APPENDIX 4.4

Unmodelled repex: Business cases for “SCADA” repex

PUBLIC

Energex

Protection Relay Replacement Program

Asset Management Division

energex

positive energy

Energex

Protection Relay 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

Energex seeks to continue to deliver sustainable outcomes for customers and business without compromise to existing safety or legislative compliance requirements. Effective and reliable operation of protection relays on the distribution network is vital to the provision of a safe and compliant network for staff and the community.

The purpose of this document is to outline the required expenditure for replacement of protection relays over the 2015/16 – 2019/20 regulatory period. The objectives for this program are to:

- Mitigate safety risks to staff and the community to As Low As Reasonably Practicable (ALARP);
- Provide for operation of the distribution network in continued compliance with protection requirements in the National Electricity Rules; and
- Minimise the likelihood of plant damage through reliable clearance of electrical faults

During the 2010/11 – 2014/15 regulatory period Energex replaced significant numbers of obsolete protection relays. The ongoing program of protection relay replacements in the 2015/16 to 2019/20 period and beyond are not well aligned with replacement of primary plant like circuit breakers in the reduced forward capex program, and are therefore represented as a focused standalone REPEX program.

There are in excess of 20,000 protection relays in service on the Energex network. Energex originally submitted a replacement program of 2,000 protection relays over a 5 year period to ensure a sustainable approach to managing protection relay assets, and relays within the program were prioritised on a risk basis. In the interim determination the AER stated Energex had taken a conservative risk approach. Energex has since revised its protection relay program replacements to deliver cost effective outcomes whilst focussing on replacement of high and medium priority relays that display higher failure rates and potential for relay mal-operation. This has resulted in a reduction in replacement quantities and Energex tolerating increased levels of risk.

The Energex revised program for protection relay replacements is for 850 relays for a total expenditure of $15 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	6.7	6.3	6.4	6.4	6.4	**32.2**
Energex Revised Proposal	2.4	2.6	3.0	3.5	3.5	**15.0**

Contents

1 Introduction

The purpose of this document is to outline protection relay replacement program requirements for the 2015/16 – 2019/20 regulatory period. Energex has in excess of 20,000 protection relays operating across its 357 substations.

Energex has developed a Protection Philosophy (BMS4187) which sets a basis for protection systems that meet good industry practice and deliver outcomes in accordance with the company's operating experience and risk framework and with regard to the operating environment in South East Queensland.

Protection relays form an integral component of the Energex network as they perform functions critical to the safe and reliable operation of the network. These functions as outlined in the Protection Philosophy are summarized below:

- Detect faults and hazardous abnormalities in order to isolate the faulty section of the network within an acceptably short time.
- Minimize danger to life and property.
- Reduce the extent of damage at the fault location to a tolerable level.
- Minimise the effect that a fault or abnormality has on the remainder of the network.
- Minimise the extent and duration of plant, equipment and circuit outages.
- Be reliable and be secure to avoid mal operation.

Energex recognises the need to effectively manage its protection relay assets and it has developed a risk based replacement program that gives a balanced outcome for safety risks, legislative compliance, reliability, and cost effectiveness. This builds upon Energex's recent obsolete relay replacement program which commenced in 2013 and replaced approximately 800 obsolete protection relays across the network.

The next five years will present new challenges to the organisation as many older electromechanical and analogue protection relays reach their end of life. Similarly, newer digital relays which began service in the mid 1990's are now requiring replacement due to the shorter life expectancy of these relays.

2 Drivers

2.1 Safety

Protection relays play a fundamental role within the Energex network in guarding the satefy of people. The strategic repacement of obsolete or unreliable relays is based on observed failure rates and industry standard life expectancies.

Energex has a risk register covering the network and have identified the following network risks associated with protection systems:

- Slow clearance of arcing faults in switchgear – safety/plant damage consequences
- Ineffective backup protection - safety/plant damage/reliability consequences
- Slow clearance of transformer faults with resultant fire risk
- Hi-impedance earth faults and sensitive earth fault sensitivity on overhead lines – public safety risk consequences
- No Live Line Sequence application – safety for workers

It should be noted that

2.1.1 Digital Relays

In consideration of the safety risks, there is a compelling case to replace older electromechanical and analogue relays with newer technology digital relays that offer improved safety performance. Amongst other benefits, digital relays allow for faster electrical fault clearance times by taking advantage of:

- Multiple characteristic curve shapes.
- A more precise time multiplier.
- Safer grading between protection devices.
- High set/speed clearing times
- Live line sequencing function

Higher speed clearing times provided by digital relays (typically less than 100 ms), result in lower conductor temperature rise under fault conditions. This considerably reduces the risk of conductor burn down which can result in a dangerous wires down event. The faster clearing times also reduce the risk of serious arc flash injury to field personnel working in proximity of the fault.

The Live Line Sequencing function is a standard on medium voltage feeders in a number of Southern States and has recently been approved as a standard for new 11 kV feeder protection on the Energex network. If available on a relay, live line sequencing is enabled when HV live work is being performed on the feeder. When enabled, the protection clearing time is reduced to instantaneous or within 100 ms, thereby reducing the arc fault energy in any fault that the live line worker could be in proximity to.

2.1.2 Back-up Protecton

In the medium to high voltage network, Energex aims to provide both primary and back-up protection for credible faults on the network at all times. Back-up protection is typically provided by a slower graded upsteam protection scheme which is designed to avoid a life threatening situation from developing.

There are a number of safety risks which are generally tolerated in industry standard protection practice and are implicit in the application of protection systems. These risks are:

- For a single network fault occurrence, backup protection systems may not satisfactorily clear faults where two or more circuit breakers that are required to operate to clear the fault, fail simultaneously. That is, circuit breaker fail protection systems are designed for one circuit breaker failure at a time.
- For a single network fault occurrence, backup protection systems may not satisfactorily clear faults where there is coincident failure of both of duplicated or redundant protection relays.
- Primary and/or backup protection may not operate securely or reliably in the case of simultaneous network faults at different locations.

There are however some faults on the network which are not protected by back-up protection. These generally fall in the category of 3 phase or phase to phase faults at the end of a long 11 kV feeder which are not cleared by back-up overcurrent protection.

The above factors put an extra burden on the reliability of primary protection to clear a network fault when required.

2.1.3 Wires Down Events

Approximately 70 percent of the Energex network consists of overhead bare conductors. When network faults occur, overhead conductors can fall down and pose a safety risk to field staff and the public if not adequately protected. In addition, field workers can also contact bare overhead conductors and protection systems are required to disconnect supply in the shortest possible time to reduce the risk of injury to the workers. Protection systems can minimise the associated risk through choice of protection system sensitivity, operating speed and reliability of function (backup).

On the Energex network, the cause of around 11 percent of overhead faults are conductor drops (excluding storm related faults), as shown in Figure 1. This causes a significant safety risk to the members of the public. The conductor drops are generally caused by fault current, failed joints/sleeves or vegetation impacts.

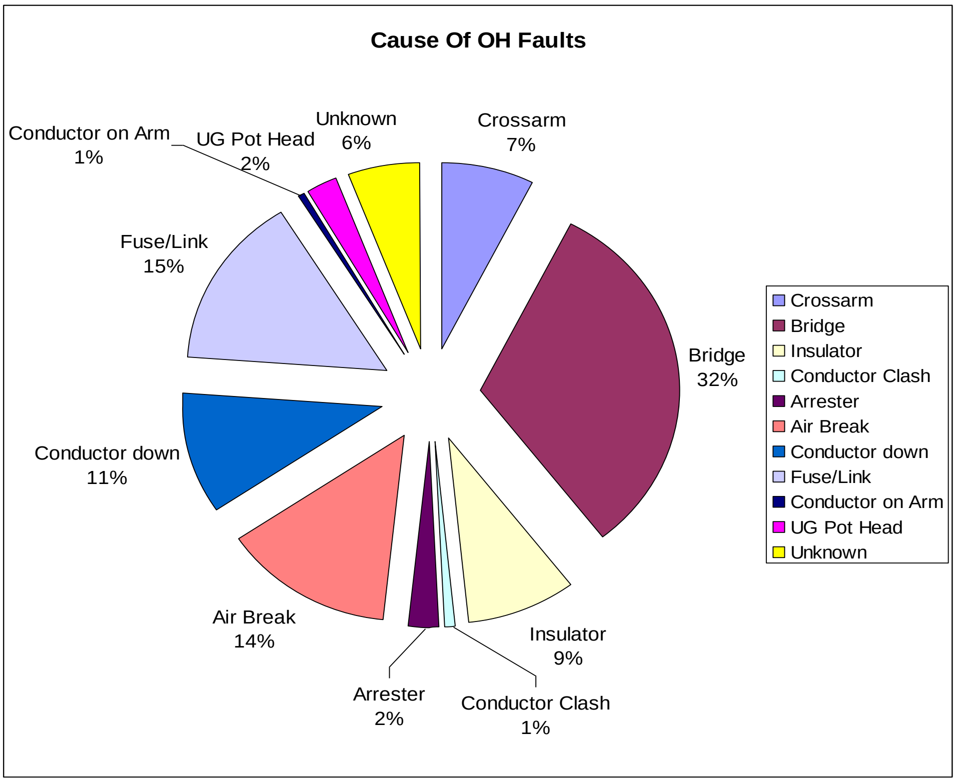

Figure 1: Causes of Overhead Fault on the Energex network.

2.2 Legislative Compliance

The protection systems installed in Energex are required to comply with and perform to the requirements of:

- National Electricity Rules (NER); in particular Section 5.1.9
- Electrical Safety Regulations (ESR)
- Good engineering practice and industry guidelines
- Connection contract obligations
- Codes of practice for Earth Potential Rise (EPR) and Low Frequency Induction (LFI)

Energex undertakes refurbishment works that can impact network protection schemes. Refurbishment works include replacing equipment as a result of demand or corrective maintenance or end of life.

The National Electricity Rules specifies;

- A performance standard commencement date of 16 November 2003 applies to facilities(substations);
- Facilities constructed or modified after 16 November 2003 are subject to technical requirements outlined in S5.1.9 (Section 5.1.9 of the NER and other relevant definitions are given in Appendix 1);
- Facilities constructed before the commencement date must maintain their existing protection capability;
- Augmentation of capacity is a modification of the facility.

The NER implies that in-situ replacement of equipment for refurbishment is not a modification.

Where refurbishment works impact protection systems at sites constructed before 16 November 2003 the minimum criteria under system normal conditions are considered to be;

- Primary protection exists for all bolted fault types;
- Sensitive earth fault protection exists for all overhead conductors;
- Other protection system related safety risks are tolerable;
- Secondary system components including communications and current transformers are suitable for any changes to protection relays or schemes;
- The protection capability of the site is not being reduced due to these works.

Refurbishment works at sites constructed or modified after 16 November 2003 should meet the above minimum criteria as well as;

- Assessed against the NER requirements and Energex policies and standards,
- Additional changes to the protection system should be included in the original works if it can be achieved at reasonable costs and timely manner and where this does not increase the overall safety risk.

Protection relay failures in service can create shortfalls in compliance with respect to Section 5.1.9 and refurbishment works mentioned above. The Energex protection relay replacement program seeks to address this issue.

See Appendix 1 for further detail on the relevant clauses of the NER.

2.3 Asset Protection

A modern protection relay is a multi-function device and provides functionality not available in a single older protection relay. In real terms the cost of providing protection schemes for the electricity system has fallen as technology has improved as these additional functions have been added into the relay as equations where in the past they have been discrete electromechanical components.

The application of highset protection elements to provide instantaneous clearing of high fault current is not a new idea as older relays have had this ability, however it was always at an additioinal cost. In additional, older overcurrent and earth fault relays were limited to a single type of protection curve.

Hightset protection elements are used to provide high speed clearing at high fault levels. Faster clearing times provide benefits to network assets in the following ways.

- A reduction in the damage to the arcing contacts within the circuit breaker will mean a reduced maintenance of high voltage plant.
- A reduction in the energy let through (I^2t) will cause less stress to the distribution system. This can result in a reduced need to reconductor areas of the distribution systems where fault levels have increased to levels where conductor damage is probable.

2.3.1 Protection Settings

The protection settings of the 11 kV network have a strong influence on the conductors suitable for the network. As thermal fault ratings are determined for worst case scenarios, a reduction in protection clearing times on the network may increase the effective current rating of the conductor.

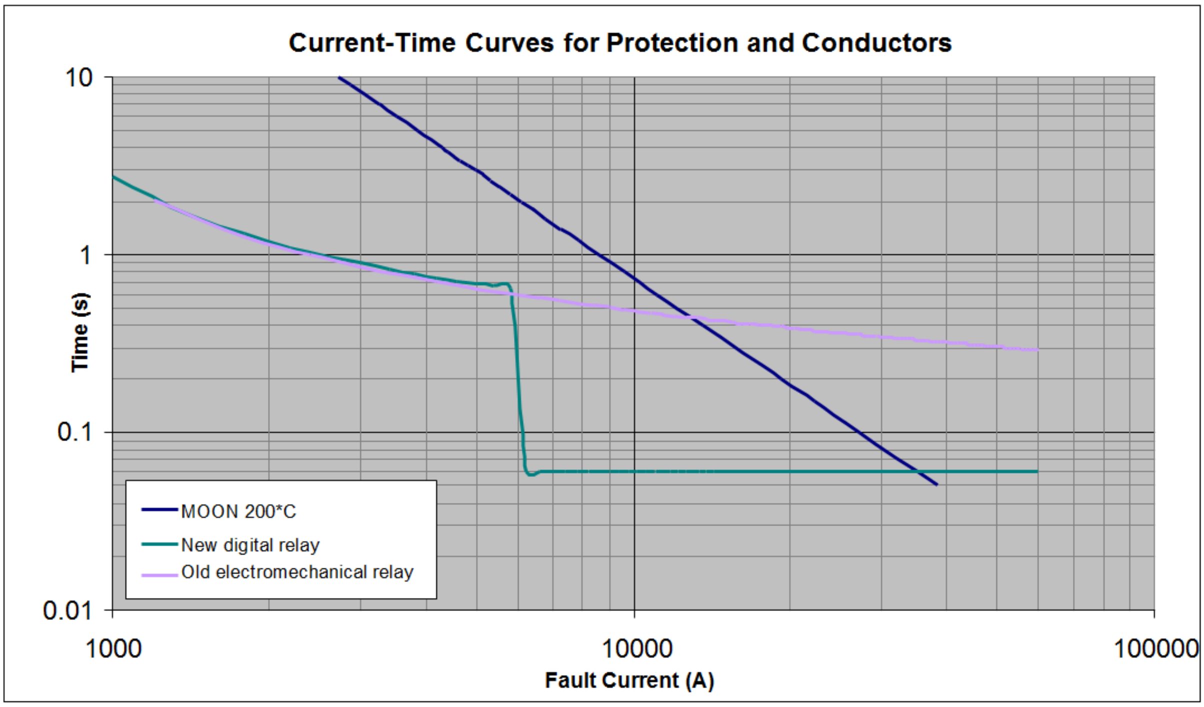

Figure 2: Protection Settings and Conductor Thermal Limits.

Figure 2 presents typical protection levels of the 11 kV network, and the required protection for 11 kV MOON conductor. The conductor line shows the time and fault current required for MOON to reach 200^{o}C (this is the maximum temperature limit stated in AS/NZ7000). If the conductor is allowed to exceed this temperature, it may become damaged and lead to burn-down.

The intersection of each relay curve with the conductor line shows the maximum fault current allowable on MOON for the given relay. Figure 2 shows that, when new digital relays are used, the fault current on MOON may be as high as 35 kA before permanent damage is caused. On the other hand, when electromechanical relays are used, the fault current on MOON must be limited to approximately 12 kA to avoid conductor damage. If this cannot be achieved, the network planner must select a larger, more expensive conductor (if possible).

The features of digital relays which enables this greater flexibility is its instantaneous setting capability, which allows it to operate much faster than the equivalent electromechanical relay for faults above approximately 6 kA.

As such, the use of digital relays enables wider usage of a given conductor across the network with less risk of conductor burn down caused by high fault levels.

2.4 Network Reliability

Network reliability performance is considered by Energex in protection system design and configuration. Network reliability can be reduced by poor asset management practices, complex protection schemes, short life of protection relays, inappropriate protection scheme application and failure of battery and auxiliary supplies.

Energex recognises that minimum cost primary plant and/or system designs may incur significantly higher secondary system costs.

Energex measures reliability performance of network and is developing programs to address systems which are not meeting the required performance levels. One such reliability improvement involves the widespread deployment of modern protection relays.

The reliability benefits from the implementation of modern protection relays as follows:

- Wider use of distance to fault data provided by new protection relays for the transmission and sub-transmission system.
- Further investigation of alternative methods of distance to fault for distribution system
- Retrieval of distance to fault data automated via SCADA
- Post fault analysis

These benefits are discussed in further detail below.

2.4.1 Fault Recording

Fault records are important pieces of evidence accessed during network event investigations. They can provide the reasons for premature equipment failure, supply waveforms and status of equipment behavior during an event, and give necessary information during post-fault event analysis. Proper use and interpretation of event records can lead to corrective action for a given system problem resulting in improved performance and reliability of the sub- transmission, and distribution system. The fault records are captured and stored within the modern microprocessor relay.

Modern microprocessor relays are capable of recording network events such as power system faults, lighting strikes, switching events and insulator flashovers. The event records show the current and voltage magnitudes, time, and duration. Analysis can detect abnormalities such as current transformer saturation, circuit breaker restrikes, etc. Investigation of current magnitudes can also be used to determine the deviation of actual fault values vs. the calculated values from network modelling software. Comparing actual and calculated values is good practice as possible inconsistencies can be identified and corrected within the network model. Transient records can further improve the analysis of such events mentioned above by providing the symmetrical component quantities of the current and voltage during steady state and fault conditions. These can then be used to verify the type of fault.

2.4.2 Distance to Fault

The distance to fault function as available within protection relays on the sub-transmission system provides an approximate fault location with the aim of reducing both the time crews spend patrolling a feeder and the amount of switching and sectionalising undertaken in order to find the fault location. As the time taken to fault find is reduced there can be a significant reduction in SAIDI.

Another application of distance to fault is to determine the cause for intermittent or transient faults. Occasionally, there are faults on the network for which there is no explanation. The feeder is patrolled and re-energised but no issue is found. If a crew can be dispatched more quickly to a suspected location it is more likely they will be able to identify the root cause. Causes can include a defective insulator or a tree branch blowing into the lines that is not immediately obvious when wind is not blowing, or, in some cases vandalism.

2.5 Other Value Adding Functions Within New Relays

Modern protection relays provide additional functions not limited to protection of the electricity network. With prudent use of these additional functions it can be possible to provide additional business benefits.

2.5.1 Measurement

The prevalence of photo-voltaic systems at low voltage has resulted in reversed power flow for certain 11 kV feeders at peak solar generation times. There is already a significant number of 11 kV feeders on the Energex network which experience reverse power flow conditions.

Previous Energex design standards included a lower cost single phase measurement to the SCADA system for feeder loads on the 33 kV and 11 kV networks. This philosophy was based upon the folllowing design assumptions:

- Power flow was always in one direction;
- Previous design standards from the 1950s to 1970s for metering connections to analogue instruments fitted to switchgear and control panels;
- Whilst the power system was never a true balanced three phase system, a single phase measurement would be suitable for the purposes of monitoring of 11 kV and 33 kV feeders that did not require revenue metering;
- Fewer current transformers required for metering purposes; and
- Hardware limitations of earlier SCADA systems in processing larger quanitities of data.

The advent of digital relays has resulted in the removal of analog meters from switchgear and control panels within Energex and removal of almost all discrete metering current transformers within 33 kV and 11 kV feeders. With multi-function liquid crystal displays on the protection relay it is possible to see three phase measurement quanities, however these values have not previously been available outside the substation switchroom.

The advent of multiple single phase photo-voltaic sytems on the low voltage network has resulted in a increasingly complex system where previous assumptions mentioned above no longer always hold true, ie:

- Powerflow on the distribution system can now be in both directions; and
- The system is not always balanced. Energex has no direct control over the connections of photo-voltaic systems up to 5 kW. Systems above 5 kW are assessed for their sutiability to connect and the impact this will have on the network.

Modern microprocessor protection relays can provide three phase, four quadrant measurement quantities via the SCADA system. This will provide a true indication of the state of the distribution power system for all powerflow contingencies and allow for future developments in distributed generation.

3 Supporting Analysis

Energex's protection relay replacement program for the 2015/16 – 2019/20 regulatory period is based on a prioritisation methodology as follows:

$$\text{Relay Ranking} = \text{AP} \times \text{LP} \times \text{Load Lost}$$

Where:-

AP = Age and/or Reliability priority

LP = Low Population modifier

Load Lost = load that would trip for a protection failure based on the calculated load lost at a substation and voltage level, by protection function.

See Appendix 2 for a detailed discussion of Energex's relay ranking methodology.

This prioritisation methodology is a recent implementation that has been enabled by technological innovations in Energex's relay data management capabilities. Namely, the introduction of the IPS (Intelligent Software Solutions) software package in 2012 provides the tools to store all protection asset and setting data, and has the ability to produce user specified performance reports.

Energex's prioritisation methodology gives a firm strategic direction to its replacement program and ensures that labour and material resources are directed in an efficient and cost-effective manner. Each of the three components to Energex's relay ranking formula is discussed in the following sub-sections.

3.1 Age and Reliability

Aged and unreliable relays present a significant safety risk to the public and Energex personnel. These relays are most likely to fail during network faults, thus leaving faults uncleared and increasing the risk of flashover or contact with people. Furthermore, the replacement of aged electromechanical and analogue relays with modern digital equivalents yields safety benefits that were discussed in Section 2.1.1 and Section 2.1.2

The relay ranking is first prioritised using age and reliability. Naturally, as a relay ages in service, its reliability declines. By synthesising relay population data with relay failure records, Energex has modelled the relay failure rate for a given relay type at any given age in its lifecycle.

3.1.1 Electromechanical Relays

Historically, electromechanical relays have been installed on the Energex network. Electromechanical devices tend to fail at end of life due to corrosion, degradation of insulation, and wear of moving parts. Industry best practice and past Energex observations indicate that the life expectancy of electromechanical relays is 45 years, on average. The results of Energex's relay failure modelling for electromechanical relays are shown in Figure 3 below.

