/20	Total
Expenditure $m, 2014/15	1.4	1.5	1.5	1.4	1.4	7.2

Table 3: Proposed Program Expenditure

6 Recommendations

It is recommended that Option 1 be endorsed for inclusion in the programs of work and reflected in Energex's revised regulatory proposal for the 2015/16 – 2019/20 regulatory period.

PUBLIC

Energex

Instrument Transformer Replacement Program

Asset Management Division

energex

positive energy

Energex

Instrument Transformer Replacement Program 2015/16 - 2019/20

Reviewed:

T Hart

Tim Hart

Group Manager Asset Life Cycle Management

Endorsed:

Peter Price

Executive General Manager Asset Management

Version control

Version	Date	Description
1	1/07/2015	Submitted

Energex Limited (Energex) is a Queensland Government Owned Corporation that builds, owns, operates and maintains the electricity distribution network in the growing region of South East Queensland. Energex provides distribution services to almost 1.4 million domestic and business connections, delivering electricity to a population base of around 3.2 million people.

Energex's key focus is distributing safe, reliable and affordable electricity in a commercially balanced way that provides value for its customers, manages risk and builds a sustainable future.

Group Manager
Corporate Communications
Energex
GPO Box 1461
BRISBANE QLD 4001

Executive Summary

Energex has experienced multiple catastrophic failures of 110kV oil filled porcelain bushing voltage transformers (VTs). Catastrophic failure of these assets results in porcelain bushing projectiles as a result of explosive failure. This poses a high safety risk to field personnel and the public. Required expenditure for mitigation of this risk is not accounted for in the modelled REPEX programs.

Powerlink Queensland experienced multiple catastrophic failures of [redacted] type Capacitor Voltage Transformers (CVTs) preceding 2012. Catastrophic failure of these assets results in porcelain bushing projectiles as a result of explosive failure. This poses a high safety risk to field personnel and the public. An incident investigation undertaken by Powerlink in late 2012 recommended the replacement of this type of CVT at or above 20 years of age.

Energex has a population of this type of CVT in its network approaching or beyond the retirement age recommended by Powerlink's failure incident investigation.

Condition assessment of Energex's CVT population and subsequent replacement planning analysis was completed by Energex in the 2013/14 and 2014/15 financial years. Implementation of CVT replacements will commence in the 2015/16 financial year.

The proposed program to replace CVTs and 110kV/132kV oil filled porcelain bushing instrument transformers will allow mitigation of the identified risks by funding the continuation of the replacement of end of life instrument transformers and the implementation of the CVT replacement program.

The original proposal to the AER for the instrument transformer program was for $2.02 million over the 2015/16 – 2019/20 regulatory period. Energex is committed to the delivery of sustainable outcomes for customers and the business with no compromise to existing safety and legislative compliance. The revised program remains unchanged from the original proposal due to the safety risks associated with catastrophic failure of instrument transformers.

The following table provides a summary of the required expenditure of $2.02 million ($2014/15 direct) over the 2015/16 – 2019/20 regulatory period.

$m, 2014/15	2015/16	2016/17	2017/18	2018/19	2019/20	Total
Energex Proposal	0.46	0.33	0.39	0.52	0.33	2.02
Energex Revised Proposal	0.46	0.33	0.39	0.52	0.33	2.02

Contents

1 Introduction

The purpose of this document is to outline the required expenditure for the replacement of 31 instrument transformers that have exceeded their expected life in the period 2015/16 – 2019/20.

<u>Changes from the original proposal</u>

The original proposal to the AER for the instrument transformer program was for $2.02 million over the 2015/16 – 2019/20 regulatory period. Energex is committed to the delivery of sustainable outcomes for customers and the business with no compromise to existing safety and legislative compliance. The revised program remains unchanged from the original proposal due to the safety risks associated with catastrophic failure of instrument transformers.

2 Drivers

Instrument transformers are used to transform high voltage or current to levels which are used to operate secondary systems instruments or metering. This class of assets consists of current transformers (CTs), voltage transformers (VTs) and capacitive voltage transformers (CVTs). The high voltage instrument transformers used on the Energex network are typically oil filled units with porcelain bushings.

Powerlink Queensland has experienced five in-service Capacitive Voltage Transformers failures of this type between 2010 and 2013 on units aged between 21 and 28 years. Detailed investigations carried out on the failed CVTs revealed that there is an inherent defect where the hermetically sealed units fail and allow moisture ingress. Free water inside the Electro Magnetic transformer tank shorts out the winding, generating heat and combustible gas that can lead to catastrophic failure. The investigation recommended that CVTs greater than 20 years be replaced prior to premature failure.

Energex CVTs of this type greater than 20 years old are very likely to fail in a similar mode as experienced by Powerlink and pose a significant safety risk. As these CVTs contain minimal oil and are hermitically sealed, it is not possible to undertake diagnostic tests on the insulating oil on a regular basis as the oil extracted for the sample cannot be replaced. This restricts sampling capability to only a handful of tests as removal of too much oil will remove the insulation capability and lead to failure. As such, CVT replacement is the only method for mitigating the associated risks.

Catastrophic failure of high voltage instrument transformers poses a safety risk to staff and the community because they are oil filled units with porcelain bushings which fragment and scatter as a result of the explosive force. Power supply reliability is also affected if adjacent equipment is damaged by an exploding instrument transformer inside the switchyard.

3 Supporting Analysis

Energex have 189 132/110kV voltage transformers in service of which 50 units are of this type. Out of the 50 CVT units of this type, 21 units are greater than 20 years old. These units are located at Nerang, Traveston, Cooroy and Cades County and are planned to be replaced in the 2015/16 – 2019/20 regulatory period. See Appendix 1 for a full detailed report on CVT condition and failure modes. Since this report was completed in May 2014, oil test results on CVTs have indicated increasing deterioration. The results attached in Appendix 2 show increased acetylene levels in oil samples which indicate arcing within the equipment.

The additional 10 instrument transformers proposed for replacement are aged between 44 and 51 and have exceeded their expected design life of 40 years according to Condition Based Risk Management (CBRM). CBRM is a structured process that combines asset data, engineering knowledge and practical experience to define the current and future condition of network assets.

Instrument transformer CBRM analysis indicates that these units are approaching or have exceeded the end of their serviceable life based on their age and condition. Once an asset has exceeded its serviceable life based on CBRM the probability of failure increases and the assets require replacement in order to prevent in service failure.

As of 2014, Energex has experienced two catastrophic failures of 110kV voltage transformers (VT). These failures occurred at Mooloolaba and Nambour substations. The catastrophic VT failure at Mooloolaba resulted in insulator shards covering the yard and surrounding substation area. The force of the explosion and resulting shrapnel was enough to cause damage to the adjacent equipment as shown in Figure 1 and Figure 2. Further details of the failure are included in Appendix 3.

Figure 1: Surrounding Equipment after VT Failure at Mooloolaba

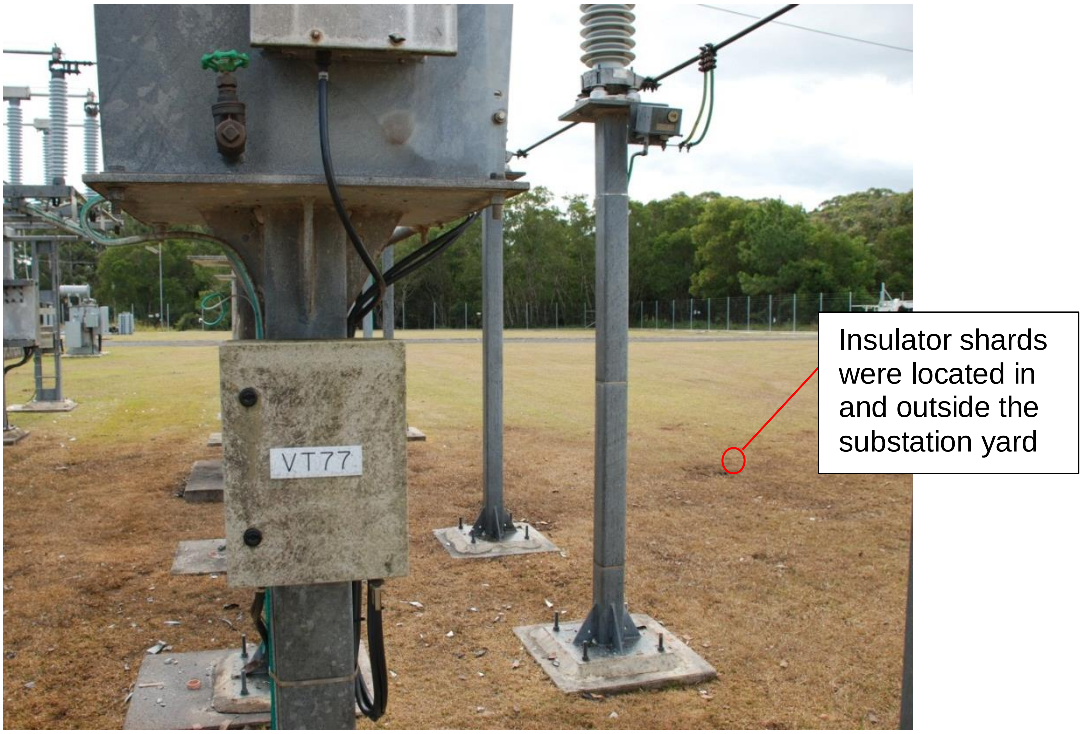


Figure 2: VT Failure at Mooloolaba – Insulator Shards Covering the Yard

The following figures show the population of instrument transformers in the Energex network and the replacement unit forecast.

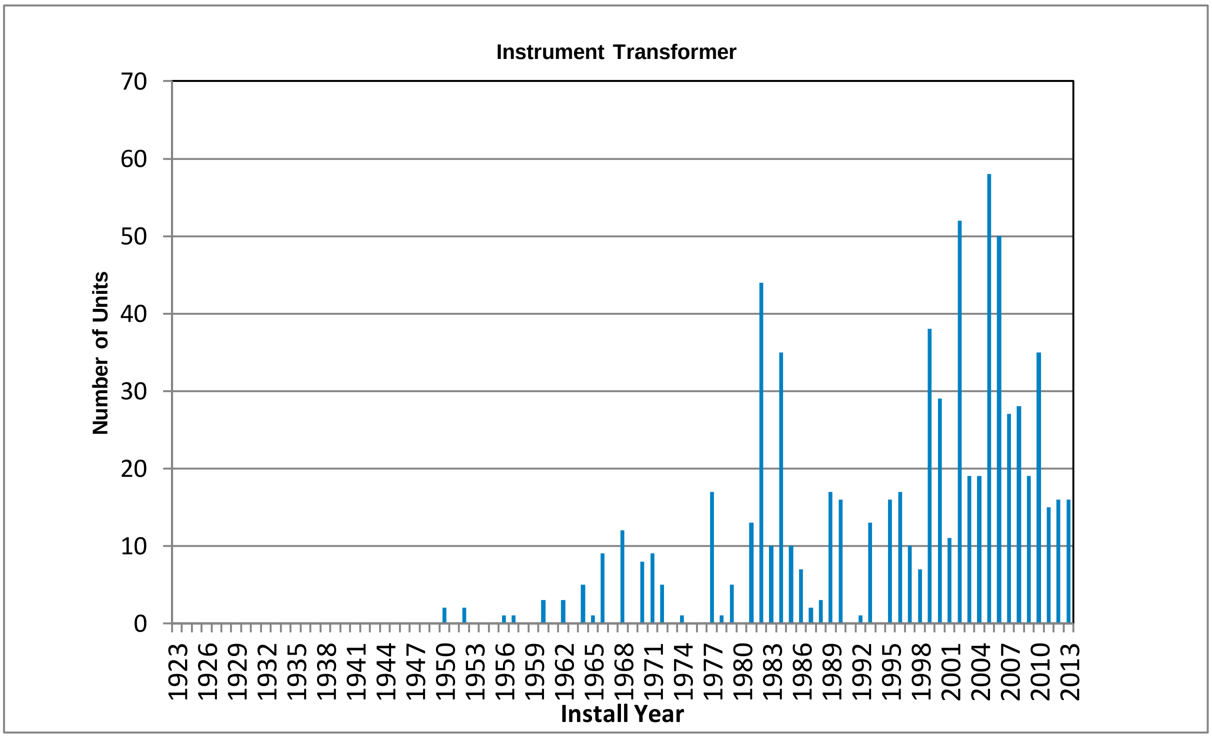


Figure 3: 132/110kV Instrument Transformer – Population Information

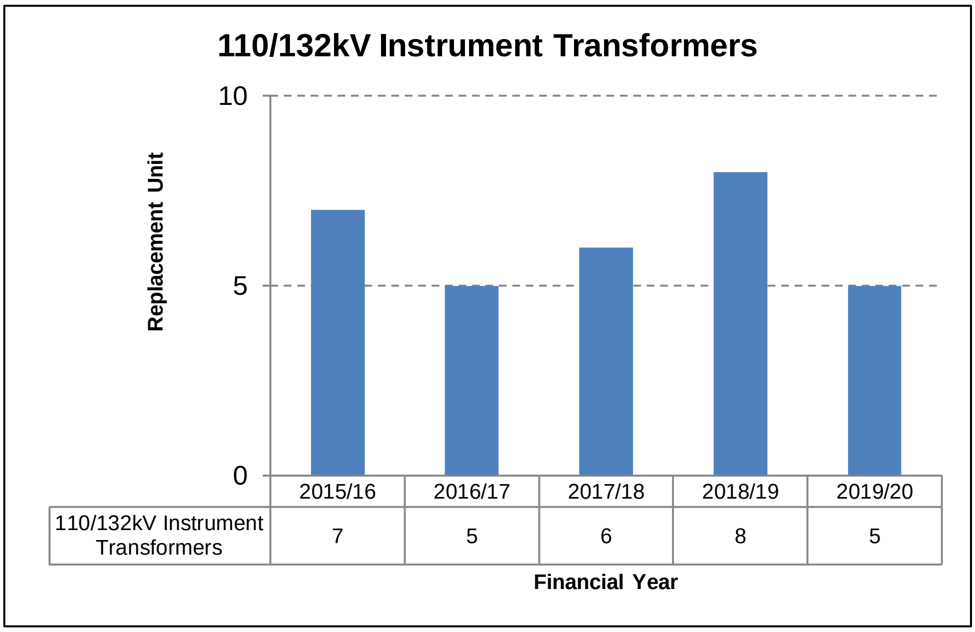


Figure 4: 132/110kV Instrument Transformer - Replacement Unit Forecast

Powerlink's investigation of CVT failures identified the following failure process:

1. Loss of Electromagnetic Unit (EMU) hermetic seal
2. Moisture ingress leading to free water on the bottom of the EMU tank
3. Shorting of intermediate transformer windings at the bottom of the EMU tank
4. Excessive heat then generated by the faulting intermediate transformer
5. Oil and insulation progressively degrades into a solid mass as the cellulose, oil and beads continue to be heated. See Figure 5 and Figure 6.
6. Internal pressure builds up inside the tank which forces the congealed mass out through the EMU seal
7. The explosive failure of the surge protective device likely as a result of the failure of the voltage transformer primary winding

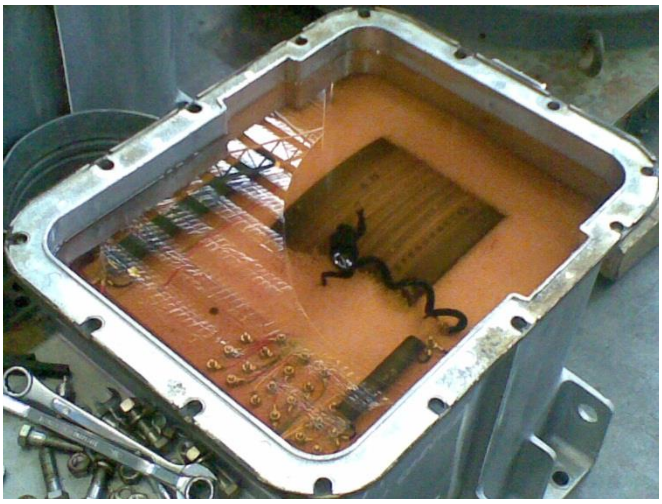


Figure 5: Healthy CVT[1]

Figure 6: Poor Condition CVT[1]

[1] Photo obtained from Powerlink Qld Investigation Report

Figure 5 shows what the internals of a healthy CVT should look like; note the clean oil with suspended synthetic beads. Figure 6 shows the internals of a unit exposed to reveal heavily oxidised oil and synthetic beads mix. Photos obtained from the Powerlink investigation report.

4 Options

4.1 Impact of Doing Nothing

The “do nothing” option, or failure to proactively replace instrument transformers, would result in an increasing likelihood of units failing catastrophically resulting in levels of safety, environmental, legislative and risk which are not considered to be as low as reasonably practicable.

Risk of the do nothing approach is quantified in the untreated risk scenarios in Table 1.

Category	Risk Scenario	Consequence	Likelihood	Risk Score
Safety	Catastrophic failure of an instrument transformer causes an explosion and insulator debris flying inside the yard resulting in multiple serious injuries to Energex personnel.	4	4	16 (Moderate Risk)
Environment	Catastrophic failure of an instrument transformer which results in loss of oil.	2	5	10 (Low Risk)
Customer Impact	Catastrophic failure of an instrument transformer which causes an explosion and insulator debris flying inside the yard causing damage to adjacent equipment which results in subsequent loss of supply to customers.	4	3	12 (Moderate Risk)
Legislated Requirements	Multiple failures of instrument transformers across the network which results in the breach of obligations under the Electrical Safety Act to provide a safe network	5	3	15 (Moderate Risk)
Business Impact	Failure of an instrument transformer resulting in the loss of a level of protection on the transmission network which imposes operating restrictions until rectification work is undertaken.	5	4	20 (High Risk)

Table 1: Untreated Risk Assessment Summary – Instrument Transformers

This Do Nothing option would call for continued risk exposure at these levels, with risks increasing over time and soon reaching intolerable levels. This outcome is not tolerable to Energex, with untreated risks not considered to be As Low As Reasonably Practicable (ALARP).

4.2 Option 1 – Replace 31 Instrument Transformers

4.2.1 Summary

This option proposes to replace 21 CVTs of this type greater than 20 years old during the period 2015/16 – 2019/20. These CVTs are located at Nerang, Traveston, Cooroy and Cades County. Additional CVTs of this type will require replacement in subsequent periods after they have exceeded 20 years.

It is also proposed to replace 10 current and voltage transformers at Beenleigh and Caboolture, aged between 44 and 51 which have reached the end of their serviceable life according to CBRM analysis.

4.2.2 Impact analysis

It is proposed to replace instrument transformers across the regulatory period and into the next period as they approach end of life based on condition. The sustainability chart shows the proposed program against the program requirement. The requirement to replace CVTs at 20 years was identified in 2012 which has resulted in the backlog shown in 2012/13. Table 2 below provides a summary of the instrument transformer replacement requirements based on the condition analysis and limitations outlined previously. Table 2 also provides a breakdown of the CVT and CT and VT requirements resulting to the variance in expected life. These units form the basis of the requirements described in the sustainability charts that follow.

Year	CVTs	Other CTs and VTs
2012/13	23	22
2013/14	-	-
2014/15	-	-
2015/16	-	-
2016/17	1	-
2017/18	-	19
2018/19	-	6
2019/20	-	5
2020/21	3	3
2021/22	-	6
2022/23	7	12
2023/24	6	-
2024/25	-	33
2025/26	4	-
2026/27	1	4
2027/28	-	-
2028/29	-	3
2029/30	4	12

Table 2: Program Requirement Breakdown – Instrument Transformers

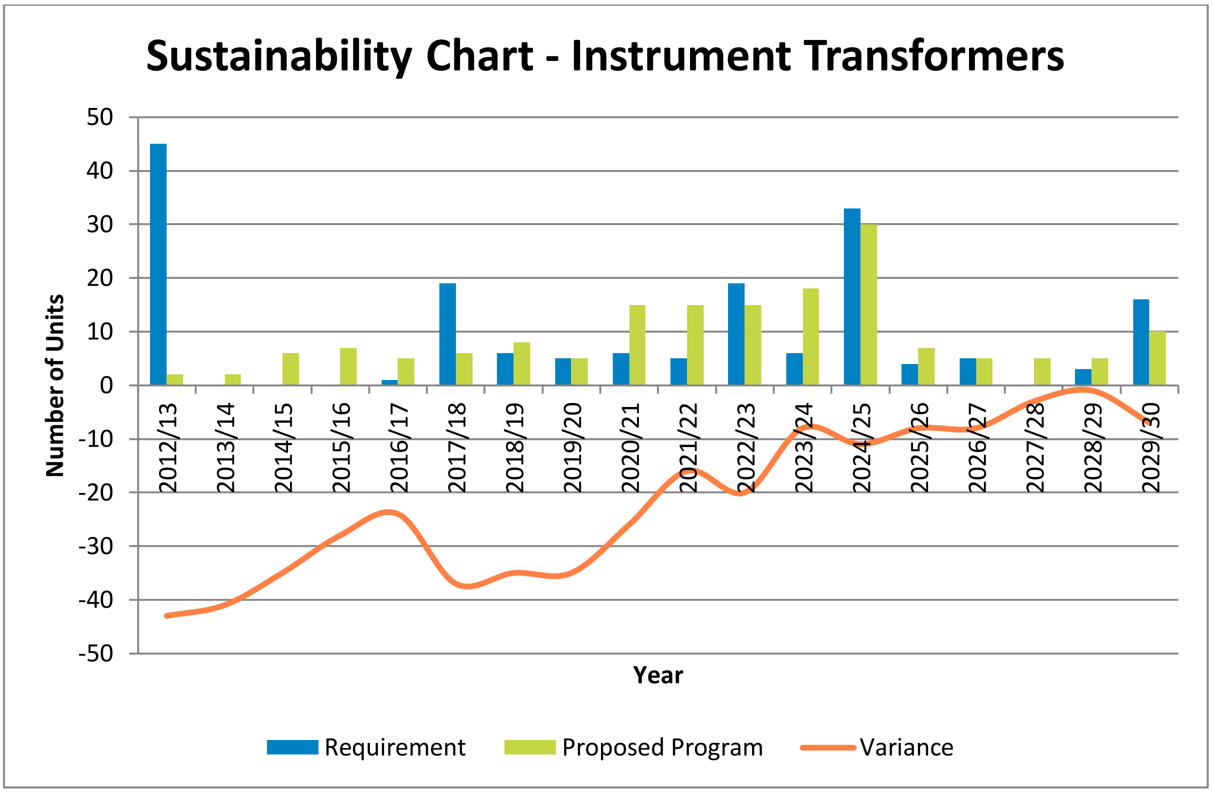


Figure 7: Sustainability Graph for Instrument Transformers – Option 1

Table 3 below outlines the required expenditure for the instrument transformer replacement program under Option 1.

Description	2015/16	2016/17	2017/18	2018/19	2019/20
Expenditure $m, 2014/15	0.46	0.33	0.39	0.52	0.33
Quantity	7	5	6	8	5

Table 3: Expenditure – Option 1

4.3 Option 2 – Replace 66 Instrument Transformers

4.3.1 Summary

This option proposes to replace 27 CVTs greater than 20 years old during the period 2015/16 – 2019/20. Additional CVTs will require replacement in subsequent periods once they have exceeded 20 years.

It is also proposed to replace 39 current and voltage transformers, aged between 30 and 51 which have reached the end of their serviceable life according to CBRM analysis.

4.3.2 Impact analysis

The sustainability chart shows the proposed program against the program requirement. The requirement to replace CVTs at 20 years was identified in 2012. It is proposed to replace CVTs and other instrument transformers as they approach end of life based on condition across the regulatory period and into the next period. Whilst, in the absence of funding restraints, this would be Energex's preferred option because it addresses the sustainability issue by 2019/20, Energex's proposal in this business case is to adopt a slightly higher risk profile embodied in Option 1.

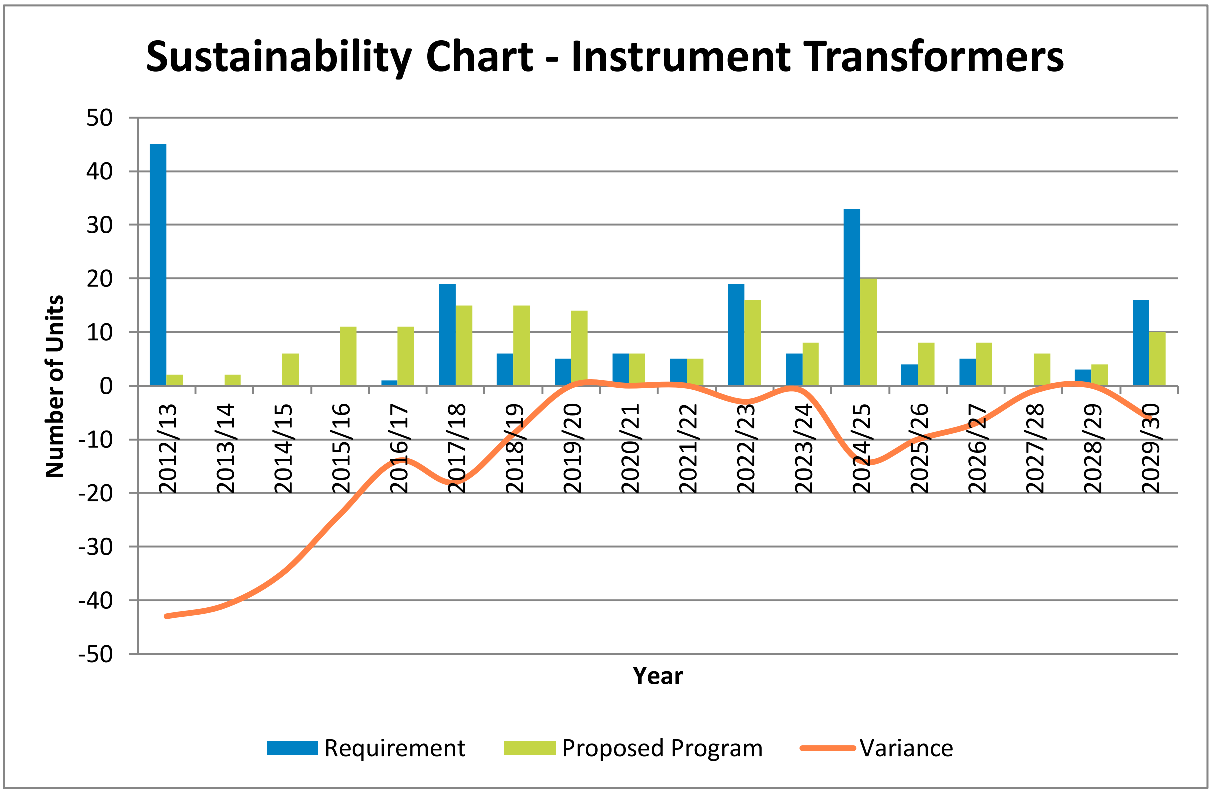


Figure 8: Sustainability Graph for Instrument Transformers – Option 2

Table 4 below outlines the required expenditure for the instrument transformer replacement program under Option 2.