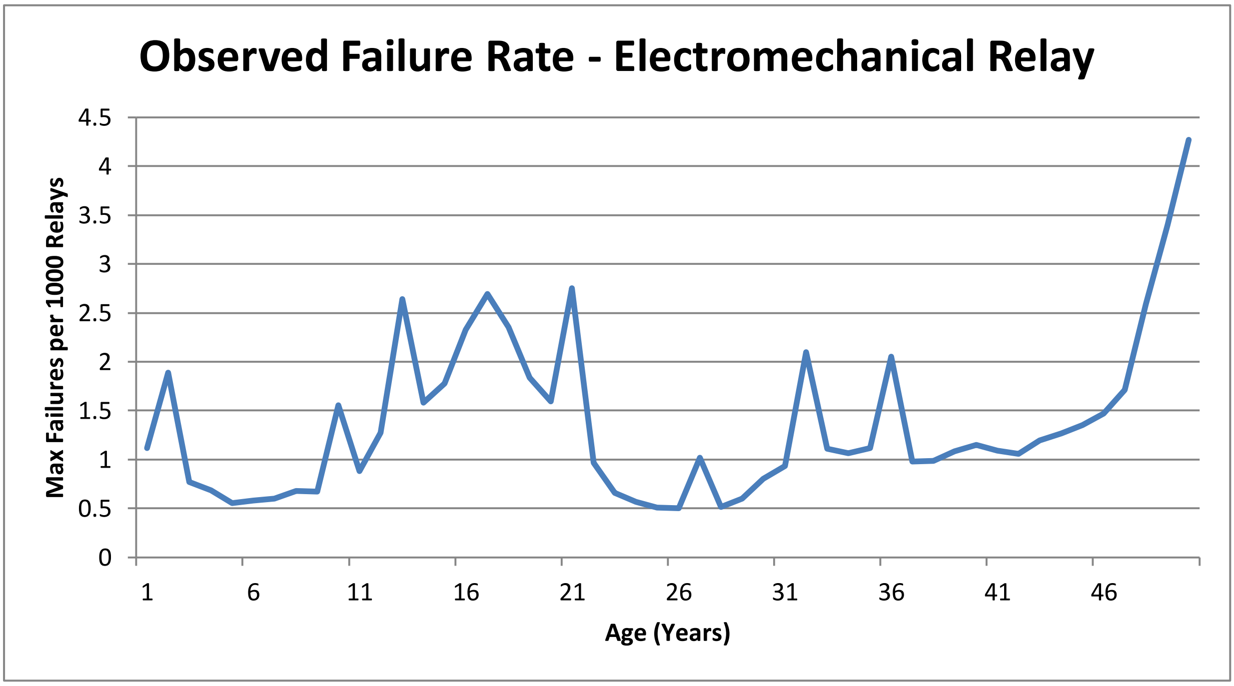

Figure 3: Observed failure rate for Energex electromechanical relays.

Figure 3shows the electromechanical relay failure rate steadily increasing at around the 25 year mark, and then increasing sharply after 46 years.

Energex has approximately 9,500 electromechanical relays in service on its network. The age profile of its installed electromechanical relays is shown below in Figure 4.

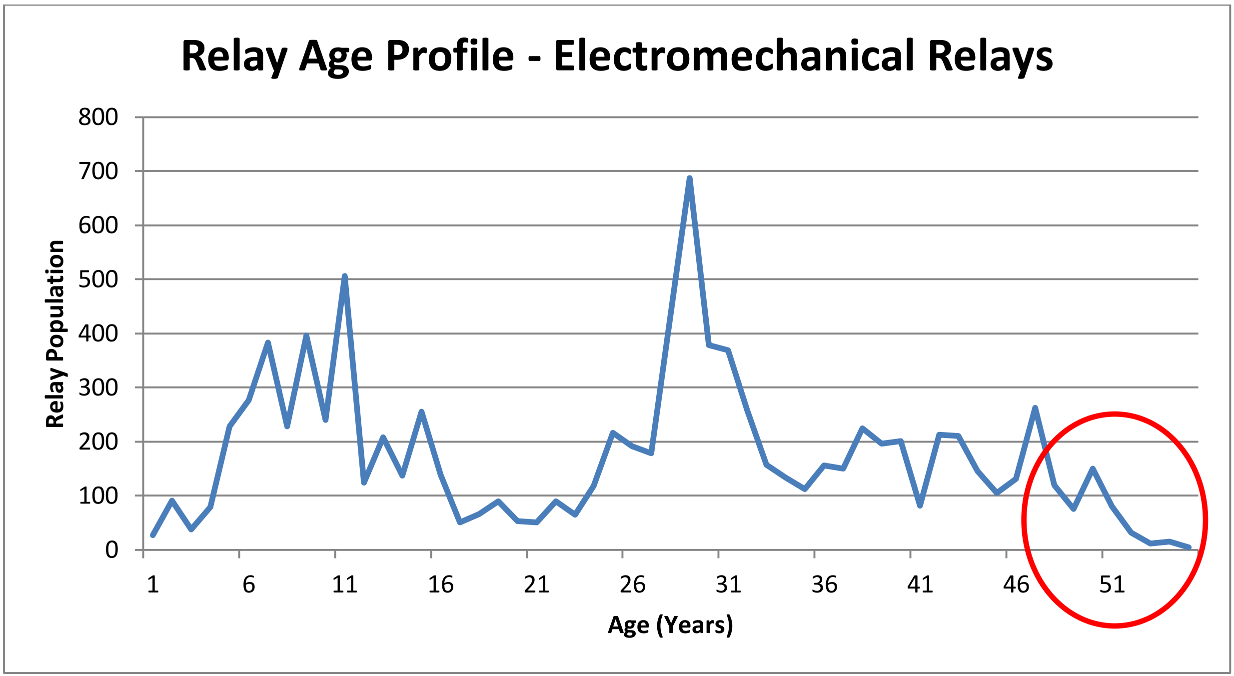

Figure 4: Age profile of Energex electromechanical relays.

The region circled in red in Figure 4 highlights the electromechanical relay population which (according to Figure 3) is experiencing dramatically increasing failure rates. There are approximately 699 relays in this group and the relay profile shows that it will grow in the next five years.

3.1.2 Analogue Relays

According to industry practice, the life expectancy of analogue protection relays is approximately 20 years. Energex has tested this assumption as it applies to the Energex network, and it has found that the most cost effective solution is to extend analogue relay replacement life to 30 years. This is supported by the trends in Figure 5 which shows the analogue relay failure rate remaining flat until approximately the 29 year mark, and increasing sharply thereafter.

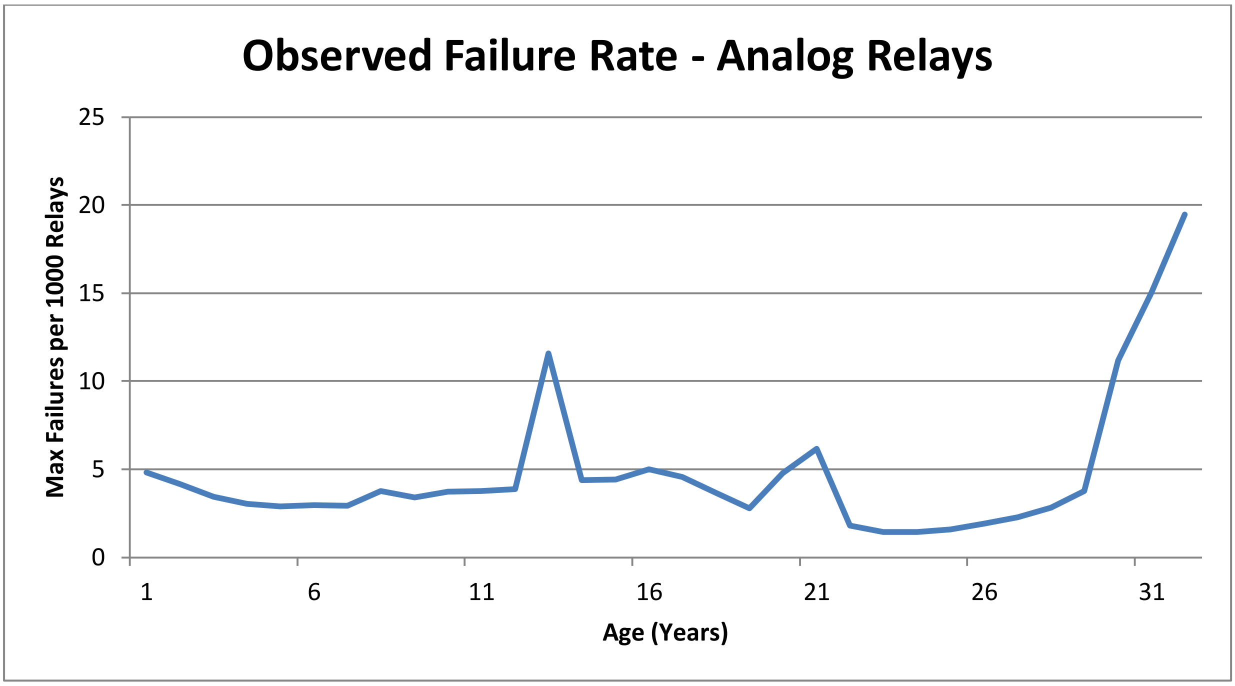

Figure 5: Observed failure rate for Energex analogue relays.

Energex has approximately 2,100 analogue relays in service on its network. The age profile of the installed analogue relays is shown below in Figure 6.

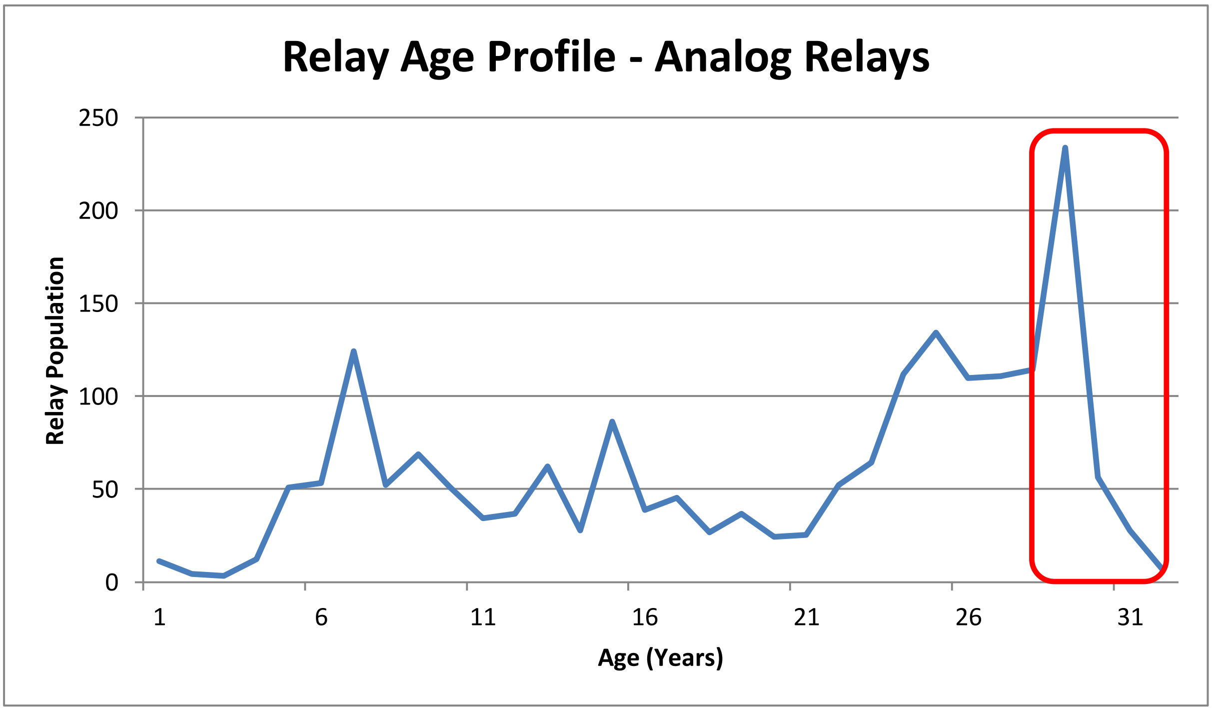

Figure 6: Age profile of Energex analogue relays.

The region circled in red in Figure 6 highlights the analogue relay population which (according to Figure 5) is experiencing dramatically increasing failure rates. There are currently approximately 504 relays in this group and the relay profile shows that it will grow in the next five years.

3.1.3 Digital Relays

In line with industry trends, Energex began installing digital protection relays in the mid 1990's. Whilst the operational performance of digital relays is unrivalled, they tend to exhibit higher failure rates than previous generation technology because they comprise a large number of discrete components. Industry practice has determined that digital relay replacement age is approximately 15-20 years. The results of Energex's relay failure modelling for digital relays are shown in Figure 7 below:

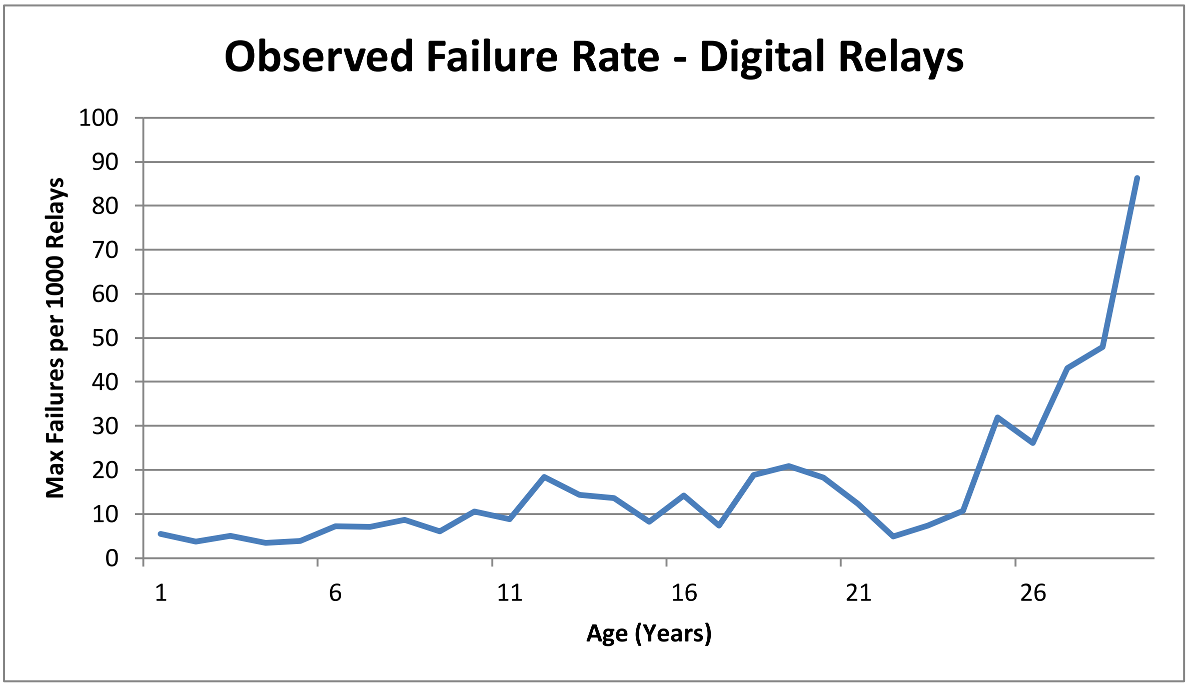

Figure 7: Observed failure rate for Energex digital relays.

Figure 7 shows the digital relay failure rate slowly increasing until approximately the 21 year mark, and increasing sharply thereafter. It should also be noted that the digital relay failure rate exceeds electromechanical and analogue relay failure rate at nearly all relay age points.

Energex has approximately 8,800 digital relays in service on its network. The age profile of its installed digital relays is shown below in Figure 8:

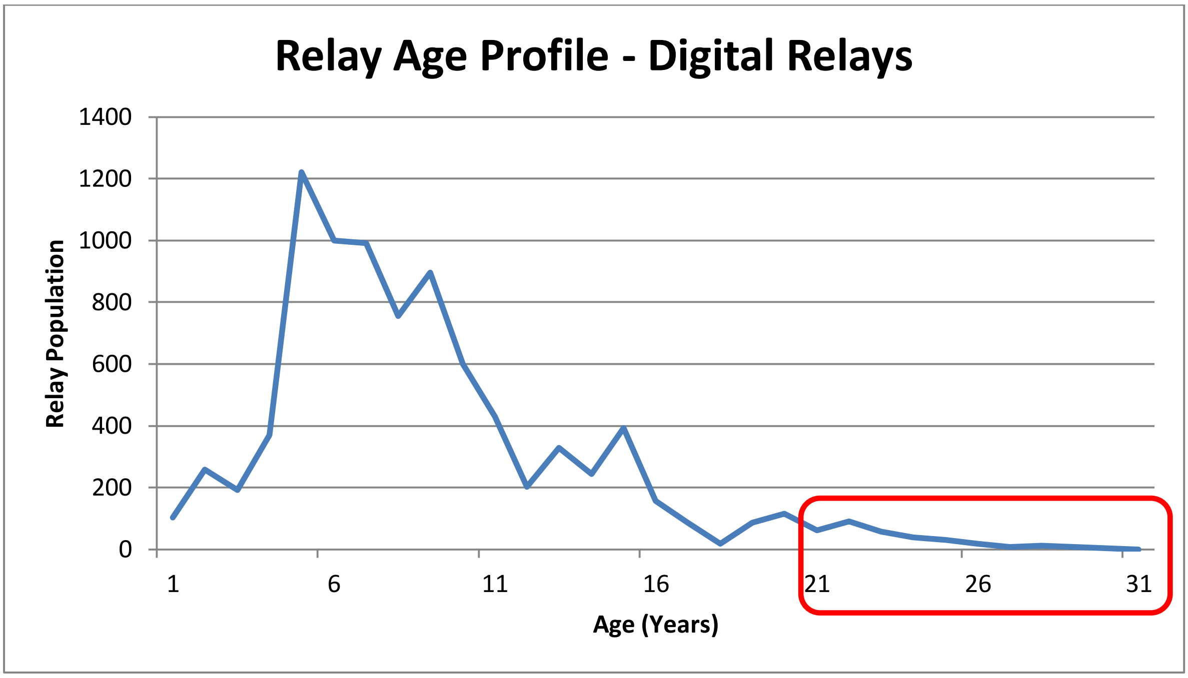

Figure 8: Age profile of Energex digital relays.

The region circled in red in Figure 8 highlights the digital relay population which (according to Figure 7) is experiencing dramatically increasing failure rates. There are approximately 255 relays in this group and the relay profile shows that it will grow in the next five years.

In summary, the previous sub-sections demonstrate that a total of 1458 relays (699 electromechanical, 504 analogue, and 255 digital) are currently in service and exceeding their end of life.

3.2 Potential for Load Lost

The first modifier Energex uses in its protection relay replacement prioritisation methodology is the potential for load lost. Power unsupplied is a direct measure of impact on customers and correlates with the replacement program drivers listed in Section 2.

By carefully considering the failure modes and consequence for each type of protection, the load lost at each substation can be determined for failure of bus protection, failure of transformer protection, and failure of feeder protection at each voltage level, or each transformation level. See Appendix 2 for further discussion of the “potential for load lost” modifier.

3.3 Low Population

The second modifier Energex uses in its relay replacement prioritisation methodology is low population.

In the past, before the centralisation of Energex’s planning process, a number of protection relay policies existed across different geographical hubs. This legacy has left Energex with 135 different relay types which each have a population less than 20. This totals 720 individual relays and includes 24 relay types which have a population of 1.

Typically, these relays are not on the current procurement contract and there are few (if any) spares available in store for replacements in the event of a relay failure. Where this occurs, additional design and construction costs are required to issue new relay settings and retrofit modern relays to older control systems panels. The resulting delays in returning the network to a system normal state has a direct impact on the drivers listed in Section 2 of this document.

As older relay types are replaced through the program of work, their populations will naturally decline. Hence, Energex must be proactive about managing its low population relays to provide a safe, legislatively compliant, and cost-effective outcome for the business and its customers.

Although we can gain a measure of the consequence when assessing the risk of low population relays, low population itself doesn’t offer a measure of likelihood. For this reason, the low population parameter doesn’t by itself give justification for relay replacement. It does, however, offer a means of economically prioritizing relay replacements. This is how the low population parameter is used in Energex’s proposed relay replacement program.

4 Options

The relay ranking methodology outlined in Section 3 categorises relay replacements into the following prioritisation: First, Second, Third, and Do Not Replace. These categories are used to assess the viability of the different relay replacement options considered below. See Appendix 3 for an overview of these categories.

4.1 Impact of Doing Nothing

The "do nothing" option comprises no protection relay replacement program, resulting in a "run to failure" approach for all types of protection relays. Reactive replacements would be required upon in-service failure or upon failing test under the six year protection testing and maintenance cycle. Digital relays would also require replacement if their self-check function detected an abnormality.

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

Risk Category	Risk Scenario	Consequence	Likelihood	Risk Score
Safety	Failure of an 11kV feeder protection relay to operate following a HV fault initiated through HV live work, resulting in a single fatality to an employee or member of the public	5	3	15 (Moderate Risk)
Legislated Requirements	A safety incident resulting from a failed protection relay prompts external investigation finding Energex in breach of N.E.R. Section 5.1.9.	5	3	15 (Moderate Risk)
Customer Impact	Failure of an 11kV feeder protection relay to operate during a high voltage network fault results in wires down and loss of supply to customers and property damage	3	3	9 (Low Risk)
Business Impact	Failure of a 33kV feeder protection relay during a network fault results in plant out of service and an abnormal network configuration.	5	3	15 (Moderate Risk)
Environmental Impact	Failure of a substation protection relay during a network fault results in catastrophic plant failure causing oil spill, clean up and rectification.	2	2	4 (Very Low Risk)

Table 1: Untreated Risks of the Doing Nothing Approach for Protection Relay Assets

No proactive replacements of problematic relays would result in an increasing likelihood over time of relays failing to operate when required to do so. This Do Nothing option would call for continued risk exposure at these levels, with risks increasing over time and soon reaching intolerable levels. In particular there are significant safety risks to both employees and the community, and all of the untreated risks are not considered to be As Low As Reasonably Practicable (ALARP). This is not considered a tolerable outcome to Energex.

4.2 Option 1 – Risk Based Relay Replacement Program: Replace 850 Relays (recommended)

4.2.1 Summary

This option involves a relay replacement program as per Table 2:

Replacement Category	Relays Deemed End of Life	Relay Replacements	Relay Replacements Per Year	Cost Per Year
First Priority	214	214	43	$ 767,340
Second Priority	620	600	120	$2,129,414
Third Priority	2668	36	7	$ 112,916
(Total)	3502	850	170	$3,009,670

Table 2: Option 1 cost summary.