Description	2015/16	2016/17	2017/18	2018/19	2019/20
Expenditure $m, 2014/15	0.72	0.72	0.98	0.91	0.91
Quantity	11	11	15	15	14

Table 4: Expenditure – Option 2

4.4 Option 3 – Replace 20 Instrument Transformers

4.4.1 Summary

This option proposes to replace 20 CVTs greater than 20 years old during the period 2015/16 – 2019/20. Additional CVTs will require replacement in subsequent periods once they have exceeded 20 years.

This option is not considered tolerable as failure to replace instrument transformers will result in an increasing chance that the units will fail catastrophically resulting in levels of safety, environmental, legislative and network risk which are not considered to be as low as reasonably practicable.

4.4.2 Impact analysis

The sustainability chart shows the proposed program against the program requirement. The requirement to replace CVTs at 20 years was identified in 2012. It is proposed to replace CVTs and other instrument transformers as they approach end of life based on condition across the regulatory period and into the next period.

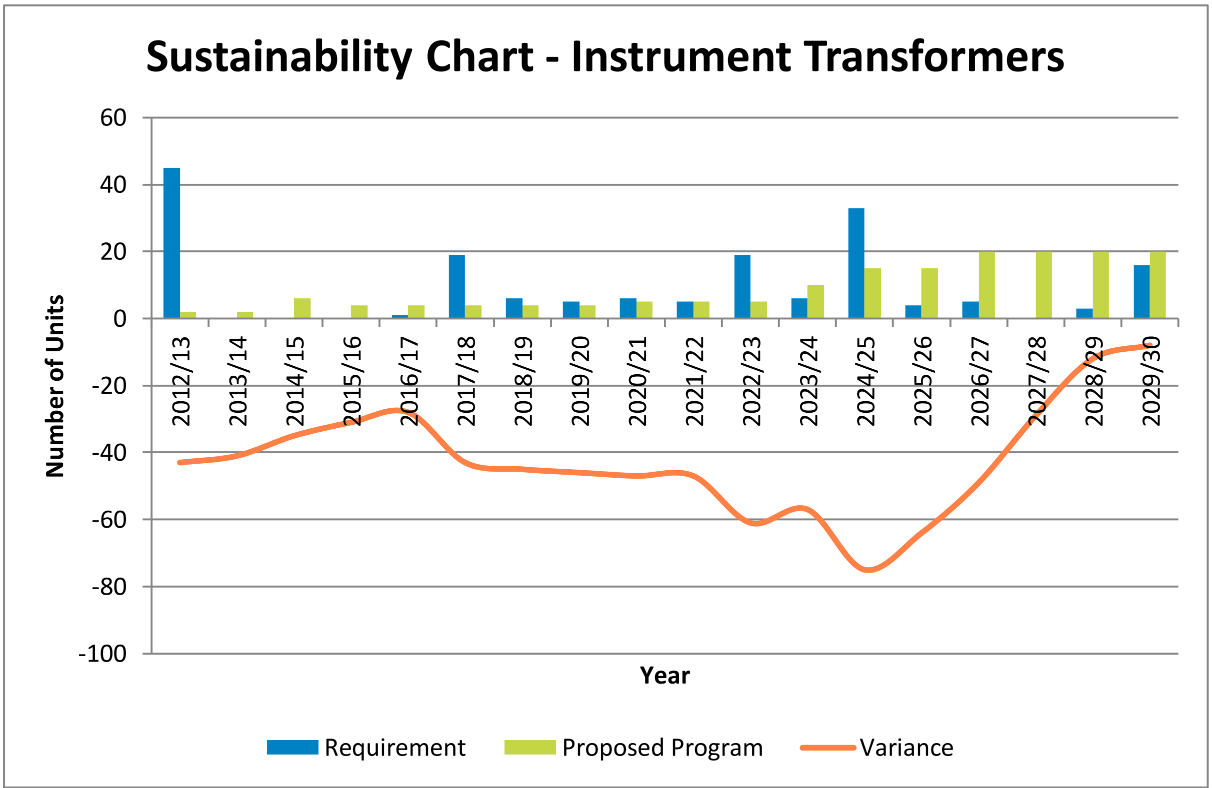


Figure 9: Sustainability Graph for Instrument Transformers – Option 3

Table 5 below outlines the required expenditure for the instrument transformer replacement program under Option 3.

Description	2015/16	2016/17	2017/18	2018/19	2019/20
Expenditure $m, 2014/15	0.26	0.26	0.26	0.26	0.26
Quantity	4	4	4	4	4

Table 5: Expenditure – Option 3

5 Proposed Works

It is proposed to implement Option 1 to replace 21 CVTs and 10 current and voltage transformers in the 2015/16 – 2019/20 period under this program. This option was selected as it provides a sustainable approach for addressing the identified limitations and managing risks to tolerable levels. Additional CVTs and instrument transformers will require replacement in future regulatory periods.

The following table provides a summary of the treated risks. The replacement of instrument transformers that have exceeded end of life according to CBRM will reduce the likelihood of failures.

Category	Risk Scenario	Consequence	Likelihood	Risk Score
Safety	Catastrophic failure of an instrument transformer causes an explosion and insulator debris flying inside the yard causing multiple serious injuries to Energex personnel.	4	2	8 (Low Risk)
Environment	Catastrophic failure of an instrument transformer which results in loss of oil.	2	2	4 (Low Risk)
Customer Impact	Catastrophic failure of an instrument transformer which causes an explosion and insulator debris flying inside the yard causing damage to adjacent equipment which results in subsequent loss of supply to customers.	4	2	6 (Low Risk)
Legislated Requirements	Multiple failures of instrument transformers across the network which results in the breach of obligations under the Electrical Safety Act to provide a safe network	5	1	5 (Low Risk)
Business Impact	Failure of an instrument transformer resulting in the loss of a level of protection on the transmission network which imposes operating restrictions until rectification work is undertaken.	5	2	10 (Low Risk)

Table 6: Treated Risk Assessment Summary – Instrument Transformers

6 Required Expenditure

Table 7 below outlines the required expenditure for Option 1, which is the preferred instrument transformer replacement program in this business case.

Description	2015/16	2016/17	2017/18	2018/19	2019/20
Expenditure $m, 2014/15	0.46	0.33	0.39	0.52	0.33
Quantity	7	5	6	8	5

Table 7: Proposed Program Expenditure

7 Recommendations

It is recommended that Option 1 be endorsed for inclusion in the programs of work and reflected in Energex's revised regulatory proposal for the 2015/16 – 2019/20 regulatory period.

Appendix 1 – CVT Memorandum

Available on request

Appendix 2 – CVT Test Results

Insulating Oil Test Report

Next Test 20.11.2015

Our Ref 7VTE00510

Customer ENERGEX GPO BOX 1461 Brisbane 4001

Report No.: 000097357

Oil Testing Services

	DGA	Oil	Moist	Insul
Sample	Green	Green	Green	
Plant	Green	Green	Green	

Plant ID SST124 VT2-7189/2A
Serial No 92430207
Manufacturer [redacted]

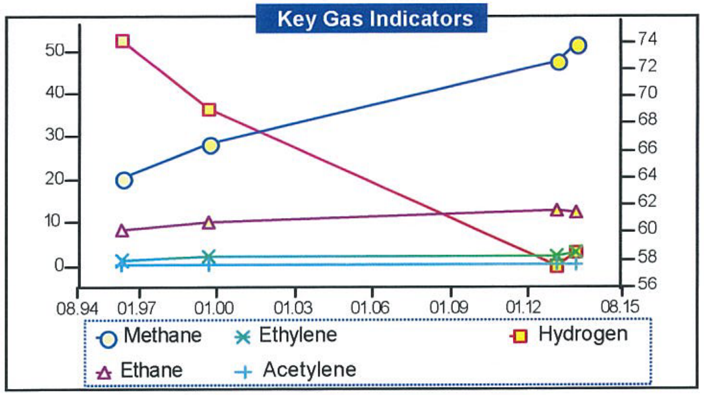
Location T124 - TRAVESTON
Feeder VT 779
Phase A

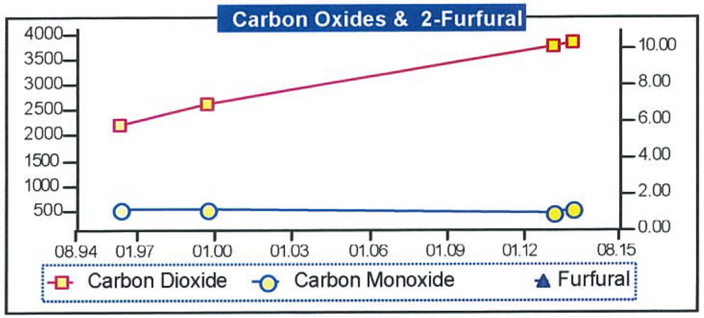
Rating (KVA)
Voltage 132000
YOM 1992

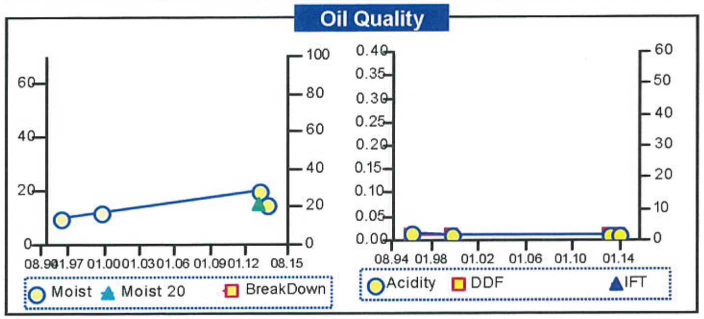
Date Received: 22.11.2013
Date Tested: 26.11.2013
Report Date: 27.11.2013

Sample Date	Hydrogen ppm	Oxygen ppm	Nitrogen ppm	Methane ppm	Carbon Monoxide ppm	Carbon Dioxide ppm	Ethylene ppm	Ethane ppm	Acetylene ppm	Total Gas ppm	TCG ppm
22.05.1996	74	979	85500	20	494	2190	1	8	0	89300	597
Bottom sample.	Test results satisfactory.										
28.09.1999	69	2850	81600	28	519	2600	2	10	0	87700	628
Bottom sample.	Test results are assessed as acceptable.										
06.03.2013	58	2820	83900	47	449	3770	2	13	0	91100	568
Tank	DGA is assessed as acceptable. Oil quality is assessed as acceptable. Moisture is assessed as acceptable.										
20.11.2013	58	2720	89900	51	507	3810	3	12	0	97100	632
Bottom sample.	DGA is assessed as acceptable. Oil quality is assessed as acceptable. Moisture is assessed as acceptable.										

Sample Date	Lab ID	Oil Temp	Moisture * ppm (20C)	Breakdown KV	Resistivity G Ohms.m	DDF @90C	Acidity mg KOH/g	Furfural ppm	IFT Dynes/cm	Colour	DBPC %	Imet39 ppm
22.05.1996	119457		10.00	---	41	0.011	0.01	---	---	---	---	---
28.09.1999	129077		12	---	35	0.010	<0.01	---	---	---	---	---
06.03.2013	299003	26	20 (15)	---	51	0.009	<0.01	---	---	---	---	---
20.11.2013	307539		15	---	52	0.009	<0.01	---	---	---	---	---







* Note: where temperatures are supplied, the equivalent ppm at 20C is reported in brackets as per IEC 60599

Analysis results relate to the condition of the sample as received. Responsibility for sampling rests entirely with the customer. This report shall not be reproduced except in full.

Procedures: DGA OLP-11, Moisture OLP-006, Acidity OLP-037/067, Furfural OLP-042, Dielectric Breakdown OLP-012, DDF OLP-016, Resistivity OLP-016, Inhibitor OLP-044, IFT OLP-036, Colour OLP-051

Approved by:

Gavin Matthews
Science Technician

PDF: 000097357 GRN T124 - TRAVESTON VT 779 A 92430207 Satisfactory

Powerlink Queensland 33 Harold Street, PO Box 1193, Virginia Qld 4014 Tel: 617 3860 2260 Fax: 617 3860 2321

Next Test 20.11.2015

Insulating Oil Test Report

Our Ref 7VTE00226

Oil Testing Services

	DGA	Oil	Moist	Insul
Sample	Green	Green	Green	
Plant	Green	Green	Green	

Customer ENERGEX GPO BOX 1461 Brisbane 4001

Report No.: 000097360

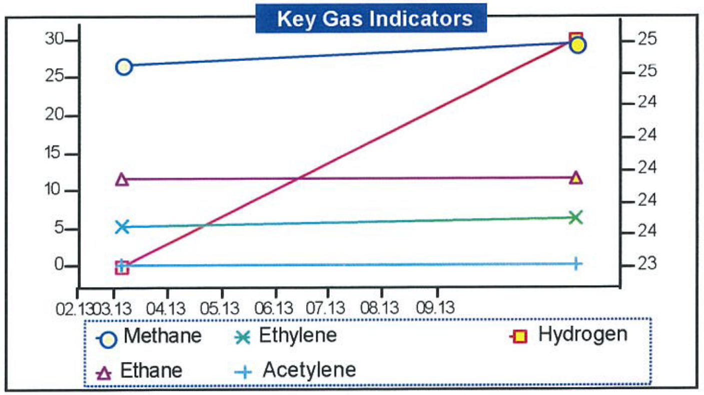
Plant ID SST124 VT2-7189/2B
Serial No 88640004
Manufacturer [redacted]

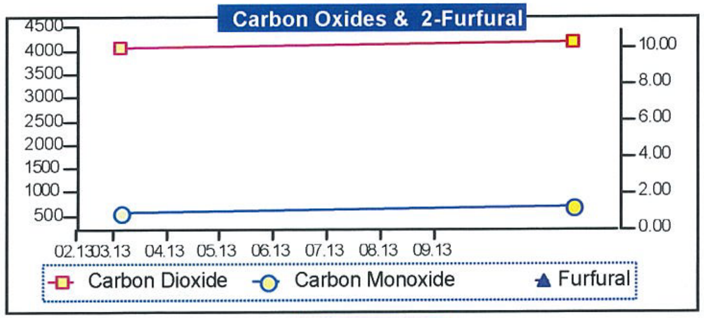
Location T124 - TRAVESTON
Feeder VT 778
Phase B

Rating (KVA) 100
Voltage 132000
YOM

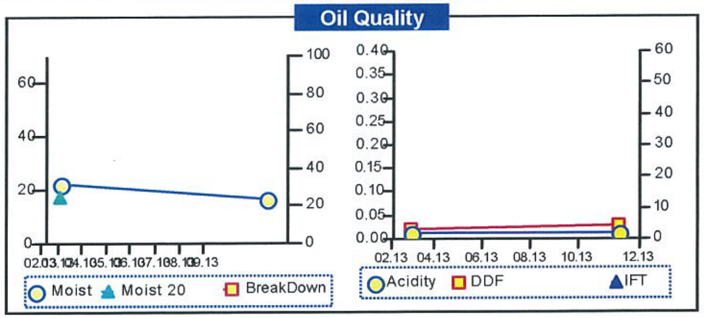
Date Received: 22.11.2013
Date Tested: 26.11.2013
Report Date: 27.11.2013

Sample Date	Hydrogen ppm	Oxygen ppm	Nitrogen ppm	Methane ppm	Carbon Monoxide ppm	Carbon Dioxide ppm	Ethylene ppm	Ethane ppm	Acetylene ppm	Total Gas ppm	TCG ppm
06.03.2013	23	6630	72500	26	566	4030	5	12	0	83800	633
Tank	DGA is assessed as acceptable. Oil quality is assessed as acceptable. Moisture is assessed as acceptable. RECOMMEND RESAMPLE IN 1 YEAR TO ESTABLISH TREND. Assessment based on single result, no trending data available.										
20.11.2013	25	4550	79000	29	670	4160	6	11	0	88500	742
Bottom sample.	DGA is assessed as acceptable. Oil quality is assessed as acceptable. Moisture is assessed as acceptable.										





Sample Date	Lab ID	Oil Temp	Moisture * ppm (20C)	Breakdown KV	Resistivity G Ohms.m	DDF @90C	Acidity mg KOH/g	Furfural ppm	IFT Dynes/cm	Colour	DBPC %	Imet39 ppm
06.03.2013	299004	26	22 (17)	---	28	0.019	<0.01	---	---	---	---	---
20.11.2013	307538		16	---	28	0.025	<0.01	---	---	---	---	---



* Note: where temperatures are supplied, the equivalent ppm at 20C is reported in brackets as per IEC 60599

Analysis results relate to the condition of the sample as received. Responsibility for sampling rests entirely with the customer. This report shall not be reproduced except in full.

Procedures: DGA OLP-11, Moisture OLP-006, Acidity OLP-037/067, Furfural OLP-042, Dielectric Breakdown OLP-012, DDF OLP-016, Resistivity OLP-016, Inhibitor OLP-044, IFT OLP-036, Colour OLP-051

Approved by:

Gavin Matthews
Science Technician

PDF: 000097360 GRN T124 - TRAVESTON VT 778 B 88640004 Satisfactory

Insulating Oil Test Report

Next Test 12.06.2015

Our Ref 7VTE00614

Customer ENERGEX GPO BOX 1461 Brisbane 4001

Report No.: 000110674

Oil Testing Services

	DGA	Oil	Moist	Insul
Sample	Red	Green	Green	
Plant	Red	Green	Green	

Plant ID

Serial No 821041B

Manufacturer [redacted]

Location T070 - COOROY

Feeder FDR 796 VT 221

Phase C

Rating (KVA)

Voltage 132000

YOM 1982

Date Received: 21.05.2015

Date Tested: 02.06.2015

Report Date: 02.06.2015

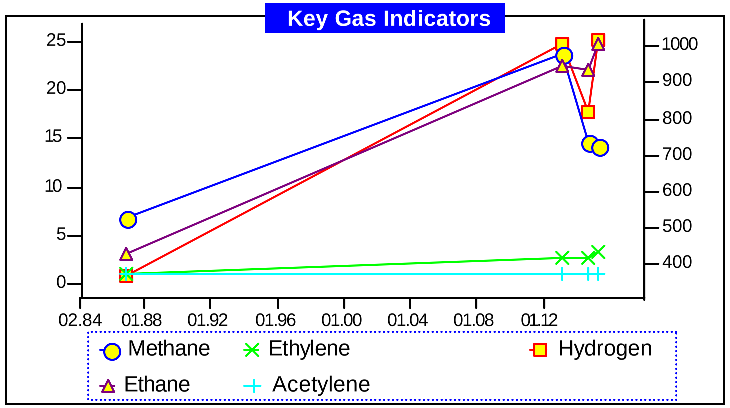
Sample Date	Hydrogen ppm	Oxygen ppm	Nitrogen ppm	Methane ppm	Carbon Monoxide ppm	Carbon Dioxide ppm	Ethylene ppm	Ethane ppm	Acetylene ppm	Total Gas ppm	TCG ppm
16.12.1986	367	8640	63900	7	272	2410	<1	3	<1	<75600	<651
26.03.2013	1000	2060	75200	24	184	7050	3	22	<1	<85500	<1240
22.10.2014	819	3910	71100	15	152	6360	3	22	<1	<82400	<1010
13.05.2015	1010	1970	67900	14	157	7040	3	25	<1	<78100	<1210

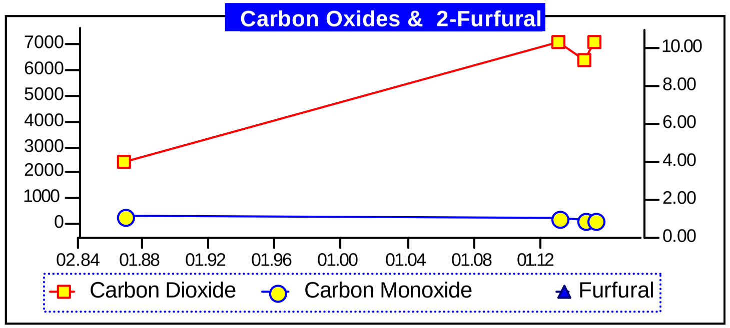
16.12.1986 — Bottom sample. HIGH H2 LEVEL PROBABLY DUE TO HYDROLYSIS CAUSED BY GALVANISED TANK.

26.03.2013 — Bottom sample. DGA suggests partial discharge has occurred. Oil quality is assessed as acceptable. Moisture is assessed as acceptable. RECOMMEND RESAMPLE IN 6 MONTHS TO MONITOR TREND.

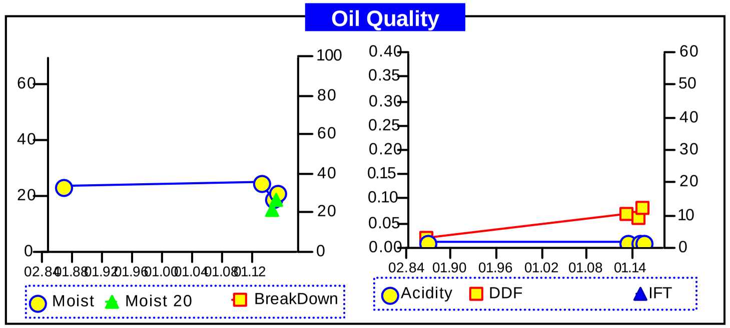
22.10.2014 — Bottom sample. Hydrogen level is high, otherwise DGA is assessed as acceptable. Oil quality is assessed as acceptable. Moisture is assessed as acceptable. RECOMMEND RESAMPLE IN 1 YEAR TO MONITOR HYDROGEN TREND.

13.05.2015 — Bottom sample. Acetylene detected (0.8ppm, repeat value 3ppm). DGA suggests arcing may have occured. Oil quality is assessed as acceptable. Moisture is assessed as acceptable. RECOMMEND INVESTIGATE. RECOMMEND RESAMPLE TO CONFIRM GAS LEVELS.





Sample Date	Lab ID	Oil Temp	Moisture * ppm (20C)	Breakdown KV	Resistivity G Ohms.m	DDF @90C	Acidity mg KOH/g	Furfural ppm	IFT Dynes/cm	Colour	DBPC %	Imet39 ppm
16.12.1986	116654		23.00	---	34	0.019	<0.01	---	---	---	---	---
26.03.2013	299886		25	---	31	0.069	<0.01	---	---	---	---	---
22.10.2014	317961	26	19 (15)	---	31	0.058	<0.01	---	---	---	---	---
13.05.2015	324584	24	21 (18)	---	23	0.079	<0.01	---	---	---	---	---



* Note: where temperatures are supplied, the equivalent ppm at 20C is reported in brackets as per IEC 60599

Analysis results relate to the condition of the sample as received. Responsibility for sampling rests entirely with the customer. This report shall not be reproduced except in full.

Approved by:

Gavin Matthews

Technical Services Officer

Laboratory Procedures: DGA OLP54/100/101, Moisture OLP006, Acidity OLP093, Furfural OLP042/091, Dielectric Breakdown OLP012/092, DDF/Resistivity Inhibitor OLP044, IFT OLP036, Colour OLP051, Irgamet OLP088, Corrosive Sulphur OLP021/098

PDF: 000110674 RED T070 - COOROY FDR 796 VT 221 C 821041B Arcing

Appendix 3 – VT Failure Investigation Report

Available on request

PUBLIC

Energex

Planned Battery Replacement Program

Asset Management Division

energex

positive energy

Energex

Planned Battery Replacement Program 2015/16 - 2019/20

Reviewed:

Tim Hart

Group Manager Asset Life Cycle Management

Endorsed:

Peter Price

Executive General Manager Asset Management

Version control

Version	Date	Description
1	1/07/2015	Submitted

Energex Limited (Energex) is a Queensland Government Owned Corporation that builds, owns, operates and maintains the electricity distribution network in the growing region of South East Queensland. Energex provides distribution services to almost 1.4 million domestic and business connections, delivering electricity to a population base of around 3.2 million people.

Energex's key focus is distributing safe, reliable and affordable electricity in a commercially balanced way that provides value for its customers, manages risk and builds a sustainable future.

Group Manager
Corporate Communications
Energex
GPO Box 1461
BRISBANE QLD 4001

Executive Summary

Energex seeks to continue to deliver sustainable outcomes for customers and business with no compromise to existing Safety and Legislative compliance.

The purpose of this document is to outline the required expenditure for the planned replacement of substation batteries over the 2015/16 – 2019/20 period. This allowance is not accounted for in the modelled REPEX budget and programs.

Energex currently has a historical spend of $2.3 million per annum on planned battery replacements. Replacement of these end-of-life battery banks is required in order to mitigate potential safety and legislative compliance risk and maintain adequate secondary systems security.

In their draft response, the Australian Energy Regulator (AER) made it clear they expected Energex to accept a higher level of risk than that which is outlined in Energex's original proposal. In response to this Energex has revised its original proposal and taken greater risk by extending the planned replacement interval of the lead acid battery banks from 5 to 6 years. Hence Energex has identified 461 substation battery banks which will be replaced within the 2015/16 – 2019/20 regulatory period.

With this approach, Energex has assessed the most economical battery types and replacement intervals for a required program expenditure of $1.7 million as outlined in the table below:

$m, 2014/15	2015/16	2016/17	2017/18	2018/19	2019/20	Total
Energex Proposal	0.5	0.5	0.4	0.5	0.5	2.4
Energex Revised Proposal	0.2	0.2	0.4	0.4	0.5	1.7

Contents

1 Introduction

The purpose of this document is to outline the required expenditure for the replacement of 461 substation battery banks which will reach the end of their serviceable life within the 2015/16 – 2019/20 regulatory period.

Changes from the original proposal

The original proposal to the AER works for the planned battery replacement program was for $2.4 million over the 2015/16 – 2019/20 regulatory period.

In their draft response the AER made it clear they expected Energex to tolerate a higher level of risk than that which is outlined in Energex's original proposal. Energex has chosen to take on a higher level of risk in the Planned Substation Battery Replacement program and revised the proposal to $1.7 million over the 2015/16 – 2019/20 regulatory period.

2 Drivers

Batteries are relied on in Energex substations for a combination of key purposes including substation control, substation and power line protection systems, communications equipment supply, and emergency lighting. The battery bank is critical to the operation of substations. During normal operation some electronic secondary systems cannot operate without batteries. Under fault conditions, no electronic systems will operate at all without batteries.

Batteries, by their construction, have an operating life span limited by chemical degradation of components during charging and discharging, necessitating periodic replacement. This lifespan is heavily affected by battery quality, mode of operation and the storage environment.

Energex mainly uses Valve Regulated Lead Acid (VRLA) type batteries within substations. The maximum expected life span of the specific VRLA batteries Energex uses is 6 years. There are small numbers of communications-equipment specific batteries that are smaller and last longer but are more expensive. These are Nickel Cadmium (VRNC) batteries, and have an expected lifespan of 20 years.

Table 1 and Table 2 provide a summary of the replacement requirements for battery banks which will exceed their expected life over the 2015/16 – 2019/20 regulatory period.