Under this replacement program, all first priority relays are replaced. The majority of second priority relays are replaced, and a small minority of third priority relays are replaced. These discretionary relays are replaced where it is economically beneficial to do so, for example when coordinating works with other projects planned for the site (such as primary plant replacements).

Replacements are prioritised at the substation level, with the substations having the greatest number of high priority relays being scheduled first. Typically this will include bulk supply substations with relays that have high failure rates and potential for large load lost.

Where possible, relay replacement works are bundled with other projects planned for the site (such as primary plant replacements). This reduces the need for stand-alone projects and minimises inefficient resource allocation.

Similarly, a small number of discretionary relays are included for replacement to avoid many small projects at one site in successive years. These discretionary relays are replaced where it is economically beneficial to do so, for example when coordinating works with other projects planned for the site (such as primary plant replacements).

Total expenditure over five years for Option 1 is $15 million.

4.2.2 Impact analysis

Figure 9 below compares the proposed protection relay replacement program with the required relay replacements over the next twenty years, with the sustainability curve being the cumulative difference between the two amounts. The "Replacement Requirement" is defined as those relays which should be replaced in order to maintain long-term sustainability. This includes all relays in the first or second priority category, and also includes approximately 50 percent of the third priority category.

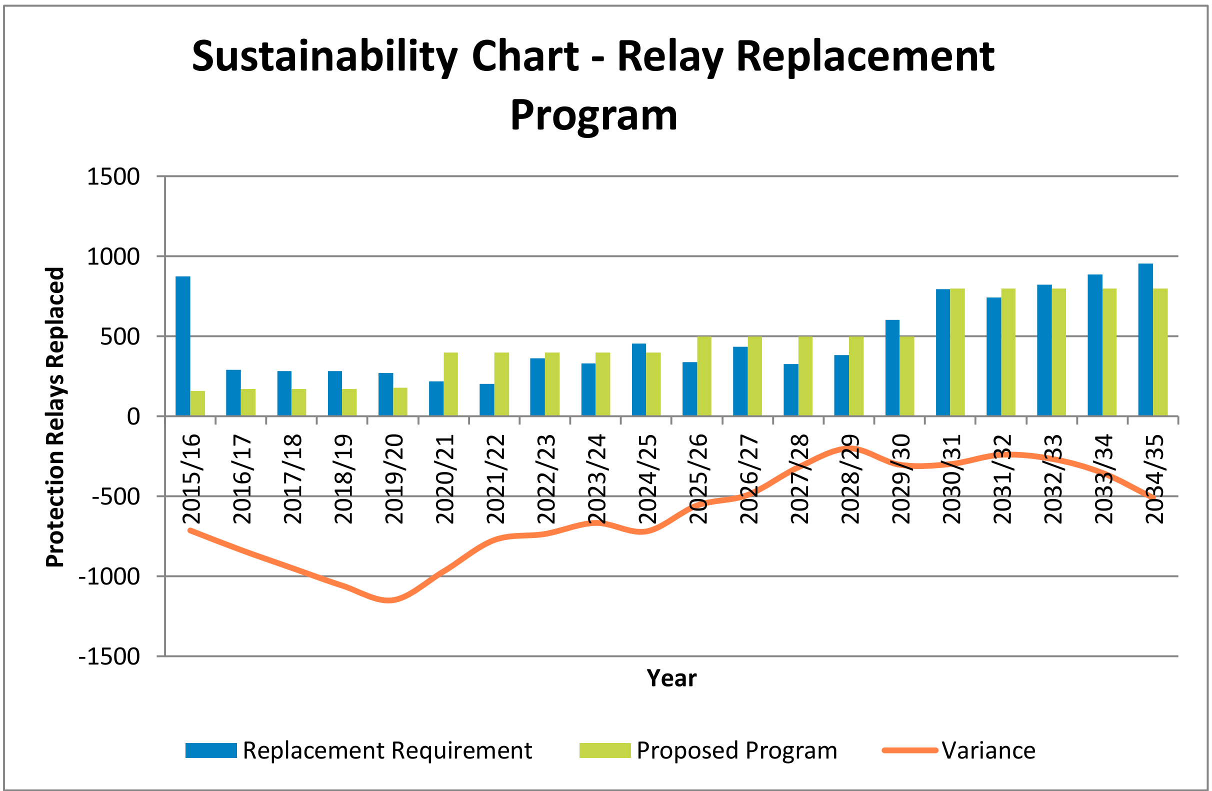

Figure 9: Sustainability chart for option 1.

The sharp increase in replacement requirements evident in years 2023 and 2030 is due to the digital relays and electromechanical relays reaching end of life, respectively. This is evident by inspection of the relay population age profiles shown in Figure 4 and Figure 8. Proposed replacements are increased in subsequent regulatory periods to account for this.

Option 1 involves increased risk as only a small number of third priority relays are being replaced. The remainder of these relays are approaching end of life and/or have low populations. Subsequent regulatory periods will require increased levels of replacement to achieve long term sustainability.

4.3 Option 2 – Risk Based Relay Replacement Program: Replace 2000 Relays

4.3.1 Summary

This option was the position which Energex took to the AER and involves a relay replacement program as per Table 3:

Replacement Category	Relays Deemed End of Life	Relay Replacements	Relay Replacements Per Year	Cost Per Year
First Priority	214	214	43	$ 767,340
Second Priority	620	620	124	$2,212,795
Third Priority	2668	1166	233	$3,467,865
(Total)	3502	2000	400	$6,448,000

Table 3: Option 2 cost summary

Under this replacement program, all first priority and second priority relays are replaced, along with 44 percent of third priority. This level of replacement drops by 25 percent in the 2020/21 – 2024/25 period and then increases in subsequent regulatory periods to address the ageing electromechanical relay population.

The cost per unit of third priority replacements decreases as more relays replacements are incorporated with existing capital works projects, creating efficient resource allocation.

Total expenditure over five years for Option 2 is $32.2 million.

4.3.2 Impact analysis

Figure 10 compares the proposed protection relay replacement program with required relay replacement over the next twenty years, with the sustainability curve being the cumulative difference between the amounts. The “Replacement Requirement” is defined as those relays which fall into the high or medium priority category, and also includes approximately 50 percent of the low priority category.

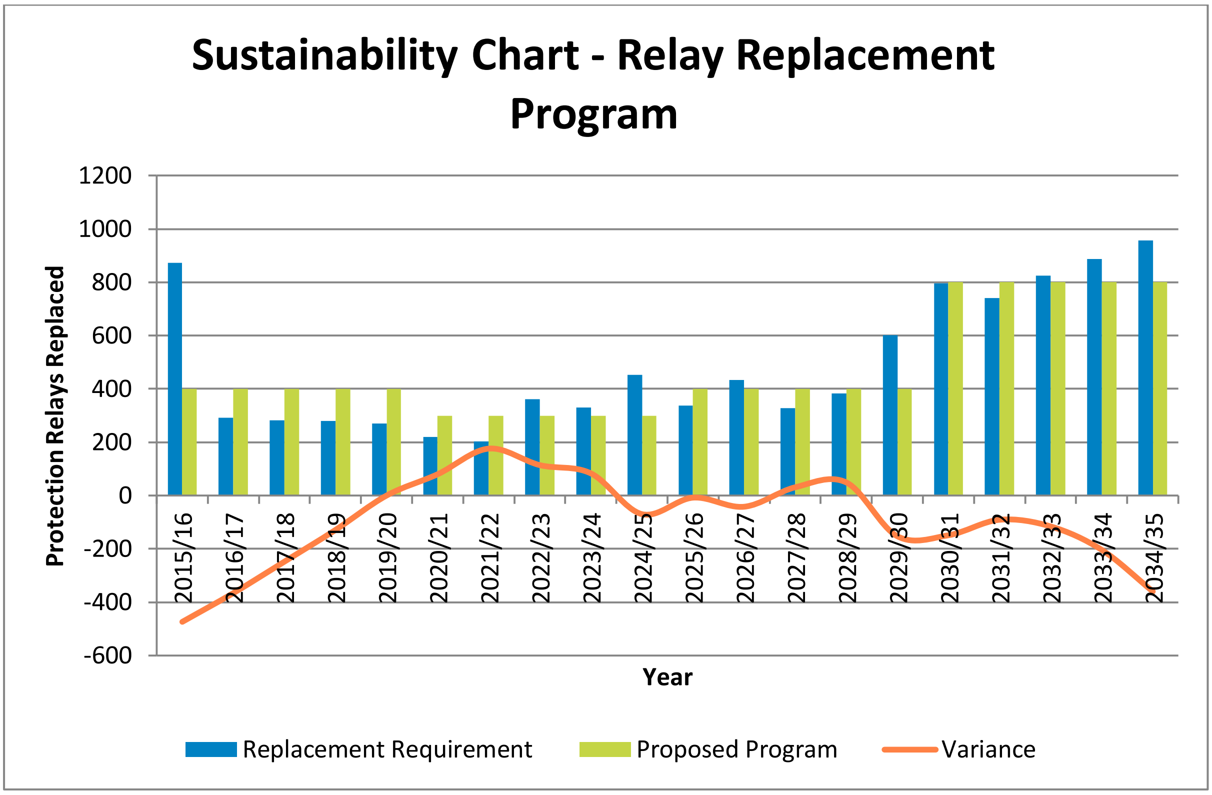

Figure 10: Sustainability Chart for option 2.

Option 2 is the least risk option (whilst also being the highest cost option) as it moves protection relay management towards a sustainable position in 2020. After this juncture Energex will be in a position to level the replacement program until 2029/30, after which the large population of electromechanical relays will be reaching end of life.

4.4 Option 3 – Risk Based Relay Replacement Program: Replace 400 Relays

4.4.1 Summary

Option 3 involves a relay replacement program as per Table 4:

Replacement Category	Relays Deemed End of Life	Relay Replacements	Relay Replacements Per Year	Cost Per Year
First Priority	214	214	43	$767,340
Second Priority	620	186	37	$658,269
Third Priority	2668	0	0	$0
(Total)	3502	400	80	$1,428,588

Table 4: Option 3 cost summary

Under this replacement program, all first priority relays are replaced and 30 percent of second priority relays are replaced. No third priority relays are replaced.

Total expenditure over five years for Option 3 is $7.2 million.

4.4.2 Impact analysis

Figure 11 below compares the proposed protection relay replacement program with required relay replacement over the next twenty years, with the sustainability curve being the cumulative difference between the amounts. The “Replacement Requirement” is defined as those relays which fall into the first or second priority category, and also includes approximately 50 percent of the third priority category.

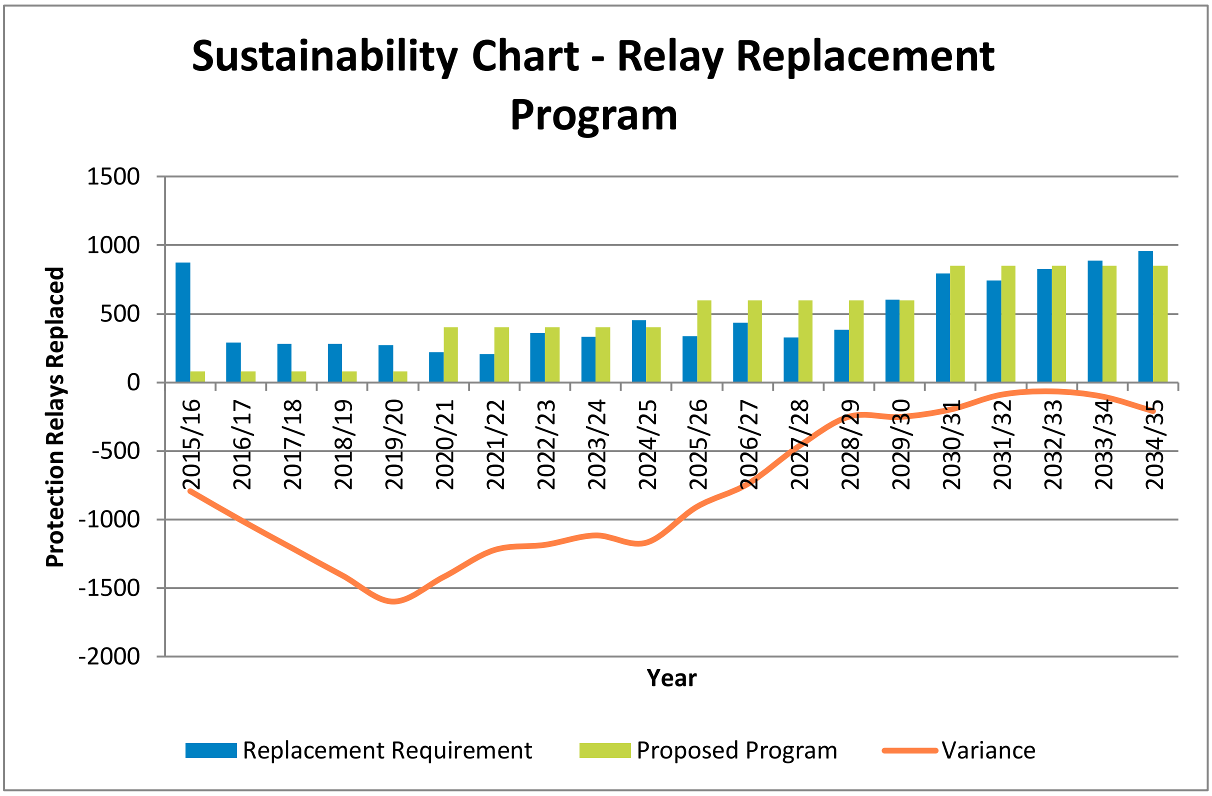

Figure 11: Sustainability Chart for Option 3.

Option 3 is the highest risk option (whilst also being the lowest cost option) as relay replacement sustainability rapidly declines until 2020. After this juncture, Energex’s relay replacement program would need to expand more than 800 percent by the year 2030 and the cost to bring Energex’s protection relay management towards a sustainable position would be significant.

5 Proposed Works

Option 2 replaces 2000 protection relays during the 2015/6 – 2019/20 regulatory period. The program includes a significant number (1100) of the lowest priority relays during the 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.

Option 3 proposes to replace only 400 protection relays during the 2015/6 – 2019/20 regulatory period, this does not address all of the two higher priority groups of relays and will not adequately mitigate risks associated with leaving these higher priority relays in service.

Option 1 to replace 850 protection relays during the 2015/16 – 2019/20 regulatory period was selected as it manages key safety and legislative compliance risks to tolerable levels whilst allowing for transition to a sustainable replay replacement approach. The program replaces the bulk of the relays in the top two priority levels and only those relays from the bottom priority that are located at sites where other relays are being replaced and thus represents the most cost effective means of replacing the unit.

It should be noted that for the selected option increasing quantities of relay replacements will be required in future regulatory periods to enable a longer term sustainable life cycle management approach for protection relays.

6 Required Expenditure

The protection relay replacement program is distributed across a five year period. This offers the necessary flexibility to schedule relay replacements that best suit the existing capital program of work.

Table 6 below outlines the required expenditure for the protection relay replacement program being $15 million over five years.

$m, 2014/15	2015/16	2016/17	2017/18	2018/19	2019/20	Total
Energex Revised Proposal	2.4	2.6	3.0	3.5	3.5	15.0
Quantity	160	160	160	160	210	850

Table 5: Required Expenditure for Recommended Option

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– Relevant Clauses from the National Electricity Rules (NER)

Relevant Clauses from the NER v55

S5.1.9 Protection systems and fault clearance times

(d) If the fault clearance time determined under clause S5.1.9(e) of a primary protection system for a two phase to ground short circuit fault is less than 10 seconds, the primary protection system must have sufficient redundancy to ensure that it can clear short circuit faults of any fault type within the relevant fault clearance time with any single protection element (including any communications facility upon which the protection system depends) out of service.

(n) The provisions of clause S5.1.9(d) apply to facilities constructed or modified on or after the performance standards commencement date.

(o) For facilities other than those referred to in clause S5.1.9(n), the requirement for primary protection system redundancy must be derived by the Network Service Provider from the existing capability of each facility on the performance standards commencement date.

Glossary Terms from the NER v55

Good electricity industry practice

The exercise of that degree of skill, diligence, prudence and foresight that reasonably would be expected from a significant proportion of operators of facilities forming part of the power system for the generation, transmission or supply of electricity under conditions comparable to those applicable to the relevant facility consistent with applicable regulatory instruments, reliability, safety and environmental protection. The determination of comparable conditions is to take into account factors such as the relative size, duty, age and technological status of the relevant facility and the applicable regulatory instruments.

Performance standards commencement date

For:

(a) Generators, Customers and Network Service Providers who plan, own, operate or control a facility located in a participating jurisdiction (other than Tasmania), the performance standards commencement date is, in relation to that facility, 16 November 2003; and

(b) Generators, Customers and Network Service Providers who plan, own, operate or control a facility located in Tasmania, the performance standards commencement date is, in relation to that facility, the date that Tasmania becomes a participating jurisdiction.

Substation

A facility at which two or more lines are switched for operational purposes. May include one or more transformers so that some connected lines operate at different nominal voltages to others.

Appendix 2– Explanation of Relay Replacement Prioritisation Methodology

Energex's proposed risk based protection relay replacement program for the next five year period is based on prioritisation methodology as follows:

Relay Ranking = AP x LP x Load Lost

Where:-

AP = Age and/or Reliability factor

LP = Low Population modifier

Load Lost = load (MVA) that would trip for a protection failure based on the calculated load lost at substation and voltage level, by protection function.

The relay ranking is first calculated by considering the Age and/or Reliability factor (AP), as per the lookup tables below. Aged and unreliable relays present a significant safety risk to the public and Energex personnel. These relays are most likely to fail during network faults, thus leaving faults uncleared and increasing the risk of flashover or contact with people.

Analog/Digital		**Failure Rate**		
		FR<0.5%	0.5%<=FR,<1.0%	FR>=1.0%
Age	Age <10	0	1	4
	10<=Age<15	0	2	8
	15<=Age<20	1	4	16
	20<=Age<25	4	8	32
	Age >=25	8	16	64

Electromechanical		**Failure Rate**		
		FR<0.5%	0.5%<=FR,<1.0%	FR>=1.0%
Age	Age <30	0	1	4
	30<=Age<45	1	4	16
	45<=Age<50	4	8	32
	Age >=50	8	16	64

The relay ranking may then be modified by the Low Population modifier (LP) as follows:

Population of relay type on network	Modifier applied to relay rank
Population <= 20	2
Population > 20	1

The relay ranking can be further modified by the amount of load that could potentially be lost due to relay failure (Load Lost). This involves deducing the asset characteristics from combined datasets and then inferring the connected load as follows:

1. Where duplicate protection, duplicate feeders or monitoring functions are detected, then no load is assumed to be lost for a feeder protection failure
2. Where duplicate protection or monitoring functions are detected, then no load is assumed to be lost for a bus or transformer protection failure
3. Load lost per bus protection failure (where 2 above does not apply) is calculated based on loss of the neighbouring bus. In the case of a 2 bus substation, this is the entire load. In the case of a three bus substation this is 2/3 of the load
4. Load lost per transformer protection failure (where 2 above does not apply) is calculated based on loss of the upstream and downstream bus. In the case of a 2 bus substation, this is the half the load at each voltage level. In the case of a three bus substation this is 1/3 of the load at each voltage level
5. Load lost per feeder protection failure (where 1 above does not apply) is calculated based on loss of the upstream bus. In the case of a 2 bus substation, this is half the load at that voltage level. In the case of a three bus substation this is 1/3 of the load

Finally, the relay ranking is categorised as follows:

Calculated Relay Ranking (RR)	Relay Replacement Prioritisation Category
RR <= 4	Do Not Replace
4 < RR <= 8	Third Priority
8 < RR <= 16	Second Priority
RR > 16	First Priority

Appendix 3 – Overview of Relay Replacement Categories

First Priority Replacements

The First Priority category typically has all of the following characteristics:

- High failure rate
- End of life
- Potential for significant load lost

In addition, First Priority may have any of the following characteristics:

- Low population

Second Priority Replacements

The Second Priority typically has all of the following characteristics:

- Medium failure rate
- End of life

In addition, the Second Priority category may have any of the following characteristics:

- Potential for some load lost
- Low population

Third Priority Replacements

The Third Priority category typically has at least one of the following characteristics:

- Medium failure rate
- Approaching end of life
- Low population
- Some potential for load lost

The Do Not Replace category includes all relays with no known issued identified.

PUBLIC

Energex

Core IP/MPLS Telecommunications Network (Matrix)

Asset Management Division

energex
positive energy

Energex

Core IP/MPLS Telecommunications Network (Matrix) 2015/16 - 2019/20

Reviewed:

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Group Manager Asset Life Cycle Management

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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

Energex has an established Telecommunication Strategy which requires the implementation of a high speed optical fibre communications network capable of supporting contemporary Internet Protocol (IP) based communications as part of the long term roadmap. This enhancement to telecommunications capability and infrastructure supports the asset management drivers for improvements to safety, compliance, power quality and productivity. The Energex telecommunications system provides an increasingly important role in facilitating operational and business systems. These systems protect power network assets, optimise power systems performance, minimise operating costs, and help mitigate safety risks to customers and staff. Energex has chosen to utilise Multiprotocol Label Switching (MPLS) to ensure that the different business needs are accommodated on a single network that can achieve the cyber security, performance and functionality requirements in a flexible and extensible manner. The telecommunications network facilitates the following core business functions:

- Centralised monitoring of substation and distribution network equipment and fault alarms;
- Remote control of substation primary plant and distribution network switches;
- Voice communications between network switching operators and field crews providing safety, operational and emergency response benefits;
- Remote access to selected secondary systems devices (protection relays, RTUs); and
- Secure and resilient carriage of corporate data between key operational sites.

In 2008 Energex identified the need for substantial improvements to its telecommunications network infrastructure due to issues with technical obsolescence and future network requirements. A program was initiated to establish a new core IP/MPLS telecommunications network within a 10 year timeframe. An associated but separate program was also established to provide the necessary optical fibre cable ‘bearers’ that would link the telecommunications nodes. During the 2010/11 – 2014/15 period Energex connected 121 substations and 12 other business facilities to the new IP/MPLS network for a total investment of $28.4 million.

The risks associated with under-investment in the Energex telecommunications infrastructure platform include:

- Increasing cyber risk exposure;
- Higher costs associated with operating/maintaining the legacy Plesiochronous Digital Hierarchy telecommunications equipment;
- Restricted ability to benefit from the full capabilities of modern power systems equipment which provides communication interfaces for monitoring, control, and management purposes;

- Restricted ability to implement/benefit from current business improvements such as condition based asset monitoring;
- Restricted agility to adapt to new business needs; and
- A decline in operational services resulting in practices that are more reactive, labour intensive and less efficient.

In the interim determination the AER stated Energex had taken a conservative risk approach. In response Energex has since revised this program to extend the timeframe for delivery of the total program.

The revised expenditure required to deliver the required IP/MPLS telecommunications network is $13.6 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	7.7	8.3	8.3	4.7	0.5	29.6
Energex Revised Proposal	2	2.8	2.9	3	2.9	13.6

The revised proposal maintains alignment with business outcomes outlined in the Energex *Telecommunications Strategic Plan 2015-20.* It is presently expected that the remaining Energex sites will connect to the IP/MPLS network during the 2020 to 2025 regulatory period.

Contents

1 Introduction

The purpose of this document is to outline the required expenditure for the continued rollout of the Core IP/MPLS Telecommunications Network in the 2015/16 – 2019/20 regulatory period.

This program provides core business functions for Energex. The main driver is the need to provide reliable and resilient telecommunications services between substations, data centres, and depots for operational systems that are used for the safe, reliable and efficient operation of the power distribution network.

The core multiplexer equipment used extensively within the previous generation telecommunication network is no longer available as the product vendor has ceased sale and support. A like-for-like replacement will not meet current or future business needs, and would not be prudent. An alternate solution needs to be deployed before unrepairable equipment failures occur.

This program therefore provides both network renewal and new capability.

This program is dependent on the availability of optical fibre communication bearers being provided as part of a distribution feeder deployment / refurbishment projects, or provided as part of the Optical Fibre cable in-fill program. (Refer "*Energex Optical Fibre Cable In-Fill Business Case*".)

Changes from the original proposal

The original proposal to the AER for the continued rollout of the Core IP/MPLS Telecommunications Network was for $27.2m over the 2015/16 – 2019/20 regulatory period. The revised proposal presented here seeks an investment of $13.6m over the 2015/16 – 2019/20 regulatory period.

2 Drivers

The key drivers of the Core IP-MPLS Telecommunications Network program are:

- Provision of high availability data and voice telecommunication services to support operational systems and equipment that function across a range of locations and a distributed workforce.
- Improved site access security at control centres, substations, depots, and hubs
- Enablement of improved remote monitoring and control of the primary distribution network plant via DMS (Distribution Management System), Substation SCADA (Supervisory Control and Data Acquisition) systems, DSS (Distribution System SCADA) system, associated systems and facilities.

- Improved customer outcomes through provision of data communications which deliver reliability and power quality improvement as well as enabling Demand Management and Load Control applications and systems
- Remote engineering access to intelligent substation systems and equipment including protection relays, SCADA and automation systems and facilitate remote collection of asset condition data to enable improved asset management.
- Provision of high availability, low latency telecommunication links between substations to facilitate key data services such as SCADA systems across diverse paths and provide a viable path to carry protection signalling.
- Workforce efficiencies and reduced ICT costs by provision of corporate data services between locations and access to corporate IT applications and systems from the field.
- Management of cyber risks

The continued rollout of the Core IP/MPLS Telecommunications Network supports the objectives in the *Telecommunications Strategic Plan 2015-20*.

3 Supporting Analysis

The substantial shift from circuit-switched to packet-switched based technologies is having a profound impact on the underpinning and supporting infrastructure of all information and communication technologies. The impacts of technological evolution are having a significant impact on the operational systems and products that are used to monitor, control, protect, and operate the power distribution network.

Energex has already extended the service life of its core telecommunications nodes, remaining with 1980's vintage PDH (Plesiochronous Digital Hierarchy[1]) technology when others in the industry are using younger SDH (Synchronous Digital Hierarchy[2]) core systems.

3.1 Existing Telecommunications Network Limitations

3.1.1 Asset Age

The PDH based network has been installed over the past 20+ years and some nodes have exceeded their retirement age of 15 years. The original vendor has ceased manufacture, and is pursuing IP/MPLS technology based products.

[1] Refer ITU-T G.705 Characteristics of plesiochronous digital hierarchy (PDH) equipment functional blocks
[2] Refer ITU-T G.783 Characteristics of synchronous digital hierarchy (SDH) equipment functional blocks

3.1.2 Asset capacity & capability

The existing legacy network, constructed of optical fibre cables and aging copper pilot cables has a maximum capacity of 100Mbits/s and 2Mbits/s between nodes respectively. The expected capacity of the future network will require 10Gbits/s and 1Gbits/s between nodes.

There is an increasing need to send and receive data to all components within the electrical network. This is due to increased intelligence in the network devices. Enhanced asset monitoring and remote management of intelligent power network devices requires a modern operational telecommunications network. The network must support secure, robust Ethernet/IP services with effective quality of service management. The ability to maximise electrical asset life whilst reducing network outage times requires a high capacity, easily serviceable telecommunications network.

Modern telecommunications networks support Ethernet/IP based services and utilise routable data packet based delivery technologies, such as IP/MPLS which is the basis of the proposed Matrix network. IP/MPLS network technology has the advantage of being in mainstream telecommunications development and can provide centralised monitoring and service provisioning, significant improvements in cyber security, higher data bandwidths, quality-of-service delivery, etc. End-to-end services are provisioned via centralised toolsets and data packets are automatically routed through the network without the constant changes to intermediate nodes and links. This technology enables future additions and changes to be made at a lower cost.

[redacted]

3.1.3 Engineering and maintenance costs

The existing network is predominantly based on end-to-end communications services established by specific design and interconnection of individual circuit segments. Additions and changes to services carried by the network require significant engineering and deployment effort and costs. This is because changes are often required at each intermediate node and link along the communications path.

The existing PDH multiplexer node equipment is predominantly equipped with E1 (2Mbps) interfaces that provide 30 channels for voice or serial data traffic. When this limited data bandwidth is fully utilised, significant investment in re-engineering and additional equipment is required. Limited provision of Ethernet/IP services had been deployed over the PDH network via low speed multiplexed channels. However, this interim solution does not meet Energex's current operational telecommunication requirements for Ethernet/IP services.

3.1.4 Cyber Security Requirements

[redacted] Energex, jointly with Ergon Energy have developed standards and architectures to support best practice security through the 2010 joint initiative known as PRISE.

3.1.5 Additional Considerations

The following drivers are additional considerations that were identified in the Energex Telecommunications Strategy 2008. These drivers either significantly impede Energex in its core business operations or present an unacceptable risk.

1. Telstra decommissioning of PAPL (copper leased lines) in 2009.
   Energex adapted equipment and migrated the data services to Telstra IP WAN as an interim solution whilst awaiting the installation of the Core IP/MPLS Telecommunications Network
2. Aging copper pilot cable assets which require refurbishment. Copper pilot cables provide inadequate communications for modern equipment.
3. Inadequate telecommunications infrastructure to support current needs.

3.1.6 IP/MPLS (Matrix) Transport network

The deployment of Energex IP/MPLS network will reduce and eventually remove dependence on the end-of-life PDH equipment and transition to a higher capability, higher capacity core transport network.

The current roll out has enabled the deployment of the new DMS (Distribution Management System) with the provision of SCADA data from existing and new substations.

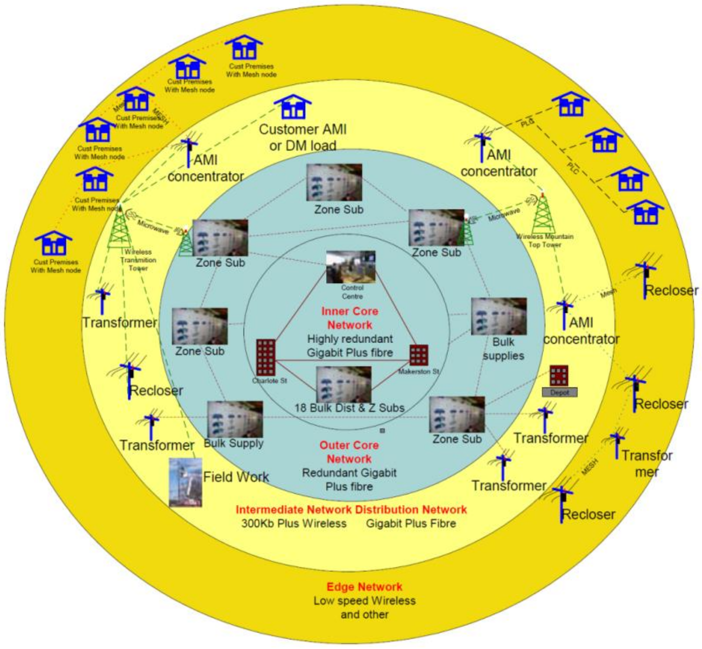

Figure 1: Matrix Network Nodes

3.1.7 Existing Network Limitations

The existing Energex telecommunications network is a vital part of Energex's operations in providing a verbal communication medium for field staff, providing corporate communications between locations and control of the electrical network through SCADA and protection systems. The majority of this telecommunications network is significantly aged, has a number of obsolete or becoming obsolete components and is no longer supported. In addition it is of low data throughput capacity and is designed for a distribution network of low data needs.

This network also does not address the emerging cyber security requirements of modern telecommunications networks.

To address this challenge, Energex is part way through implementing an approved telecommunication strategy to roll out an IP Based Multi-Protocol Label Switching (MPLS) carrier grade network consisting of two datacentres, a 10GbE inner-core of Backbone Nodes and a 1GbE outer-core General Nodes network to all Energex's Offices, depots and key substations.

This program has a dependency on the availability of optical fibre bearers, some of which are currently available, others being provided as part of distribution feeder deployment or other projects, and some provided as part of the Optical Fibre In-Fill program. (Refer "*Energex Optical Fibre Cable In-Fill Business Case*").

3.2 Extent of IP/MPLS network deployment to date

In the 2010/11 – 2014/15 regulatory period, Energex have delivered the following:

The establishment of:

- Operational Technology Environments (OTE) at both operational data centres. This was required for deployment of the new Distribution Management System (DMS) and supporting systems (Data Historian, Load Control System, etc.);
- Technical Support Centre,
- Network Operations Centres,

and IP/MPLS Nodes and telecommunications services at:

- Corporate office,
- 3 metropolitan offices,
- 5 depots,
- 3 communications facilities,
- 121 bulk supply and zone substations at sites across south-east Queensland,
- 37 substations with partial facilities,

The implementation of the first two stages of the Core IP/MPLS Telecommunications Network contributed to the successful G20 Summit held in Brisbane in 2014, enabling Energex to significantly improve the security stance of its telecommunications and other secondary systems prior to the event.

3.3 Remaining IP/MPLS network deployment

The Core IP/MPLS Telecommunications Network is required to be rolled out to a further 194 sites to meet the objectives of the strategic plan. These 194 sites consist of:

- 153 zone substations;
- 10 depots;
- 15 communications facilities; and
- 16 key C&I substations

Many other Energex projects and programs are also dependent upon the core IP/MPLS network being available, such as Operational Telephone Network Replacement, Substation Power Quality Monitoring and Substation Site Security Monitoring

4 Options

4.1 Impact of Doing Nothing

The existing Energex telecommunications network is aging and [redacted] and puts network reliability at risk. The obsolete software and hardware on the network no longer meets current or future business requirements. Examples of potential impacts include:

- Limits area of deployment of IP based system, facilities and applications (to the areas of the distribution network where the IP/MPLS nodes are deployed).
- Operation of the legacy PDH telecommunications network must be maintained for a much larger area of the distribution network, with higher operational costs.
- Limited coverage of security improvements.
- Limited coverage of proposed condition monitoring systems.

Without intervention, Energex will be unable to effectively manage future power network equipment and deliver future power network solutions. Old PDH network equipment will fail increasing the risk of [redacted] operational issues.

Not proceeding with the program will also necessitate the replacement, under maintenance, of older 'limited bandwidth' solutions which is not cost effective and not a tolerable business outcome for Energex.

4.2 Option 1– Install IP/MPLS Telecommunications Network to 194 Sites

4.2.1 Summary

This option proposes the complete the rollout of an IP/MPLS network with the existing standard node designs to 194 sites as per the original proposal for an estimated cost $27.2 million.

4.2.2 Impact analysis

This option provides the telecommunications network required to deliver the future enhancements as listed below:-

- New technology solutions to manage Energex infrastructure are moving to Ethernet/IP based solution and the Matrix program and associated initiatives will provide a network that can deliver these solutions in a secure and efficient manner. Examples include protection relay management, Remote Terminal Unit monitoring and management and the management of the telecommunications network itself.
- New technologies that Energex may choose to deploy in its network will require secure IP connectivity that is cost effective.

- [redacted]

4.3 Option 2 –Install IP/MPLS Telecommunications Network to 155 Sites

4.3.1 Summary

This option presents a slower rollout with reduced network coverage, and has lower network resilience (less redundant bearer paths) to some general nodes which will result in adopting a higher operational risk at those substations.

The estimated cost of this program is $22.7 million. Adopting this option also has a corresponding saving on the associated program for Optical Fibre Cable In-Fill.

4.3.2 Impact analysis

This option achieves a similar level of network coverage to Option 1 with the exclusion of some zone substations that supply lower load (such as in more rural areas), and the exclusion of some of the larger C&I substation. These excluded sites are proposed for deferral into the following regulatory period.

This option also adopts a higher operational risk at some substations. The network topology to achieve the designed service resilience and performance requires redundant links to all bulk supply substations, major zone substations, and large C&I substations with those links provided by optical fibres. This option provides bearer redundancy to fewer of these general substation nodes and accepts the resulting higher risk of increase outage duration for systems that utilise the proposed network.

During this outage period the operational systems that are reliant on the telecommunications network would be unavailable, such as SCADA/DMS monitoring and control at affected sites, and remote engineering to assist with the assessing correct operation of protection schemes. Loss of these operational systems and facilities presents a higher operational risks and would likely result in higher operational costs to diagnose and repair the fault condition. The provision of facilities to deliver more redundant links would then be considered in the next regulatory period.

4.4 Option 3 – Install IP/MPLS Telecommunications Network to 115 Sites

4.4.1 Summary

Option 3 proposes a much slower rollout (slower than both option 1 and 2) with reduced network coverage and lower network resilience (less redundant bearer paths) to some general nodes which will result in adopting a higher operational risk at those substations. These excluded sites are proposed for deferral into the following regulatory period.

The estimated cost of this program is $13.6 million. Adopting this option would also have a corresponding saving on the associated program for Optical Fibre Cable In-Fill.

4.4.2 Impact analysis

This option achieves only half of the network expansion that would have been achieved under Option 1. Network coverage is focused on the larger zone substation, larger depots, communications facilities, and only some of the larger C&I substations initially considered. The excluded sites effectively would be deferred into the next regulatory period.

This option also adopts a higher operational risk at some substations compared to both option 1 and 2.

This option also adopts a lower functionality solution for the C&I substation than originally envisaged. Whilst this solution is yet to be developed, it is targeted for a lower deployment cost and may operate over copper pilot cable.

5 Proposed Works

The three options presented will deliver the required works at different rates. Option 1 will deliver the proposed remaining works in the coming period and the other two options delivering in the 2020-25 period. Option one is not in line with the feedback received from the AER as it retains the higher level of redundancy initially proposed. Options two and three differ in the speed of delivery only and as such Energex is proposing to proceed with option 3 as it is considered as the more sustainable of the two options and reflects Energex's position of taking a higher risk approach.

It is proposed to implement Option 3 to install IP/MPLS Telecommunications Network to a further 115 sites over the 2015/16 -2019/20 regulatory period as follows:

- 90 zone substations
- 5 depots
- 15 communications facilities
- 5 key C&I substations

This revised program for 2015/16 – 2019/20 proposes the deployment of significantly fewer sites than the original proposal. The focus for the 2015/16 – 2019/20 period is to expand network coverage from that which has been established to date, to facilitate the business requirements for telecommunications at zone substations and some Commercial & Industrial (C&I) substations.

Under this option the following sites would be deferred to the 2020/21 – 2024/25 in order to complete the objectives outlined in the strategic plan:

- 63 zone substation
- 5 depots
- 11 key C&I substations

Appendix 2 provides a more detailed summary of the staging of deployments under the revised proposal. The implementation of Option 3 provides a sustainable approach for managing the strategic risks associated with the continuation of the IP-MPLS Telecommunications Network rollout.

6 Required Expenditure

Table 1 below outlines the required expenditure for the Core IP/MPLS Telecommunications Network Rollout program for 2015-20 of $13.6 million.

$m, 2014/15	2015/16	2016/17	2017/18	2018/19	2019/20	Total
Energex Revised Proposal	2.0	2.8	2.9	3.0	2.9	13.6

Table 1: Proposed Program Expenditure

7 Recommendations

It is recommended that Option 3 Install IP/MPLS Telecommunications Network to 115 Sites 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

[redacted] network related issues – a sample of recent faults

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Appendix 2: Summary of the Deployment Staging

Program Summary:	IP/MPLS Core Telecoms Network									
Site Type	Network Rollout : 2010-15 [Completed & In Progress]				Network Rollout : 2015-20 [In Progress & Proposed]			Subtotal		Future
	Stage 1	Stage 2	Stage 3	Other	Stage 4	Stage 5		2010-15	2015-20	2020-25
Data Centre (incl OTE)	2							2		
Technical Support Centre	1							1		
Office	2	2		1				5		
Depot	2		3		1	4		5	5	5
Comms Facility		1	2			15		3	15	
Substation: Backbone node	8	9						17		
Substation : General node	7	36	48	13	54	36		104	90	63
Substation : switch node		5	27	5				37		
Substation : C&I						5			5	11
Total:	**22**	**53**	**80**	**19**	**55**	**60**		**174**	**115**	**79**

Note: * Interim switch nodes are upgraded to general nodes

PUBLIC

Energex

Optical Fibre Cable In-Fill

Asset Management Division

energex

positive energy

Energex

Optical Fibre Cable In-Fill 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	01/07/2015	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
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Executive Summary

Energex has an established Telecommunication Strategy which requires optical fibre cable connectivity to substations and key sites. Optical fibre connectivity provides for a high speed, high capacity and robust telecommunications network, supporting the primary power distribution network in order to meet legislative, safety, business and customer requirements. The Optical Fibre (OF) cable network provides OF cores for;

- Telecommunications network bearers;
- Tele-protection schemes (directly, or via telecommunications network);

Tele-protection schemes include differential protection, direct inter-tripping, permissive inter-trip and a range of other protection capabilities. These tele-protection functions facilitate high speed protection which enhances the power network's ability to protect personnel and equipment, and to minimise the impact when faults occur on the primary network.

The main drivers for the Optical Fibre Cable In-Fill program are to:-

- Facilitate the continued rollout of the Core IP/MPLS[1] Telecommunications Network, via an associated but separate program, to targeted areas where improved performance/ capability is needed and to enable the safe and reliable operation of the power distribution network;
- Facilitate the continued operation and improvement of protection schemes, and replacement of aged protection relays for the safety of staff and members of the public; and
- Meet the requirements in the National Electricity Rules - Schedule S5.1.2.1 (d) for availability of protection functionality.

Prior to the 2010/11 – 2014/15 regulatory period, the OF cable network was largely delivered as part of various power network augmentation/renewal projects. This approach, whilst efficient, cost effective and adequate for point-to-point links did not provide sufficient coverage to facilitate the rollout of the Core IP/MPLS Telecommunications Network. Significant 'gaps' in the OF interconnection coverage remained such that several initiatives were adopted to address this issue. The Optical Fibre Cable In-Fill program was established to 'fill-the-remaining-OF-gaps' required for the Core IP/MPLS Telecommunications Network roll out thereby enabling subsequent commissioning of the associated IP/MPLS nodes. During the 2010/11 – 2014/15 regulatory period, the OF Cable In-Fill program expenditure totalled $11.5 million.

[1] The new Core Internet Protocol/Multi-Protocol Label Switching (IP/MPLS) Telecommunications Network is based on Ethernet and modern packet switched technologies.

In the interim determination the AER stated Energex had taken a conservative risk approach. Energex has the view that the risk of not proceeding with core telecommunications requirements is not tolerable as this program is an enabler for the rollout of the Core IP/MPLS Telecommunications Network. Energex has however been able to reduce expenditure requirements for the program by adopting a staged approach to further implementation, tolerating increased customer outage risks and increased duration of outages for secondary systems at smaller zone substation and C&I substations as a result. The revised expenditure requirements are $11.5 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	4.5	5	5	5	5	24.5
Energex Revised Proposal	2	2	2.5	2.5	2.5	11.5

The revised proposal aligns with the business outcomes outlined in the Energex *Telecommunications Strategic Plan 2015-20,* and is consistent with the revised timing of the *Core IP/MPLS Telecommunications Network* program which now extends into the 2020 to 2025 regulatory period.

Contents

1 Introduction

The purpose of this document is to outline the required expenditure for the Optical Fibre (OF) Cable In-Fill program for the 2015/16 – 2019/20 regulatory period.

This program is important as it enables a number of other key programs including the continued roll out of the Core IP/MPLS Telecommunications Network. (refer: Core IP/MPLS Telecommunications Network program) and the provision of OF links for teleprotection.

The provision of OF cables contributes to the safe, efficient and effective operation of the distribution power network and to the mitigation of risk from damage or incorrect operation during faults or incidents that affect the primary power network assets.

An associated program is proposed for replacement of end-of-life copper pilot cables with fibre optic cables. Both of these complementary programs contribute to provision of new fibre optic cable.

Changes from original AER proposal

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 its original proposal. Energex has determined the risk of not proceeding with core telecommunications requirements is not tolerable as this program is an enabler for the rollout of the Core IP/MPLS Telecommunications Network. Energex has however been able to reduce the cost of the program by adopting a phased approach to implementation and adopting a higher risk of outage, and duration of outage for secondary systems at smaller zone substation and C&I substations. As such Energex has revised the program expenditure to $11.5m over the 2015/16 – 2019/20 regulatory period.

2 Drivers

2.1 Power Network Impacts

The ability to operate and maintain the power distribution network in a safe, and efficient manner is underpinned by a number of operational systems (such as the SCADA/DMS, and protections schemes) that in turn, are reliant on the underlying telecommunications systems, which are likewise reliant on the various telecommunications bearers. The network of OF cables provides highly available and secure bearers to the telecommunications systems (the legacy PDH[2] Multiplex network, and the new IP/MPLS network.) Other bearers include the copper pilot cable network, and a number of microwave radio links. Some external carrier services are also used.

OF bearers are preferred as they provide high bandwidth and high performance links that are required by modern telecommunications technologies and systems. Furthermore, OF bearers are highly available and secure through being co-located with the power network feeder assets which provides resilience against the natural disasters that impact South East Queensland, such as storms and floods.