Type	2015/16	2016/17	2017/18	2018/19	2019/20	Unit Cost
110V, 160Ah, VRLA[1]	26	14	57	55	56	$5,533
48V, 110Ah, VRLA	12	11	9	18	33	$2,493
32V, 110Ah, VRLA	6	5	12	8	6	$2,191
24V, 110Ah, VRLA	23	28	21	15	32	$2,204
32V, 32Ah, VRNC	0	0	0	1	13	$4,584
Yearly Totals	67	58	99	97	140	
Period Total					461	

Table 1: Quantities of Replacement of Different Types of Battery Banks

Type	2015/16	2016/17	2017/18	2018/19	2019/20
110V, 160Ah, VRLA[1]	$143,854	$77,460	$315,371	$304,306	$309,839
48V, 110Ah, VRLA	$29,919	$27,426	$22,439	$44,879	$82,278
32V, 110Ah, VRLA	$13,148	$10,956	$26,295	$17,530	$13,148
24V, 110Ah, VRLA	$50,698	$61,720	$46,290	$33,064	$70,537
32V, 32Ah, VRNC	-	-	-	$4,584	$59,596
Yearly Totals	$237,619	$177,562	$410,396	$404,363	$535,396
				Period Total	$1.7 million

Table 2: Cost of Replacement of Different Types of Battery Banks

[1] *Thirty (30) 110V battery banks which require replacement over the period have been excluded from the figures shown as they are planned to be upgraded by the Matrix Telecoms Upgrade project for installation of 1GB nodes within substations. This represents a reduction of $165,985 of the planned battery replacement program that is accounted for under Project Matrix.*

Figure 1 and Figure 2 outline the numbers and cost of replacement of different types of battery banks which exist within Energex substations. These are based on the assets reaching end of life; the VRLA type battery banks reaching 6 years of age, and the VRNC type battery banks reaching 20 years of age in the financial years outlined.

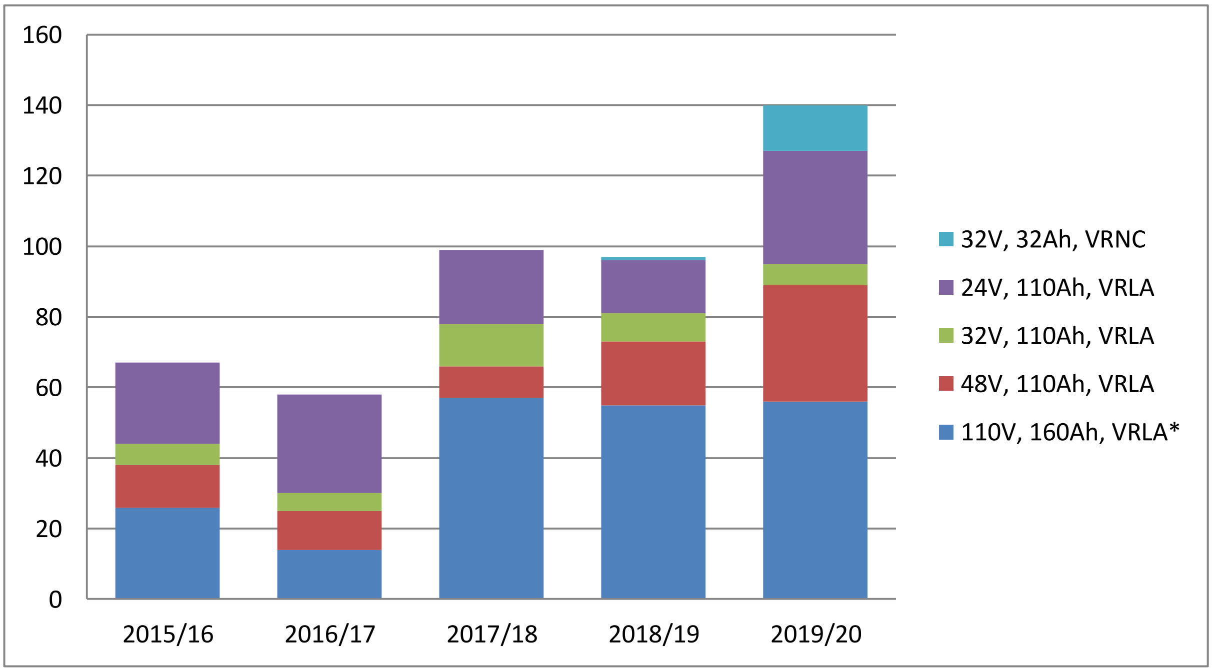


Figure 1: Number of Battery Banks Requiring Replacement Per Financial Year

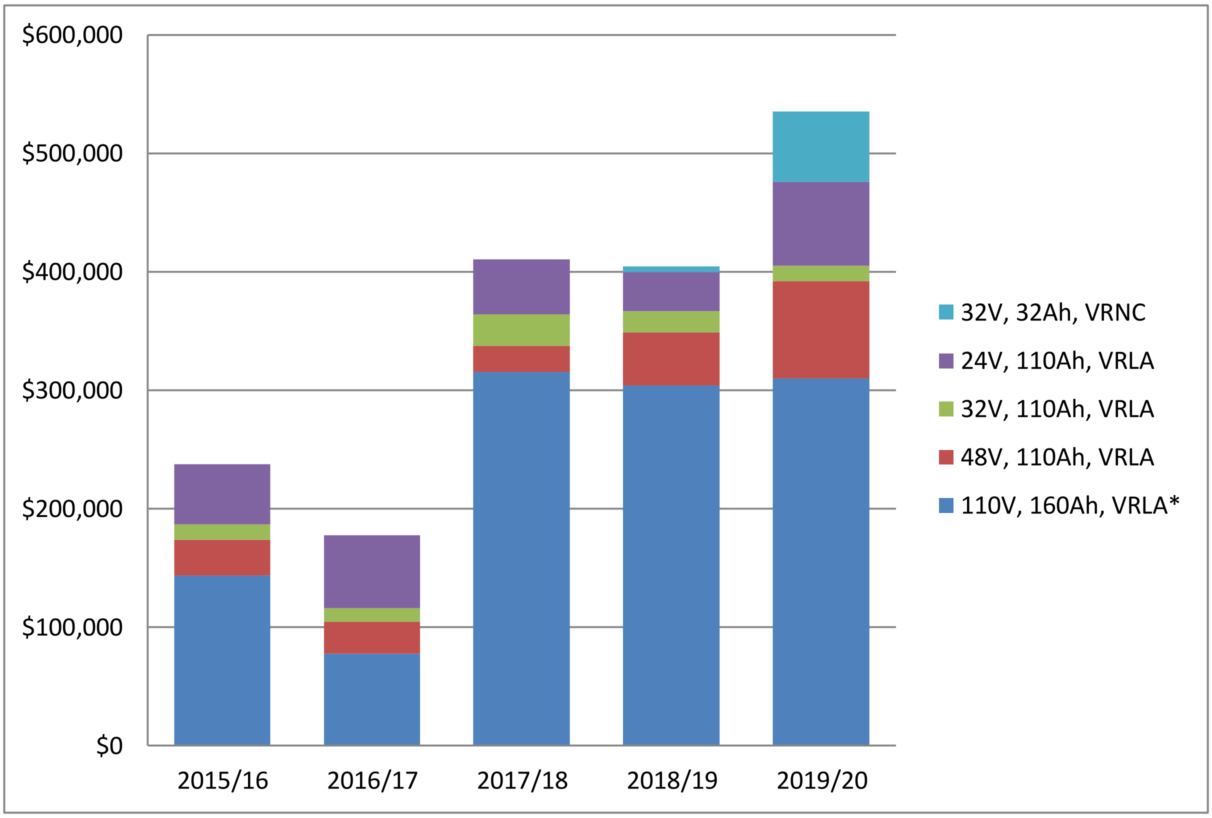


Figure 2: Required Expenditure for the Required Battery Bank Replacement

3 Supporting Analysis

Energex has assessed that it is most economical to use relatively inexpensive Current Supplier VRLA batteries for substation secondary system applications. More expensive, longer lasting units were considered; however, the increased service life of the more expensive units of around one year at twice the material cost means that this is not an economical option. In geographically disperse networks where the travel component of the labour cost for battery replacements accounts for a significant component of the overall cost a more expensive battery could be warranted. However, in the relatively contained geographic area of the Energex network where travel times to access substations are minimal, a shorter life battery can be justified.

Lead acid batteries have a shorter life when operated at higher temperatures. This is the case for all manufacturers and their type of lead acid batteries. This effect is described by the “Arrhenius Equation”. Figure 3 shows battery float life (operational life) versus operating temperature according to the Arrhenius equation. As can be seen in Figure 3, if lead acid batteries operate in an average ambient temperature environment range of up to 30°C (which are South East Queensland typical average summer temperatures[2]) the float life will reduce by 70 to 50 percent of nominal design life of the battery. The manufacturer of the Energex Current Supplier VRLA batteries indicates that the nominal 20°C design life is 12 years. The nominal design life of 12 years will then reduce to 6 years expected life when operating in temperatures such as those experienced on the Energex network.

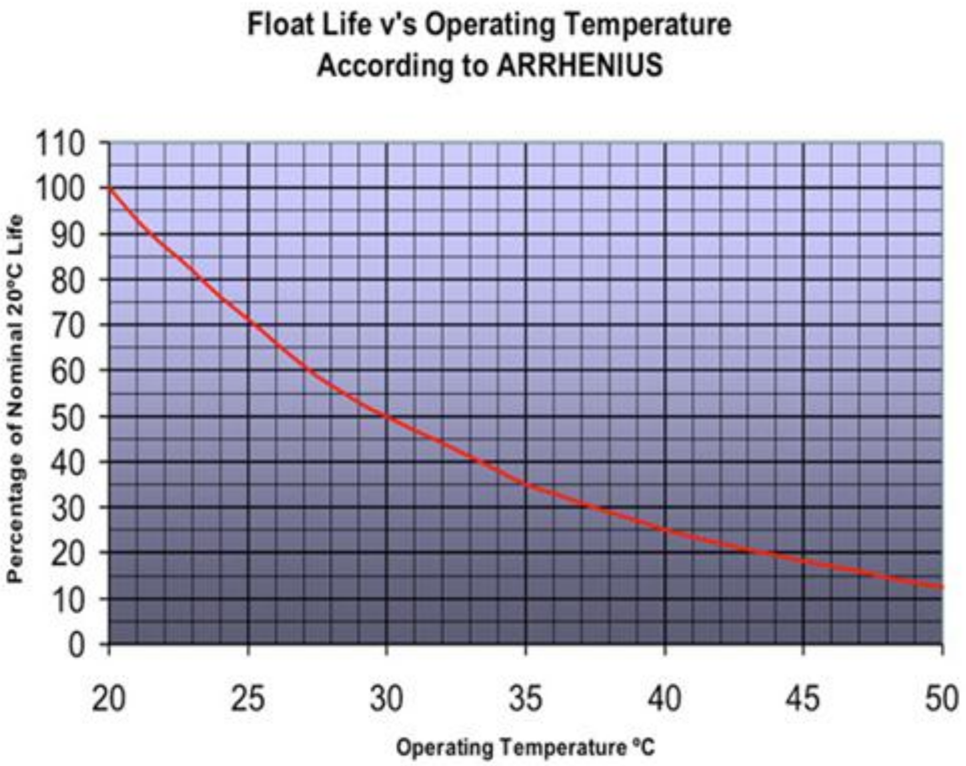


Figure 3: Arrhenius Equation - Float Life vs Operating Temperature

Ad-hoc, reactive (unplanned) battery bank replacements cost more than planned replacements. This is due to the overtime costs often associated with replacing the battery banks out of hours, or the inefficiency and overheads caused by having to reschedule normal planned works to complete reactive works. As the age of battery banks is known, the replacement of banks can be done in a more financially economical way if the replacements are planned.

In the previous regulatory period the replacement interval was set at 5 years for Current Supplier VRLA batteries and 20 years for VRNC batteries. Energex has reviewed the existing program and taken greater risk by extending the planned replacement interval for VRLA battery banks from 5 years to the maximum expected life of 6 years (for the Current Supplier type) . The VRNC type replacement at 20 years has been maintained. These combinations of battery types and replacement intervals has been chosen to minimise costs

[2] Referenced from www.bom.gov.au

and maximise the interval between replacements without incurring a high risk of failure and uneconomical ad-hoc replacements under the reactive work program.

4 Options

4.1 Impact of Doing Nothing

The “do nothing” option, or failure to proactively replace substation batteries, would result in an increasing likelihood of units failing leading to inadequate protection and control systems for Energex substations resulting in levels of safety, legislative and business risks which are not considered to be as low as reasonably practicable.

Failure of a battery bank leads to inadequate protection resulting in potential safety consequences, a breach of requirements under the National Electricity Rules (NER), as well as a reduction in secondary systems security.

Batteries are relied on in Energex substations for a combination of key purposes including substation control, substation and power line protection systems, communications equipment supply, and emergency lighting. The battery bank is critical to the operation of substations. During normal operation some electronic secondary systems cannot operate without batteries. Under fault conditions, no electronic systems will operate at all without batteries.

Risk of the do nothing approach is quantified in the untreated risk scenarios in Table 3.

Category	Risk Scenario	Consequence	Likelihood	Risk Score
Safety	Failure of a battery bank without a battery system monitor leading to inadequate protection which fails to clear a fault in the event of a wire down leading to a single fatality to an employed or a member of the public.	5	2	10 (Low)
Legislated Requirements	Failure of a battery bank leading to inadequate protection resulting in a breach of requirements under the National Electricity Rules (NER)	5	3	15 (Moderate)

Table 3: Untreated Risk Assessment Summary – Substation Batteries

4.2 Option 1 – Planned Substation Battery Replacement (Current Supplier)

This option proposes to undertake a planned program of substation battery replacement which replaces Current Supplier VRLA batteries like for like in their 6th year of operation, and Ni-Cad batteries in their 20th year of operation.

The extension of the replacement frequency from the 5 years used in the previous regulatory period demonstrates Energex's higher risk tolerance. Six years is the maximum expected life for the Current Supplier batteries operating in temperatures experienced on the Energex network. As some substation batteries will operate in average ambient temperatures above 30°C some premature failures can be expected.

4.3 Option 2 – Planned Substation Battery Replacement (Alternative Supplier)

This option proposes to undertake a planned program of substation battery replacement which replaces existing Current Supplier VRLA batteries in their 6th year of operation with an Alternative Supplier VRLA with a serviceable life of 7 years, and Ni-Cad batteries in their 20th year of operation.

Under this option, the same replacements are performed, but each replacement is initially more expensive to change to a battery bank with a serviceable life of 7 years.

4.4 Present Value Analysis

Table 4 provides a summary of the economic analysis performed. The analysis was performed for a single 110V, 160 Ah battery bank. Refer to Appendix A for further detail.

Scenario Name:		Medium Demand		
Option Number	**Option Name**	**Rank**	**Net Economic Benefit ($ real)**	**PV of CAPEX ($ real)**
1	Replace with Current Supplier VRLA 110V 160Ah battery bank	1	-$10,876	$10,876
2	Replace with Alternative Supplier VRLA 110V 160Ah battery bank	2	-$16,490	$16,490

Table 4: Net Present Value Analysis

The NPV analysis shows that the planned battery replacement with Current Supplier VRLA batteries is the lowest cost option.

5 Proposed Works

It is proposed to implement Option 1 to undertake a planned battery replacement program which replaces Current Supplier VRLA batteries like for like in their 6th year of operation, and Ni-Cad batteries in their 20th year of operation. This option was selected as it provides a sustainable approach for addressing the identified limitations and managing risks to tolerable levels.

The following table provides a summary of the treated risks. The replacement of substation batteries that have exceeded end of life will reduce the likelihood of failures.

Category	Risk Scenario	Consequence	Likelihood	Risk Score
Safety	Failure of a battery bank without a battery system monitor leading to inadequate protection which fails to clear a fault in the event of a wire down leading to a single fatality to an employed or a member of the public.	5	1	5 (Very Low)
Legislated Requirements	Failure of a battery bank leading to inadequate protection resulting in a breach of requirements under the National Electricity Rules (NER)	5	2	10 (Low)

Table 5: Treated Risk Assessment Summary – Substation Batteries

6 Required Expenditure

Table 6 below outlines the required expenditure for Option 1, which is the preferred planned battery replacement program in this business case.

Description	2015/16	2016/17	2017/18	2018/19	2019/20	Total
Expenditure $m, 2014/15	0.2	0.2	0.4	0.4	0.5	1.7
Quantity	67	58	99	97	140	461

Table 6: Proposed Program Expenditure

Table 7 below provides a summary of the various battery types and quantities which make up the proposed program.

Type	2015/16	2016/17	2017/18	2018/19	2019/20
110V, 160Ah, VRLA[3]	26	14	57	55	56
48V, 110Ah, VRLA	12	11	9	18	33
32V, 110Ah, VRLA	6	5	12	8	6
24V, 110Ah, VRLA	23	28	21	15	32
32V, 32Ah, VRNC	0	0	0	1	13
Yearly Total	67	58	99	97	140
Period Total					461

Table 7: Substation Battery Bank – Replacement Units Required per Financial Year

7 Recommendations

It is recommended that Option 1 be endorsed for inclusion in the programs of work and reflected in Energex’s revised regulatory proposal for the 2015/16 – 2019/20 regulatory period.

[3] *Thirty (30) 110V battery banks which require replacement over the period have been excluded from the figures shown as they are planned to be upgraded by the Matrix Telecoms Upgrade project for installation of 1GB nodes within substations. This represents a reduction of $165,985 of the planned battery replacement program that is accounted for under Project Matrix.*

Appendix A– Net Present Value Analysis

		NPV Ranking:	1	2
		Net NPV:	-$ 10,876	-$ 16,490
		Stage Count:	8	7
	Decommissioned Assets			
Stage Title	Recovery Date	Recovery Value	Stage Timing Option 1	Stage Timing Option 2
Current Supplier			Jun-2016	
Current Supplier			Jun-2022	
Current Supplier			Jun-2028	
Current Supplier			Jun-2034	
Current Supplier			Jun-2040	
Current Supplier			Jun-2046	
Current Supplier			Jun-2052	
Current Supplier			Jun-2058	
Alternative Supplier				Jun-2016
Alternative Supplier				Jun-2023
Alternative Supplier				Jun-2030
Alternative Supplier				Jun-2037
Alternative Supplier				Jun-2044
Alternative Supplier				Jun-2051
Alternative Supplier				Jun-2058

Type	Labour	Materials	Unit Cost
110V, 160Ah, Current VRLA	$1,653	$3,880	$5,533
110V, 160Ah, Alternative VRLA	$1,653	$7,760	$9,413

PUBLIC

Energex

Air Break Switch Replacement Program

Asset Management Division

energex

positive energy

Energex

Air Break Switch Replacement Program 2015/16 - 2019/20

Reviewed:

Tim Hart

Group Manager Asset Life Cycle Management

Endorsed:

Peter Price

Executive General Manager Asset Management

Version control

Version	Date	Description
1	1/07/2015	Submitted

Energex Limited (Energex) is a Queensland Government Owned Corporation that builds, owns, operates and maintains the electricity distribution network in the growing region of South East Queensland. Energex provides distribution services to almost 1.4 million domestic and business connections, delivering electricity to a population base of around 3.2 million people.

Energex's key focus is distributing safe, reliable and affordable electricity in a commercially balanced way that provides value for its customers, manages risk and builds a sustainable future.

Group Manager
Corporate Communications
Energex
GPO Box 1461
BRISBANE QLD 4001

Executive Summary

Energex has experienced a series of failures of [redacted] Air Break Switches in recent history. Failures of this type of Air Break Switches have resulted in localised outages, potential safety incidents and network operating restrictions and future failures may have an even greater impact. An Energex investigation carried out in December 2013 identified the root cause of failure to be a manufacturing defect. Energex conducted risk assessments and issued a Safety Alert to the business and industry at this time.

The proposed program to replace 33kV Air Break Switch-tops will allow mitigation of the identified risks by funding the replacement of end of life Air Break Switches. This is not accounted for in the modelled REPEX programs.

Energex has a population of 33kV [redacted] Air Break Switches in its network experiencing premature failure as a result of moisture ingress and pin corrosion. The development of replacement plans for the problematic population of air break switches was completed by Energex in the 2013/14 and 2014/15 financial years following the outcomes of the investigation into the failures. Implementation of this type of Air Break Switch-top replacements is programmed to commence in the 2015/16 financial year.

The original proposal to the AER for the Air Break Switch Replacement program was for $0.57 million over the 2015/16 – 2019/20 regulatory period. Energex is committed to the delivery of sustainable outcomes for customers and the business with no compromise to existing safety and legislative compliance. The intention of the revised program remains unchanged from the original proposal due to the safety risks associated with failure of this type of Air Break Switches.

A review of the costing associated with the original program has determined that there was an error in the original submission which resulted in an under estimation of $0.84m. The cost of the program has been reviewed and revised to $1.41 million over the 2015/16 – 2019/20 regulatory period.

The following table provides a summary of the required expenditure of $1.41 million ($2014/15 direct) over the 2015/16 – 2019/20 regulatory period.

$m, 2014/15	2015/16	2016/17	2017/18	2018/19	2019/20	Total
Energex Proposal	0.11	0.11	0.11	0.12	0.12	0.57
Energex Revised Proposal	0.23	0.42	0.20	0.23	0.33	1.41

Contents

1 Introduction

The purpose of this document is to outline the required expenditure for the replacement of 89 x 33kV Air Break Switches (ABS) used as isolators inside the bulk supply and zone substations. These switches are manually operated to isolate busbars, transformers and outgoing power lines on the high voltage network.

Energex has experienced a series of failures of [redacted] Air Break Switches in recent history which have resulted in localised outages, potential safety incidents and network operating restrictions. Investigations have identified the root cause of these failures to be a manufacturing defect in the switches.

<u>Changes from the original proposal</u>

The original proposal to the AER for this Air Break Switch program was for $0.57 million over the 2015/16 – 2019/20 regulatory period. Energex is committed to the delivery of sustainable outcomes for customers and the business with no compromise to existing safety and legislative compliance. The revised program remains unchanged in scope and intent from the original proposal due to the safety risks associated with catastrophic failure of this type of Air Break Switches. A review of the costing associated with the program however has determined that there was an error in the original submission which resulted in under estimation. The cost of the program has been reviewed and revised to $1.41 million over the 2015/16 – 2019/20 regulatory period.

2 Drivers

A total of 102 x 33kV Air Break Switches, manufactured between 1989 and 1996, are installed at various bulk supply and Zone substations on the Energex network. The service life of these switches varies from 18 and 25 years. Thirteen (13) of these switches are currently scheduled to be replaced in conjunction with projects in the Energex modelled REPEX submission which will leave 89 switches on the network.

Energex has experienced several in service failures of this type of Air Break Switches during operation. Investigations into the failure of the 33kV Air Break Switches have revealed that galvanised steel pins corrode due to moisture ingress via the porous cement that is used to grout the pin into the porcelain insulators. Hairline cracks develop on the porcelain due to internal expansion of the pins which results in a loss of mechanical strength and failure during operation.

The operating handle is directly beneath the switch which exposes the operator to falling shards of porcelain when a cracked insulator fails as well as sparks and arcs due to insulator failure and flashover. Either circumstance can lead to serious injury. Energex has implemented operating restrictions on these switches as a result of the failures experienced and the potential safety risks (Refer to Appendix 1). This is considered an interim risk mitigation as it is a procedural intervention only.

The Air Break Switches in service are used to isolate sections of bus, feeders or power transformers. Failure of these switches during operation can result in substantial loss of supply as large portions of a substation or subtransmission network are isolated by the upstream protection. Similarly, if cracks are identified in the insulators of a switch prior to operation, the switching must be modified. This results in delays to programmed works, additional switching costs, and isolation of larger sections of network which reduces network security.

3 Supporting Analysis

Typical 33kV Air Break Switches within the Energex network have an economic mean life of 40 years. The mean life of this type of Air Break Switch in the Energex network is 22 years based on the historical replacement rate. This significant gap is attributed to the premature failure of the switches as a result of moisture ingress and pin corrosion as outlined in Section 2 above.

It is approximated that greater than 1000 switching operations are performed on these Air Break Switches remaining in the Energex network per year. As these switches are used to isolate buses, feeders and power transformers during planned maintenance or to undertake corrective works, the requirement to operate them will continue into the future.

Of the 102 x 33kV Air Break Switches remaining in the network, 13 are currently scheduled to be replaced in conjunction with projects in the Energex modelled REPEX submission which will leave 89 switches remaining. A capital replacement program is required to mitigate the safety, legislative compliance and business risks as failures of these Air Break Switches continue to occur in spite of prudent application of inspection and maintenance programs.

Figure 1: Typical 33kV ABS Isolator in the Switchyard

Figure 2: Large Crack on the Underside of an ABS Insulator from SST16

Figure 3: Hairline Crack and the Sealant on the Insulator ABS Insulator from SST16 (Nambour Substation)

Figure 4: Signs of Pin Corrosion on the Bottom Side of the Isolator Insulator – T136 (Abermain Substation)

The location of all [redacted] Air Break Switches in the Energex network is outlined Table 1 below.

Substation	Year of Manufacture	Total ABSs on site
ABM (T136)	1989-1994	30
NBR (T16)	1989-1993	16
CLM	1995	1
CBW	1995	2
LDR	1994	1
GIS	1990	5
LYT	1989-1990	10
CMY	1994	1
LRE (T78)	1994	1
THL	1989, 1996	2
SRD	1990	3
CPK	1996	3
DRA	1996	1
HLG	1989	2
IBS	1990	6
SPE	1995-1996	12
KSN	1996	3
CVL	1995	1
NGE	1994	1
RBS (T24)	1994	1

Table 1: Population of [redacted] Switches

Figure 5 show the population of this type of Air Break Switch in the Energex network.

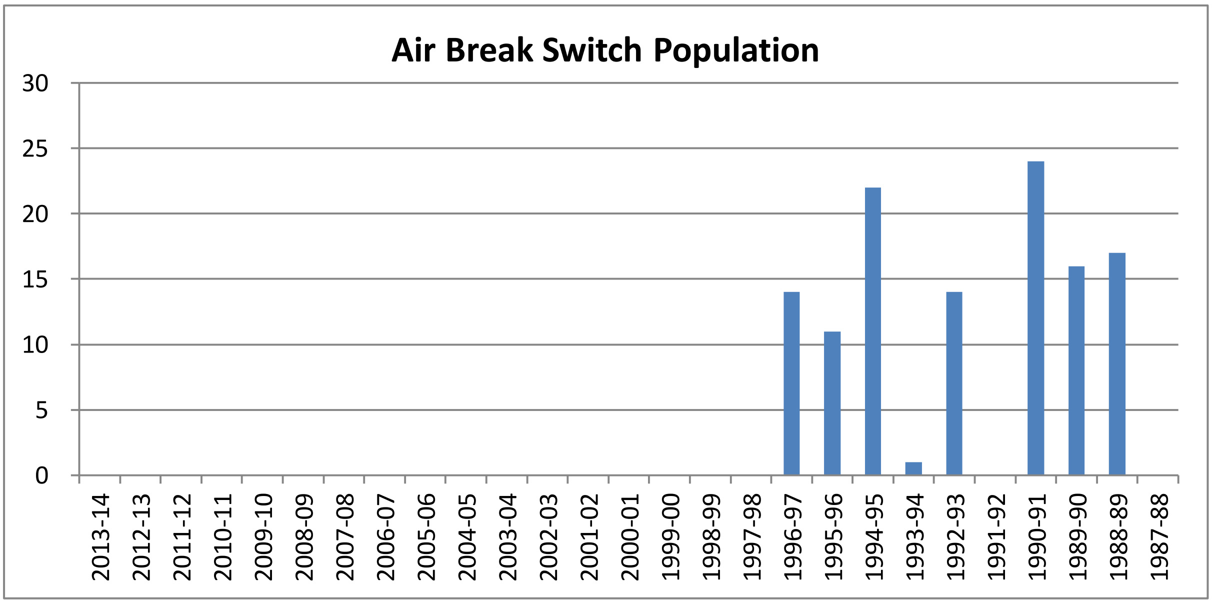


Figure 5: 33kV ABS – Population Information

4 Comparison of Rectification Alternatives

The following sections provide a summary of the technically feasible rectification alternatives available to remove the this type of ABS risk from the network.

4.1 Switch-top Assembly Replacement (Original Proposal)

Switch-top assembly replacement was the scope of works recommended in the initial Energex AER submission. This alternative involves the replacement of the complete contact assemblies of each phase of the ABS and the addition of adaptor plates. The existing operating handle and support structure can be reused. This option also replaces current carrying components of the switch, effectively giving the switch a 40 year economic mean life from the date of replacement.

4.2 Complete Switch Replacement

This alternative involves the replacement of the entire switch and support structure to allow installation of the current standard AEM air break switch. This would require modification of the bus bars due to the different mechanical dimensions of the AEM ABS as compared to the existing ABS.

4.3 Financial Comparison of Replacement Alternatives

The respective per unit costs of the above replacement alternatives are detailed in Table 2 below. This shows that the replacement of the switch-top assembly as per the scope of the original submission is the lowest cost rectification alternative. Switch-top assembly replacement has therefore been chosen as the preferred alternative and forms the basis of scope for the replacement program options discussed Section 6.

Rectification Alternatives Costs (Construction Only)	Materials Cost ($,000 / switch)	Labour Cost ($,000 / switch)	Total Cost ($,000 / switch)
Switch-top Assembly Replacement	6.00	14.55	20.55
Complete Switch Replacement	18.49	17.69	36.18

Table 2: Comparison of Rectification Alternatives ($ 2014/15 direct)

5 Options

5.1 Impact of Doing Nothing

The “do nothing” option, or failure to proactively replace this type of Air Break Switches, would result in an increasing likelihood of switches failing resulting in levels of safety, legislative, business and network risks which are not considered to be as low as reasonably practicable.

Risk of the do nothing approach is quantified in the untreated risk scenarios in Table 3.

Category	Risk Scenario	Consequence	Likelihood	Risk Score
Safety	Air Break Switch fails during switching operation resulting in porcelain shards falling from height causing serious injury to the operator.	3	4	12 (Moderate Risk)
Customer Impact	Air Break Switch fails during switching operation resulting in loss of the 33kV bus and subsequent loss of supply to >5000 customers.	3	3	9 (Low Risk)
Legislated Requirements	Air Break Switch fails during switching operation resulting in porcelain shards falling from height causing an injury or near miss which must be reported to the Electrical Safety Office resulting in a breach of legislated requirements (ESA, WHS).	5	4	20 (High Risk)
Business Impact	Air Break Switch fails during switching operation resulting in porcelain shards falling from height causing an injury or near miss resulting in banning operation of this type of ABS and inability to effectively switch multiple bulk supply substations.	4	4	16 (Moderate Risk)

Table 3: Untreated Risk Assessment Summary – Air Break Switches

Energex is committed to the delivery of sustainable outcomes for customers and the business with no compromise to existing safety and legislative compliance. The untreated risks associated with the Air Break Switch program is not considered to be as low as reasonably practicable.

5.2 Option 1 – Switch-top Assembly Replacement over 5 years

5.2.1 Summary

This option proposes to replace 89 [redacted] ABSs over 5 years during the 2015/16 – 2019/20 period and is the option recommended in the original Energex Submission.

5.2.2 Impact analysis

The sustainability chart shows the proposed program against the program requirement. Energex engineers have conducted investigations into the failed ABSs as detailed above. The investigations and associated risk assessments concluded that the untreated risk of failure during operation was not as low as reasonably practicable. Energex has implemented interim procedural controls to mitigate this risk in the short term until a replacement program is undertaken. As a consequence, all of this type of Air Break Switch are categorised as requiring replacement at the beginning of the forthcoming regulatory period.

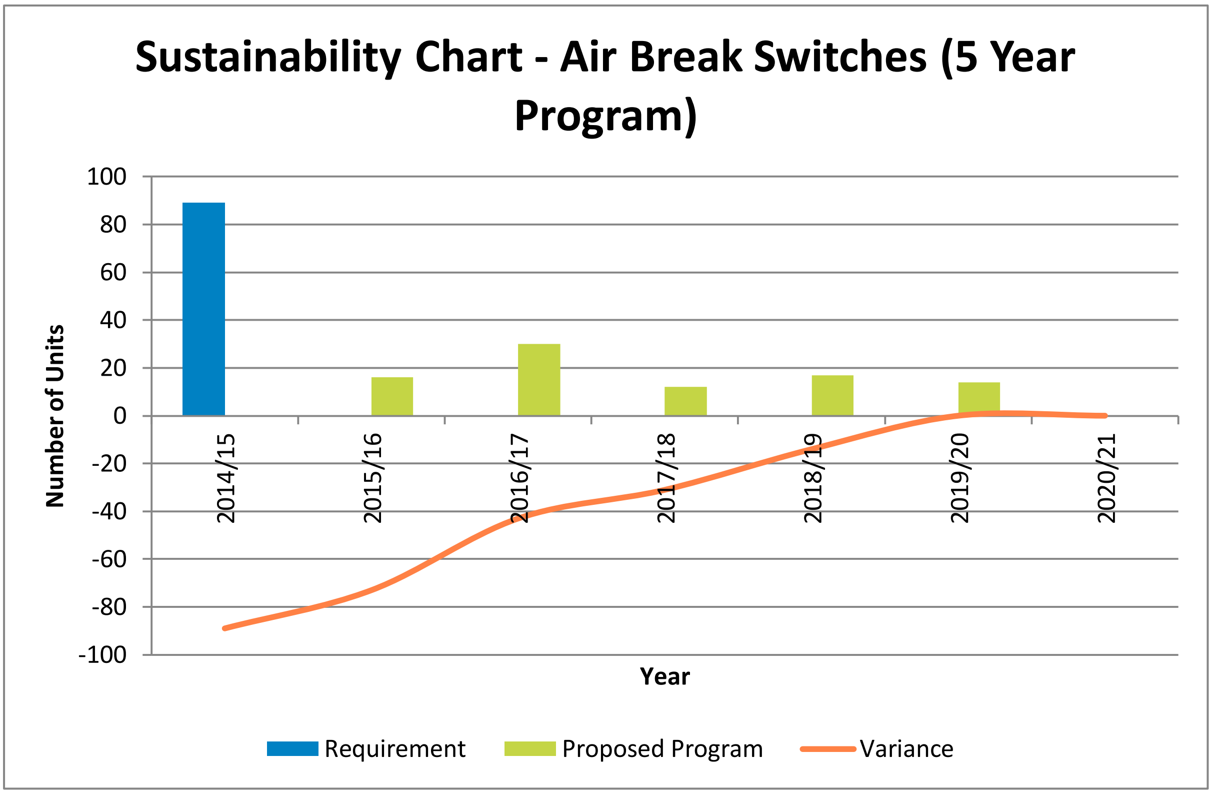


Figure 6: Sustainability Graph for ABS – Option 1 (5 Year Program)

The replacement of switches over the 5 year period will eliminate the risk from the network by 2019/20.

Table 4 below outlines the required expenditure for the Air Break Switch replacement program under Option 1.

Description	2015/16	2016/17	2017/18	2018/19	2019/20
Expenditure $m, 2014/15	0.23	0.42	0.20	0.23	0.33
Quantity	16	30	12	13	14

Table 4: Expenditure – Option 1

5.3 Option 2 – Switch-top Assembly Replacement over 3 years

5.3.1 Summary

This option proposes an accelerated program to replace 89 Air Break Switches over 3 years during the 2015/16 – 2019/20 period.

5.3.2 Impact analysis

The sustainability chart shows the proposed program against the program requirement. As per Option 1 all of this type of Air Break Switches are categorised as requiring replacement at the beginning of the forthcoming regulatory period.

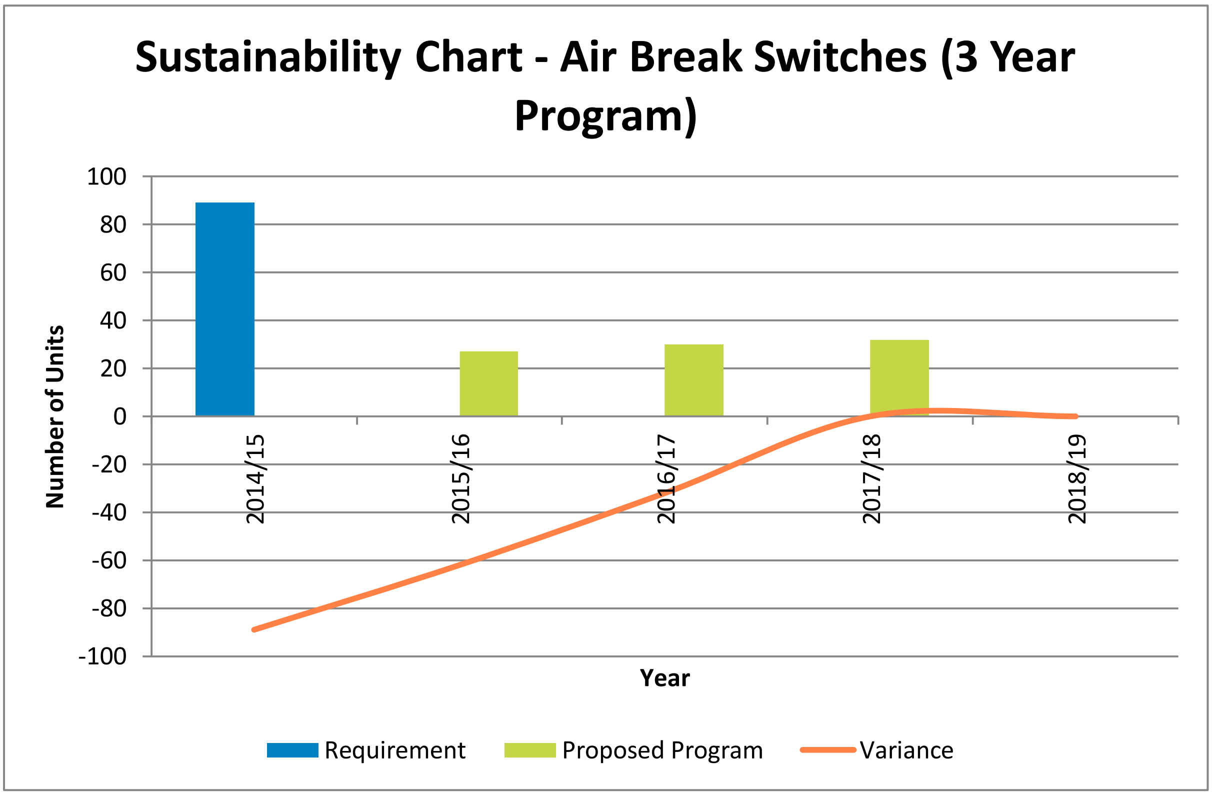


Figure 7: Sustainability Graph for ABS – Option 2 (3 Year Program)

The replacement of switches over a 3 year period will eliminate the risk from the network by 2017/18. Whilst, in the absence of funding restraints, this would be Energex's preferred option because it addresses the sustainability issue by 2017/18, Energex's proposal in this business case is to adopt a slightly higher risk profile embodied in Option 1.

Table 5 below outlines the required expenditure for this Air Break Switch replacement program under Option 2.

Description	2015/16	2016/17	2017/18	2018/19	2019/20
Expenditure $m, 2014/15	0.45	0.42	0.54	0	0
Quantity	27	30	32	0	0

Table 5: Expenditure – Option 2

5.4 Option 3 – Switch-top Assembly Replacement over 10 years

5.4.1 Summary

This option proposes to replace 46 Air Break Switches during the 2015/16 – 2019/20 period and a further 43 switches in the 2020/21 – 2024/25 period.

5.4.2 Impact analysis

The sustainability chart shows the proposed program against the program requirement. As per Option 1 all of this type of Air Break Switch are categorised as requiring replacement at the beginning of the forthcoming regulatory period.

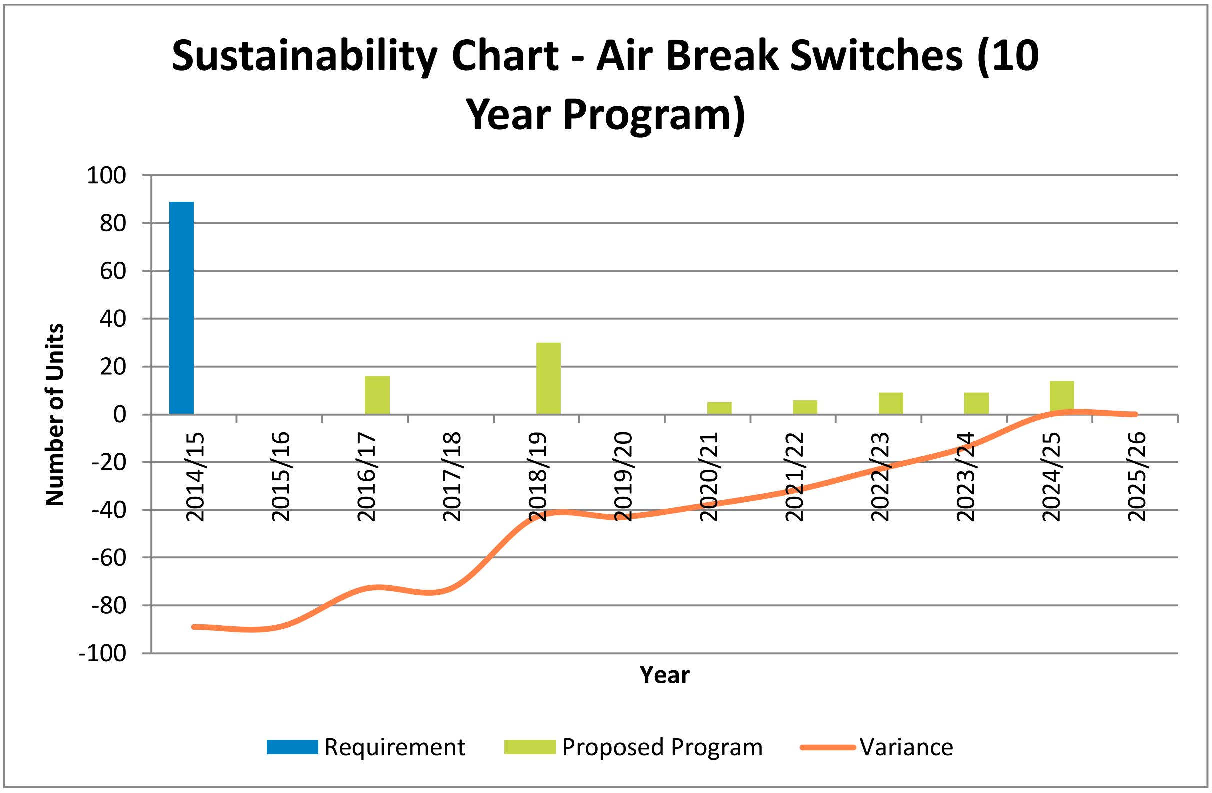


Figure 8: Sustainability Graph for ABS – Option 3 (10 Year Program)

The replacement of switches over a 10 year period will result in a prolonged exposure to the risks outlined above as they will not be eliminated from the network until 2024/25. The following table provides a summary of the risk at the end of the 2015/16 – 2019/20 regulatory period under this scenario. As shown in the table, the risk has not reduced from the untreated scenario.

Category	Risk Scenario	Consequence	Likelihood	Risk Score
Safety	Air Break Switch fails during switching operation resulting in porcelain shards falling from height causing serious injury to the operator.	3	4	12 (Moderate Risk)
Customer Impact	Air Break Switch fails during switching operation resulting in loss of the 33kV bus and subsequent loss of supply to >5000 customers.	3	3	9 (Low Risk)
Legislated Requirements	Air Break Switch fails during switching operation resulting in porcelain shards falling from height causing an injury or near miss which must be reported to the Electrical Safety Office resulting in a breach of legislated requirements (ESA, WHS).	5	4	20 (High Risk)
Business Impact	Air Break Switch fails during switching operation resulting in porcelain shards falling from height causing an injury or near miss resulting in banning operation of ABS and inability to effectively switch multiple bulk supply substations.	4	4	16 (Moderate Risk)

Table 6: Option 3 Treated Risk Assessment Summary at End of 2019/2020 –Air Break Switches

Table 7 below outlines the required expenditure for the Air Break Switch replacement program under Option 3.

Description	2015/16	2016/17	2017/18	2018/19	2019/20
Expenditure $m, 2014/15	0	0.23	0	0.42	0
Quantity	0	16	0	30	0

Table 7: Expenditure – Option 3

6 Proposed Works

It is proposed to implement Option 1 to replace 89 Air Break Switches over a 5 year program in the 2015/16 – 2019/20 period. This option was selected as it provides a sustainable approach for addressing the identified limitations and managing risks to tolerable levels. Protraction of delivery beyond 2019/20 was not considered prudent. The following projects have been identified and prioritised for delivery.

Substations Requiring Replacement of Air Break Switch-top Assemblies	No. of ABS	Total cost ($)	5 year schedule
NBR (T16) Nambour Substation	16	230,945	Y1
ABM (T136) Abermain Substation	30	417,962	Y2
IBS Ibis Substation	6	73,715	Y3
GIS Gibson Island Substation	5	92,874	Y3
CVL Cleveland Substation	1	30,845	Y3
SRD Scrub Rd Substation	3	60,889	Y4
LYT Lytton Substation	10	167,746	Y4
KSN Kingston Substation	3	57,007	Y5
THL Tent Hill Substation	2	45,867	Y5
DRA Darra Substation	1	32,786	Y5
NGE Nudgee Substation	1	32,786	Y5
CLM Coolum Substation	1	30,845	Y5
CPK Carole Park Substation	3	57,007	Y5
CBW Caboolture West Substation	2	43,926	Y5
LRE (T78) Lockrose Substation	1	30,845	Y5

Table 8: Proposed Projects for 2015/16 – 2019/20

Projects have been prioritised on the basis of prior failure and identification of defects, exposure to polluted and salt air and age. As SST16 Nambour Substation and SST136 Abermain Substation have already experienced failures and defects identified, they are scheduled for switch-top assembly replacement in the first two years of this proposal.

7 Required Expenditure

Table 9 below outlines the required expenditure for Option 1, which is the preferred Air Break Switch replacement program in this business case.

Description	2015/16	2016/17	2017/18	2018/19	2019/20
Expenditure $m, 2014/15	0.23	0.41	0.23	0.25	0.43
Quantity	16	30	12	13	14

Table 9: Proposed Program Expenditure

8 Recommendations

It is recommended that Option 1 be endorsed for inclusion in the programs of work and reflected in Energex's revised regulatory proposal for the 2015/16 – 2019/20 regulatory period.

Appendix 1 –Air Break Switch Safety Alert

SAFETY ALERT

Alert Number: HS-17-13
Issue Date: 12-12-2013

Operation of 33 kV [redacted] Air Break Isolators

Background

Energex installed the 33 kV [redacted] Air Break isolators supplied by [redacted] in some zone and bulk supply substations in the late 1980s and early 1990s. These isolators are generally used to isolate bus sections, transformers or feeder circuits inside the switch yard. It has been observed recently that these 33 kV [redacted] isolators are demonstrating the same failure mode experienced with the [redacted] ABS in the Distribution Network. Hair line cracks are developing on the isolator support insulators due to pin corrosion and when operated, these insulators may crack further resulting in porcelain shards falling posing a hazard to the operator.

Fig 1- A typical 33 kV [redacted] isolator in switchyard

Figure 2- Hairline crack on the support insulator.

The [redacted] isolators can be easily identified by the manufacturer's identification tag located on the operating handle. Energex is currently working to establish how many of these are in the network. Additionally, investigation is underway on an improvement strategy in consultation with the supplier so that all [redacted] units are programmed for replacement/rectification to eliminate the risks associated with its operation.

Action Required

1. a) The Switching Operator must inspect the manufacturer's identification tag located on the operating handle to identify the switch as [redacted] isolators.
   b) Before each operation, conduct a 360 degree visual inspection of isolator insulators **from the ground, strictly maintaining the exclusion zone from Exposed Live Parts** to identify any signs of insulator cracking (hair- line fracture) on all insulators.
   c) If insulator cracking is identified, the isolator shall not be operated and the Switching Operator must
      i) Notify the Switching Coordinator.
      ii) Place a "Hazardous Condition Warning Tag" as directed by the Switching Coordinator.
      iii) Switching Coordinator shall tag an Equipment Operating Restriction (EOR) against the faulty device in PowerOn.
      iv)The Switching Operator shall notify their Supervisor for appropriate rectification actions.
2. All Process Owners to review relevant work practices and associated risk assessments with regard to the information contained in this Alert.
3. Managers and Coordinators must ensure that:
   a) This Alert is brought to the notice of all workers and records kept of discussions with workers;
   b) A copy of this Alert is placed on all Safety Noticeboards.

Appendix 2 –Air Break Switch Investigation Report

Available on request

PUBLIC

Energex

Commercial SCADA RTU Program

Asset Management Division

energex

positive energy

Energex

Commercial SCADA RTU Program 2015/16 - 2019/20

Reviewed:

Tim Hart

Group Manager Asset Life Cycle Management

Endorsed:

Peter Price

Executive General Manager Asset Management

Version control

Version	Date	Description
1	1/07/2015	Submitted

Energex Limited (Energex) is a Queensland Government Owned Corporation that builds, owns, operates and maintains the electricity distribution network in the growing region of South East Queensland. Energex provides distribution services to almost 1.4 million domestic and business connections, delivering electricity to a population base of around 3.2 million people.

Energex's key focus is distributing safe, reliable and affordable electricity in a commercially balanced way that provides value for its customers, manages risk and builds a sustainable future.

Group Manager
Corporate Communications
Energex
GPO Box 1461
BRISBANE QLD 4001

Executive Summary

Remote Terminal Units (RTUs) are electronic devices used to interface between physical elements of the power network and the SCADA system. Energex and its predecessors have used in-house developed products for substation Supervisory Control And Data Acquisition (SCADA) and automation requirements since SCADA was introduced in the late 1970s. Some other Distribution Network Service Providers (DNSPs) initially followed a similar approach, but most have now transitioned to commercial off-the-shelf (COTS) products. The requirements of DNSPs around SCADA and automation systems are only increasing in functional complexity, availability, and security when transitioning to “Smart Grids”.

Commercial vendors have risen to the challenge with products of increasing power and sophistication by leveraging the rapid advance of components and technologies for “main stream” and consumer electronic equipment. As such, Energex can no longer cost effectively develop and support an in-house RTU product for its own use. In addition, there are increasing risks around continuing with a home grown product, which is unlikely to have the future capability of similar commercial products. Energex has therefore embarked on a program to transition from an in-house product to a COTS RTU which will enable continued deployment of smart network technologies. Due to the complexities involved with transition, this is a significant strategic technological undertaking which also requires changes to related systems.

This program would progress from initiation to completion over a period of five years. Transitioning of the asset base will proceed via growth and natural attrition until the remnants of the existing RTU fleet reach the point where they are no longer supportable. Once the selection of the COTS RTU and associated development work is complete Energex will commence the transition process.

The scope of the works has not changed compared to the original submission, however the timing of the expenditure can be deferred for one year to align the completion of the program with the latest timing considered prudent to manage the risk. Further deferral is considered unacceptable as the current fleet will have aged to the point where further costly redesign will be unavoidable to ensure reliability and maintainability.

This document outlines the required expenditure for a project to specify, select and integrate COTS products into Energex’s substation SCADA systems, at a total cost of $9.4 million over the 2015/16 – 2019/20 regulatory period. This expenditure is not accounted for in the modelled REPEX programs.

$m, 2014/15	2015/16	2016/17	2017/18	2018/19	2019/20	Total
Energex Revised Proposal	-	0.8	2.5	3.6	2.5	9.4

Contents

1 Introduction

The purpose of this document is to outline the required expenditure for a program to specify, select and integrate COTS RTUs into Energex's substation SCADA systems.

This program is important because Energex can no longer afford the research and development (R&D) necessary to sustain and develop its in-house RTUs. COTS RTU products have the potential to provide better long term value with potentially enhanced functionality.

The proposed transition involves a process of specifying, selecting and integrating new COTS RTU products to form the basis of a new generation of standard building blocks. In this context, "integration" means the work necessary to determine global configuration settings that enable efficient and trouble-free interoperation with the rest of the SCADA / automation systems and ensure that new products are correctly and efficiently modelled in engineering design and asset management toolsets.

The scope of this proposal **excludes** Energex's Distribution Management System (DMS) and all other control-room-based systems.

2 Drivers

The drivers for this program are:

- Obsolescence – The rate of turnover of key off-the-shelf electronic components and subassemblies is increasing, with a consequent increase in overheads to keep in-house products manufacturable and maintainable;
- Cost – It is no longer efficient for Energex to carry out the R&D necessary to develop its in-house RTUs, given that the marketplace now contains a wide range of products and services suiting the substation SCADA and automation needs of DNSPs; and
- Appropriate use of internal resources – Energex's internal resources should be focused at the level of processes and systems, rather than product R&D.

3 Supporting Analysis

3.1 Background

Energex and its predecessors have used in-house products for SCADA and automation since SCADA was introduced in the late 1970s.Over time, these products have evolved to incorporate higher levels of standards-based subsystems and components, but the innovation and integration work has remained primarily in house. Some other DNSPs followed a similar path initially, but most have now transitioned to COTS products. Energex is arguably unique in Australia in still having a predominance of in-house products in its substation SCADA and automation systems. This has provided some significant advantages (in particular the ability to prioritise remedial and development work in accordance with the requirements and risks particular to Energex), but the benefits are insufficient to outweigh the underlying conflict between this level of specialisation and the strategic direction of Energex.

The penetration of SCADA and automation into substations has reached nearly 100%, and the marketplace now contains a wide range of COTS products and services suiting the substation SCADA and automation needs of DNSPs. This has driven costs down over time and it is now timely to consider a move to COTS products.

In addition, the requirements of DNSPs are expected to increase dramatically in terms of functional complexity, availability and security as we evolve toward the “Smart Grid”. For example:

- SCADA and automation functions will most likely have to extend to customer and/or retailer integration in support of embedded generation, demand management, virtual power plants and the like;
- The criticality of such functions will dictate a need for redundancy in various forms; and
- Systems will have to remain robust in the face of increasing cyber security threats.