Copper pilot cables cannot provide the required bandwidth and high performance links needed for modern telecommunications technologies and systems. As such Energex has determined it is prudent to invest in expanding the network of OF cables and the continued rollout of the Core IP/MPLS Telecommunications Network in preference of further investments in Copper pilot cables and related technologies.

The continued rollout of the Core IP/MPLS Telecommunications Network is a key recommendation of the Telecommunications Strategic Plan 2015-20.

> *'Energex embarked on a substantial telecommunications infrastructure modernisation program in 2009 with investment in an IP/MPLS core network … as described in the 2008 Energex Telecommunications Strategy [8].*
>
> *Energex considers that, as part of the Telecommunications Strategy 2015-20 (the Strategy), it is prudent to continue the core network deployment … and continue the work needed for capitalising on the improved core network infrastructure, to deliver better long term outcomes for both Energex and its customers'*

For details refer to the Energex Telecommunications Strategic Plan 2015-20.

The continued rollout of the Core IP/MPLS Telecommunications Network is the subject of a separate program which is reliant upon this. [Refer Core IP/MPLS Telecommunications Network Rollout]

> *'Energex's multi-stage approach to implementing the Core IP/MPLS Telecommunications Network, with roll-out of nodes being scheduled over a number of years. This allows for the associated and necessary optical fibre links to also be provided in an efficient and prudent fashion, as part of normal feeder establishment/ renewal program-of-work, or via selective Optical Fibre In-Fill projects.'*

[2] The telecommunications networks include the legacy Plesiochronous Digital Hierarchy (PDH) Telecommunications Network based on older Time Division Multiplexer circuit switched technology.

In past years a significant portion of the network of OF cables was provided via power network feeder projects such as new feeders for new/expanded substation, or feeder refurbishment works. The quantity of these other power network projects is significantly reduced in this upcoming regulatory period hence there is more reliance on this OF Cable In-Fill program to provide the required OF links.

The network of OF cables also provides direct fibre links for some inter-substation teleprotection systems where the protection relays communicate directly over the OF cable rather than via a PDH Multiplex link. The continuation of the OF Cable In-Fill program also enables such teleprotection schemes.

2.2 Legislative Compliance

Energex has obligations under the National Electricity Rules (NER) Schedule S5.1.2.1 (d) as follows:

> *The Network Service Provider must ensure that all protection systems for lines at a voltage above 66 kV, including associated inter-tripping, are well maintained so as to be available at all times other than for short periods (not greater than eight hours) while the maintenance of a protection system is being carried out.*

To adhere to this requirement Energex needs to ensure that the fibre cable network associated with protection of its higher voltage lines is “well maintained”.

Energex needs to comply with NER / AEMO requirements in the instance that a protection function is lost due to a fibre cable fault, whether the fault is as a result of slow degradation of the cable, or some form of mechanical damage such as caused by a back hoe or directional borer. In the event of a failure of any 132kV, 110kV or certain 33kV protection schemes, Energex is required to notify Powerlink who will subsequently notify AEMO of the outage. Energex has an obligation to restore the protection function of the line “as quickly as possible”. AEMO may determine that having a line in service without the affected protection function will compromise the security of the network should a fault occur, and require Energex to de-energise the line. Without suitable alternative communications paths that can be relied upon during service outages, Energex risks its ability to meet these legislative requirements.

The key drivers for the continuation of the OF Cable In-Fill program can therefore be summarised as:

- Enabling the continued rollout of the Core IP/MPLS Telecommunications Network to extend the network coverage to additional substation sites;
- Enabling the improved resilience of the Core IP/MPLS Telecommunications Network by providing alternate network paths to important sites that currently have only a single path; and
- Meeting the NER Schedule S5.1.2.1 (d) legislative compliance for availability.

3 Supporting Analysis

3.1 Existing Network / Background

Energex has a telecommunications cable network comprising of copper and OF cables running between substations, depots, communications nodes and a variety of other locations in the distribution network.

Energex owns and operates an extensive network of OF cables with approximately 3400km of both underground and overhead OF cables. These cables are primarily used as a transport medium for teleprotection between substations, SCADA control, provision of corporate network access into substations and a range of other services. Energex is progressively installing OF cable to replace the copper network based on an overall strategy to progressively move from an aging copper network to the newer OF network with greater bandwidth and capacity to enable and support modern technologies.

Refer to Appendix 1 for an overview of the existing OF cable network.

At the end of the 2012/13 financial year the following quantities were present in the network:

Asset Name	Total in service	Age profile	Implementation
Optic Fibre Cable	1464 individual cables of total estimated length 3366 km	Average age of 7 years , maximum age 28 years	Energex wide, however concentrated in metropolitan areas

Table 1 – Optic fibre cable assets in service

The various services that run over the OF network utilise either direct connectivity via the cable or use communications equipment that combine multiple services to operate over individual fibre cores. The two most important services running over the network are protection signalling and SCADA telecommunications, which run between various bulk supply substations and zone substations and the operational data centres.

Records show cables having been installed from mid1980’s with quantities per year as per the graphs below.

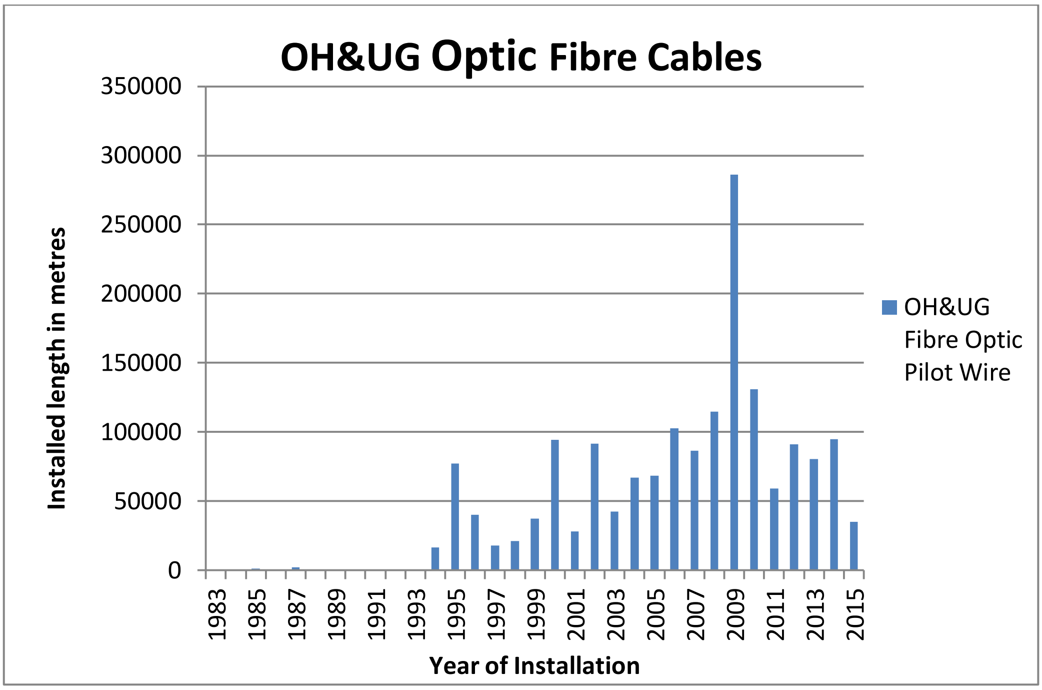


Figure 1 – Installation metres per year for Optic Fibre

The roll-out of OF cables has mostly been achieved as part of the scope of power network feeder projects, whether for new capacity, or refurbishment. Optical Ground Wire (OPGW) cable is installed with new 110kV and 33kV overhead feeders, and when feeder earth wire requires replacement. Underground OF cable is installed with new, upgraded, or replacement underground feeders. This approach has been most effective and is very cost efficient given the small incremental cost to the power network feeder project. This approach however results in some gaps between sites where OF links are required for the Core IP/MPLS Telecommunications network. The OF cable In-Fill program fills in these 'gaps'. See Appendix 1 for a map of the OF network.

The 2015/16 – 2019/20 regulatory period has a significant reduction in new/upgrade feeder works, and reliability driven feeder refurbishment works. As a result the provision of the required OF cable must be done as a dedicated program of OF In-Fill. The continued roll out of the Core IP/MPLS Telecommunications Network is dependent on this program for provision of some of the OF bearers that are needed for the inter-substation links.

3.2 Limitations of the Existing Network

The following sections outline the limitations of the existing telecommunication OF cable bearer network.

3.2.1 Network Coverage

The OF network is not provided to a number of substations or substations have no path back to the remainder of the network. Also there is no redundant path at locations requiring dual communications paths (these are predominately substations where 110 kV feeders terminate and protection circuits must be provided with redundant communications links to meet NER requirements). Also with certain services now needing to have fibre connectivity many sites with only copper pilot cables cannot receive the latest equipment requiring work arounds to be employed or requiring that older generations of equipment are utilised. This revised program has scaled back the additional network coverage that was originally proposed, to reflect the corresponding reduced roll-out under the associated *Core IP/MPLS Telecommunications Network* program.

3.2.2 Limited Fibre Capacity on Older OF Cables.

The initial installation of OF was with cables having only a few fibres cores. With the expanding need for OF based telecommunications services, some of the earlier deployed cables are facing fibre congestion. In some cables the quality of the fibre does not meet current standards required for modern IP/MPLS equipment, hence some of these cables must be replaced or additional cable installed as the most prudent alternative to meet the business needs. This revised program has deferred the OF congestion relief that was originally proposed, to reflect the adoption of a higher risk.

3.2.3 Future Requirements

Energex’s current and future business needs require the provision of IP based services, and requires much higher data rates than can be achieved over the existing old copper pilot cables. Decisions about replacement of existing cabling include consideration of the strategic direction towards high speed communications and the need to have fibre optic cabling to achieve this. This revised program has been reduced to only facilitate the current requirements for deploying the associated Core IP/MPLS Telecommunications Network program.

3.2.4 End of Life Pilot Cables

Energex also has an extensive network of copper pilot cables, many of which are near or at end of life and need to be replaced. The strategic approach is to replace these copper pilot cables with OF cable where prudent, such as where the cable location aligns with the need for an OF link for the Core IP/MPLS Telecommunications Network, or for direct teleprotection links. This cable replacement work is covered by a separate but associated program, (refer: *Pilot Cable Replacement program*)

3.2.5 OF Cable Network Gaps

In nearly all cases, if protection is required at a substation then some type of Energex telecommunications service will be present. The bulk of these will be copper and OF pilot cables, however some locations use microwave links to provide the required protection circuits. The current coverage of the OF cable network is concentrated in the Brisbane metropolitan area with some extensions to the North Coast, the South Coast, and West as shown in Appendix 1. It can be seen that the cables do not currently form a fully interconnected network.

With the strategic direction to move to a fibre network, analysis has been performed to identify the gap between the current fibre network and what is required to effectively transition away from copper pilot cables.

Below is a summary of current communication network limitations that will impact the strategic direction to introduce modern communication systems. The high level results of the fibre network coverage analysis:

- 27 substations with protection circuits on copper pilot cables and no fibre cable (includes C&I)
- 6 substations with 110kV protection on copper pilot cables and no fibre cables
- 2 substations with 110kV protection and a single fibre only
- 160 substations with non-protection circuits on copper pilot cables and no fibre (includes subs with protection as well)
- 30 substations with non-protection circuits on copper pilot cables and one fibre
- 43 substations with no pilot (copper and fibre) cables
- 11 substations with fibre that are not interconnected to the remainder of the network with either a high speed microwave link or a fibre cable

To achieve provision of fibre cable to cover all the above limitations Energex estimates that 1479 km of cable would need to be installed. This would see a number of very small substations provisioned with fibre cable with limited value generated.

Energex is targeting to install fibre optic cable to all zone and bulk supply substations above 5MVA which would require a total of 261km of cable to be installed.

The options presented in section 4 of this business case form the basis of addressing these communication network limitations.

4 Options

4.1 Impact of Doing Nothing

The do nothing approach does nothing to address equipment continuing to age and resultant increases to failure rates, fails to mitigate any of the identified risks, and would likely result in Energex suffering continuing increases in protection services that cannot quickly be returned to service using alternate cabling. It would also necessitate expenditure on maintenance/ replacement of legacy/obsolete PDH telecommunications equipment with like for like systems that only allow for continued operation of the existing services.

Risk of the do nothing approach is quantified in the untreated risk scenarios in Table 2.

Category	Risk Scenario	Consequence	Likelihood	Risk Score
Business Impact	Energex has a number of requirements for modern secure high speed communications (refer section 2). Failure to complete the rollout prevents requirements being met.	4	5	20 (High Risk)
Legislated Requirements	Fault on a fibre cable carrying 110kV protection. No available alternative path and cannot be repaired in reasonable time frame. Powerlink / AEMO notified and request received to reconfigure network	5	2	10 (Low Risk)

Table 2: Untreated Risk Assessment Summary – OF Cable In-fill

Not proceeding with the program is not prudent as the legacy network is inadequate for current and future business needs such as improved protection schemes, improved remote engineering access, enabling condition based asset management, improved site access security and failure to provide the backbone for future communications network.

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 Proposal) Optical Fibre In-Fill – Accelerated Program

4.2.1 Option 1 Summary:

This option proposes the installation of OF cables to in-fill the gaps needed to facilitate the continued rollout of the Core IP/MPLS Telecommunications Network, achieve network resilience goals, and relieve some fibre congestion. This option would proactively identify where OF cable is required to support the ongoing development of the power network and associated telecommunications network and to enable the transition off the copper pilot cables.

4.2.2 Option 1 Impact Analysis

The work comprises the implementation of OF cable between substations locations.

The proposed candidate list of cables is included in Appendix 2, Appendix 3 and Appendix 4.

This option is a summary of Energex's original AER submission. This option provides cables that are needed for the continued rollout of the Core IP/MPLS Telecommunications Network and to address some OF cable congestion issues.

Description	2015/16	2016/17	2017/18	2018/19	2019/20
Expenditure $m, 2014/15	4.5	5.0	5.0	5.0	5.0

Assuming Energex was to continue to deliver cable at this rate (220 km per 5 years) then the fibre infill program would be completed during the 2020 to 2025 period.

4.3 Option 2 – Optic Fibre In-Fill – Reduced Rate

4.3.1 Option 2 Summary:

This option proposes the installation of fibre cables to in-fill the gaps needed to facilitate the continued rollout of the Core IP/MPLS Telecommunications Network at a reduced rate, implement less network resilience goals and accept the congested cable constraints. This option is based on Option 1, but with a much reduced scope and modified as detailed below.

The proposed candidate list of cables is included in Section 5. This is a subset of the original candidate list in Appendix 2 with some of the longer links deferred into the following period and focused on substations with load >8MVA.

4.3.2 Option 2 Impact Analysis

The work comprises the implementation of OF cable between substations locations at a reduced rate compared to original proposal (Option 1). This option has been modified from the scope in Option 1 as follows:

- Reduce candidate list Appendix 2 to only substations with load >8MVA and defer remaining substations into the following period. Estimated deferred cost $6.5m
- Defer candidate list of Appendix 3: Substations with load >5MVA that require alternate network path. Defer into the following period. Estimated deferred cost $5m
- Defer candidate list of Appendix 4: Substations with load >15MVA that require additional cable to address fibre congestion. Defer into the following period. Estimated deferred cost $1.5m

On the basis of tolerating increased degree of business risk, this becomes the preferred option.

Description	2015/16	2016/17	2017/18	2018/19	2019/20
Expenditure $m, 2014/15	2.0	2.0	2.5	2.5	2.5

Assuming Energex was to continue to deliver cable at this rate (115 km per 5 years) then the fibre infill program would be completed at the end of the 2025 to 2030 period.

5 Proposed Works

It is proposed to implement Option 2 to undertake the optical fibre cable at a reduced rate. This option provides a sustainable approach for addressing the identified limitations whilst reducing the expenditure requirements of the program in the regulatory period by adopting a phased approach to implementation and tolerating increased risk of outages occurring, and increased outage duration for secondary systems at smaller zone substation and C&I substations. The proposed OF cable in fill program will assist in the implementation of the strategic direction to install a backbone OF cable network.

The candidate list for additional OF cables under the revised proposal is detailed below:

Fibre Infill Projects	Distance	Reason	adds	Load (MVA)
SSEMP to SSGCT	3	Substation Addition	SSEMP	33.57
SST78 to SSGBS	20.5	Substation Addition	SSGBS	31.96
SSAHL to SSGLY	1.1	Substation Addition	SSAHL	31.95
SST24 to SSSBK	4.2	Substation Addition	SSSBK	29.62
SSMTG to SSUMG	1.4	Substation Addition	SSMTG	26.84
SSCPL to SSARG	3.7	Substation Addition	SSCPL	23.93

Fibre Infill Projects	Distance	Reason	adds	Load (MVA)
SSNMC to PLQ S3	4.2	Substation Addition	SSNMC	23.48
SSDRD to SSRCF	4	Substation Addition	SSRCF	23.08
SSHIL to SSDRD	6	Substation Addition	SSDRD	22.02
SSGBS to SSGTN	7.2	Substation Addition	SSGTN	21.1
SSHPE to SSMTG	3.1	Substation Addition	SSHPE	20.75
SSCFD to OFEMQ	1.7	Substation Addition	SSCFD	20.16
SSVSP to SSGRW	1.2	Substation Addition	SSVSP	18.11
SSH9 to SSPWC	3.5	Substation Addition	SSPWC	17.96
SSABY to SSABL/SSRAAF	0.9	Substation Addition	SSABL	17.08
SSWMN to SSLTA	4.4	Substation Addition	SSLTA	16.9
SSRCF to SSSBH	2.4	Substation Addition	SSSBH	15.45
SSBOC to SSBWI	0.1	Substation Addition	SSBOC	14.71
SSHMT to SST73	2.7	Substation Addition	SSHMT	13.89
SSMCW to SSH36	1.3	Substation Addition	SSMCW	13.75
SSMTC to SSH36	2.1	Substation Addition	SSMTC	13.08
SSLBH to FO601	4	Substation Addition	SSLBH	11.06
SSRLA to SSSBY	1.4	Substation Addition	SSSBY	10.01
SSBMT to SST70	7.8	Substation Addition	SSBMT	9.1
SSPGN to SSSRH	8.7	Substation Addition	SSPGN	8.39
SST78 to SSGGR	7	Substation Addition	SSGGR	8.37
SSBTN to SSBDT	7.8	Substation Addition	SSBTN	8.24

Table 3: Proposed works

6 Required Expenditure

Table 4 below outlines the required expenditure for Option 2, which is the preferred optical fibre cable in-fill program in this business case.

Description	2015/16	2016/17	2017/18	2018/19	2019/20
Expenditure $m, 2014/15	2.0	2.0	2.5	2.5	2.5

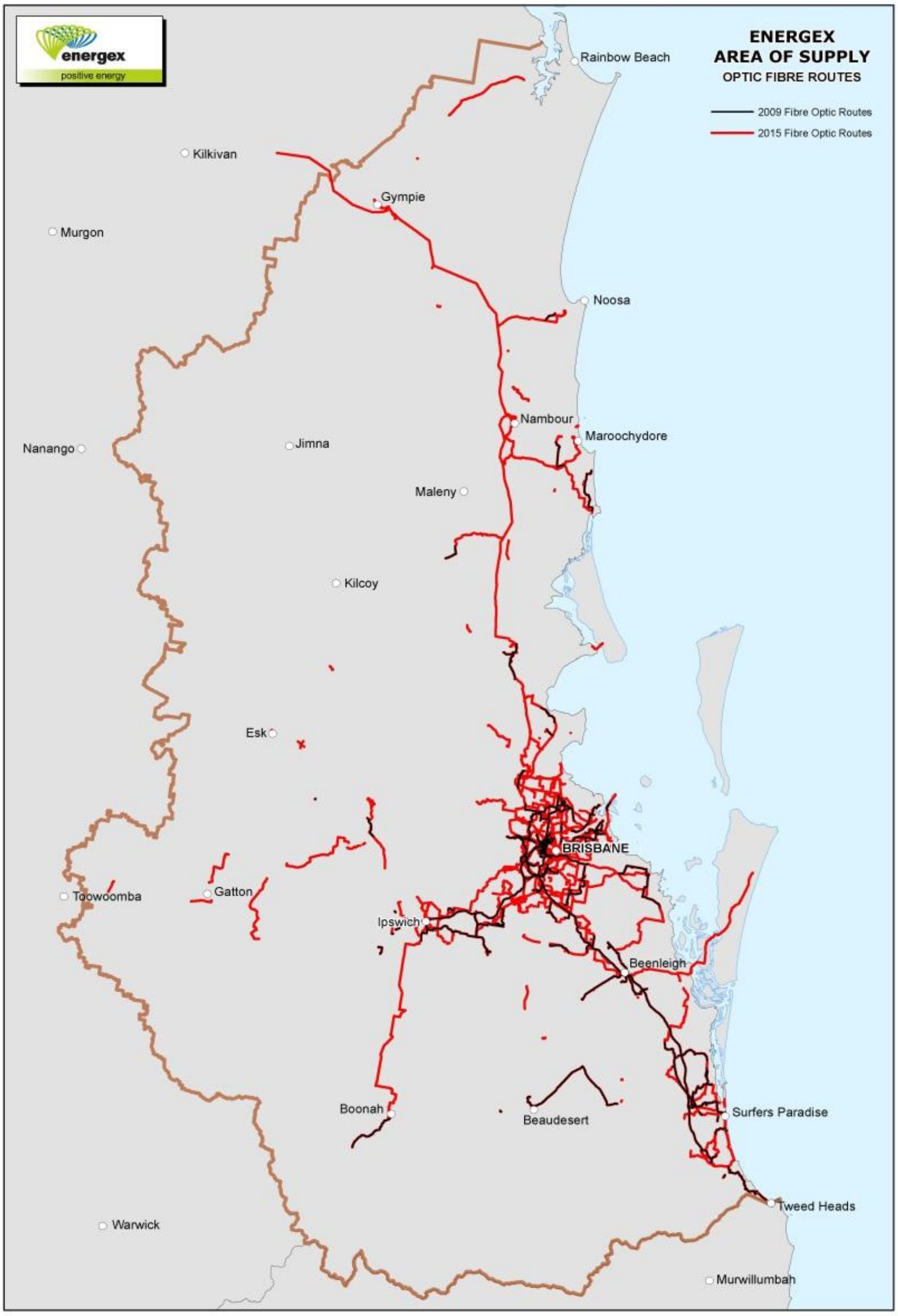
Table 4: Expenditure

This option presents a 53% reduction in required expenditure from the original proposal, reduced on the basis of accepting an increased degree of risk by phasing the program over several regulatory periods.