While unlikely to be significantly more expensive in the short term, Energex does not believe it would be efficient in the longer term to continue to develop an RTU product capable of meeting these requirements. Vendors of COTS products can spread the costs of maintaining existing products and developing innovative new products across many customers in a global marketplace.

Through reducing the burden of RTU product design maintenance, Energex seeks to re-focus its SCADA & automation resources on the larger scale technical challenges that Energex (like most DNSPs) faces with the rapidly evolving energy distribution industry.

3.2 Existing Fleet and Support Regimes

3.2.1 Hardware

Energex’s substation RTU fleet comprises of several general generations of in-house technology. In recent years, cost reduction efforts have been focussed on fleet rationalisation – upgrading old sites to the current standard in order to reduce spares inventory and simplify servicing.

Table 1 shows the equipment currently in service within the Energex network.

<table>
<tr><th>Function</th><th>Equipment</th><th>Number in Service</th></tr>
<tr><td>IED (alarm concentrator in small zone substations)</td><td>SICM2 [Serial Interface control module] (obsolete) [1]</td><td>9</td></tr>
<tr><td>Cable marshalling (zone and bulk supply substations)</td><td>Passive marshalling boards – numerous types (obsolete) [1]</td><td>Approx. 500</td></tr>
<tr><td>Statistical metering (zone and bulk supply substations)</td><td>Statistical metering board - two types (obsolete) [1]</td><td>Approx. 100</td></tr>
<tr><td rowspan="2">IED (distributed interface to substation equipment in zone and bulk supply substations)</td><td>SICM1 (obsolete) [1]</td><td>Approx. 500</td></tr>
<tr><td>SICM2B (current, but has component obsolescence issues) [1]</td><td>6500+</td></tr>
<tr><td rowspan="4">RTU (SCADA and automation host in zone and bulk supply substations)</td><td>PC-MiniSACS (obsolete) [2]</td><td>24</td></tr>
<tr><td>PC-SACS V2.x (variants - obsolete) [2]</td><td>27</td></tr>
<tr><td>PC-SACS P5.0 (variants – current, but has component obsolescence problems) [2]</td><td>92</td></tr>
<tr><td rowspan="2">PC-SACS S1.x (variants – current, but has component obsolescence problems) [2]</td><td rowspan="2">158</td></tr>
<tr><td>Master Data Concentrator (MDC) / Remote Data Concentrator (RDC) / DSS Gateway / C&I Concentrator</td></tr>
</table>

[1] These products are of in-house discrete component board level design

[2] These products are in-house design using industrial-grade commercial off the shelf components

Table 1: Energex's substation RTU fleet detail

Support for substation SCADA and automation hardware is carried out by Energex employees. Energex currently expends approximately two full time employees of effort on hardware design maintenance support.

3.2.2 Hardware Support Activity

Support activity for hardware is generally triggered by an announcement from a component vendor that a component used by Energex will no longer be manufactured. Depending on the number in service and the age, Energex's response may be to:

- Do nothing, because the product will soon no longer be used;
- Buy or recover spare parts sufficient to last for the life of the product. Recovery may involve upgrading some of the impacted sites and salvaging the recovered equipment for spares;
- Find alternative components that are compatible with the product; or
- Redesign the product using components that are still being manufactured.

All of these options require evaluation, but the latter ones can be expensive and time consuming. Examples from recent years include:

- End-of-life of the ID “tag” used on SICM2B IEDs. Energex designed and manufactured a replacement component (preventing the need for far more expensive software & firmware deployments);
- End-of-life of the PC-SACS P5/S1 CPU card. Energex found a compatible replacement;
- End-of-life of IDE hard-drive technology. Energex bulk-purchased spares;
- High failure rate of spinning hard drives. Energex adopted solid state drive technology; and
- End-of-life of the SICM2 IED. This is a current issue as outlined below.

The SICM2 IED is a small, in-house developed electronics module which functions as a SCADA system interface in small substations. Summary alarms (D.C. supply failure, CB open, etc.) are wired to the substation interface of the SICM2. When an alarm condition occurs, the SICM2 [redacted] communicates the alarm information via the SCADA system to the Control Centre. The SICM2 is typically used in substations where: (a) significant load is served (C&I substations and small, rural zone substations), but a full-sized RTU cannot be justified, [redacted] It is anticipated that SICM2-like functionality will be required for a small number of substations for the foreseeable future, but the SICM2 has reached end-of-life.

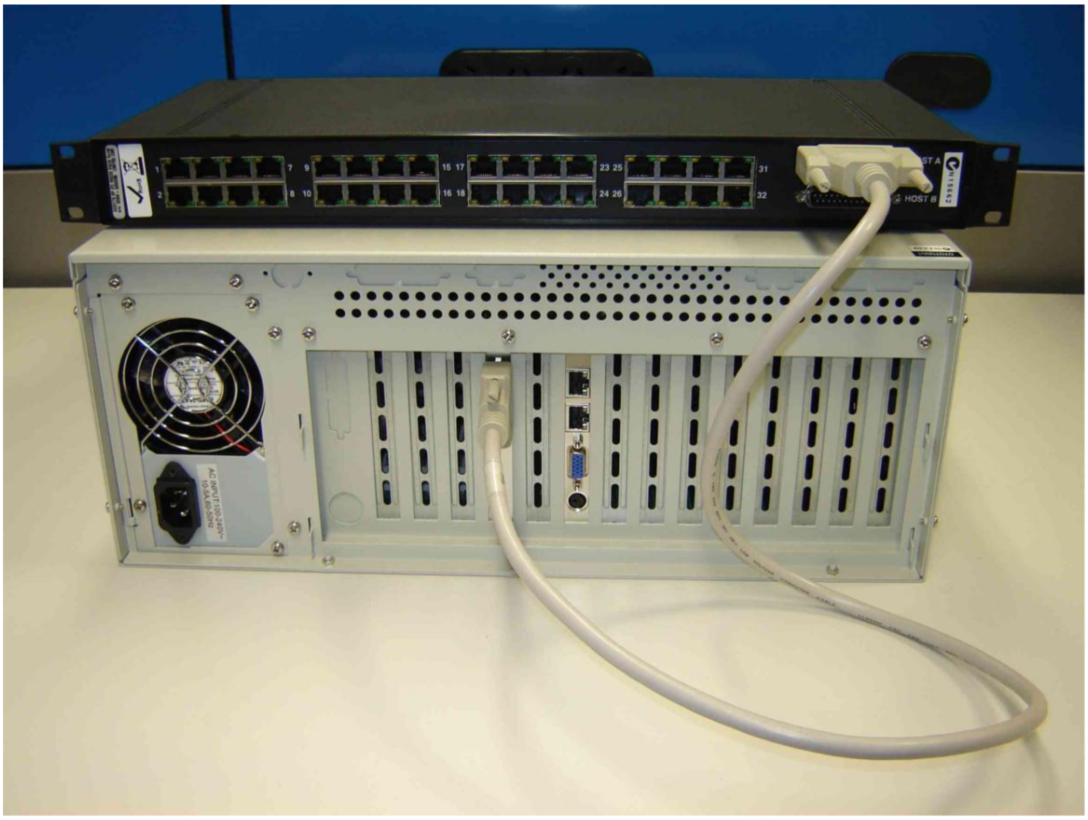
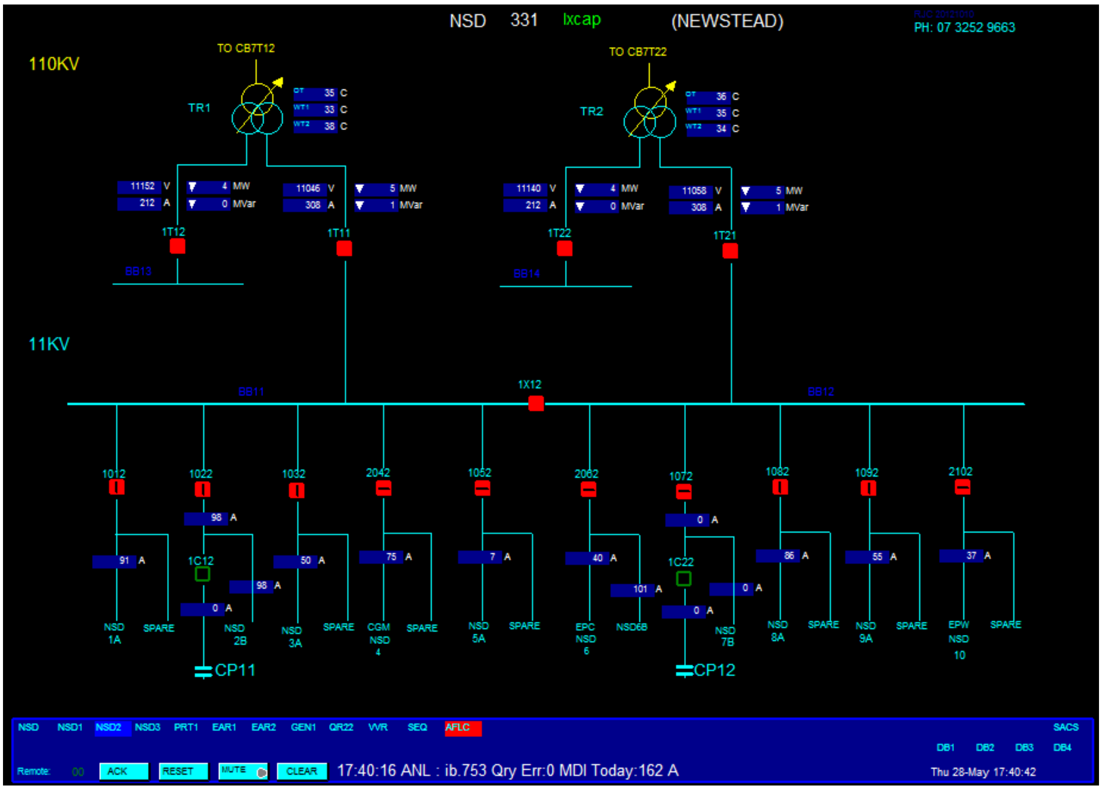


Figure 1: PC-SACS S1.0 Rear View



[redacted]

3.2.3 SCADA Communication Protocols

Table 2 below shows communication protocols currently employed in Energex.

Protocol	Usage	Number of Links utilising the protocol in Energex
[redacted]	[redacted]	Thousands
[redacted]	[redacted]	Hundreds
[redacted]	[redacted]	Legacy - almost eliminated

Table 2: Energex's current Communication Protocols

Support activity for protocols is performed as part of support activity for software (see Table 3 below).

3.2.4 Software

The table below details the various software that is utilised within Energex's SCADA RTU fleet.

Function	Identification	Type
[redacted]	[redacted]	Commercial
[redacted]	[redacted]	In-house
	[redacted]	Commercial
	[redacted]	Commercial
[redacted]	[redacted]	Commercial and in-house
[redacted]	[redacted]	Commercial
[redacted]	[redacted]	In-house
[redacted]	[redacted]	In-house
Standard substation automation applications	Volt-var regulation Autoreclose Autorestore Autochangeover Audiofrequency load control Group load control Plant overload protection	In-house
[redacted]	[redacted]	Commercial
[redacted]	[redacted]	In-house
[redacted]	[redacted]	Commercial and in-house
[redacted]	[redacted]	In-house

Table 3: Energex's current software detail

[redacted]

3.2.5 Software Support Activities

Support activity for software may be triggered by any of the following:

- The introduction of a new or upgraded hardware or software component;

- A change to a system with which the product must exchange data;
- An announcement from a vendor that software used by Energex will no longer be supported;
- Difficulty applying an existing software product to a specific situation;
- The emergence of a need for new or extended functionality;
- The discovery of performance issues – capacity or speed limitations with a wide range of possible causes; or
- The discovery of anomalous or unstable behaviour with a wide range of possible causes.

Depending on the number of devices in service and the age, Energex's response may be to:

- Do nothing, because the product will soon no longer be used;
- Provide application support;
- Upgrade or replace the product;
- Upgrade or rework product interfaces;
- Port the product to a new platform;
- Investigate a problem and repair the product (find and fix bugs);
- Implement new features or extend existing features in an existing product; or
- Develop a new product.

All of these options require evaluation, but the latter ones can be expensive and time consuming. Examples from recent years include:

- Cessation of vendor support for [redacted] libraries currently in use by Energex. Energex upgraded the [redacted] protocol suite to use the latest version of the [redacted] libraries;
- Inability to apply VVR5 in modular zone substations with combined feeder/bus tie CBs (a new, cost saving substation configuration). Energex added "dummy buses" and associated configuration to the existing VVR5 application;
- Reversion of power system planning guidelines from N-1 to risk-based planning. Energex derived a new Network Overload Mitigation Software (NOMS) application from existing Plant Overload Protection Software (POPS) application; and
- Status and alarms not reported from poletop switchgear sites due to overloading of [redacted] links. Energex reconfigured [redacted] Gateways for a [redacted] integrity scan period.

3.3 Emerging Requirements and Options

The requirements of DNSPs are expected to increase dramatically in terms of functional complexity, availability and security as we evolve toward the "Smart Grid". For example:

- SCADA and automation functions will most likely have to extend to customer and/or retailer integration in support of embedded generation, demand management, virtual power plants and the like;
- The criticality of such functions will dictate a need for redundancy in various forms; and

- Systems will have to remain robust in the face of increasing cyber security threats.

Many vendors of COTS RTUs are rising to the challenge with products of increasing power and sophistication by leveraging the rapid advance of components and technologies for "main stream" and consumer electronic equipment – processors, memory, communications technology, network technology, software development methodologies, and so on. These advantages are somewhat negated by shorter component life cycles.

In the past, the selection of a COTS product vendor often carried with it the near-certainly of "lock-in" to that vendor's complete product line including hardware, software, engineering toolset, and even SCADA communication protocol(s). Today, the risk of vendor "lock-in" has receded and the quality of offerings has improved thanks the development and adoption of International Standards. Examples include:

- Real-time operating system services – [redacted]
- "Main stream" data communications – [redacted]
- "Main stream" networking – [redacted]
- SCADA communication protocols – [redacted]
- Communications and interoperability for power system automation – [redacted]
- Programmable logic – [redacted]
- Dielectric withstand and surge withstand capability – [redacted]
- Environmental compatibility – [redacted]
- Electromagnetic compatibility – [redacted]
- Time synchronisation – [redacted]
- Resource monitoring and management – [redacted];
- Data representation – [redacted]
- Communications media (twisted pair) – [redacted]
- Communications media (optical fibre) – [redacted] and
- Equipment accommodation (19 inch / 483mm rack standard) – [redacted]

With the development of powerful protection and control IEDs, some functions previously performed by the substation RTU are now done better in the IEDs, e.g. autoreclosing. This "migration" of functions between platforms (of which autoreclosing is just one example) is potentially problematic without an enabling framework – one that makes functions and the interactions between them as platform-independent as possible.

IEC 61850 provides a powerful framework for interoperability between "smart" substation components, however simple or complex. Although IEC 61850 is experiencing a difficult birth, it remains the only realistic candidate, and it will certainly mature and improve over time. For this reason, a substation SCADA and automation architecture based on IEC 61850 is an obvious target for the future.

However standards are still absent in significant areas such as:

- Vendor agnostic, end-to-end engineering processes and toolsets;
- Human-machine interfaces;
- Substation automation applications;
- Low-level process logic (e.g. for protection logic and interlocks); and

- Real-time database Application Programming Interfaces (APIs).

A key concern in adopting COTS products is to avoid areas not covered by Standards, where Energex already has good solutions.

3.4 Advantages of COTS Products

The following is a list of advantages associated with COTS products:

- Energex specifications can be founded on common Industry Standards to maximise competition and minimise vendor [1] "lock-in";
- Vendors must develop product roadmaps which ensure product continuity while accommodating emerging Industry requirements;
- R&D costs are met by vendor(s) who can spread those costs over many customers;
- R&D risks and failures are borne by vendors, not Energex;
- Vendors must develop succession and training plans to ensure that internal IP and knowhow are preserved and enhanced;
- Vendors can employ R&D specialists who would be difficult to justify in the service of a DNSP;
- Vendors are responsible for periodically refreshing their product designs to overcome component obsolescence issues;
- Vendors can drive down costs by mass-producing products with appeal to numerous customers;
- Energex can engage in a cycle of requirements review / specification / application / improvement which enhances business focus and removes the drudgery of continuous product support; and
- If properly specified, COTS products can continue to support unique and/or valuable solutions for which there are no standards or commercial offerings.

3.5 Disadvantages of COTS Products

The following is a list of disadvantages associated with COTS products:

- The choice of boundaries between COTS replacement and existing systems can be problematic – every boundary represents an interface (potentially a cross-vendor interface) which must be seamlessly maintained;
- The existence of IP and know how within the end user business can sometimes facilitate rapid innovation – this opportunity is lost when a solution is outsourced;
- Unless a desired innovation has appeal to many customers, a vendor may be slow to respond or may charge highly to develop a single-customer product, or for older products may simply refuse to accommodate the need;
- In the quest for product differentiation and market advantage, vendors will try to ignore, bend or extend Standards, with the potential for vendor "lock-in";

[1] Throughout this document substitute "manufacturer" for "vendor" as appropriate (the creator, not the agent)

3.6 Future COTS-based Scenarios

Energex cannot abandon its existing RTU fleet immediately, or all at once:

- The recent and ongoing fleet rationalisation means that the core electronic components in most of the fleet have sufficient remaining service life to allow a staged transition;
- The current products are generally fit for purpose now, although ultimately not in the future;
- Projects are underway or proposed for the 2015-2020 AER period to implement enhancements and/or overcome the immediate component obsolescence issues;
- Without considerable forethought, the costs of rewiring substations to interface with COTS RTUs could be very high; and
- A bulk replacement would be logistically impossible at any time.

The major objectives for the next generation (building blocks ready for deployment into service by 2020) should be to:

- Replace “platform” components (hardware, operating system, device drivers, networking, time synchronisation, resource monitoring and management, protocol suites, etc.) with standards-based, commercial alternatives;
- Cater for a range of substation sizes and the associated functional requirements;
- Integrate the replacement products(s) into the existing SCADA and automation ecosystem. This is particularly important with respect to the engineering toolset, which is critical to the end-to-end integrity of the operational system, and which is not covered by Industry Standards;
- Port (transfer) standard substation automation applications to the new platform(s), where suitable COTS alternatives cannot be found;
- Ensure support for legacy [redacted] IEDs where required;
- Ensure support for the IEC 61850 “station bus,” and have a roadmap for IEC 61850 “process bus” support; and
- Ensure support, or have a roadmap for, functional redundancy of software and hardware.

The major objectives of the following generation (building blocks ready for deployment into service by 2025) should be:

- To achieve continuity with the previous generation in terms of standards compliance and functionality;
- To ensure full support for IEC 61850 in the incarnation of the day;
- To ensure support, or have a roadmap for the “Smart Grid” standards of the day; and
- To enable migration from the previous engineering toolset to a COTS engineering toolset.

4 Options

4.1 Option 1 – Develop and Maintain In-House Products

4.1.1 Summary

This option involves the continuation of the development and maintenance of in-house substation SCADA and automation products. This option is considered to be unsustainable in the medium term. The marketplace now contains a wide range of products and services suiting the substation SCADA and automation needs of DNSPs. Vendors of COTS products can spread the costs of maintaining existing products and developing innovative new products across many customers, driving costs down.

4.1.2 Impact analysis

To achieve COTS-equivalent functionality and quality in future in-house products, it is estimated that the following additional full time employees (FTEs) would be required for a period of approximately five years:

- 1 x SPARQ engineer/analyst for requirements engineering;
- 1 x SPARQ programmer for platform development;
- 1 x SPARQ technical writer for documentation;
- 1 x SPARQ test engineer for test environment maintenance; and
- 1 x SPARQ test engineer for product verification and validation

In addition up to $1 million would have to be invested in development and testing facilities.

This assumes:

- Existing Energex and SPARQ FTEs will be fully occupied supporting the legacy fleet;
- Energex costs for specification, acceptance testing and training would be equivalent to Option 2; and
- SPARQ costs for application porting and toolset development would be equivalent to Option 2.

The total cost of this option would be approximately $16.5 million in 2014/15 dollars over five years from 2016/17 to 2020/21.

The two SPARQ FTEs supporting the current products would be retrained to support the new products.

This option is not supported on grounds of both higher cost and risk than Option 2.

Table 4 below outlines the required expenditure for the Commercial SCADA RTU Program under Option 1.

$m, 2014/15	2015/16	2016/17	2017/18	2018/19	2019/20
Option 1	-	1.3	4.0	5.8	4.0

Table 4: Expenditure – Option 1

For this option, Energex would continue to deploy in-house products for substation SCADA and automation. Core substation SCADA and automation capabilities decline and Energex cannot maintain service levels in this area at an acceptable standard, as a result of:

- The retirement of key personnel with the associated drain on detailed and specific product knowledge within the organisation;
- Component obsolescence, which renders in-house products unmanufacturable and unmaintainable; and
- Use of in-house technologies and processes, which make it difficult and time consuming to recruit external and/or train internal support resources.

4.2 Option 2 – Full Integration of COTS Building Blocks

4.2.1 Summary

This option involves specification, selection and integration of COTS building blocks for substation SCADA and automation. COTS standard building blocks based on strategic requirements allow the organisation to source its products competitively, and expand its capabilities as required, while ensuring continuity of internal knowhow. R&D is required to integrate COTS products into Energex's SCADA and automation ecosystem, which extends beyond substations and contains both new and legacy technologies, as is normal for any change to major subsystem of complex system.

4.2.2 Impact analysis

This approach represents a balance of the need to replace obsolete equipment with commercially available products, with the safety, compliance and operational risks faced by the business. A project to progressively acquire "next generation" products as described above has been costed at $10.3 million in 2014/15 dollars over five years from 2016/17 to 2020/21. The funds requested for the 2015/16 – 2019/20 regulatory period are $9.4 million.

This proposal differs from the original AER proposal in that the program has been deferred for a year. This reduces the net present value (of the program), but it also extends the time for which Energex's in-house products must be supported. Energex does not consider it prudent to defer the development of an alternative solution beyond 2020/21 as the current fleet will have aged to the point where further design will be unavoidable to ensure reliability and maintainability.

Table 6 below outlines the proposed expenditure for the instrument transformer replacement program under Option 2.

$m, 2014/15	2015/16	2016/17	2017/18	2018/19	2019/20
Option 2	-	0.8	2.5	3.6	2.5

Table 6: Expenditure – Option 2

4.3 Option 3 – Partial Integration of COTS Building Blocks

4.3.1 Summary

This option involves specification, selection and partial integration of COTS building blocks for substation SCADA and automation without enterprise integration. Option 3 attempts to save money by (at least partly) avoiding the expense of integrating new products with the existing system.

4.3.2 Impact analysis

This option has not been developed further because it contradicts pursuit of the critical corporate objectives of efficiency and quality in the design, deployment, operation and management of SCADA and automation system assets.

The current SCADA and automation system engineering toolset is centred on SCADAbase, which acts as the “source of truth” for the technical configuration of the system. SCADAbase has been developed in the absence of a suitable COTS toolset. SCADAbase subjects each design to a suite of validation rules before automatically generating new or updated configuration data for SCADA and automation system elements (RTUs, concentrators and the DMS) – it plays a crucial role in maintaining the end-to-end integrity of the operational system.

The alternative to SCADAbase is a patchwork of vendor-based toolsets, cobbled together with a suite of complex and difficult-to-maintain interfaces. With a high degree of probability, the end result would be unreliable, error prone and require significantly more staff to engineer, check and test new deployments and modifications of existing deployments.

Another aspect of the integration challenge is to correctly and efficiently model SCADA and automation assets in the Enterprise Resource Planning system(s), for the purpose of asset management. This aspect cannot be overlooked given that efficiency of asset management processes, and access to ongoing funds, both depend on the availability of accurate records.

5 Proposed Works

It is proposed to implement Option 2 as this was considered the most sustainable and cost effective. The following work is proposed under Option 2.

Scheduling	Task	Outcome
Year 1	Specification, market approach, evaluation, business case, approvals, contract establishment	Approved supplier and business case
Year 2	Solution designs and test specifications, Project staff training,	Approved design and test documentation
Year 3	System establishment, integration and support documentation	Environment established ready for configuration and testing
Year 4	Application specification, design, implementation and testing. System test specifications, non-production testing	Complete solution ready for field trials
Year 5 (note not in this regulatory period)	Field trial sites selection, testing specifications, site design, construction and testing. Changes to standard designs.	Building blocks ready for ongoing implementation in the Energex network

Table 7: Proposed Works

For a comprehensive break down of the work, see Appendix 1.This proposal differs from the original AER proposal in that the timing has been deferred for a year. This reduces the net present value (of the program), and reduces the overall cost for the next five years, but it also extends the time for which Energex's in-house products must be supported.

This option is consistent with the SCADA and Automation Strategic Plan 2015 – 2020 and satisfies the risk management approach for RTU assets.

6 Required Expenditure

Table 9 below outlines the required expenditure for Option 2, which is the preferred Commercial SCADA RTU Program in this business case. The funds requested for the 2015-20 regulatory period are $9.4 million.

$m, 2014/15	2015/16	2016/17	2017/18	2018/19	2019/20
Energex Revised Proposal	-	0.8	2.5	3.6	2.5

Table 9: Proposed Program Expenditure

7 Recommendations

It is recommended that Option 2 be endorsed for inclusion in the programs of work and reflected in Energex's revised regulatory proposal for the 2015/16 – 2019/20 regulatory period. This option selects and integrates commercial-off-the-shelf (COTS) building blocks for substation SCADA and automation.