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: Optical Fibre cable network



Appendix 2: Original Proposal - Optical Fibre cable candidate list: Substations with load >5MVA

On the basis of adopting greater risk, a number of these links to be deferred until after the 2015-20 period.[Estimated cost deferred $6.5m]

Fibre Infill Projects	Distance	Reason	Adds	Load
SSEMP to SSGCT	3	Substation Addition	SSEMP	33.57
SST78 to SSGBS	20.5	Substation Addition	SSGBS	31.96
SSAHL to SSGLY	1.1	Substation Addition	SSAHL	31.95
SST24 to SSSBK	4.2	Substation Addition	SSSBK	29.62
SSWFD to SSCBW	21	Substation Addition	SSCBW	27.98
SSMTG to SSUMG	1.4	Substation Addition	SSMTG	26.84
SSCPL to SSARG	3.7	Substation Addition	SSCPL	23.93
SSNMC to PLQ S3	4.2	Substation Addition	SSNMC	23.48
SSDRD to SSRCF	4	Substation Addition	SSRCF	23.08
SSHIL to SSDRD	6	Substation Addition	SSDRD	22.02
SSGBS to SSGTN	7.2	Substation Addition	SSGTN	21.1
SSHPE to SSMTG	3.1	Substation Addition	SSHPE	20.75
SSBIS to SSTPT	2	Substation Addition	SSBIS	20.51
SSCFD to OFEMQ	1.7	Substation Addition	SSCFD	20.16
SSVSP to SSGRW	1.2	Substation Addition	SSVSP	18.11
SSH9 to SSPWC	3.5	Substation Addition	SSPWC	17.96
SSABY to SSABL/SSRAAF	0.9	Substation Addition	SSABL	17.08
SSWMN to SSLTA	4.4	Substation Addition	SSLTA	16.9
SSRCF to SSSBH	2.4	Substation Addition	SSSBH	15.45
SSBOC to SSBWI	0.1	Substation Addition	SSBOC	14.71
SSHMT to SST73	2.7	Substation Addition	SSHMT	13.89
SSMCW to SSH36	1.3	Substation Addition	SSMCW	13.75
SSMTC to SSH36	2.1	Substation Addition	SSMTC	13.08
SSLBH to FO601	4	Substation Addition	SSLBH	11.06
SSSDM to SSKCY	17.5	Substation Addition	SSKCY	10.11
SSRLA to SSSBY	1.4	Substation Addition	SSSBY	10.01
SSWFD to SSBWH	10	Substation Addition	SSWFD	9.84
SSBMT to SST70	7.8	Substation Addition	SSBMT	9.1

SSPGN to SSSRH	8.7	Substation Addition	SSPGN	8.39
SST78 to SSGGR	7	Substation Addition	SSGGR	8.37
SSBTN to SSBDT	7.8	Substation Addition	SSBTN	8.24
SSNGI to SST11	12.2	Substation Addition	SSNGI	8.04
SSHTL to SSSWP	0.35	Substation Addition	SSSWP	6.74
SSABY to SSRWD	12.6	Substation Addition	SSRWD	6.5
SSCMY to SSWHH	10.5	Substation Addition	SSCMY	6.13
SSYDA to SST16	6.8	Substation Addition	SSYDA	5.95
SSMLY to RRWKB	8	Substation Addition	SSMLY	5.65
SSTPT to SST11	20.5	Substation Addition	SSTPT	5.63
SSKWH to SST16	24.5	Substation Addition	SSKWH	5.13

Appendix 3: Original Proposal - Optical Fibre cable candidate list: Substations with load >5MVA that require alternate network path.

On the basis of adopting greater risk, these links to be deferred until after the 2015-20 period. [Estimated cost deferred $5m]

Fibre Infill Projects	Distance	Reason	Load
SSEMP to SST24	4.2	Network resilience	33.57
SSH9 to SSWMD	18	Network resilience	32.96
SSQPT to TW1604-N	0.5	Network resilience	28.78
SSBLB to TW1614-M	0.4	Network resilience	24.78
SSHPK to SSMTG	5.6	Network resilience	21.06
SSHPK to SSHPE	3.6	Network resilience	20.75
SSCFD to SSHDA	2.4	Network resilience	20.16
SSMGP to SST128	3.58	Network resilience	16.67
SSBTA to SSKSN	5.58	Network resilience	16.62
RAAF to YMT	6.73	Network resilience	11.4
SSBLN to SST108	0.9	Network resilience	10.56
SSLDR to SSPKW	3.41	Network resilience	9.8
SSSGT to SSBRT	4.3	Network resilience	9.01
SSYDA to SST40	6.8	Network resilience	5.95

Appendix 4: Original Proposal - Optical Fibre cable candidate list: Substations with load >15MVA that require additional cable to address fibre congestion.

On the basis of adopting greater risk, these links to be deferred until after the 2015-20 period. [Estimated cost deferred $1.5m]

Fibre Infill Projects	Distance	Reason	Load
SSVPK to SSCST	3	Congestion	101.97
SSVPK to SSGSC	0.9	Congestion	101.97
SSNSD to SSMLS	1.8	Congestion	39.23
SSVPK to SSNSD	2.8	Congestion	39.23
SSATC to SSAST	0.4	Congestion	28.69
SSLBS to SSGIS	2.9	Congestion	20.2

Appendix 5: Regulation associated with Protection outages that need to be applied for communications links providing communications for protection services

National Electricity Regulator (NER) Schedule S5.1.2.1 (d)

The Network Service Provider must ensure that all protection systems for lines at a voltage above 66 kV, including associated intertripping, are well maintained so as to be available at all times other than for short periods (not greater than eight hours) while the maintenance of a protection system is being carried out.

AEMO security guide lines

16. Protection System Outages

If a Registered Participant becomes aware that any relevant protection system or control system is defective or unavailable for service, that Registered Participant must advise AEMO. If AEMO considers it to be a threat to power system security, AEMO may direct that the equipment protected or operated by the relevant protection system or control system be taken out of operation or operated as AEMO directs.

16.1 Total Outage of Protection Schemes

If all the primary protection schemes on a transmission element are removed from service the transmission line is normally removed from service. An exception to this may arise if the outage of the transmission line would interrupt supply and adequate backup protection is available to maintain system security. Situations of this kind should be resolved between the NSP and AEMO.

16.2 Planned Outage of One Protection of a Duplicated Scheme

Normally the power system equipment can remain in service

The duration of the outage should be kept to a minimum and not greater than eight hours unless agreed by AEMO and the relevant NSPs. Refer NER Schedule S5.1.2.1 (d).

If the protection remains unserviceable after 8 hours and provided there is agreement between AEMO and the relevant NSPs for the outage to continue, then follow the approach as for unplanned outages.

16.3 Unplanned Outage of One Protection of a Duplicated Scheme

The Rules (refer S5.1.2.1 (d)) may be interpreted to apply to planned outages for maintenance purposes and the following clarifies the approach for unplanned outages of one protection of a duplicated scheme.

Normally the transmission element can remain in service provided that the NSP provides reasonable assurance that the remaining protection will clear a fault in primary protection timeframe; and

The protection repair is being progressed with the intention of returning the duplicate protection to service as soon as possible.

If these conditions are not met then the affected transmission element must be taken out of service.

16.4 Degraded Clearing Times

Degraded or longer clearing times can result during outages of protection signalling or inter-tripping equipment. Degraded clearing times can also result if high speed primary protection such as distance or pilot wire protection is taken out of service and the alternative protection is a slower directional over current scheme. Temporary protection schemes can also result in longer clearing times. The effect of this on system security needs to be assessed in consultation with the TNSP.

Where there is a risk to system security and any of the following apply:

High speed clearance of some faults is no longer possible.

There are periods when the risk of fault on the power system is high.

The degraded clearing times are to apply for extended periods.

Then:

The power system must be operated to more restrictive limits which correspond to the longer clearing times, or;

The protection settings must be reduced to provide faster clearing times. If this leads to loss of discrimination, operating limits must be reduced to correspond with the possibility of inappropriate operation, or;

The affected transmission element must be taken out of service.

16.5 Outage of Additional Non- Duplicated Protection Schemes

Protection schemes required for the detection of special low probability events such as Directional Earth Fault Comparison schemes, designed to detect high impedance faults which may occur during bushfires, may be taken out of service, and the primary plant left in service. This action may only be taken provided the risk of this type of fault is not high and the outage is of short duration, that is, less than 8 hours unless agreed by AEMO and the relevant NSPs.

Outages of other types of protection schemes which may not be duplicated, such as transformer buchholz or differential protection, should be treated in a similar way.

16.6 Outage of Signalling Systems

Outages of signalling systems such as fast zone two blocking can cause loss of discrimination and suitable remedial measures should be agreed with the TNSP. These measures may include the temporary application of a block or removal of the fast zone two tripping feature.

Outages of accelerated inter-tripping on one protection scheme of a duplicated scheme normally will not result in loss of zone one clearing times on the protected transmission element and thus should not impact on system security.

Outages of direct or accelerated inter-tripping associated with Circuit Breaker Fail protection in "breaker and a half" switchyards may require opening of coupler circuit breakers provided this does not cause additional security problems.

Provided the system security issues have been adequately addressed the affected primary plant can remain in service.

16.7 Transfer Limit Reductions due to Protection Outages

Outages of protection or associated signalling equipment can lead to a reduction in transient stability transfer limits.

Various types of protection schemes designed to enhance system stability such as single pole tripping and reclosing or power swing blocking could also result in a reduction of safe power transfer limits if they are not available. Changes to these limits will be agreed between AEMO and the appropriate TNSP.

16.8 System Protection Services

Under frequency protection is designed to return system frequency to normal following multiple generation contingencies. The National Electricity Rules requires 60% of the total load of a region to be connected to under frequency protection. This protection is distributed across the region and taking the under frequency scheme out of service at one substation has little effect on the overall scheme and the security of the power system.

Under voltage schemes are designed to protect smaller areas within the power system from under voltages during contingencies. The outage of these schemes will impact on the security of the power system but only for a limited number of contingencies. The outage will need to be assessed against other planned outages of system equipment and any known risk factors such as weather conditions.

There are special control schemes and devices that allow higher Inter-Regional and Intra-Regional transfer levels when they are in service. Outages of these schemes will be assessed to determine if new constraints need to be applied to the associated transfer limits.

16.9 NEM Rules Requirements

The National Electricity Rules Clause 4.3.1 defines the responsibility AEMO has for system security.

Clause4.6.2. AEMO is required to co-ordinate, in consultation with Network Service Providers, the protection of power system plant which could affect power system security.

Clause 4.6.5 defines AEMO's responsibility to determine, in consultation with the Network Service Providers, the best course of action to adopt for partial, or complete, removal from service of the protection equipment protecting transmission lines. The NSP must comply with AEMO's determination unless in their reasonable opinion it would threaten the safety of any person or cause material damage.

Clause 4.8.2 defines a registered participant's responsibility to advise AEMO of any relevant protection or control system that is defective or unavailable. If there is risk to system security AEMO can direct the affected plant to be taken out of service or to be operated in an appropriate manner. The Registered participant must comply with a direction given by AEMO.

PUBLIC

Energex

Pilot Cable Replacement Program

Asset Management Division

energex

positive energy

Energex

Pilot Cable 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

Energex has an established Telecommunication Strategy which requires the implementation of the Pilot Cable Replacement program as part of the long term roadmap. Energex requires a robust telecommunications network to support the primary electrical network to meet the safety, legislative, business and customer requirements. An important component of this telecommunications strategy is the phasing out of the legacy copper pilot cable network of which Energex owns and operates over 930 km of both underground and overhead cables. The protection and signalling services provided by the pilot cable network are fundamental to the power networks ability to protect personnel and equipment during abnormalities including high voltage faults, and to ensure safe and effective operation of the power network.

The purpose of this document is to outline the required expenditure for replacement of Copper Pilot Cables over the 2015/16 – 2019/20 regulatory period. The objectives for this program are to:

- Provide for continued operation of the high voltage network in accordance with protection system requirements in the National Electricity Rules, which places obligations on how the pilot cable communications network is managed; and
- Minimise the likelihood of plant damage and customer outages caused by loss of Energex communications systems;

The Pilot Cable Replacement Program consists of both planned and reactive works to target high risk cable routes for proactive replacement, whilst also responding to replacement of pilot cables when failures occur.

The original proposal to the AER for the pilot cable replacement program was for $10.5 million over the 2015/16 – 2019/20 regulatory period. Total expenditure of the revised program remains unchanged due to the critical nature of communications links to the operation of the electricity distribution network. Timing of some work was revised to ensure efficient delivery.

$m, 2014/15	2015/16	2016/17	2017/18	2018/19	2019/20	Total
Energex Proposal	2.1	2.1	2.1	2.1	2.1	10.5
Energex Revised Proposal	1.5	1.5	2.5	2.5	2.5	10.5

The revised proposal aligns with the business outcomes outlined in the Energex *Telecommunications Strategic Plan 2015-20.*

Contents

1 Introduction

Prior to the introduction of fibre optic cables, copper pilot cables were the preferred communications medium for telecommunications between substation sites. However over time, the Energex copper pilot cable network has become aged, heavily committed, (little or no spare channels) and increasingly unreliable. Copper networks are now considered obsolete technology and suffer propagation and speed limitations thereby limiting the services they can provide. Whilst Energex no longer actively deploys new copper pilot cable bearers, a substantial installed base of copper pilot cable bearers is still in use for telecommunications, with the majority of the copper bearer network utilised for direct connection of protection circuits. Energex currently owns and manages over 1100 copper pilot cable bearers across more than 930 km of network.

The pilot cable replacement program targets replacement of end-of-life or at-risk pilot cables. Preference is given to replacement of pilot cable with modern equivalent optical fibre cable, with new copper pilot cable used only in situations where fibre is unfeasible or costs outweigh benefits.

2 Drivers

The main drivers of this program fall across two categories; legislative compliance and customer impact.

2.1 Legislated Requirements

Energex is bound by the National Electricity Rules (NER). Whilst various aspects of the NER are impacted by pilot cable reliability, the most pertinent is the requirement outlined in Schedule S5.1.2.1(d):

> *The Network Service Provider must ensure that all protection systems for lines at a voltage above 66 kV, including associated inter-tripping, are well maintained so as to be available at all times other than for short periods (not greater than eight hours) while the maintenance of a protection system is being carried out.*

To adhere to this requirement Energex needs to ensure the pilot cable network associated with protection for high voltage lines is well maintained. For instances where a protection function is unavailable due to a pilot cable fault, whether faults are a result of progressive cable degradation or some form of external mechanical damage, Energex has an obligation to restore the protection function of the line "as quickly as possible". In the event of a failure of any 132kV, 110kV or certain 33kV protection schemes, Energex is required to notify Powerlink who will subsequently notify AEMO of the outage. AEMO may determine that having a line in service without the relevant protection function will compromise the security of the network should a fault occur, and require Energex to de-energise the line. Without suitable alternative communications paths that can be relied upon during service outages, Energex risks its ability to meet these legislative requirements.

2.2 Customer and Business Impact

As the copper pilot network reaches the end of its design life, the reliability and performance of the individual cables rapidly decrease. This has various impacts as outlined in the following sections.

2.2.1 Tripping of Feeder Protection Scheme When Cables / Cores Fail.

In some limited cases such as DC direct inter-tripping and some feeder differential schemes, when cables / cores fail the protection may mal operate, causing tripping of feeders and resulting in loss of supply. This has potential customer impacts.

2.2.2 Increased Risk of Plant Damage and Larger than Necessary Outages When Communications Facilities are Not Operating.

For periods when protection circuits are not operating there are potential risks to plant damage / premature aging due to longer periods before backup protection clears faults. There are also increased outage impacts should a fault occur during the period of the communication issues. While the duration of protection circuits not operating is normally a short period during repairs, in some cases such as a silent failure, it can be an indeterminate period.

2.2.3 Security in the Power Network May be Reduced.

If a protection circuit is lost on a 33KV, 110KV and 132KV feeder (and for certain important 11kV feeders) it may be necessary to de-energise the feeder. This results in an abnormal network configuration and loss of N-1 security until such time as the circuits can be returned, increasing the risk of otherwise un-necessary outages.

2.2.4 Loss of Contingency Capability

When issues occur, various indirect consequences can increase the risk to the organisation. A recent example of this was the loss of pilot cable PC93 Inala to Coopers Plains. When the pilot went out of service, feeder protection was not operable for a 33kV contingency feeder in the area until such time as the protection could be placed onto another route.

2.2.5 Alternate Paths Inoperable when Required

Energex is noticing an increasing number of issues encountered whilst swapping circuits onto alternate paths. A recent example was PC61, which is an alternate pilot cable for PC90. When an issue developed on PC90, staff attempted to move circuits to PC61 however the cable was found to be faulty and could not be utilised.

2.3 Modernisation of telecommunications to address obsolescence

Energex's Telecommunications Strategic Plan 2015 – 2020 deems copper pilot cables an obsolete technology. The advantages of fibre optic cable are well documented and DNSPs in developed countries are progressively migrating to fibre optic. When a copper pilot cable nears its end of life and where cost justified, Energex will install fibre optic cable to take advantage of fibre connectivity. Advantages include:

- 5 orders of magnitude improvement in data speed through fibre cable. This results in:
    - Improvement in the speed of SCADA communications allowing more data to be collected and reported back to controller and ultimately back to planners to make better planning decisions
    - Provision of increased range of management capability due to the increased data capability. Project Matrix will leverage fibre cable installed under these programs to provide a range of improvements (refer Core IP/MPLS Telecommunications Network Rollout business case)
    - Ability to provide corporate computing access to locations with fibre cable and MPLS equipment, which allows greater productivity for our work force or reduction in costs of Telecommunications carriage providers.
- Immunity to Electromagnetic Interference (including lightning surge)

2.4 Impact on operating costs

The pilot cable network is often heavily meshed. This means that significant effort can be expended attempting to find alternate paths following a path failure. As attempts are made to relocate failed circuits onto alternate cores or alternate paths if these cables are not in good repair circuits will not operate over them. Often multiple attempts are required and in some cases no alternative will be found.

A recent example of this occurred on the supply to a major hospital. After a pilot cable was hit by a directional borer, the protection was placed onto a different pilot cable path in order to retain the functionality. This resulted in protection for both the 11kV feeders to the hospital being on a single pilot cable. A fault on this cable whilst in this configuration would have resulted in the loss of both of the feeders to the hospital. To mitigate this issue, Energex arranged a protection outage, assigned and installed the alternate path and attempted to commission the protection on the revised path. The alternate path was found to be in too poor a condition and the protection had to be returned to the non-redundant path. This situation was in place for 3 months as repair to the cable went ahead.

2.5 Return to Existing Redundancy via Refurbishment / Repair

Once a pilot cable has been found faulted and the circuits that cable carried have been swapped to another path, an evaluation of the need to restore any capability lost due to the failure is performed. As Energex moves away from copper cabling the number of instances when work will be required will reduce as alternate routes would be available in the fibre network. As a consequence, some cables will simply be decommissioned.

Where the capabilities that the cable provided will be required, the best means to return that capability for the network must be determined and actioned. In some cases the most effective solution will be to refurbish / repair the cable by replacing a section of the cable. Whilst not the preferred solution as it does not provide the advantages that fibre cable offers, continued access to copper may be required. By way of example, some protection equipment can only operate over copper pilots and Energex has 1279 of these units operating in the network that are not nearing replacement. In such cases, it can be more cost effective to stay with copper cabling.

3 Supporting Analysis

Whilst Energex has made reasonable progress towards the ultimate goal of decommissioning copper pilot cables from the network, much work is left to be done. A total of 170 sites still have copper only pilot connections and 76 of these sites are connected by only a single copper pilot cable.

3.1 Network Age

Figure 1 below shows the age profile of the current copper pilot network. The spike in 1989 was due to an asset transfer from Powerlink. In 2010 Energex removed copper pilot cables from its standard building block designs as part of the strategic move to fibre optic cable. Some installations of copper pilot cables have occurred beyond 2010 due to previously designed projects or for repair and reconfiguration of existing cabling. While copper pilot cables notionally have a design lifetime of 50 years, Energex's experience is that age related failure rates increase well before this particularly for overhead pilot cables.

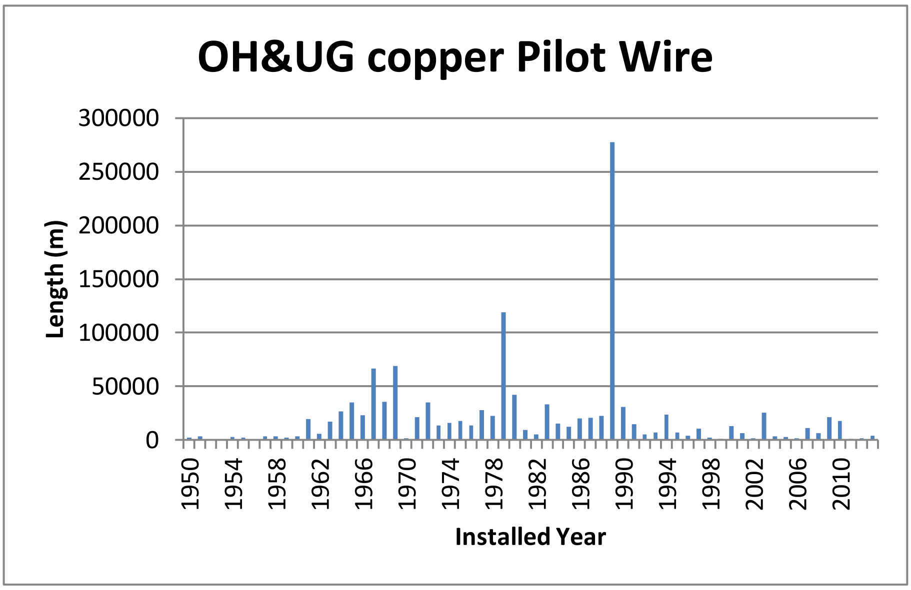

Figure 1: Copper Pilot Wire Age Population

3.2 Performance of the Pilot Cable Network

Appendix 2 details failures of secondary system equipment including copper pilot cables that required intervention by the network operators due to impacts on the primary power network in the 2008/09 to 2013/14 financial years. In total 68 emergency call outs were required to fix issues with copper pilot cables over the 6 years of the reporting.

Of particular note are the 14 separate incidents experienced on a single pilot cable PC273 in pursuit of a suitable solution. The cable provides protection communications for various 33kV feeders. The cable is 48 years old and is considered beyond end of life. Energex staff has attempted to find alternate cores and alternate paths for the circuits on the pilot cable and would move the circuits believing that the change would resolve issues, only to find that errors would again occur days, weeks or months later. This highlights the issue with operating pilot cables beyond their expected life.