Appendix 1 – Work Break Down

Task	Outcome	Approx. Spend (% of total)	Approx. Scheduling
High-level requirements	Requirements for market scan / EOI	0.8	1st year **Funded from OPEX**
Requirements review	Requirements agreed	0.7	
Market scan / EOI	Vendors respond	0.8	
Procurement specifications	Specifications for competitive tendering	0.8	
Specification review	Specifications agreed	0.5	
Tender evaluation	Offers evaluated on paper	0.8	
Product evaluation	Offers evaluated on bench	1.9	
Evaluation review	Offer evaluation agreed	0.5	
Cost / benefit (products selected)	Value proposition determined (products selected)	0.4	
Cost / benefit review (selection agreed)	Value proposition agreed (selection agreed)	0.5	
SME training	SMEs familiarised (for integration phase)	5.7	2nd year
Integration specifications	Specifications for integrator	2.3	
Integration test specifications	Test specifications for integrator and testers	2.3	
Specification review	Specifications agreed	2.0	
Integration design	Integration design elucidated	3.4	
Design review	Integration design agreed	1.4	
Integration	Integration works completed	11.4	3rd year
Tests of integration	Integration works accepted for trials	4.6	
Documentation	Documentation prepared	2.3	
Documentation review	Documentation accepted	1.4	
Non-SME training	Non-SMEs trained	24.0	

Task	Outcome	Approx. Spend (% of total)	Approx. Scheduling
Application ports - specification	Port specifications prepared	2.3	4th year
Application ports - specification review	Port specifications accepted	1.3	
Application ports - design	Port designs completed	1.1	
Application ports - design review	Port designs accepted	1.5	
Application ports - test suite design	Test suite designed	2.3	
Application ports - test suite implementation	Test suite implemented	2.3	
Application ports - implementation	Ports completed	2.3	
Application ports - design verification	Ports verified	2.3	
Application ports - bench validation	Ports validated	2.3	
End-to-end trial specifications	Specifications for trial personnel	1.1	
Specification review	Specifications agreed	1.5	
End-to-end bench trials	Solution tested on bench	5.7	
End-to-end field trials - scope/design	Field trial sites designed	1.7	5th year **Outside 2015/20 AER period**
End-to-end field trials - build/test	Field trial sites built and tested	0.7	
End-to-end field trials - install/commission	Field trial sites commissioned	2.4	
Final evaluation and closeout	Lessons incorporated into systems	0.7	

Table 10: Proposed Works

PUBLIC

Energex

SCADA Feature Implementation Program

Asset Management Division

energex

positive energy

Energex

SCADA Feature Implementation Program 2015/16 - 2019/20

Reviewed:

Tim Hart

Group Manager Asset Life Cycle Management

Endorsed:

Peter Price

Executive General Manager Asset Management

Version control

Version	Date	Description
1	1/07/2015	Submitted

Energex Limited (Energex) is a Queensland Government Owned Corporation that builds, owns, operates and maintains the electricity distribution network in the growing region of South East Queensland. Energex provides distribution services to almost 1.4 million domestic and business connections, delivering electricity to a population base of around 3.2 million people.

Energex's key focus is distributing safe, reliable and affordable electricity in a commercially balanced way that provides value for its customers, manages risk and builds a sustainable future.

Group Manager
Corporate Communications
Energex
GPO Box 1461
BRISBANE QLD 4001

Executive Summary

SCADA (Supervisory Control And Data Acquisition) is a system which operates using coded signals over communication channels allowing control of remote equipment used to operate the Energex network. Energex relies upon SCADA systems for effective and efficient management of the distribution network. Through remote control and monitoring, the network can be operated at lower cost and with fewer risks, providing the ability to remotely isolate electricity supply in emergency situations much faster than if crews were required to attend site to do so.

As with any complex system involving software, the SCADA system requires modifications to both remedy issues and adapt to and continue to meet business evolving requirements. The purpose of this program is to provide critical upgrades to SCADA plant and Remote Terminal Units (RTUs), thereby ensuring the network is operated to meet safety and compliance obligations.

The SCADA feature implementation program includes the following key initiatives:

- Replacement of at-risk Automatic Voltage Regulators (AVRs) with VVR5
- Deployment to sites at highest risk changes to:
    - VVR5 improvements
    - Network Overload Mitigation Software (NOMS)
    - RTU Monitoring & Management Software
    - [redacted]
    - SCADA Migration to IP/MPLS

In addition, a small allowance for initial works for remote monitoring & control of:

- Four Quadrant STATCOM units for LV Network (required to manage high penetration of domestic PV)
- Alternate Solutions for LV Network Management

Failure to address these issues would compromise Energex's ability to meet compliance obligations, particularly with respect to customer statutory voltage limits of Queensland Electricity Regulation 2006, s13. It also increases the likelihood of impacts to customers through reduced reliability of supply.

In the original submission Energex proposed total expenditure of $10.2 million across two work programs to address the SCADA feature implementation and SCADA Migration to IP/MPLS work outlined above. Addressing feedback from the AER in its preliminary decision, Energex has consolidated and revised this work into one program and removed from scope items deemed lower risk. The revised expenditure required is $4.6 million over the 2015/16 – 2019/20 regulatory period. This expenditure is not accounted for in the modelled REPEX programs.

$m, 2014/15	2015/16	2016/17	2017/18	2018/19	2019/20	Total
Energex Revised Proposal	0.3	0.7	0.8	1.4	1.4	4.6

Contents

1 Introduction

The purpose of this document is to outline the required expenditure for the SCADA feature implementation program.

This program is important due to the potential consequences of the risks to the operation of the Energex distribution network if left untreated.

The proposed program covers the rectification of numerous known deficiencies as well as accepting the reality of the need to selectively address higher risk issues that emerge over time with complex electronic and software based systems.

<u>Changes from the original proposal</u>

The original proposal to the AER for the works associated with this program was for $10.2 million ($7.99 million for the Feature Rollout program, $2.21 million for the SCADA Migration to IP/MPLS works which was originally split out to a separate program).

Following feedback from the AER in its preliminary decision, Energex has re-evaluated its capital programs to take a higher risk position than described in the original submission. Accordingly, the works have been reviewed and items with lower risk have been removed.

Since the initial preparation of the submission, Energex has also committed to adoption of new secondary system building blocks which incorporate protection relays with SCADA via the industry standard [redacted] protocol. This decision has impacted the previous plan for SCADA & Automation works by pushing back the proposed timeframe for the adoption of IEC-61850 standards based integrated secondary systems (though the adoption of IEC-61850 Station Bus signalling for signalling between protection devices may still proceed earlier than broader-scale adoption).

The revised proposal presented here outlines a required investment of $4.6 million over the five year period.

2 Drivers

The drivers for this program include:

- To meet safety and compliance obligations (maintain voltage to customers within the statutory limits of The Queensland Electricity Regulation 2006, s13)
- Deployment of critical upgrades to in-service SCADA plant and mitigation of risks to network performance.
- Efficiency improvements for tools used to generate configuration for secondary systems plant
- Resolve issues in existing SCADA implementations [redacted]

The following sections provide additional detail on the above.

2.1 Existing Network/Background

The Energex SCADA & Automation fleet comprises 369 RTUs across substations in South-East Queensland. These devices are used to remotely control primary plant and monitor the operational state of the electricity network. If the SCADA & Automation system is unavailable, only local (person-on-site) manual control of the network is possible. Mal-operation of the SCADA & Automation system can cause damage to plant, unplanned outages, overvoltage etc.

In order to meet the changing needs of the distribution network, modifications to SCADA and Automation will need to be deployed to existing installations.

The continuous improvement of SCADA & Automation (SCADA Software Continuous Improvement Program) funds the engineering of the changes needed. This complementary project funds the deployment / installation of the changes into the operational system.

In previous years, the higher level of capital works has facilitated the deployment of remedial changes for SCADA through the need for updates of the RTUs to enable changes to primary plant. In effect this has masked the true level of recent historical expenditure on SCADA deployments. With the significant reduction in works planned for the 2015/16 – 2019/20 regulatory period, such opportunities for coordinating SCADA changes with primary plant capital works are reduced.

The work associated with this program can be divided into the following categories:

1. Items for which details are known and mitigations are known to be required (section 2.2);
2. Items identified as concerns which have high potential to develop into issues requiring remedial action within the 2015/16 – 2019/20 regulatory period (section 2.3); and
3. Items identified where SCADA deployment works are likely to be required to support strategic objectives (section 2.4).

2.2 Specific identified changes required to remedy existing issues

2.2.1 Summary Replacement of at-risk Automatic Voltage Regulators (AVRs) with VVR5

In 2012 an internal report identified sixteen Energex sites which are required to change from independently operating Automatic Voltage Regulators to the standard Energex substation voltage regulation system (VVR5).

"It is recommended that a review is conducted of the substation bus voltage controllers, aimed at establishing a program for progressively upgrading them to SACS Voltage Var Regulator option (VVR5) where practicable." – Energex Voltage Management Issues, Nov 2012, Ver1.2

A number of sites identified in the report have since had VVR5 installed. After detailed analysis, Energex has identified that of the sites:

- A total of nine sites require remedial works as part of this program; and
- Of those nine sites, seven will be executed in combination with other works required at those sites, with the remaining two requiring specific projects to address this problem.

Sub ID	Substation Name	Status
[redacted]	[redacted]	No Independent project – to be added to WR5790576 - AMR Replace Tx (June 2017)
[redacted]	[redacted]	No Independent project – to be added to WR6603936 - EBV Upgrade SACS (Oct 2015)
[redacted]	[redacted]	An independent project has been created (WR6603686). Project is still progressing.
[redacted]	[redacted]	No Independent project – to be added to WR6040438 MSV Replace Tx (Sept 2017)
[redacted]	[redacted]	No Independent project – to be added to WR5616526 - MTC Replace Tx (Jul 2017)
[redacted]	[redacted]	No Independent project – to be added to WR6298785 - NPD Replace Tx (Jun 2020)
[redacted]	[redacted]	No Independent project – to be added to WR6452079 - SFD Upgrade SACS & Replace 33kV CB (July 2016)
[redacted]	[redacted]	No Independent project – to be added to WR6502788 - TRP Replace 33kV CB (July 2018)
[redacted]	[redacted]	An independent project has been created (WR6603844). Project is still progressing.

Table 1: Energex sites requiring replacement of AVRs with VVR5

The status of remaining sites identified in the report which no longer require AVR replacement are:

Sub ID	Substation Name	Reason why not included
[redacted]	[redacted]	VVR5 now available as result of other works
[redacted]	[redacted]	VVR5 now available as result of other works
[redacted]	[redacted]	VVR5 now available as result of other works
[redacted]	[redacted]	VVR5 now available as result of other works
[redacted]	[redacted]	To be completed under project WR5966112 - [redacted] Rebuild (Sept 2016)
[redacted]	[redacted]	Site decommissioned.
[redacted]	[redacted]	Re-assessed as not required.

Table 2: Sites identified as no longer requiring replacement of AVRs with VVR5

2.2.2 Deployment of VVR5 improvements

Energex employs the VVR5 software within its substations to control substation bus voltage to meet its regulatory requirements for voltage regulation.

Energex carries out this function with a combination of primary plant (OLTC transformers, capacitor banks and step voltage regulators) and secondary control systems. Control system software called volt-var regulation (VVR) compares measured voltage(s) with target value(s) and sends coordinated control commands to transformers and capacitor banks in bulk supply and zone substations. Pole-mounted step voltage regulators operate independently.

Actions have been initiated in Energex's corporate safety record system to investigate and remediate problems with VVR and VVR-related subsystems and components. If these improvements are not deployed, the risk of re-occurrence of similar overvoltage incidents will remain at unacceptable levels, which carries risk of damage to customer equipment and potential for ignition of fires.

In addition, with the increasing penetration of solar PV in the network, voltage regulation issues are expected to increase (refer to Energex DAPR 2014/15 – 2018/19 Volume 1, page 137).

A collected list of the voltage regulation related incidents is presented in Appendix 3.

2.2.3 Deployment of Network Overload Mitigation Software (NOMS)

The Network Overload Mitigation Software SCADA application is being developed under project C350374 as a replacement of the current Plant Overload Protection Software (POPS).

POPS automates the process of rapidly de-loading the plant still in service after a contingency event to a short-term sustainable level, pending restoration of the power system to a secure configuration by manual operation. As part of the move away from deterministic network security standards, POPS will be deployed to all substations with load at risk under the revised "Customer Outcomes Standard" planning guidelines developed following the Electricity Network Capital Program Review 2011.

POPS was widely deployed in support of the Reliability Assessment Planning (RAP) guidelines used in the 1990s. Worst case N-1 overloads under the new planning guidelines will be more severe than under RAP, and accordingly the role of POPS will be more significant.

NOMS will automate the processes removing the immediate need for operators to manually react, significantly reducing the risk of plant overload and breaching Energex's network reliability obligations.

2.2.4 Deployment of RTU Monitoring & Management Software

Energex has had limited remote monitoring capabilities for its SCADA fleet. Secondary system health information and diagnostic data has been intermingled with power system SCADA data. Network operators have been responsible for fielding and interpreting this data and initiating repair callouts.

While it is useful for operators to be aware of the status of secondary systems, it is counterproductive to present them with detailed diagnostic data of a technical nature. One way to preclude this is to separate monitoring and management data from power system SCADA data by classifying them into separate "areas of responsibility" at the control centre. However in this case SCADA communications bandwidth is still used for the transport of non-SCADA data, and secondary systems personnel must rely on the Distribution Management System (DMS) as a source of data.

Converged remote monitoring and management infrastructure will enable better informed planning, integrated operational workflows and closer scrutiny of secondary systems with respect to performance and reliability.

Deployment of monitoring of Remote Terminal Unit (RTU) internal health diagnostics (deployment of the work done under C0105532 RTU Monitoring & Management Project) will enable earlier detection of SCADA faults and assist the migration from scheduled maintenance to condition based maintenance of the RTU fleet.

[redacted]

2.2.6 SCADA Migration to IP/MPLS

Energex has been rolling out an IP/MPLS network as part of a strategic program that will provide enhanced communications capabilities, including the ability to provide secure IP connectivity for RTU control and management access. As the IP/MPLS network deployment progresses, the RTU will be migrated to the IP/MPLS network where hardware and software is compatible. However there is a back log of approximately 39 existing sites where IP/MPLS infrastructure has been installed but at the time the SCADA Remote Terminal Unit (RTU) could not be cutover to the new system.

At the time that this document was written only two RTU units were using IP communications as their means of sending both control traffic and engineering management traffic. [redacted]

The subsections below describe the limitations being addressed by the migration of the RTU onto the IP/MPLS network.

[redacted]

Condition Based Maintenance - IP based communication networks provide the ability to perform remote monitoring functionality using international standard protocols [redacted]

[redacted] for which there is extensive off-the-shelf support for monitoring systems. [redacted] allows operators to see alarms and events associated with the SCADA equipment to minimise in-service failures and have the potential to identify problems before they occur. The legacy network does not adequately support the transport of these remote monitoring protocols and often issues are not known until a fault occurs. Many of these faults require site visits and manual investigation to identify the cause.

Performance - Energex anticipates that with the upgrade to IP communications, response to commands will improve from around multiple seconds to less than a second. Also with the improved performance, Energex will be able to consider bringing back an increased level of data. Some of the examples that will be advantageous would be:

- Bring back all phase measurement information from 11kV feeders (currently only the B phase is measured). This would assist with negative flow analysis, imbalance studies and improved phasing information (note this will require enhancements to the infrastructure installed at the substation).
- Energex use Programmable Logic Controllers (PLCs) to perform on-site transformer control. Remote monitoring and control would be possible for these devices with the increased channel capacity provided by the IP/MPLS network.
- As Energex rolls out automation capabilities to 11kV and LV connection points, this will lead to the ability to gain increased levels of measurement data from the customer and support the introduction of smart grid technology. The IP/MPLS network is well suited to facilitate the transportation of this increase in data.

Obsolescence - A number of components used by the RTU have reached end of life as described below:

- The “personality card” one of the variant cards which provides the hardware to implement the serial communications path (that is to be replaced with an IP solution under this program) and reached end of life nearly 10 years ago. Energex currently utilises spares from equipment that has been removed from service.
- [redacted]
- The legacy communications network that is used for the majority of the SCADA RTU fleet is no longer supported by the manufacturer and Energex has made a strategic choice to begin migrating to IP/MPLS technology. Moving the SCADA fleet off the existing network onto the new network is one of many initiatives that is being progressed ahead of the eventual removal of the current legacy Plesiochronous Digital Hierarchy (PDH) telecommunications network.

Reliability - [redacted] During the period from 21/01/2013 to 29/12/2014 a total of

261 incidents were logged [redacted] This equates to over 2 faults per week relating to the [redacted] echnology resulting in unplanned maintenance to rectify the fault. The increasing rate of failure of the backup link raises the risk of no connectivity to the RTU while the primary link is not in operation.

2.3 Other potential remedial works

A number of areas have been identified where risk is developing which may require deployment of on-site changes. Energex is intending to tolerate increased risk in this regard and no expenditure is requested for these concerns for this revised submission.

Should these concerns develop into high risk issues requiring treatment through deployment of changes, funding will be taken from this program to address them based on priority:

Area of risk	Reference(s)	Description of risk
Analogue Input cards [redacted] SACS	[redacted] Issues : Rolling analogues [redacted]	Currently under investigation – issue encountered with stability of the measurements made by the 64channel analogue input card used in these assemblies. If need to execute remedial works for all then could involve up to 92 substation sites.
[redacted] SACS units (those which are not funded for replacement with current standard)		Increased failure rates and issues – may need to deploy changes to mitigate if not able to migrate to current platform.
HDD failure rates & risk to continued supply of disks with IDE interface ---		If unable to update may need other remedial works to mitigate the risks.
[redacted]	SCS incidents	[redacted] If unable to continue deployment of replacement IP-MPLS network based network links, may need deployment of other mitigating SCADA works (such as redundancy of Ethernet network interfaces) to manage the increasing risks.
[redacted] I/O modules	SCS incidents	Again if unable to migrate off parallel I/O at substations, may need to deploy hardware refresh at sites to mitigate the risks from old hardware.
SICM Tags	TSD0142a , SCS incidents	While Energex have actively been replacing the older tag units as opportunities in corrective maintenance appear, is still risk that will begin to encounter accelerating failures of the older tag units which rely on non-replaceable batteries to maintain state during power loss.

Table 3: Areas where risk is developing which may require deployment of on-site changes

Detailed information on recent history of the need to deploy changes to remedy issues with the SCADA & Automation system is provided in Appendix 1.

2.4 Other SCADA deployment works (subject to trial outcomes)

Energex is conducting trials likely to result in the need for deployment works to enable remote control and monitoring of the resulting systems. An allowance for these SCADA deployment works towards the end of the regulatory period has been included within this business case. The following subsections describe the systems expecting to require these works.

2.4.1 Four Quadrant STATCOM units for LV Network – Remote monitoring & control

Drivers for the Low Voltage Management project executed by Energex during the 2010-2015 regulatory period are:

- The LV network accounts for greater than 50% of Energex's total network length and the performance of the LV network is largely unquantified;
- Increasing domestic rooftop photovoltaic (PV) penetration is causing greater voltage variability on the LV network;
- Electric vehicles (EVs) and customer energy storage in low voltage networks is already emerging; and
- New technologies present opportunities for greater cost effectiveness over traditional 'static' engineering solutions.

Part of this project has been the in-service trial of STATCOM units for LV network management.

During the trial the units are operated independently of the operational SCADA system to reduce the cost of the trial.

Initial concept trials have indicated the STATCOMs can positively impact network voltage reduction and further works are proceeding.

If larger scale deployment proceeds, this will likely require deployment of SCADA changes to provide remote control of these devices to mitigate the risks associated with their operation, protecting both customers and network assets.

Figure 1: Trial unit - Trailer fitted with batteries, STATCOMs and auxiliary gear

Figure 2: Trial unit - Trailer in service at trial site [redacted]

2.4.2 Alternate Solutions for LV Network Management – Remote monitoring & control

Initial investigation of LV network performance suggests that the optimal regulation solution may differ depending on the characteristics of the specific LV network. Therefore, alternate technologies are also under consideration including regulating distribution transformers, LV regulators and LV capacitors. Each of these may have technologies will have different SCADA requirements. One such device is [redacted] shown in Figure 3.

Figure 3: Trial unit – [redacted] due to installation in FY 2015/16

Two [redacted] units are currently planned to be installed during FY2015/16. The technology will be evaluated over 12 to 24 months. This solution differs from the STATCOM in that it will regulate the voltage at the distribution transformer, as opposed to part way down the LV circuit (as with the STATCOM). An alternate distribution transformer with an On-Load-Tap-Changer (OLTC) is also proposed for trial in this sub-category.

As with the STATCOM project, during trial the units will be operated independently of the SCADA system to reduce project costs and complexity. However, once the principal technology has been evaluated in trial, decisions will be made about the size and extent of a larger scale rollout. If a larger scale rollout of this or any LV regulation solution proceeds, SCADA changes will be required.

3 Options

3.1 Impact of Doing Nothing

The “do nothing” option, or failure to proactively address issues present with voltage control of distribution plant places Energex at risk of:

- Additional incidents resulting from defects, likely resulting in failure to comply with regulatory requirements;
- Unable to benefit from improvements that could otherwise enhance customer outcomes and network performance.

Risk of the do nothing approach is quantified in the untreated risk scenarios in Table 4.

Category	Risk Scenario	Consequence	Likelihood	Risk Score
Safety	A failure in the measurement chain causes the RTU to incorrectly increase tap settings, causing an overvoltage excursion, resulting in a house fire and multiple fatalities	6	2	12 (Moderate Risk)
Customer Impact	A failure in the measurement chain causes the RTU to incorrectly increase tap settings, causing an overvoltage excursion, resulting in a damage to customer equipment	4	3	12 (Moderate Risk)
Legislated Requirements	A failure in the measurement chain causes the RTU to incorrectly increase tap settings, causing an overvoltage excursion that needs to be reported to the regulator	4	3	12 (Moderate Risk)
Business Impact	A failure in the measurement chain causes the RTU to incorrectly increase tap settings, compliance breach with Energex standards and policy	3	3	9 (Low Risk)

Table 4: Untreated Risk Assessment Summary – SCADA Feature Implementation

This outcome is not tolerable to Energex, with untreated risk not considered to be As Low As Reasonably Practicable (ALARP).

3.2 Option 1 – Implement Available Fixes at 75 Sites (recommended)

3.2.1 Summary

This option proposes to resolve all known higher risk items targeting 75 sites. Since Energex has revised its risk position, removing proposed works with a lower level of risk can reduce expenditure while still treating the items of greatest concern. These works align with the Energex SCADA & Automation Strategy.

3.2.2 Impact analysis

The Energex SCADA & Automation system provides a number of key business functions for mitigation of operational risks and improvement of network performance. Failure of the system to provide its specified business functions can have a direct impact on safety risks to the public, safety risks to staff and key business success measures. The reduction of the number of sites to which software changes are deployed (from approximately 25 per annum to 15 per annum) increases risk and will reduce the benefit obtained from improvements.

The minimisation of cost for the migration of SCADA to the IP/MPLS network will result in lower system availability than would have been obtained with the original planned works due to the removal of work to support multiple communication paths.

This option provides no allowance to revisit sites that have already been rolled out for issues that emerge over the 2015/16 – 2019/20 regulatory period (refer 2.3). Any relevant enhancement available before site deployment would be included to gain maximum benefit. Past experience indicates high risk issues will emerge that will require revisits and this will be funded out of this program, by removing low priority proposed sites.

3.3 Option 2 – Implement Available Fixes at 125 sites (original proposal)

3.3.1 Summary

This option proposes to implement all available relevant fixes as roll out of the higher risk items proceeds to 125 sites as per the original proposal.

3.3.2 Impact analysis

Taking reasonable steps to correct defects and implement enhancements, would be delivering the best engineering solution within the bounds of prudent expenditure, current company capability and system limitations.

4 Proposed Works

Option 1 was selected as balanced outcome which resolves identified issues and the majority of risks whilst reducing the required expenditure of the program in the next regulatory period. Whilst Option 2 would have been Energex's preferred option because it mitigates all risks to As Low As Reasonably Practical, Energex's proposal in this business case is to adopt a slightly higher risk profile at some sites as described by Option 1, while not compromising on its treatment of safety risks. The proposed works are therefore:

- Replacement of at-risk Automatic Voltage Regulators (AVRs) with VVR5
- VVR & other RTU software deployment
- Remote monitoring & control for STATCOM and Alternate Solutions for LV Network Management
- SCADA Migration to IP/MPLS

The following table provides a summary of the treated risks.

Category	Risk Scenario	Consequence	Likelihood	Risk Score
Safety	A failure in the measurement chain causes the RTU to incorrectly increase tap settings, causing an overvoltage excursion, resulting in a house fire and multiple fatalities	6	1	6 (Low Risk)
Customer Impact	A failure in the measurement chain causes the RTU to incorrectly increase tap settings, causing an overvoltage excursion, resulting in a damage to customer equipment	4	1	4 (Very Low Risk)
Legislated Requirements	A failure in the measurement chain causes the RTU to incorrectly increase tap settings, causing an overvoltage excursion that needs to be reported to the regulator	4	1	4 (Very Low Risk)
Business Impact	A failure in the measurement chain causes the RTU to incorrectly increase tap settings, compliance breach with Energex standards and policy	3	1	3 (Very Low Risk)

Table 5: Treated Risk Assessment Summary – SCADA Feature Implementation

5 Required Expenditure

The expenditure for the program is comprised mainly of the deployment of software improvements to the SACS RTU, targeting voltage regulation issues and rolling out other enhancements at the same time.

A slow start is planned for these software deployment works to both accommodate the delivery of the software changes, and the impacts of the deployment of new secondary systems standards on key resource availability.

The replacement of the at-risk Automatic Voltage Regulators (AVRs) with VVR5 in contrast is heavily front loaded as a result of the timing of other works at the sites where these changes need to take place. This provides for more cost-effective deployment.

Table 6 below outlines the required expenditure for the SCADA Feature Rollout program, with a total value of $4.6 million.

$m, 2014/15	2015/16	2016/17	2017/18	2018/19	2019/20
Energex Revised Proposal	0.3	0.7	0.8	1.4	1.4

Table 6: Proposed SCADA Feature Rollout Program Expenditure

6 Recommendations

It is recommended that Option 1 be endorsed for inclusion in the programs of work and reflected in Energex's revised regulatory proposal for the 2015/16 – 2019/20 regulatory period.

Appendix 1 – Recent history of required deployments to remedy issues with SCADA & Automation system

Recent history of the need to deploy changes to remedy issues:

Example of issues requiring SCADA deployment to remedy	Reference(s)	Sites/units affected
SICM1 hardware issue resulting in overvoltage excursions	eSafe: INC-113200 INC-113263 Investigation No. SR-12-19 C Investigation Report: IMS-127	As at 15/5/2015, 658 SICM1 units installed across 121 sites.
History of software remedial works for SACS requiring deployment of changes	SCADA Software remedial work testing work orders	Varies depending on the specific issue.
End of Life of SICM configuration memory device (SICM Tag)	Technical Instruction TSD-142a	All sites with SICM units (1,2,or 2B) 121 SICM1 407 sites with SCIM2B 2 sites with SICM2
[redacted] history of issues (example of problematic COTS unit requiring field changes) **“Early adopter” issues:** Every [redacted] configuration is uniquely different (product frequently changing). Most sites needed to have firmware upgraded. Hardware differences, e.g. [redacted] module used at [redacted] s not used anywhere else. Thermal model issues **Optical temperature transducer issue:** A signal noise issue was found in the optical fibre temperature transducers that interface to the [redacted] units (part of the [redacted]		116 units across 73 sites Approximately 30 units impacted (typically 1 or 2 per site)

product). The issue was causing false tripping. Approximately 30 units that had the problem transducers. Remedy required removal of the transducer and its replacement.		
[redacted]	[redacted]	[redacted]
History of revision changes for SCADA embedded Software and Firmware: [redacted] **Voltage Regulators** [redacted] [redacted] **Reclosers** [redacted] [redacted]	Technical Instruction TSD-124.8 Standards Alert: StdsA168	

Table 7: Example works required for deployment of remedial SCADA works

Appendix 2 – Risk and Incidents – Supporting Information

4(a) Substation entry insecure:

Incident Date	Incident Number	Incident Summary
[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]

Table 8: Example incidents with substation site security

4(b) Site insecure, Theft of equipment, potential damage to plant and risk to persons

Incident Date	Incident Number	Incident Summary
[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]

[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]

Table 9: Example incidents with substation site security

Substation Battery Monitoring function

Base risks:

(A) Undetected failure of substation battery at Site, followed by need for a protection trip operation which fails, resulting in significant plant damage and potential hazards to public.

(B) Undetected failure of protection system, followed by need for a protection trip operation which fails, resulting in significant plant damage and potential hazards to public.

(C) Undetected protection operation at Site, resulting in increase of time to restore power to CBD customers.

Example of occurrence: eSafe HAZ-100905 - No DC supply to trip or close CBs on site Battery and charger controlled by customer.

Detailed assessments of variations on base risks for battery monitoring failure

ID	Risk Description	Likelihood	Consequence	Rating
1.	Risk (A) is realised and results in multiple deaths	1 in 100 years	6	6
2.	Risk (A) is realised and results in single death	1 in 50 years	5	5
3.	Risk (A) is realised and results in multiple people with serious injuries	1 in 30 years	4	8
4.	Risk (A) is realised and results in single person serious injury	1 in 20 years	3	6
5.	Risk (A) is realised and results in fire requiring rebuild of C&I substation and significant CBD customer supply impact	1 in 50 years	3	3
6.	Risk (A) is realised and results in feeder cable destruction requiring replacement significant CBD customer supply impact	1 in 20 years	3	6
7.	Risk (A) is realised and results in significant CBD customer supply impact	1 in 10 years	3	6

Appendix 3 –VVR / Voltage regulation related issues

Sub	Report	INC	eSafe action	STOC Ref	Date
[redacted]					10/09/2012
[redacted]	SR12-08	INC-112368	ACT-123223		May-12
[redacted]				STOC-1485, SCS-2779	17/12/2014
[redacted]					9/12/2014
[redacted]				STOC-1100	8-9/07/2014
[redacted]	SR12-19				15/05/2012
[redacted]		INC-112367			11/11/2011
[redacted]		INC-117582			14/01/2014
[redacted]				ENGOPS-353 STOC-1104	
[redacted]		INC-115842			May-13
[redacted]					Dec-14
[redacted]	SR12-19				May-12
[redacted]		INC-114695			4/12/2012
[redacted]					03/10/2013
[redacted]		INC-117838			19/02/2014
[redacted]		INC-115719			24/04/2013

Table 10: VVR / Voltage regulation related issues consolidated list

Appendix 4 –ICS-CERT Alerts & Advisories – summaries

source = https://ics-cert.us-cert.gov/alerts

Cybersecurity Incidents reported by sector – ICS CERT Year in Review 2014 report.

Sector	FY 2012	FY 2013	FY 2014
Chemical Sector	4	0	1
Commercial Facilities Sector	2	0	2
Communications Sector	0	2	0
Critical Manufacturing Sector	1	0	0
Dams Sector	0	0	0
Defence Industrial Base Sector	12	1	0
Emergency Services Sector	3	0	0
Energy Sector	**7**	**18**	**43**
Financial Services Sector	**6**	**0**	**0**
Food and Agricultural Sector	0	0	0
Government Facilities Sector	3	2	5
Healthcare and Public Health Sector	1	5	0
Information Technology Sector	5	2	0
Nuclear Reactors, Materials, and Waste Sector	8	8	5
Transportation Systems Sector	10	10	10
Water and Wastewater Systems Sector	25	24	38
Totals	87	72	104

Source: https://ics-cert.us-cert.gov/sites/default/files/documents/Year_in_Review_FY2014_Final.pdf

PUBLIC

Energex

SCADA Software Continuous Improvement Program

Asset Management Division

energex

positive energy

Energex

SCADA Software Continuous Improvement Program 2015/16 - 2019/20

Reviewed:

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Group Manager Asset Life Cycle Management

Endorsed:

Peter Price

Executive General Manager Asset Management

Version control

Version	Date	Description
1	1/07/2015	Submitted

Energex Limited (Energex) is a Queensland Government Owned Corporation that builds, owns, operates and maintains the electricity distribution network in the growing region of South East Queensland. Energex provides distribution services to almost 1.4 million domestic and business connections, delivering electricity to a population base of around 3.2 million people.

Energex's key focus is distributing safe, reliable and affordable electricity in a commercially balanced way that provides value for its customers, manages risk and builds a sustainable future.

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Executive Summary

The purpose of this document is to outline the required expenditure forecast for continuous improvement of software for SCADA (Supervisory Control And Data Acquisition) and automation systems. This expenditure is not accounted for in the modelled REPEX programs.

SCADA is a system which operates using coded signals over communication channels allowing control of remote equipment used to operate the Energex network. The functions of Energex's SCADA and automation system are implemented in computer software which can be affected by anomalous or unstable operation. These can occur as a result of implementation errors (bugs), unforeseen application, operator input or unforeseen network conditions. In addition, new business challenges can give rise to the need for software alterations and enhancements.

In cases where a software deficiency poses significant risk Energex takes corrective action to reduce the risks to tolerable levels. The purpose of this proposed program is to develop SCADA improvements which can subsequently be deployed to new installations in the course of normal business, and to existing installations in separate, risk-prioritised rollout programs. Energex needs to fund development of software, the associated testing and any other change requirements to allow implementation.

In the original submission Energex proposed total expenditure of $3.2 million across three work programs to address the SCADA issues outlined above. Addressing feedback from the AER in its preliminary decision, Energex has consolidated and revised this work into one program and removed from scope items deemed lower risk.

The following table provides a summary of the required expenditure of $1.5 million ($2014/15 direct) over the 2015/16 – 2019/20 regulatory period.

$m, 2014/15	2015/16	2016/17	2017/18	2018/19	2019/20	Total
Energex Revised Proposal	0.3	0.3	0.3	0.3	0.3	1.5

Contents

1 Introduction

The purpose of this document is to outline the required expenditure for a program of continuous improvements to SCADA and automation software.

This program is important because, as with all software-based systems:

- Untreated bugs are an ongoing source of lost productivity and error, sometimes with safety implications; and
- Enhancements and new features can be implemented at any time (within reason) and failure to implement them simply defers the flow of the associated benefits.

Changes from the original proposal

In their draft determination, the AER has made it clear is expects Energex to operate with a high level of risk. Accordingly, the works have been reviewed and items with lower risk have been removed.

The original proposal to the AER included three separate programs which have been rolled into this single proposal and reduced in scope commensurate with a higher risk position:

- SCADA & Automation System Software Improvements - originally $1.74 million
- SCADA Software Changes - Maintenance – originally $0.52 million
- Core DSS Radio infrastructure – originally $0.92 million

The combined total for these three programs was for $3.2 million over the 2015/16 – 2019/20 regulatory period in the original submission.

The total expenditure proposed for the reduced works is now $1.5 million.

2 Drivers

The main drivers for this program are:

- Ensure operational visibility of the network with a fully functioning SCADA and automation system
- Rectification of SCADA software bugs which can affect performance of new installations
- Proactive system rectification and risk mitigation

3 Supporting Analysis

3.1 SCADA and Automation Software Domains

Locations in Energex's SCADA and automation system can be broadly classified as:

- SCADA master station (out of scope of this proposal);
- Substations (in scope of this proposal); and
- Distribution system, especially the 11kV primary distribution system (in scope of this proposal).

The substation and distribution system domains are qualitatively different, and accordingly they are discussed in separate sections of this business case.

3.2 Substation SCADA and Automation

3.2.1 Background

Energex and its predecessors have used in-house products for SCADA and automation since SCADA was introduced in the late 1970s.

As with all computer-based systems, the functions of these products are implemented in software, much of which has also been developed in-house. VVR (Volt-Var Regulation) and NOMS (Network Overload Mitigation Software) are examples of in-house applications with functions that are not often seen in commercial alternatives.

As with all software, anomalous or unstable operation can occur as a result of implementation errors (bugs), unforeseen application, operator input or unforeseen network conditions. Sometimes the consequences are tolerable; at other times the previously unrealised risk is regarded as intolerable and the anomalous behaviour must be investigated, diagnosed and rectified.

New business challenges can give rise to the need for software alterations and enhancements.

Another business case for selection and integration of commercial off-the-shelf (COTS) RTUs seeks funding for a transition from in-house to COTS products. This business case deals with continuous improvement of existing software products in the period until that transition can be executed.

3.2.2 Existing Software and Support Regime

Function	Identification	Type
[redacted]	[redacted]	Commercial
[redacted]	[redacted]	In-house
	[redacted]	Commercial
	[redacted]	Commercial
[redacted]	[redacted]	Commercial and in-house
[redacted]	[redacted]	Commercial
[redacted]	[redacted]	In-house
[redacted]	[redacted]	In-house
Standard substation automation applications	Volt-var regulation Autoreclose Autorestore Autochangeover Audiofrequency load control Group load control Plant overload protection	In-house
[redacted]	[redacted]	Commercial
[redacted]	[redacted]	In-house
[redacted]	[redacted]	In-house
[redacted]	[redacted]	In-house

Table 1: Existing Software and Support Regime detail

With the exception of custom soft-PLC-based substation automation applications (developed by Energex), support for substation SCADA and automation software is carried out by SPARQ Solutions (SPARQ).

Support activity for software may be triggered by any of the following:

- The introduction of a new or upgraded hardware or software component;
- A change to a system with which the product must exchange data;
- An announcement from a vendor that software used by Energex will no longer be supported;

- Difficulty applying an existing software product to a specific situation;
- The emergence of a need for new or extended functionality;
- The discovery of performance issues – capacity or speed limitations with a wide range of possible causes; and
- The discovery of anomalous or unstable behaviour with a wide range of possible causes.

Depending on the number of units in service and their age, Energex's response may be to:

- Do nothing, because the product will soon no longer be used;
- Provide application support;
- Upgrade or replace the product;
- Port the product to a new platform;
- Investigate a problem and repair the product (find and fix bugs);
- Implement new features or extend existing features in an existing product; and
- Develop a new product.

Detailed evaluation is performed to determine the appropriate response.

3.2.3 Continuous Improvement History (Recent Examples)

Between 2010 and 2015, SPARQ issued 108 software releases of new, altered, enhanced or repaired SACS and SICM software, and related administrative activities. Appendix 1 itemises and describes these releases.

One example from each of the above trigger categories is included in the table below.

Trigger Category	Issue	Benefit	Action
The introduction of a new or upgraded hardware or software component, often due to obsolescence of an existing component	[redacted] SACS CPU card obsolescence	[redacted] SACS product line continuity. Availability of new and improved features (e.g. speed). Compliance with the latest Standards. Continuity of vendor support	Select a replacement card. Determine implement and test configuration for compatibility with the rest of the ecosystem, e.g. operating system and peripherals
A change to a system with which the product must exchange data	Replacement of the [redacted] DMS [redacted]	Avoided cost to Energex [redacted] to implement an "orphan" protocol	[redacted]
An announcement from a vendor that software used by Energex will no longer be supported	Cessation of vendor support for [redacted] libraries currently in use by Energex	Improved cyber security. Improved software robustness. Availability of new and improved features. Continuity of vendor support for the libraries	Upgrade [redacted] protocol suite to use the latest version [redacted]
Difficulty applying an	Inability to apply VVR5	Avoided cost of finding	Add "dummy buses"

Trigger Category	Issue	Benefit	Action
existing software product to a specific situation	in modular zone substations with combined feeder/bus tie CBs (a new, cost saving substation configuration)	or developing, integrating and deploying an alternative volt/var regulation product	and associated configuration to existing VVR5 application
The emergence of a need for new or extended functionality	Reversion of power system planning guidelines from N-1 to risk-based planning	Reduced or avoided plant tripping due to overload in N-1 conditions resulting in avoided CAIDI and SAIDI	Derive new Network Overload Mitigation Software (NOMS) application from existing Plant Overload Protection Software (POPS) application
The discovery of performance issues – capacity or speed limitations with a wide range of possible causes	Status and alarms not reported from poletop switchgear sites [redacted] -	Avoided risk of Operators viewing incorrect power system status and hence making incorrect operating decisions	Reconfigure [redacted] Gateways fo[redacted] ntegrity scan period
The discovery of anomalous or unstable behaviour with a wide range of possible causes	Sustained overvoltages due to anomalous operation of VVR5 (various instances, some giving rise to safety investigations and actions)	Avoided risks: Customer and Energex equipment damage; Injury or loss of life caused by fire or explosion	Conduct investigations. Specify, develop and test VVR5 enhancements

Table 2: Continuous Improvement History (Recent Examples)

3.3 Distribution System SCADA

3.3.1 Background

Distribution System SCADA (DSS) is SCADA for the distribution system – remote monitoring and control of poletop and kerbside equipment. DSS enables faster response and more effective power system operations such as:

- Live line access for power system augmentation and maintenance;
- Adaptation of protection settings to current conditions (e.g. bushfire days, load transfer);
- Load transfers;
- Fault diagnosis;
- Partial supply restoration after faults; and
- Load monitoring.

The plant under DSS control includes Automatic Circuit Reclosers (ACRs), sectionalisers, load break switches, Step Voltage Regulators (SVRs) and Ring Main Units (RMUs).

Distribution system plant such as this differs from substation plant in that the equipment supervision, protection and SCADA functions are typically “embedded,” i.e. the plant, its electronic controller and the controller software are designed, manufactured and delivered as an integrated system. In the SCADA domain, the controller is often referred to as an Integrated Electronic Device (IED), and embedded software is referred to as “firmware”. In pursuit of seamless interoperability with the rest of the SCADA and automation system, Energex relies on Standards such as RS-232/RS-485 (for electrical signal compatibility) and [redacted] (for SCADA communication).

Like all software, firmware evolves over time as bugs are fixed and new features are added.

Vendors usually supply and maintain “configurator” software – PC-based software used by service technicians to configure the controller, diagnose faults, retrieve event logs and oscillographic records, and update controller firmware. Configurator software also evolves over time as bugs are fixed and new features are added. Configurator software is not covered by Standards and there is usually a unique configurator product per manufacturer and sometimes even per product line.

Energex does not maintain or tamper with DSS equipment firmware or configurator software - it is treated as a standard product of the manufacturer. When a firmware and/or configurator software upgrade is announced, Energex assesses the need to upgrade.

The ability to remotely install new firmware (a feature of so-called “remote engineering access”) could significantly reduce some barriers to adoption of new and enhanced firmware, but at present the DSS communication system used by Energex, the [redacted] mesh radio system, cannot efficiently support remote access. For this reason, upgrades are generally motivated only by unacceptable risks (associated with bugs) or rewards (associated with new features).

The DSS fleet currently contains RMUs (which are not integrated devices) plus:

- 2,238 poletop switches (ACRs, sectionalisers and load break switches);
- 26 SVRs; and
- 2 capacitor controllers.

The number of SVRs is increasing following the recent successful integration[1] of the [redacted] controller.

[1] In this context, “integration” means the work necessary to (a) determine global configuration settings that enable efficient and trouble-free interoperation the rest of the SCADA and automaton ecosystem, and (b) ensure that the new products are correctly and efficiently modelled in engineering design and asset management toolsets.

3.3.2 Continuous Improvement History (Recent Examples)

The following examples illustrate the need:

- Energex called tenders for the supply of 11kV SVRs. The winning manufacturer's offer included the capability for remote monitoring and control using the Industry Standard [redacted] protocol. The benefits of remote monitoring and control were assessed as being significant, especially as SVRs are typically installed on long and/or remote feeders. Energex selected a suitable subset of the available indications and controls and carried out integration and testing works. SCADA control is now a standard feature of this network building block.
- One manufacturer's 11kV load break switches started to malfunction in the field. The cause was traced to the substitution of the original drive motor with another having different characteristics. The problem could be resolved without hardware changes by modifying the controller firmware. The manufacturer developed and released new firmware. After testing the firmware, Energex installed it on the affected subset of switches, about 50 in total. The new firmware was made "standard" for new installations and maintenance retrofits.
- One manufacturer's 33kV ACRs exhibited spurious tripping under reverse power flow conditions. The problem was limited to a few ACRs, but the impact was significant because the ACRs were installed on the 33kV subtransmission network. The manufacturer diagnosed the cause as a firmware bug, and released bug-fixed version of the firmware. After testing the firmware, Energex installed it on the affected subset of ACRs. The new firmware was made "standard" for new installations and maintenance retrofits.

3.3.3 Requirements

In accordance with best practice in cybersecurity (as defined by NERC CIP guidelines), new firmware should be tested and made available for installation in cases where it addresses cybersecurity vulnerabilities to which Energex is exposed.

The authorised version of firmware for one manufacturer's ACR is over 10 years old and is many versions out of date. The associated hardware is no longer manufactured. Some of these ACRs have exhibited anomalous behaviour – whether this is due to the age of the equipment or a bug in the firmware is unknown, but the manufacturer's ability to provide support is constrained by the age of the firmware. Energex believes the best strategy for this situation is to test the latest (and possibly the last, for this model) version of firmware and make it available for installation for problem investigations and future maintenance retrofits.

Advances in technology make it possible to configure an ACR with multiple "protection setting groups" and also to implement "live line sequence" control (also known as "hot line tag" control). The ability to select between protection setting groups makes it possible to use the settings most appropriate to current power system conditions (e.g. bush fire day, or abnormal power flow due to load transfer). Live line sequence control sets a new benchmark for ALARP risk in live line operations. Turning the control "On" disables automatic reclosing and simultaneously selects fast, sensitive protection settings. The adoption of new firmware, remote protection setting group selection for remote live line sequence control will be implemented.

Figure 1: Remotely Controlled Load Break Switch (Side Mount) with Auxiliary Supply VT, Controller and Radio Antenna

4 Options

4.1 Option 1 – Doing Nothing

The “do nothing” option accepts continued operation of existing systems with software deficiencies, resulting in increasing likelihood of bugs or cybersecurity resulting in safety, legislated, business and customer risks being realised.

The failure to continuously improve existing substation SCADA and automation software will result in limitations and bugs in key substation automation applications remaining present in the network. This has associated risks with the software not operating as expected which could result in for example the inability to identify overvoltages, unexpected behaviour or lack of response to controller commands which would have potential safety consequences. Current system limitations are likely to result in the inability to implement new operating policies, particularly safety-related policies. An example is the live-line sequence control on devices not previously configured with this feature. The use of this feature has significant safety benefits for live line crews.

Risk of the do nothing approach is quantified in the untreated risk scenarios in Table 3.

Category	Risk Scenario	Consequence	Likelihood	Risk Score
Safety	A defect in the VVR software causes the RTU to incorrectly increase tap settings, causing an overvoltage excursion, resulting in a house fire and multiple fatalities.	6	2	12 (Moderate Risk)
	Failure to remedy firmware bug in DSS controlled network switch results in mal-operation and consequential single serious injury.	3	2	6 (Low Risk)
Customer Impact	A defect in the VVR software causes the RTU to incorrectly increase tap settings, causing an overvoltage excursion, resulting in a damage to customer equipment	4	3	12 (Moderate Risk)
Legislated Requirements	A defect in the VVR software causes the RTU to incorrectly increase tap settings, causing an overvoltage excursion that needs to be reported to the regulator.	4	3	12 (Moderate Risk)
	Failure to remedy firmware bug in DSS controlled network switch results in mal-operation and consequential dangerous electrical incident.	4	3	12 (Moderate Risk)
Business Impact	A defect in the VVR software causes the RTU to incorrectly increase tap settings, compliance breach with Energex standards and policy	3	3	9 (Low Risk)

Table 3: Untreated Risk Assessment Summary – Software Continuous Improvement Program

4.2 Option 2 – Bug fixes and feature enhancements to substation SCADA automation and DSS software

4.2.1 Summary

This program funds the new development of software improvements and high priority bug fixes. Software improvements are triggered by shortcomings in existing products, or by the need to meet new business requirements. The improvements can be deployed to new installations in the course of normal business. However, the roll out of software improvements to existing installations is funded through the SCADA Feature Implementation program.

4.2.2 Impact analysis

Historically, software changes have been driven by changes to security standards. For example:

- The NOMS project, $0.9 million, was undertaken in support of a change to the power system planning guidelines; and
- The safety driven VVR5 Enhancement project, $1.2 million, includes an allowance for the improvement of software test facilities.

Appendix 2 itemises and describes software continuous improvements currently underway or identified. The benefit from the software improvements will not be fully realised until the projects are completed thus continued funding is required in the 2015/16 – 2019/20 regulatory period to ensure the benefits are realised.

Appendix 3 itemises and describes anomalous behaviours of existing software requiring investigation and possible remediation (bug fixing and administrative activities).

The occurrence of unexpected software bugs or future changes in security standards are unable to be predicted, however funding for these changes is critical to ensure that SCADA automation and DSS software is maintained.

The following table demonstrates the process flow for software continuous improvements required under this program.

Phase	Task	Outcome
Pre-project (Initially funded from OPEX)	Investigation	Problem or opportunity is characterised and understood
	Risk / opportunity assessment	Associated risk or opportunity is quantified
	Ranking	Item is ranked on the bug list or wish list
Initiate	Requirements elucidation	Functional and non-functional characteristics of new / modified software products are documented and agreed. Acceptance criteria are documented and agreed
	High-level design and architectural compliance assessment	Nature of software changes (including changes to associated products, e.g. engineering toolset) is documented and agreed. High level cost estimate is agreed
Design/develop	Specification	Detailed requirements are documented and agreed. Test criteria are documented and agreed

	Detailed design	Major design artefacts are produced and agreed
	Implementation	Major software artefacts and documentation are produced, unit tested and integration tested. Test suites are produced
	SME training	SMEs and testers are familiarised with new / modified software products
	Verification and validation	New / modified software products are tested and (where necessary) remediated. Provisional acceptance
Construct / trial	Non-SME training	Affected non-SMEs are familiarised with new / modified software products
	Field trial design	Field trial sites are selected. Individual deployments are designed
	Field trial	New / modified software products are deployed to the field and monitored. Final acceptance
Closeout	Closeout	Learnings are assimilated. Project is finalised

Table 4: Software Continuous Improvement Process

5 Proposed Works

It is proposed to implement Option 2 to remediate bugs and develop feature enhancements to substation SCADA and automation and DSS software. This option was selected as it provides a sustainable approach to addressing the identified limitations and managing risks to tolerable levels.

The following table provides a summary of the treated risks.

Category	Risk Scenario	Consequence	Likelihood	Risk Score
Safety	A defect in the VVR software causes the RTU to incorrectly increase tap settings, causing an overvoltage excursion, resulting in a house fire and multiple fatalities.	6	1	6 (Low Risk)
	Failure to remedy firmware bug in DSS controlled network switch results in mal-operation and consequential single serious injury.	3	1	3 (Very Low Risk)
Customer Impact	A defect in the VVR software causes the RTU to incorrectly increase tap settings, causing an overvoltage excursion, resulting in a damage to customer equipment	4	1	4 (Very Low Risk)
Legislated Requirements	A defect in the VVR software causes the RTU to incorrectly increase tap settings, causing an overvoltage excursion that needs to be reported to the regulator.	4	1	4 (Very Low Risk)
	Failure to remedy firmware bug in DSS controlled network switch results in mal-operation and consequential dangerous electrical incident.	4	1	
Business Impact	A defect in the VVR software causes the RTU to incorrectly increase tap settings, compliance breach with Energex standards and policy	3	1	3 (Very Low Risk)

Table 5: Treated Risk Assessment Summary – Software Continuous Improvement Program

6 Required Expenditure

Table 6 below outlines the required expenditure for Option 2, $1.3 million for substation SCADA and automation and $0.2 million for DSS software which is the preferred Software Continuous Improvement program in this business case.

$m, 2014/15	2015/16	2016/17	2017/18	2018/19	2019/20
Energex Revised Proposal	0.3	0.3	0.3	0.3	0.3

Table 6: Proposed Program Expenditure

7 Recommendations

It is recommended that Option 2 be endorsed for inclusion in the programs of work and reflected in Energex's revised regulatory proposal for the 2015/16 – 2019/20 regulatory period.

Appendix 1 – Recent (2010-2015) Software Releases

Platform Classification	Classification	Count	Totals
[redacted]	BM	4	31
	BS	4	
	CD	7	
	EL	1	
	EM	2	
	ES	13	
[redacted]	BS	1	2
	EM	1	
[redacted]	BM	1	11
	BS	5	
	CD	2	
	EM	1	
	UP	2	
[redacted]	BL	1	60
	BM	9	
	BS	18	
	CD	10	
	EL	5	
	EM	1	
	ES	14	
	UA	2	
[redacted]	UP	1	1
[redacted]	BM	1	3
	BS	1	
	EL	1	

Classification	Description
	Unclassified
BL	Bug fix large
BM	Bug fix medium
BS	Bug fix small
CD	Configuration data change(s) or minor script change(s)
D	Documentation
EL	Enhancement large
EM	Enhancement medium
ES	Enhancement small
N	Not software
UA	Upgrade application, e.g. new version of infrastructure or utility
UP	Upgrade platform and/or port existing application to new platform

Appendix 2 – Development Candidates

Feature * Development in progress	Type (New, Enhancement, Refresh)	Development Trigger
NOMS*	New – derived from existing	• POPS (Plant Overload Protection Software) was developed for substation RTUs in the 1990s to support the risk-based power system planning regime in place at that time • POPS detects overloads caused by contingency events, and can automatically reduce load to below the 2 hour emergency rating using a range of pre-programed control measures • The 2012 review of network planning standards resulted in a reversion to a risk-based planning regime • Approval has been given to enhance POPS to improve its flexibility and usability • The enhanced version will be called NOMS (Network Overload Mitigation Software)
VVR5 Enhancements*	Enhancement	• Some failure modes (hardware, software and operational) of the current volt/var regulation system result in avoidable system overvoltages • Recent overvoltage incidents have resulted in damage to both customer and Energex equipment, with consequent damage to Energex's bottom line and brand reputation • Approval has been given to enhance VVR5 and the associated configuration mechanism and user interface, in order to reduce the incidence of system overvoltages
Enhanced Time Synchronisation*	Enhancement	• The speed and quality of post-incident investigations are hampered by the accuracy of time stamps on power system event data • Accepted good practice for time synchronisation accuracy is approximately 1 millisecond • At present, time synchronisation within the SCADA and automation system is achieved via the SCADA communication protocols – overall accuracy is no better than tens of milliseconds • The majority of recent-model protective relays used by Energex have a time

		synchronisation interface, but none are synchronised - their internal clocks are set manually on commissioning and occasionally thereafter. Some relays have subsequently been found to be adrift by several seconds • As a result, post-incident investigations must begin with the time consuming and error prone task of manually aligning and interleaving event records • The cost of standards-based time synchronisation equipment and systems is decreasing, aided by the rollout of the IP/MPLS communication network • Approval has been given to develop an enhanced time synchronisation capability for substation automation systems (including protective relays and other IEDs, whether or not integrated with the SCADA and automation system) • Additional benefits will result from the avoided costs of stand-alone GPS clocks where needed for precise time synchronisation of current differential relays in multi-ended feeder protection schemes
IP/MPLS Connectivity [redacted]	Enhancement	• The rollout of the IP/MPLS network will enable faster, higher volume, more reliable SCADA communications • This will have many benefits, including the enablement of advanced asset management practices for both the primary and secondary systems • It will also facilitate the ultimate retirement of [redacted] in-house products) • Approval has been given to develop [redacted] enhancements to take advantage of this new technology
RTU Monitoring and Management *	Enhancement	• As a matter of policy, new OT products must include contemporary monitoring and management features [redacted] • This enables more efficient modes of asset management facilitated by the collection of asset condition data • It also enables failure response to be managed efficiently by the OT Operations Centre • Approval has been given to develop monitoring and management enhancements for [redacted] RTUs to be integrated into this architecture • Under this project, monitoring “hooks” will be added to most SACS applications.