3.3 Pilot cable life expectancy

Energex has evaluated the pilot cable assets to inform their expected life. The investigation looked at core failures within the cable. Generally failure tends to take the form of slow insulation degradation such that a pair or pairs have poor insulation to earth or between cores. The resulting poor performance makes it increasingly difficult for signals to be received at the remote end. Performance degradation is also observed as cables ages, with fast degradation typically occurring due to water ingress into the cable core. A demonstrated correlation exists between cable age and failed pilot cable pairs shown in Figure 2

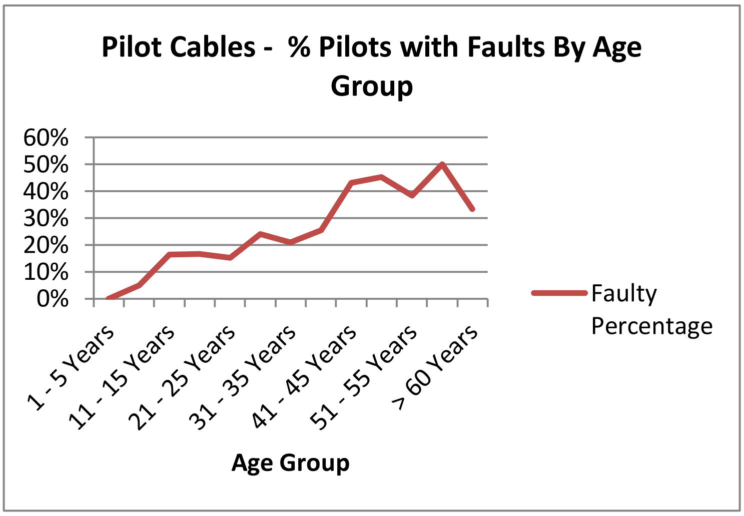

Figure 2: Copper Pilots with Faulty Cores as a Function of Age

Energex also looked at cables that have previously been deemed as unserviceable and the cable has been “decommissioned”. The decommissioning ages are shown in Figure 3. Evaluation of these decommissioned copper cables reveals an average decommissioning age of 40.3 years. Energex will not simply replace a cable based on age. Condition Based Risk Management (CBRM) is used to forecast proactive replacements and evaluate risk (noting that age is a variable used in the analysis) whilst field reports will be used to determine reactive work.

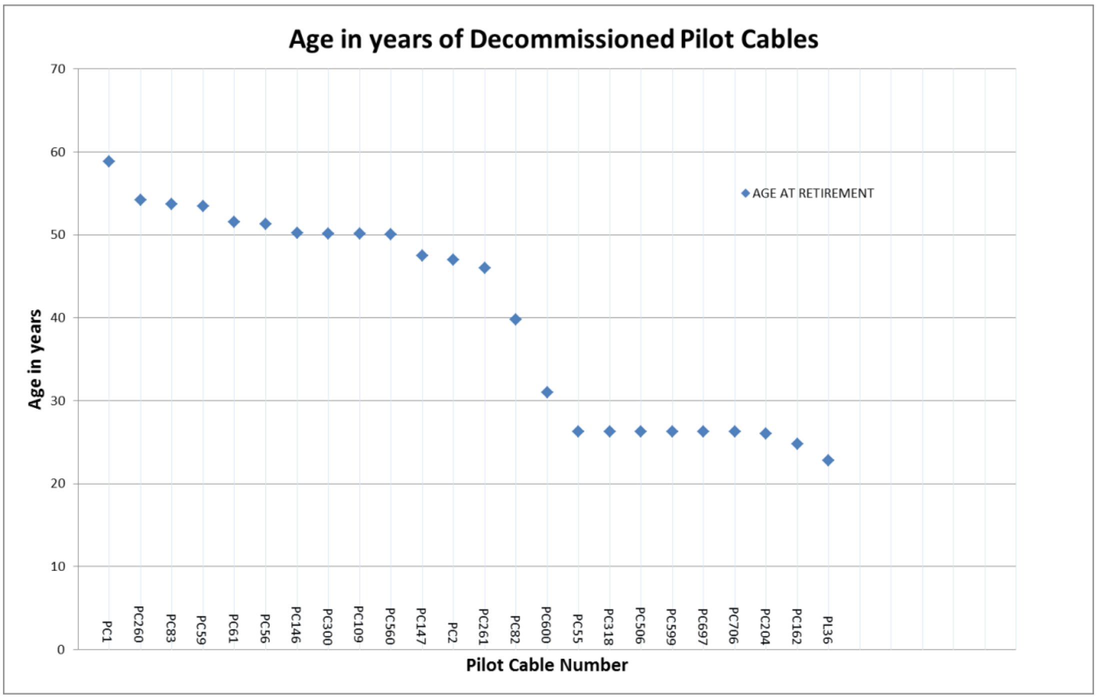

Figure 3: Cable Age Upon Decommissioning

4 Options

4.1 Impact of Doing Nothing

The do nothing approach does nothing to address an ageing asset profile, fails to mitigate any of the identified risks, and would likely result in Energex suffering continuing increases in protection services that cannot quickly be returned to service using alternate cabling. This will result in increasing instances of either loss of N-1 capacity or the need to run on back up protection until such time as repairs can be affected. Eventually if left long enough, Energex will see increasing customer outages and legislated breaches due to the poor state of cabling.

Energex will also experience increased costs to reactively repair or replace pilot cables upon failure. Energex will be forced to repair cabling where exact fault location is problematic requiring large sections of cabling to be replaced in short time frames.

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

Category	Risk Scenario	Consequence	Likelihood	Risk Score
Legislated Requirements	Fault on a pilot cable carrying 110kV protection. No available alternative path and cannot be repaired in reasonable time frame. Powerlink / AEMO notified and request received to reconfigure network	5	3	15 (Moderate Risk)
Customer Impact	Fault on a pilot cable carrying protection for critical customer. No available alternative path and cannot be repaired in reasonable time frame, protection placed on same cable as redundant feed. Subsequent fault on shared cable results in outage to customer	4	3	12 (Moderate Risk)
Business Impact	Failure of a pilot cable leading to feeder protection not working which necessitates the de-energisation of the feeder until repairs can be made resulting in an abnormal network configuration.	5	3	15 (Moderate Risk)

Table 1: Untreated Risk Assessment Summary – Pilot cable

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 – Prioritised Pilot Cable Replacements Using Optical Fibre

4.2.1 Summary

This option per Energex's original regulatory submission would see cables nearing end of life evaluated to determine whether to repair or replace with optical fibre cable. For the coming regulatory period the cables that would be considered for replacement would be as per Table 3 below. Cabling that has been reported from the field as requiring attention would also be evaluated.

Energex has used Condition Based Risk Management (CBRM) to evaluate the health of individual pilot cables and their probability of failure as a means to prioritise management of pilot cable assets. The CBRM analysis is useful to identify potential candidates, however further analysis was performed to determine intervention requirements that account for topology of the copper pilot network and the presence of available optical fibre routes. Appendix 3 summarises the list of cables identified by CBRM as requiring replacement.

4.2.2 Impact analysis

Energex needs to ensure that the required functionality the cabling provides can be maintained in a sustainable manner. This option targets approximately 100 km of the total pilot cable network to sites that have only a copper pilot connection. Of these 100 kilometres, 61 km is associated with sites that have a single copper cable connection to the remainder of the network. The sustainability chart below shows sustainability of the proposed program when considered against this subset of the complete pilot cable network.

The chart below shows the sustainability of Option 1.

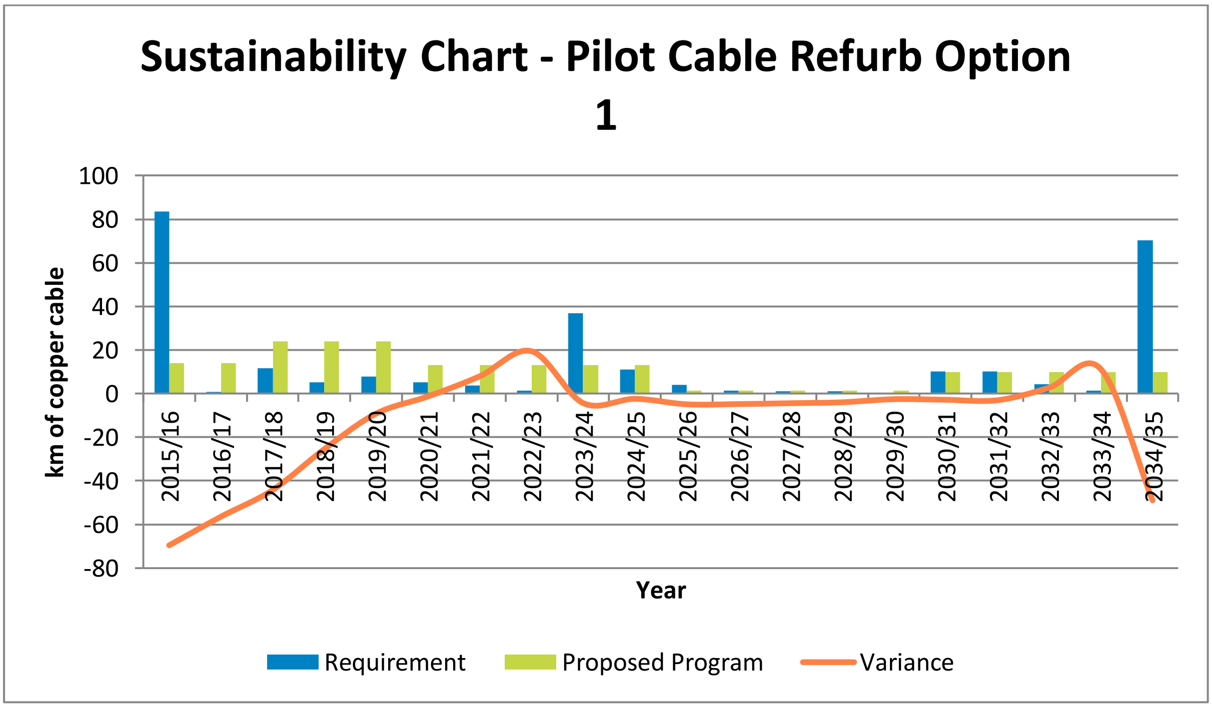

Figure 4: Sustainability Graph for Pilot cable Refurb – Option 1

The following table provides a summary of the treated risks as per this option.

Category	Risk Scenario	Consequence	Likelihood	Risk Score
Customer Impact	Fault on a pilot cable carrying protection for critical customer. No available alternative path and cannot be repaired in reasonable time frame, protection placed on same cable as redundant feed. Subsequent fault on shared cable results in outage to customer	4	2	8 (Low Risk)
Legislated Requirements	Fault on a pilot cable carrying 110kV protection. No available alternative path and cannot be repaired in reasonable time frame. Powerlink / AEMO notified and request received to reconfigure network	5	1	5 (Low Risk)
Business Impact	Failure of a pilot cable leading to feeder protection not working which necessitates the de-energisation of the feeder until repairs can be made resulting in an abnormal network configuration.	5	1	5 (Very Low Risk)

Table 2: Treated Risk Assessment Summary – Pilot Cable

Table 3 below outlines the expenditure forecast for this option.

Description	2015/16	2016/17	2017/18	2018/19	2019/20
Expenditure $m, 2014/15	1.5	1.5	2.5	2.5	2.5
Quantity (km)	14	14	24	24	24

Table 3: Expenditure – Option 1

4.3 Option 2 – Replace with New Copper Pilot Cable

4.3.1 Summary

This option would install only copper cable to replace failed and at risk cabling. It would entail a similar level of expenditure to Option 1 without providing any of the benefits or improvements offered through the installation of fibre optic cable. Accordingly this option would mitigate risks to a similar level as Option 1.

4.4 Option 3 – Constant Replacement Rate

4.4.1 Summary

This option would see Energex replace cabling at a constant rate (12 km of cable per year) for the foreseeable future. This option would defer capital expenditure, provide a constant level of work into the program of work year on year and would achieve an end state variance from a sustainably perspective much the same as the proposed program. This option exposes Energex to significant amounts of pilot cable operating beyond its expected life until the year 2027/28.

4.4.2 Impact analysis

The chart below shows the sustainability of Option 3.

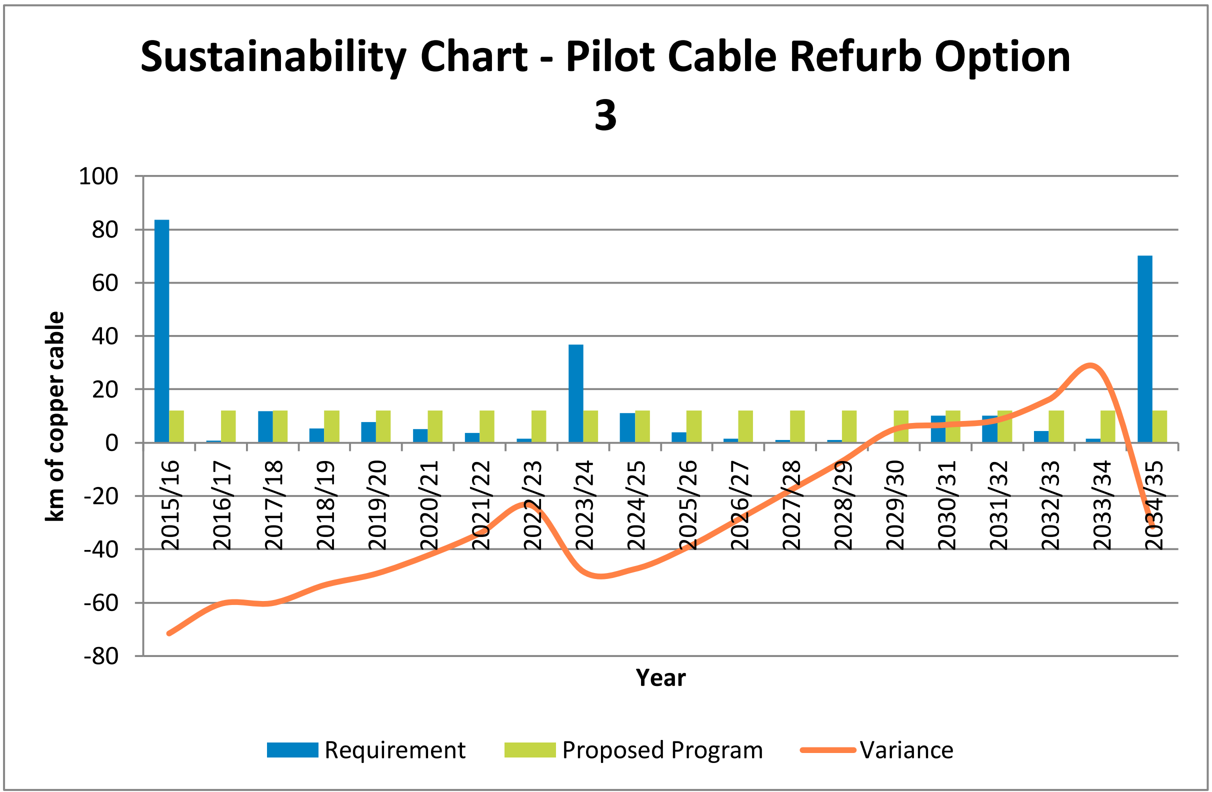

Figure 5: Sustainability Graph for Pilot cable Refurb – Option 3

Table 4 below outlines the required expenditure for the pilot cable replacement program under Option 3.

Description	2015/16	2016/17	2017/18	2018/19	2019/20
Expenditure $m, 2014/15	1.3	1.3	1.3	1.3	1.3
Quantity	12	12	12	12	12

Table 4: Expenditure – Option 3

4.5 Option 4 – Replace Communications to Sites Connected Only by Copper Pilot over the Next Four Regulatory Periods

4.5.1 Summary

This option would see Energex implement fibre optic cable such that all services at the time that terminal equipment (protection relays, modems for RTU equipment and other miscellaneous services) replacement becomes due could migrate to fibre optic cable. The option would also be dependent on funding for the fibre infill program to be able to achieve the decommissioning. This would allow decommissioning of the bulk of the copper pilot cable in the next 20 years.

Energex will at some point be forced down a path similar to this option. Manufacturers will eventually remove copper pilot cable from their production schedules or will make supply of the cable so costly that this option would provide better value / risk proposition for Energex. To achieve this Energex would need to install 32km of cable each year for the two coming regulatory periods. Thus assuming approximately a 20 year life for terminal equipment, and that Energex can manage the rollout targeting cables replacements to have been completed immediately before where the terminal equipment is due for replacement then Energex will have removed all equipment of all copper cabling in the next 20 years.

4.5.2 Impact Analysis

The chart below shows the sustainability of the proposed option.

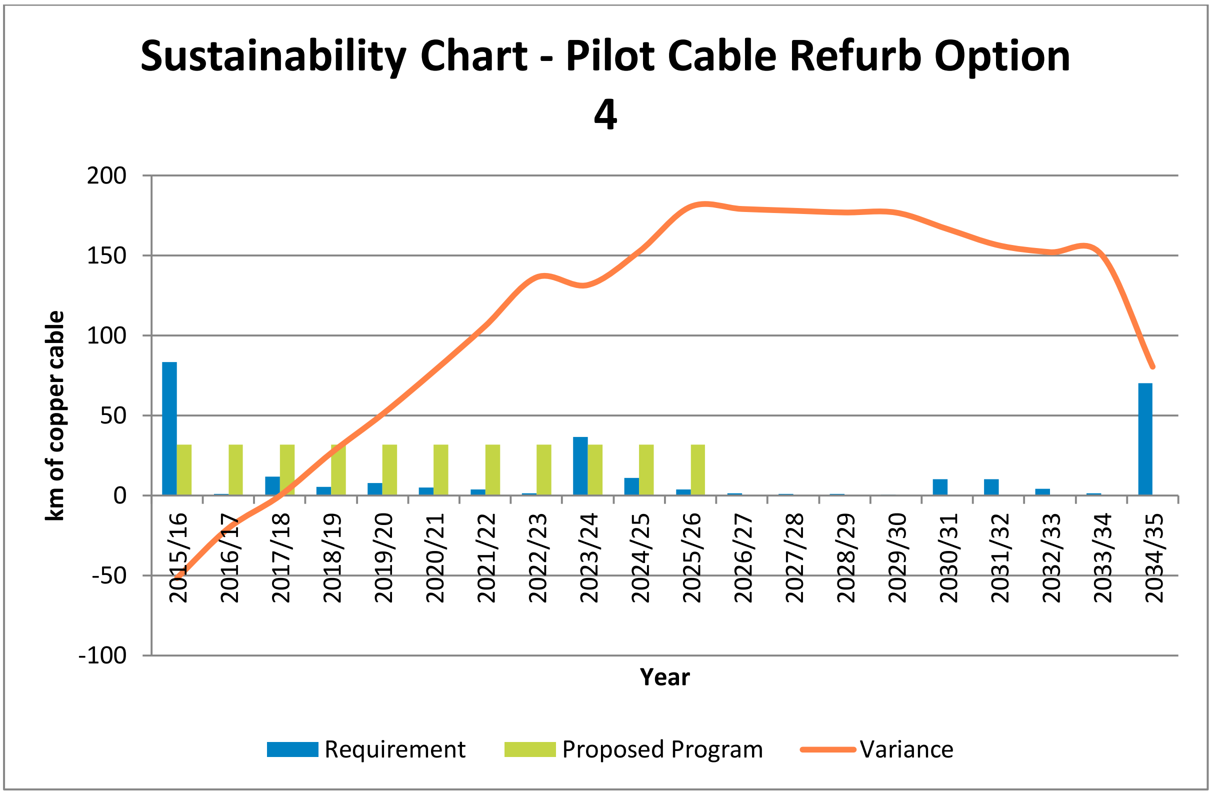

Figure 6: Sustainability Graph for Pilot cable Refurb – Option 4

Table 5 below outlines the required expenditure for the pilot cable replacement program under Option 5.

Description	2015/16	2016/17	2017/18	2018/19	2019/20
Expenditure $m, 2014/15	3.6	3.6	3.6	3.6	3.6
Quantity	32	32	32	32	32

Table 5: Expenditure – Option 4

4.6 Option 5 – Non-Network Options

The possibility of other non-network options has been considered. This would entail the use of commercial telecommunications providers. This option is not considered feasible due to the following:

- Carriers do not lease copper only connections. Telstra ceased this practice in the 1980's. As such all copper only connected protection relays could not operate (approximately 1200 relays).
- The access control required by Energex cannot be achieved by commercial operators
- Costs (for those services that could be carried) exceed those that Energex incurs providing the services internally.

5 Proposed Works

It is proposed to implement Option 1 to replace a total of 100 km of pilot cable in the 2015/16 – 2019/20 period under this program.