		Repeated testing will be avoided by doing this work in conjunction with the [redacted] Upgrade project, in which the applications will also have to be tested
[redacted]	Refresh	• Vendor support for the currently deployed version of [redacted] has ceased • The currently supported version of [redacted] does not support IDE disk drives, which are used in the current standard hardware • The currently used CPU card supports only IDE disk drives • A [redacted] upgrade therefore mandates a CPU card upgrade • See also "CPU Card Upgrade for [redacted]" A [redacted] upgrade and the associated CPU upgrade could be avoided by migrating to a COTS RTU before stocks of the currently used CPU card are exhausted, and before IDE disk drives can no longer be purchased; however Energex does not have the resources to properly orchestrate a migration in this time frame • Under this project, all SACS applications will have to be recompiled. Repeated testing will be avoided by doing this work in conjunction with the RTU Monitoring and Management project, in which the applications will also have to be tested
CPU Card Upgrade [redacted]	Refresh	• The currently used CPU card has reached end of life • Because of changes in technology standards, an interchangeable replacement with a reasonable remaining life cannot be sourced • Energex has purchased enough CPU cards to last for a considerable time; however the card supports only IDE disk drives which are becoming harder to source • A CPU card upgrade could be avoided by migrating to a COTS RTU before stocks of the currently used CPU card are exhausted, and before IDE disk drives can no longer be purchased; however Energex does not have the resources to properly orchestrate a migration in this time frame
SICM2B Refresh	Refresh	• The SICM2B is an in-house [redacted] compliant IED that serves as an interface between substation secondary equipment and the SCADA system • Standard configurations exist to suit the many roles in which the SICM2B can be deployed • Over 6000 units are in service throughout Energex • The SICM2B will remain a standard building

		block for some years, filling specialised niches for which COTS products cannot be identified • A refresh will be needed when any major component goes to obsolescence, as is anticipated within the 2015-2020 period
SCADA Load Measurement Improvements	Enhancement	• Energy sometimes flows "upstream" on some Energex distribution feeders due to solar PV generation • Directional power flow measurements will be provided by substation and DSS standard building blocks currently under development; however existing measurements (the vast majority) are non-directional • Hence power system planning data is being compromised • The extent of the problem is increasing as solar PV penetration deepens
[redacted]	[redacted]	[redacted]
Product-specific Software Versions	Enhancement	• Some SCADA and automation software products are used on multiple platforms[redacted] • Until now, Energex has had a policy of producing common releases for all platforms, with the objective of preventing code divergence between platforms • This policy has caused unacceptable deployment delays in cases where parallel changes have been required for different platforms, due to the need to test all changes on all platforms prior to a release • The installation and use of contemporary version management and testing tools and methodologies will avert future problems of this nature
SCADAbase Enhancements	Enhancement	• SCADAbase is the configuration manager for Energex's SCADA and automation systems

		• It supports two major processes: Design and Build • In the Design process, an abstract specification for the end-to end system is maintained on a project-by-project basis • In the Build process, configuration data for each device impacted by a design change is built, in the format required by that device. Automation ensures consistency and boosts productivity • The use of a common “source of truth” ensures that all devices are configured consistently, minimising configuration errors • From time to time, business changes result in the need to add or modify SCADAbase functionality • An example is the need to support “operational changes” to application parameters such as VVR settings, in effect allowing site changes to be made without the need for a full Design/Build cycle. This increases the operational efficacy of the SCADA and automation systems (flexibility and speed of response to the needs of Network Operators) • It is not always possible to foresee the need for such enhancements because they can be reactive to external influences, unforeseen business opportunities or risks • Furthermore, enhancements of a general nature such as this cannot always be funded by the operate/maintain budget for SCADAbase

Appendix 3 – Remediation Candidates

Classification	Description
	Unclassified
BL	Bug fix large
BM	Bug fix medium
BS	Bug fix small
CD	Configuration data change(s) or minor script change(s)
D	Documentation
EL	Enhancement large
EM	Enhancement medium
ES	Enhancement small
N	Not software
UA	Upgrade application, e.g. new version of infrastructure or utility
UP	Upgrade platform and/or port existing application to new platform

Platform Class'n	Count
[redacted]	**37**
BM	1
BS	17
CD	10
D	3
EL	1
EM	2
ES	2
UP	1
[redacted]	**2**
BS	1
[redacted]	**8**
BS	4
CD	2
ES	1
UP	1
[redacted]	**58**
BS	37
CD	6

EM	1
ES	12
N	2
SICM (any)	**2**
BS	2
SICM2B	**2**
BS	2

PUBLIC

Energex

OT Environment - Establishment and Migrations Program

Asset Management Division

energex

positive energy

Energex

OT Environment Establishment and Migrations Program 2015/16 - 2019/20

Reviewed:

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Group Manager Asset Life Cycle Management

Endorsed:

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Executive General Manager Asset Management

Version control

Version	Date	Description
1	1/07/2015	Submitted

Energex Limited (Energex) is a Queensland Government Owned Corporation that builds, owns, operates and maintains the electricity distribution network in the growing region of South East Queensland. Energex provides distribution services to almost 1.4 million domestic and business connections, delivering electricity to a population base of around 3.2 million people.

Energex's key focus is distributing safe, reliable and affordable electricity in a commercially balanced way that provides value for its customers, manages risk and builds a sustainable future.

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Executive Summary

Energex has established an Operational Technology Environment (OTE) to enable operationally critical Information Technology (IT) solutions to be deployed into a suitably architected, secure network environment. The OTE is separated from, but connected with the corporate IT network environment. Applications hosted within the OTE communicate with field devices on the distribution electrical network via the Energex high speed fibre communications network which supports contemporary Internet Protocol communications, as well as through older legacy telecommunication networks and links.

The OTE was established initially to facilitate the deployment of the new Distribution Management System (DMS), the Network Management Systems (NMS) for the operational telecommunications networks, and other associated operationally relevant IT systems. Due to the significance and complexity of establishing the OTE and deployment of these systems, a phased implementation approach was adopted. This includes the eventual migration of other operationally relevant applications from the Corporate IT environment into the OTE, and the further enhancements to address emerging cyber risks. The OTE Establishment and Migrations program for the 2015/16 – 2019/20 period has been prepared to progress this outstanding work. The major drivers for this program include:

- Enable Energex's future ability to deliver new capability which meets various service standards (such as Minimum Service Standards in the Electricity Industry Code);
- [redacted]
- Ensure OTE systems are able to address reliability, availability, [redacted]

Incorporated within Energex's original regulatory submission were expenditure requirements of $4 million over the 2015/16 – 2019/20 to mitigate those risks identified to be of most concern. The revised program remains unchanged from the original proposal and only addresses the highest risk issues.

It should be noted the expenditure for this program is not accounted for in the modelled REPEX programs. The following table outlines the required expenditure being $4 million over the 2015/16 – 2019/20 regulatory period. Timing of some work within the period has changed to reflect current requirements and ensure efficient delivery.

$m, 2014/15	2015/16	2016/17	2017/18	2018/19	2019/20	Total
Energex Proposal	0.8	0.8	0.8	0.8	0.8	4.0
Energex Revised Proposal	0.7	0.4	1.4	1.4	0.1	4.0

Contents

1 Introduction

The purpose of this document is to outline the required expenditure for the Operational Technology Environment (OTE) establishment and migrations program.

Managing, monitoring and operating a contemporary electricity network increasingly involves Information Technology (IT) and computer systems as well as the traditional substations, poles and wires. This change has driven improved network performance and better customer outcomes through safer and more reliable network operation.

Energex has established an Operational Technology Environment (OTE) to enable operationally important Information Technology (IT) solutions to be deployed into a suitably architected, secure network environment. The OTE environment was proposed as part of a Joint Workings initiative with Ergon Energy known as PRISE (Power Related Intelligent System Evolution). The PRISE project identified the need for an Information Technology environment that was architected to meet the reliability, availability and cyber security requirements of the multitude of new solutions that are becoming available for power distribution companies.

The PRISE project proposed architectures and methodologies that have been since refined and updated to realise the OTE network that is now operating.

The OTE is separated from, but connected with the Corporate IT network environment. Applications hosted within the OTE communicate with field devices via the core IP/MPLS network, substation legacy network, or carrier fringe networks.

This program will include the following:

- [redacted]
- Enhancements to the OTE environment [redacted]
- Migration of applications to the environment
- [redacted]

2 Drivers

The major drivers for this program include:

- Enable Energex's future ability to deliver new capability which meets various service standards (such as Minimum Service Standards in the Electricity Industry Code).
- [redacted]
- Ensure OTE systems are able to address reliability, availability [redacted] concerns.

The OTE was established initially to facilitate the deployment of the new Distribution Management System (DMS), the Network Management Systems (NMS) for the operational telecommunications networks, and other associated operationally relevant IT systems. Due to the significance and complexity of establishing the OTE, and the deployment of these systems, a phased implementation approach was adopted, which includes the eventual migration of other operationally relevant applications from the Corporate LAN environment into the OTE, [redacted]

The OTE Establishment and Migrations program for the 2015/16 – 2019/20 period has been prepared to progress this outstanding work and consists of the following programs which are discussed in more detail in Section 3:

- [redacted]
- PQM Meters
- Monitoring environment establishment
- [redacted]
- Application migrations
- CP2 console replacement

3 Supporting Analysis

3.1 [redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

3.2 Power Quality Meter Data Collection (PQM)

PQMs at substation will help ensure Energex can meet its regulatory and technical standard obligations for power quality. The criteria include:

- Magnitude of Power Frequency Voltage
- Voltage Fluctuations
- Voltage Harmonic Distortion
- Voltage Unbalance

This project will establish server infrastructure [redacted] for substation Power Quality Meters.

Energex is installing Power Quality Meters into substations to provide data on the performance of the electrical supply quality. The PQMs are generally funded under various substation projects and there is a current project to retrofit the PQM's to additional specific sites.

The communications path for the PQM's is provided by the Energex IP/MPLS telecommunications network which is being delivered by Project Matrix.

Hence, the PQM's and the communications path will be provided under other initiatives, however the computing system to collect the data and make it available for analysis will be provided by this project.

This project will provide server infrastructure and software systems [redacted] to collect the data, and software systems [redacted] allow the data to be replicated into the corporate network for analytics and reporting. Without the computing system proposed under this project, the data from the PQM will not be able to be gathered and the sunk cost for the PQM project will not provide a benefit to the business.

3.3 Monitoring Environment Establishment

The deployment of the OTE and the IP/MPLS has provided a foundation for secure and high speed systems reach into substations.

Any new application requires significant planning, design, review and approval before deployment is approved. This process ensures cyber security requirements are met as well as usability. The process is quite onerous and time consuming, but appropriate for deploying a new system or migrating a system.

Energex is constantly investigating new tools and technologies to improve the efficiency of managing and operating the distribution network. This often involves trialling a piece of equipment at a substation and gathering data.

[redacted]

The effort and cost required to deploy a short term evaluation or trial into the OTE and IP/MPLS network [redacted] is high. This project proposes to establish a new environment that [redacted] is isolated from the OTE, and minimises risk to the corporate network.

This will allow Energex to conduct trials of new equipment that requires a communication path at minimal cost, minimal effort and protection of the OTE and corporate network.

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

3.5 Application Migrations

[redacted]

The project will migrate or interface a number of applications and legacy networks into the OTE. [redacted]

- [redacted]

3.5.1 [redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted] [redacted]

[redacted]

[redacted]

[redacted]

[redacted] [redacted]

[redacted]

[redacted]

[redacted] [redacted]

[redacted]

[redacted]

3.6 CP2 replacement

The CP2 is a console for the Trunk Mobile Radio system. The Trunk Mobile Radio (TMR) system is a radio network provided by Telstra. Energex uses the TMR for voice communications to field crews where mobile phone coverage is not available, emergency communication and as an alternate to mobile phones during times of natural disaster. Any failure of the CP2 consoles will reduce voice communications capability to the field crew in remote areas. This will lead to increased cost to perform maintenance and repair activity in remote areas and delay emergency response.

The CP2 have facilities specially designed for radio dispatcher operation. In addition to speech calls, they are capable of handling different types of data messages, (call requests with TMR number displayed, user-definable status messages and text). Multiple speech calls can be buffered at the exchange and retained in the incoming call queue for the CP2. Incoming data messages are stored into CP2 data buffer memory. Both speech and data call buffers can be browsed and the contents displayed. The operator can select any stored speech or data call for reply.

The CP2 consoles have been end of life for over 4 years. Energex does not hold any spares and spares are not available for purchase.

A solution is required to replace the equipment, the project will determine a suitable solution and implement the result into the OTE.

4 Options

4.1 Impact of Doing Nothing

The "do nothing" option would fail to [redacted] provide an Operational Technology Environment suitable for Energex's current and future distribution network requirements.

Risk of the do nothing approach is quantified in the untreated risk scenarios in Table 1.

Category	Risk Scenario	Consequence	Likelihood	Risk Score
Safety	[redacted]	6	2	12 (Moderate Risk)
Customer Impact	[redacted]	4	3	12 (Moderate Risk)
Business Impact	[redacted]	4	3	12 (Moderate Risk)

Table 1: Untreated Risk Assessment Summary – OTE Establishment and Migrations

This outcome is not tolerable to Energex, with untreated risks not considered to be As Low As Reasonably Practicable (ALARP).

4.2 Option 1 – Complete Higher Risk Projects (recommended)

4.2.1 Summary

This option proposes to undertake only the medium and high risk projects associated with the Operation Technology Environment as per the original proposal with a revised timing of expenditure. These projects include:

- [redacted]
- PQM Data Collection
- Monitoring environment establishment
- [redacted]
- Application Migrations
- CP2 Replacement

Refer to Appendix 1 for a full list of candidate projects.

4.2.2 Impact analysis

The following table provides a summary of the treated risks under this option.

Risk	Risk Scenario	Consequence	Likelihood	Score
Safety	[redacted]	6	1	6 (Low)
Customer Impact	[redacted]	4	1	4 (Very Low)
Business Impact	[redacted]	4	1	4 (Very Low)

Table 2: Treated Risk Assessment Summary – OTE Establishment and Migrations

Table 3 below outlines the required expenditure for the OT Environment Establishment and Migrations program under Option 1.

Description	2015/16	2016/17	2017/18	2018/19	2019/20
Expenditure $m, 2014/15	0.7	0.4	1.4	1.4	0.1

Table 3: Expenditure – Option 1

4.3 Option 2 – Complete All Candidate Projects

4.3.1 Summary

This option is to undertake all the identified candidate projects as outlined in Appendix 1 in order to fulfil Energex's strategic plan for migration to the OTE, [redacted] and to have an environment that can adapt easily to unforeseen requirements.

4.3.2 Impact analysis

Table 4 below outlines the required expenditure for the OT Environment Establishment and Migrations program under Option 2. The total estimated cost of this option is $13.5m. Whilst, in the absence of funding restraints, this would be Energex's preferred option because it delivers the intent of the strategic plan, Energex's proposal in this business case is to adopt a higher risk profile embodied in Option 1.

Description	2015/16	2016/17	2017/18	2018/19	2019/20
Expenditure $m, 2014/15	2.7	2.7	2.7	2.7	2.7

Table 4: Expenditure – Option 2

5 Proposed Works

It is proposed to implement Option 1 to complete the higher risk projects in the OTE space in the 2015/16 – 2019/20 period under this program. This option was selected as it provides a sustainable approach for addressing the identified limitations and managing risks to tolerable levels. Table 5 shows the projects proposed as part of the program and the expenditure for each.

Proposed project	Expenditure $m, 2014/15
Migrate distribution transformer monitoring to OTE	0.29
[redacted]	2.59
Monitoring environment establishment	0.21
[redacted]	0.52
Application migrations	0.29
CP2 console replacement	0.10
Total	**4.00**

Table 5: Proposed Works

6 Required Expenditure

Table 6 below outlines the required expenditure for Option 1, which is the preferred OT Environment Establishment and Migrations program in this business case.

Description	2015/16	2016/17	2017/18	2018/19	2019/20
Expenditure $m, 2014/15	0.7	0.4	1.4	1.4	0.1

Table 6: Proposed Program Expenditure

7 Recommendations

It is recommended that Option 1 be endorsed for inclusion in the programs of work and reflected in Energex's revised regulatory proposal for the 2015/16 – 2019/20 regulatory period.

Appendix 1: OTE Candidate Projects

The list below shows the projects that were considered as part of this program. Energex ranked the projects and removed those projects that were seen as lower risk from the recommended program under Option 1.

Candidate Project	Included in Option 1	Included in Option 2
[redacted]	Y	Y
PQ Meters	Y	Y
Monitoring environment establishment	Y	Y
[redacted]	Y	Y
Application migrations	Y	Y
CP2 console replacement	Y	Y
[redacted]	N	Y
Video surveillance for bulk supply substations	N	Y
Video surveillance for remote repeater stations	N	Y
Video surveillance for zone substations	N	Y
[redacted]	N	Y
Centralised Alarm Management solution	N	Y
[redacted]	N	Y
[redacted]	N	Y
[redacted]	N	Y
[redacted]	N	Y
Environmental monitoring	N	Y
[redacted]	N	Y
VOIP cutover for sites already on MPLS	N	Y
[redacted]	N	Y
Trouble ticketing integration	N	Y
Asset inventory integration	N	Y

PUBLIC

Energex

OT Environment - Refurbishment

Asset Management Division

positive energy

Energex

OT Environment - Refurbishment 2015/16 - 2019/20

Reviewed:

Tim Hart

Group Manager Asset Life Cycle Management

Endorsed:

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Executive General Manager Asset Management

Version control

Version	Date	Description
1	1/07/2015	Submitted

Energex Limited (Energex) is a Queensland Government Owned Corporation that builds, owns, operates and maintains the electricity distribution network in the growing region of South East Queensland. Energex provides distribution services to almost 1.4 million domestic and business connections, delivering electricity to a population base of around 3.2 million people.

Energex's key focus is distributing safe, reliable and affordable electricity in a commercially balanced way that provides value for its customers, manages risk and builds a sustainable future.

Group Manager
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Executive Summary

The purpose of this document is to outline the required expenditure for replacement of equipment associated with the Operational Technology Environment (OTE) over the 2015/16 – 2019/20 regulatory period. This expenditure is not accounted for in the modelled REPEX programs.

Energex's Operational Technology Environment (OTE) is an IT environment which allows operation of mission critical real time IT systems in an extensible manner that is more highly secured compared to a standard corporate IT environment . OTE allows Energex to operate the Distribution Management System (DMS), controller telephony and outage management system. The OTE is primarily housed in two data centres and comprises of communications facilities and a range of appliances and services necessary for the operation of the environment.

The OTE is a critical enabling system for the operation and maintenance of the Energex distribution network. The equipment in the OTE is aging and certain components are now end of life with increasing risk associated with in service failure. Failure of the OTE would render Energex unable to manage the power network leading to a range of safety, legislative, business and customer impacts.

The objectives of this program are to:

- Reduce safety risks to staff and the community to As Low As Reasonably Practicable that are present during an OTE network failure;
- Ensure that the OTE maintains adequate cyber security to protect Energex systems and the community and remains fit for purpose for the deployment of future "Smart Network" technologies as detailed in Energex's *SCADA and Automation Strategic Plan*;
- Meet legislated obligations with respect to provision of necessary data to AEMO as required by the national market; and
- Prevent customer outages that would result from failures in the OTE network.

Energex is committed to the delivery of sustainable outcomes for customers and the business with no compromise to safety and legislative compliance. The intent of the revised program remains unchanged from the original submission, being to replace obsolete and end of life equipment within the OTE. A review of the scope has however identified additional end of life equipment than originally noted resulting in a revised expenditure of $1.4 million over the 2015/16 – 2019/20 regulatory period.

$m, 2014/15	2015/16	2016/17	2017/18	2018/19	2019/20	Total
Energex Original Proposal	-	-	-	0.6	0.6	1.2
Energex Revised Proposal	0.2	-	-	0.9	0.3	1.4

Contents

1 Introduction

The purpose of this document is to outline the required expenditure for the replacement of OTE ageing and obsolete equipment in the period 2015/16 – 2019/20.

This program is important to enable the performance of the OTE which will ensure that:

- Energex retains remote control of the power network;
- The telephone communication systems for the power network continue to operate;
- Energex continue to deliver data necessary for compliance with the requirements of the national electricity market; and
- Energex can minimise customer outages and plant damage during power system abnormalities and faults.

The equipment to be replaced during this regulatory consist of Ethernet switches, core data centres and network routers.

2 Drivers

Obsolescence and system failure prevention are the major drivers for the replacement of the OTE equipment.

OTE equipment requires replacement when the manufacturer ceases to provide replacement components and software support. Equipment that cannot be replaced in this manner exposes Energex to potential cyber security attacks and subsequent failures reduces operational flexibility. Energex must ensure that the OTE maintains adequate cyber security to protect Energex systems and the community and remains fit for purpose for the deployment of future “Smart Network” technologies as detailed in Energex’s *SCADA and Automation Strategic Plan.*

OTE data centres host Energex operational real time systems, most critically, the DMS, as well as the telephony system for network operators. It is imperative that these operational systems function continually.

3 Supporting Analysis

Table 1 shows the equipment in the OTE datacentres and if an end of life (EOL) notice or end of support date has been issued by the manufacturer. Beyond the end of support date the manufacturer will no longer provide replacement equipment on failure, patches for any software issues or patches for cyber security vulnerabilities.

Equipment	Quantity	End of Life Notice Received	End of Support Date
[redacted]	6	Main Processor module	15 Dec 2020
[redacted]	6	Nil	
[redacted]	2	Main processor module	28 Mar 2020
[redacted]	5	Product	31 Dec 2019
[redacted]	5	Product	31 Dec 2019
[redacted]	66	Nil	
[redacted]	3	Nil	
[redacted]	3	Nil	
[redacted]	5	Product	01 Feb 2022
[redacted]	3	Product	31 Dec 2015
[redacted]	2	Nil	

Table 1: Operational Technology Equipment EOL Summary

4 Options

4.1 Impact of Doing Nothing

The “do nothing” option would entail no replacement of obsolete equipment within the OTE. As the equipment ages the likelihood of issues emerging on the equipment would continue to increase, with resultant issues and failures impacting the operation of the OTE and the Energex distribution network. The OTE is a critical part of managing Energex’s safety, operations and regulatory obligations as the OTE hosts the computer systems required to remotely manage and operate the Energex distribution network.

Should the telecommunications equipment fail, the systems in the datacentre will become unavailable and operators will not be able to remotely operate or manage the network. Power network outages that are being managed at the time of OTE issues that affect network control would have extended restoration times while personnel restart / reconfigure / replace (if possible) the required equipment. Work crews may be exposed to an increased safety risk as coordination of work and remote operation becomes more difficult during these events and Energex’s ability to respond to issues on the power network (i.e. wires down) would also impact public safety.

Risk of the do nothing approach is quantified in the untreated risk scenarios in Table 2.

Category	Risk Scenario	Consequence	Likelihood	Risk Score
Safety	OTE environment fails due to end of life equipment issues with no existing fix available and manufacturer unable to remediate. OTE out of service periodically as issue re-occurs. A wires down event away from supply occurs while OTE down and controllers are unable to de-energise the line remotely resulting in single fatality.	5	3	15 (Moderate Risk)
Customer Impact	OTE environment fails due to an issue with no existing fix available and equipment is EOL, Manufacturer unable to remediate, OTE out of service periodically as issue re-occurs. 15,000 customers experiencing service interruption due to increased time to identify cause of fault and restore as OTE out service during restoration effort.	4	3	12 (Moderate Risk)
Legislated Requirements	OTE environment fails due to an issue with no existing fix available and equipment is EOL, Manufacturer unable to remediate, OTE out of service	5	3	15 (Moderate)

Category	Risk Scenario	Consequence	Likelihood	Risk Score
	periodically as issue re-occurs. MSS target missed.			
Business Impact	OTE environment fails due to an issue with no existing fix available and equipment is EOL, Manufacturer unable to remediate, OTE out of service periodically as issue re-occurs. Periodic inability to remotely control majority of Energex network for the duration of the outage,	6	3	18 (High)

Table 2: Untreated Risk Assessment

This outcome is not tolerable to Energex, with untreated risk not considered to be As Low As Reasonably Practicable (ALARP).

4.2 Option 1 – Replace Obsolete Equipment

This option proposes to replace end of life equipment within 12 months of the end of support date.

The main processor modules reaching end of life require hardware and software replacement. New software must be analysed for:

- Changes in command line structure and syntax;
- Known bugs and limitations; and
- Memory consumption.

Other equipment requiring replacement requires the entire device replacement. Replacement equipment requires additional checks to ensure the new device meets functional requirements and any changes to operations are managed and deployed.

This option will address the various risks of not proceeding with the proposed work by ensuring that EOL equipment is removed from the environment within 12 months of the end of support date of the manufacturer.

4.3 Option 2 – Replace on Failure

This option is based on replacing the end of life equipment when it fails or begins to have issues. This option has the same level of risk as the do nothing option and is likely to cost the same as option 1. The equipment referred to in this document cannot be simply replaced like for like. The first failure of equipment like the firewall components is expected to take approximately 1 month to replace. During this time, the services and security provided by the OTE will be significantly impacted.

5 Proposed Works

It is proposed to implement Option 1 to replace end of life equipment in the OT environment within 12 months of the end of support date. The implementation of Option 1 provides a prudent approach for managing the risks associated with the end of support for obsolescent equipment in the OT Environment. The other options presented do not mitigate the risks identified.

The proposed work and cost estimates for each project is shown in the table below.

Equipment	QTY	End of Life Notice Received	End of Support Date	Cost Estimate $m 2014/15
[redacted]	6	Main Processor module	15 Dec 2020	0.23
[redacted]	2	Main processor module	28 Mar 2020	0.07
[redacted]	5	Product	31 Dec 2019	0.60
[redacted]	5	Product	31 Dec 2019	0.30
[redacted]	5	Product	01 Feb 2022	To be funded in 2020-2025
[redacted]	3	Product	31 Dec 2015	0.20
Total				**1.40**

6 Required Expenditure

Table 3 below outlines the required expenditure for the preferred option for refurbishment of OTE ageing and obsolete equipment.

$m, 2014/15	2015/16	2016/17	2017/18	2018/19	2019/20	Total
Energex Original Proposal	-	-	-	0.6	0.6	1.2
Energex Revised Proposal	0.2	-	-	0.9	0.3	1.4

Table 3: Expenditure

7 Recommendations

It is recommended that Option 1 be endorsed for inclusion in the programs of work and reflected in Energex's revised regulatory proposal for the 2015/16 – 2019/20 regulatory period.