6 Required Expenditure

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

Description	2015/16	2016/17	2017/18	2018/19	2019/20
Expenditure $m, 2014/15	1.5	1.5	2.5	2.5	2.5
Quantity	14	14	24	24	24

Table 6: Required 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– Supporting Information

Energex Telecommunications Strategic Plan 2015-2020

http://www.aer.gov.au/sites/default/files/Energex%20-%2027.%20Telecommunications%20Strategic%20Plan%202015-20%20-%20October%202014.pdf

Appendix 2– Pilot Cable Failures Requiring Emergency Call Out

The table below details records of emergency call outs from the failure of copper pilot cables

Plant Details	Description of issue	Date occurred
PC135	PC135 Repair	10/03/2009
SSINA	SSINA F619 Pilot circuit faulty	9/03/2010
SSINA	SSINA 619 Pilot Circuit Faulty	10/03/2010
SSINA	SSINA Inv. F619 faulty pilot cct.	15/03/2010
SSZMR	SSZMR F664 Pilot CCT Faulty	22/04/2010
SSZMR	SSZMR F664 Pilot CCT Faulty	1/04/2010
SSNDH	SSNDH F535 Pilot CCT Fault	28/08/2010
SSGBG	SSGBG F524 Pilot Circuit Fault	25/11/2010
P10956-D/10956	Mtn Pilot Cable P10956 Roderick St Ipswi	1/01/2011
X3059-E/AB11	Pilot cable work refer C0134407	1/01/2011
SSGBG/CBSPARE12	SSGBG f524 pilot circuit faulty	2/12/2010
SSDRA/CB6162	SSDRA F616 Pilot Circuit Faulty	15/01/2011
SSNIP	SSNIP - TR1 Pilot cct. faulty	12/01/2011
SSDRA/CB6162	SSDRA- Inv F616 Pilot CCT Faulty Alarm	27/01/2011
SSSPD/CB9162	F811 Pilot CCT Faulty Alarm up	19/02/2011
SSSPD	SSSPD 811 Pilot Circuit Faulty	22/02/2011
SSZMR/CB5242	SSZMR, F665 Pilot Circuit Faulty alarm u	25/02/2011
SSAGE/CB6762	AGE/F676 Pilot Cct faulty - See Job Inst	17/03/2011
SSZMR	FD Pilot Cable on F665 - Alarming	25/03/2011
SSGBG	SSGBG - F524 Pilot circuit faulty	13/05/2011
SSGBG/CBSPARE12	FDR524 @ GBG Pilot Circuit Faulty	17/05/2011
SSAGE	SSAGE Pilot Circuit Fault / Op CB2042	18/05/2011
SSGBG/CBSPARE12	SSGBG F524 Pilot CCT Faulty	19/05/2011
SSGBG/CBSPARE12	SSGBG, F524 Pilot Crt. FAULTY	4/07/2011
FO26	CM - FO26 unplanned outage	1/12/2010
SSDBS/CB4162	SSMRE F416 Pilot CCT Faulty	20/06/2011
SST128	Pilot fault at T128	18/10/2011
SSMEX	Faulty Pilot Cable between SSMEX - SSCGS	18/10/2011
TEMTG	CM - SSMTG/SSBBS F631 Toggling alarm	6/01/2012
SSCSE/CB6072	SSCSE F607 pilot circuit faulty	25/01/2012
SSDRA/CB6172	ssdra pilot faulty f617	24/01/2012
SSINA	SSINA 33KV Feeder 619 Pilot Circuit	5/02/2012
619	F619 pilot cct faulty	6/02/2012
SSINA	SSINA - F619 pilot circuit faulty alarm	7/02/2012
SSINA/CB6192	SSINA CB6192 F619 Pilot Cct Faulty	9/02/2012

ZZSSGLY/CB2052OLD D01	SSGLY - pilot cct faulty BSEGLY5	10/02/2012
SSINA	SSINA F619 Pilot Circuit Faulty	29/02/2012
SSMTN	SSMTN BAPMTN8 / 3 PILOT CIRCUIT FAULTY	15/03/2012
SSKMM	SSKMM Inv Loss of Status	3/04/2012
SSINA	SSINA - F619 pilot cct faulty	6/02/2012
SSMRE	SSMRE F416 Pilot CCT Faulty	8/05/2012
SSMTN/CB4722	SSMTN F472 path b itrip faulty toggling	10/06/2012
PL68	PL68 - Pilot Cable wrapped in LV Mains	28/06/2012
SSNDH	SSNDH F593 Pilot CCT Faulty.	4/08/2012
SSHMT	SSHMT 599 Pilot circuit faulty	17/11/2012
SSSPD	SPD 827 pilot cable faulty alarm.	2/12/2012
SSSPD	SSSPD 827 Pilot circuit faulty.	19/12/2012
SSINA/CB6192	ssina f619 pilot circuit faulty.	10/02/2013
SSINA/CB6192	SSINA, F619 Pilot Circuit Faulty alarm	22/02/2013
SSINA	SSINA 619 Pilot circuit faulty alarm.	8/02/2013
SSINA	SSINA Pilot Circuit Faulty F619	8/03/2013
SSINA	SSINA F619 inv pilot cct faulty	11/03/2013
SSH4	F706 pilot investigation	16/05/2013
SSINA	SSINA 619 pilot circuit faulty	27/07/2013
SSZMR/CB6642	SSZMR - F664 pilot faulty	21/04/2013
SSHMT	SSHMT 603 pilot circuit faulty alarm	1/02/2014
SSSRH	SSSRH/SST70 - F797/F7298 Intertrip fail	2/01/2014
SST108	SST108 F405 F465 comms path fail	12/02/2014
SSHMT	SSHMT - F599 Pilot Circuit Faulty	28/03/2014

Appendix 3– CBRM Output Analysis

Pilot Cable	A / B ends	Cable Health Index	Load At risk (MVA)	Summary actions required
PL114	PTPWC/SSMLB	13.35	110.66	No alternate copper path is available should the cable fail. Fibre Cable will be installed in 2017 under and Augmentation project C0077634 and protection services cutover to the fibre cable. A project occurred in 2014/15 to remediate various issues on the cable and advice from the field personnel is that the cable is in good enough shape to continue in operation till the fibre cable is installed. No further action required
PL00000113	PTPWC/SSH9	6.67	110.66	As above
PC00000613	SSSRH/SST70	0.56	74.47	No alternate copper path is available should the cable fail. Fibre Cable will be installed in 2017 under project WR3345498 which will provide an alternate path and protection services will be reconfigured to ensure we can take advantage of the alternate path should the cable fail. Project is still in pre-project and must be progressed.
PC00000351	SSBHL/SSZMR	4.45	29.4	Evaluation has identified that enough diversity is available in the area and services will need to be relocated off the cable. Project to be generated
PL00000043	PTKRN/SSAGW	0.56	10.626	Initial review suggests that enough diversity is present in the area, however full review required.
PC00000060	JP37/SSGBG	4.45	224.7	Multiple alternate paths are available in the event of a failure of this pilot cable. Suggest inspection of cable to confirm health.
PC00000705	JP43/SSZMR		24.629	Multiple alternate paths are available in the event of a failure of this pilot cable. Also when issues with PC351 above are resolved, high risk services will also be moved of this cable. Suggest inspection of cable to confirm health.
PL00000044	PTAHL/UKT		10.626	Initial review suggests that enough diversity is present in the area, however full review required.
PC00000274	SSHDA/SSNGE	0.56	46.5	Alternate path available in the event of a failure of this cable. Suggest inspection of cable to confirm health.
PL35A00000	SSCPB/SSH3		101.53	Alternate Fibre optic cable exists for this cable. . Suggest inspection to determine health of the cable
PL00000072	PTCNW/PTSSR		62.48	Alternate fibre optic cable exists (FO346). Projects required to modify protection circuits to enable cut over to the fibre cable.
PC00000101	SSHMT/SSTGP	3.33	21.5	Significant issues in this area. Alternate copper path is available however cables significant increase in length and likely to be unusable in a failure situation. Fibre infill project C0432137 will provide a single cable from SSHMT to T73 which can then be used to provide a path between SSHMT and SSTGP. Project required to

Pilot Cable	A / B ends	Cable Health Index	Load At risk (MVA)	Summary actions required
				consider changes in protection to move over to the fibre cable.
PC00000125	JP1/JP2	6.67	129.5	Significant issues in the area. See report for PC61.
PC00000090	SSAGE/SSENG	8.9	0.3	Significant issues in the area. See report for PC61.
PC00000068	JP3/JP50	0.56	31.9	Diverse pilot and fibre available. Suggest inspection of cable to confirm health.
PC00000061	SSNMK/SSENG	13.35	5.3	Significant issues in the area. Evaluation concluded that a new cable should be installed between NMK and KRN to alleviate issues in the area.
PC00000364	SSNGE/SSVGA		18.843	Two alternate copper paths available. Suggest inspection of cable to confirm health.
PC00000126	JP2/SSKRN	6.67	24.7	Significant issues in the area. See report for PC61.
PC00000355	SSBBS/SSCHL		21.351	Alternate copper and fibre paths available. Suggest inspection of cable to confirm health.
PC00000140	SSCHL/SSCPR	0.56	9.3	Alternate fibre path available. Project required to consider replacement of copper only protection relays.
PC00000558	SSBDL/SSCDR		54.78	Alternate copper and fibre paths available. Suggest inspection of cable to confirm health.
PL00000101	SSBRL/SSMGB	3.33	101.42	Significant issues in this area. Proposal is to migrate to fibre optic cable.
PC00000056	JP23/SSBST	13.35	10.2	Complete evaluation required however likely that another fibre cable required between SSQPT and T73. Suggest complete evaluation report be completed
PC00000128	JP40/SSKMR		22.3	Alternate copper path is available and fibre cable infill is proposed (C0309943). Suggest inspection of cable to confirm health.
PC00000591	SSAHD/SSMLB		31.79	Alternate fibre cable path available. Need to ensure that replacement protection relays can operate over fibre cable.
PC00000656	SSLTA/SSTGP		21.087	Alternate pilot cable available, however unlikely that paths would operate. Suggest complete evaluation report required
PC00000046	JP26/SSGBP	6.67	9.3	Alternative path available, however unlikely that paths would operate. Suggest complete evaluation report required
PC00000585	SSCST/SSMST		69.96	Fibre optic cable available and available pilot paths. No action required
PC00000332	JP43/SSGBG		39.347	Significant potential issues in this area, however also reasonable coverage for fibre optic cable in the area. Suggest an evaluation report for the area
PC00000096	JP5/JP6	8.9	8.0	Single copper cable to site. Suggest inspection to determine health of the cable.
PL35C00000	JP58/SSCVL		126.544	Single copper cable to site. Suggest inspection to determine health of the cable

Table of pilots with a health index of 8 or greater

PC00000010	SSAGE/SSNMK	15.00	*See above*
PL00000044	PTAHL/UKT	15.00	*See above*
PL00000043	PTKRN/SSAGW	15.00	*See above*
PC00000056	JP23/SSBST	13.35	*See above*
PC00000061	SSNMK/SSENG	13.35	*See above*
PL00000114	PTPWC/SSMLB	13.35	*See above*
PC00000448	SSACF/SSQBI	12.64	*Single copper cable. Suggest inspection to determine health of the cable*
PC00000090	SSAGE/SSENG	8.90	*See above*
PC00000096	JP5/JP6	8.90	*Significant issues in the area. Suggest complete evaluation of the area required. PC97identified as all pairs down to earth.*
PC00000117	JP1/SSSFD	8.90	*Significant issues in the area. Suggest complete evaluation of the area required.*
PC00000273	SSINA/SSRLD	8.90	*See report on PC93.*
PC00000354	SSKMR/SSMGL	8.90	*Suggest full evaluation of the area required.*
PC00000297	SSRBS/SSSBK	8.90	*Suggest full evaluation of the area. Note potential candidate area for fibre infill*

PUBLIC

Energex

Obsolete Telecommunications Equipment

Asset Management Division

energex

positive energy

Energex

Obsolete Telecommunications Equipment 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.

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Executive Summary

Energex has an established Telecommunication Strategy which requires the removal of obsolete Telecommunications Equipment as part of the long term roadmap.

The reliability of the telecommunications network is essential to ensuring the distribution network is operated safely, the intended protection functionality is available, and network controllers have visibility of events enabling operation of the power network. A functional telecommunications network enables faster response to faults, and contributes to minimising impacts to customers. As the life-cycle of telecommunications network assets is typically shorter than that of power system assets, a continued program of review and replacement is necessary to maintain the required functionality.

The primary drivers for this program are listed below:

- Safety – Energex needs to ensure it meets its safety obligations associated with provision of telephone isolation at substation locations;
- Power network performance - Obsolescence of telecommunications equipment causes risks associated with achieving appropriate levels of power network performance;
- Legislative – Energex needs to meet a range of requirements associated with protection signalling performance.

Energex has combined a number of the programs proposed in the original submission (Distribution System SCADA Stage 5 and Miscellaneous Telecoms equipment) which totalled $6.1 million of expenditure, into this single business case. The scope of this program was also revised to remove some low risk replacements from scope, but Energex has also since become aware of some additional telecommunications router components that have reached end of life. The net result is a small increase to total required expenditure for this program with a total of $6.5 million over the 2015/16 – 2019/20 regulatory period.

$m, 2014/15	2015/16	2016/17	2017/18	2018/19	2019/20	Total
Revised Expenditure	1.0	1.0	1.5	1.5	1.5	6.5

The revised proposal aligns with the business outcomes outlined in the Energex *Telecommunications Strategic Plan 2015-20.*

Contents

1 Introduction

The purpose of this document is to outline the required expenditure for the replacement of Obsolete Telecommunications Equipment in the 2015/16 – 2019/20 regulatory period.

This program is important due to the potential consequences of the risks associated with safety and the operation of the Energex Distribution Network if left untreated.

The proposed program covers the replacement of end of life telecommunications equipment which does not fall within the scope of other programs.

Changes from the original proposal

In the revised proposal, Energex has taken some low risk projects out of the program but has become aware of additional telecommunications router components that have reached end of life. These high risk projects will incur extra expenditure for the coming period. The net result is a small increase in the total expenditure being requested in this program. The total expenditure proposed for this program is $6.5 million in 2014/15 dollars.

2 Drivers

2.1 Safety

Energex needs to ensure that telephone isolation equipment is present in certain circumstances, to mitigate risks associated with operating a telephone at a location with high Earth Potential Rise (EPR). See Section 2.3 Legislated Compliance for further details on these requirements.

2.2 Power Network Reliability and Risk Impacts

Obsolescence is the primary driver for the replacement of most telecommunications equipment used within Energex. Once the software, equipment or individual components become obsolete, various risk factors resulting from the failure of the equipment continue to rise, until the risk associated with the continued use of this equipment becomes intolerable.

Energex has a range of aging at-risk telecommunications equipment. A subset of the equipment in this category either has an intolerable risk during in-service failure or has other factors that drive proactive replacement activities.

During periods when protection circuits are not operating due to communications system failures there are potential risks to plant damage / premature aging due to longer periods before backup protection clears faults and increased outage impacts should a fault occur during the period of the communication issues.

If a protection circuit is lost on a 33kV, 110kV and 132kV feeder (and for certain important 11kv feeders) and it is necessary to de-energise the feeder then N-1 capacity will be lost until such time as the circuits can be returned. This increases the risk of otherwise un-necessary outages.

When issues occur, various indirect consequences can increase the risk to the organisation. For example, if communications services are not operating, protection services move back to simple over current / over voltage protection, and as a result certain faults will not be cleared and clearing times can be significantly increased during these times.

2.3 Legislated Compliance

Energex needs to comply with the NER / AEMO in instances where the protection function is lost due to an equipment failure, or a bearer fault (such as degradation or mechanical damage). Under circumstances resulting in the failure of any 132 / 110kV (and some 33kV) protection circuits, Energex will notify Powerlink who will subsequently notify AEMO of the outage.

Energex is also required to restore the affected protection function "as soon as possible". AEMO may determine that having a feeder in service without the protection function will compromise the security of the network in the event that a fault occurs. AEMO may call for the feeder to be de-energised.

If Energex does not replace End of Life equipment before in-service failure occurs, it puts the ability to meet these compliance requirements at risk.

Appendix 1 provides extracts from the relevant legislation / guidelines.

Energex also needs to comply with relevant standards for telephone isolation equipment at substations. The rules are defined in an ACMA (Australian Communications & Media Authority) document[1].

The standard requires that:-

> *Where an installation cannot be placed in a location where the EPR hazard is less than 430V a.c., the installation* ***shall not*** *proceed unless on the basis of a design certified by a qualified electrical engineer as complying with the principles of AS/NZS 3835.1.*

Energex needs to identify installations that do not meet these requirements and ensure that they are upgraded as necessary.

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[1] AS/CA S009:2013 Installation requirements for the customer cabling (Wiring Rules)

2.4 Spectrum Reallocation

The ACMA has the responsibility to manage use of electromagnetic spectrum. As part of discharging this duty, the authority reallocates spectrum usage periodically. The ACMA released a discussion paper in 2011 that indicated a potential reallocation of spectrum that is being utilised by various Energex microwave links. This paper identified a number of services that directly impact Energex. Specifically:

As discussed in section 2.2, the 850–865 MHz segment is currently allocated to a number of services which are listed in Table 3.1. Some of these services would be required to migrate out of this segment if it were replanned for new FDD services. The future use of spectrum used for the paired segments of two-frequency services shown in Table 3.1 is discussed in Chapter 5.[2]

The timeline published for a final decision for the band should have seen a decision provided in 2014 calendar year. As yet the final decision has not been provided. Previous experience has been that once a decision is made, timelines to vacate the spectrum are between 2 to 5 years. This is expected to occur during the forthcoming regulatory period which will require Energex to remove the 5 microwave links operating in the affected spectrum.

2.5 Modernisation

Latest generation equipment has a range of different advantages when compared to older technologies widely deployed by Energex. These include:

- Higher speed links – The current generation of microwave link equipment utilised by Energex provides a 150 Mbit/sec digital link, compared to previous equipment that provided 32 Mbit/sec or 0.7 Mbit/sec.
- Native IP capability - The latest generation of equipment is IP based which improves our ability to integrate the equipment into the Matrix[3] solution.

3 Supporting Analysis

3.1 Existing Network/Background

The table below shows the current population of equipment identified as at-risk telecommunications equipment.

[2] http://www.acma.gov.au/webwr/_assets/main/lib312085/900mhz_review-exploring_new_opportunities.pdf

[3] Project Matrix is the Energex MPLS network solution implemented to provide a secure Operational Technology Environment, and ultimately support the business telecommunications into the future.

Equipment	Product	Amount in Service 2015	Obsolescence Status
Microwave Links	Sinewave 900 MHz fractional E1 units	10 (5 links)	Obsolete
	Alcatel 9400 LX, 9400 AWY	18 (9 links)	Obsolete
	NERA	TBD	Current
Diesel Generators	Varies	8 units	NA Age based replacement 15 years
Communications Site Chargers	Varies	34	Obsolete and current
Batteries	Varies	34 site batteries (includes sites with redundant batteries)	NA Chemistry / construction to give Age when will be replaced, 7 years for SLA
Solar Arrays	Varies	15	NA replacement after reduce to 70% capacity (assume 25 years)
TLIU (Isolation units)	Varies	Est of 320	Varies
Towers and Masts	Varies	55	NA Inspection based replacement
Miscellaneous Replacement (including VGDL equipment)	Varies	Est 500	Various items going End Of Life in the control period
PDH Multiplex	Nokia Dynanet	3000 + active cards	Most equipment now obsolete
Powerlink SDH shutoff	NA	10 (5 links)	Powerlink have advised that they will be removing the equipment by end of 2017
Site Security	Varies	8	25 year life

Table 1: Population of equipment identified as at-risk

3.2 Current Performance

Table 2 shows the current performance and failure rates of telecommunications equipment.

Equipment	Failure / fault rates per unit in Service*	Examples / comments
Sinewave 900 MHz fractional E1 units	0.8 per unit per year	Failure of units requires replacement – no onsite serviceable parts. Early serial numbers unrepairable. Refer to Appendix 2 for fault details.
Alcatel 9400 LX, 9400 AWY	0.12 per unit per year	Although failures of this radio type are rare, due to difficulties in obtaining spare parts, faults are less likely to be resolved.
NERA		Numerous incidences of rain-fade
Diesel Generators	0.57 per unit per year	STOC-1958; STOC 1952; STOC-1934; STOC-1508; STOC-1387; STOC-1279; STOC-1234; STOC-628; STOC-370; STOC-174 Examples include faulty oil pressure sensors, fuel hoses requiring replacement and a magnetic pickup (speed sensor) fault.
Communications Site Chargers	RRDAG – 3.2 faults per year	RRDAG chargers are the least reliable – 8 individual fault reports in 2.5 years.
Batteries		No faults recorded
Solar Arrays & Regulators	0.4 per unit per year	STOC-178; Most faults occurred at RRDAG – regulator faults
TLIU (Isolation units)		Various isolation card faults
Towers and Masts		No faults or failures have been recorded; however remedial work is needed at RRGHR due to overloading of the structure.
Miscellaneous Replacement (includes VGDL devices)		To date a range of issues have been identified.
PDH Multiplex	< 0.025 per unit per year	Age related failures are starting to increase.
Powerlink SDH shutoff	Nil	No faults recorded as these radios are managed by Powerlink.
Site Security	< 1 per unit per year	STOC-1989 – Mt Tamborine, tamper switch failure.
* Current ticketing system has been in place for 2.5 years. Previous to this, faults are difficult to track. The fault rate may not give a true indication of the condition or reliability of the system.		

Table 2: Performance and failure rates

3.3 Other Issues Driving Replacement

Equipment	Issue	Examples / comments
Sinewave 900 MHz fractional E1 units	Manufacturer no longer supplies spares / fixes existing units and Energex's spares holding is down to 1 unit	This type of radio ceased production 31 January 2013. No new units are available for purchase. Limited communications capacity prevents further expansion.
Alcatel 9400 AWY, 9000 AWY	Manufacturer no longer supplies spares / fixes existing units	https://support.alcatel-lucent.com/portal/productContent.do?productId=null&entryId=1-0000000002421&type=alpha https://support.alcatel-lucent.com/portal/productContent.do?productId=&entryId=1-0000000002420
NERA		No replacements in this period
Diesel Generators	Age based replacement	D'Aguilar Range generator was manufactured 8/9/1997. As this site is primarily solar powered, this generator has accumulated the highest run time.
Communications Site Chargers	Age based replacement	D'Aguilar Range Repeater chargers have recorded 8 individual faults in 2.5 years. In all cases, the faulty rectifier required replacement.
DSS Core Infrastructure		Installation of new infrastructure to support existing network where performance is deficient.

Table 3: Other issues that are driving replacement or repair

The various proposed replacement programs are in line with the Protocol for Refurbishment and Replacement and the specific Telecommunications Standard for Refurbishment and Replacement.

3.4 Proposed Replacement Numbers

The complete history of installations is not available for all of these assets and as such no reliable REPEX model has been able to be generated. Table 4 below summarises the reasoning for the proposed replacement programs and available details of equipment performance.

Equipment	Amount in Service 2015	2015/20 AER program proposal
Sinewave 900 MHz fractional E1 units	10 (5 links)	Remove from Service as manufacturer no longer will repair units and AMCA has advised that the spectrum they operate on is likely to be re-assigned. Replace with current standard microwave radio.
Alcatel 9400 AWY, 9000 AWY	18 (9 links)	Remove from Service as manufacturer no longer will repair units. Replace with current standard microwave radio where required.
NERA	TBD	None anticipated
Diesel Generators	8 units	15 year life, 2 units
Communications Site Chargers	34	3 sites requiring replacement during this period.
Batteries	28 site batteries (includes sites with redundant batteries)	1 replacement due this period, with two sites requiring testing (batteries within the design life)
Solar Arrays	15	15 sites, 25 year life, no solar array replacements due this period, however 1 site's solar regulators are due.
TLIU (Isolation units)	322	Only upgrade those not installed to current standard, approximately 5 units else fail fix
Towers and Masts	60	NA Inspection based replacement / refurbishment. 1 site requires refurbishment due to identified structural issues.
Miscellaneous Replacement (includes VGDL devices)	Est 500	Modems, routers, switch etc. VGDL will likely go end of life in the coming AER period
PDH Multiplex	3000+ active cards	Allow for minimal replacement for failures and incompatibility issues with replacement equipment
Powerlink SDH shutoff	10 (5 links)	Of the 5 links, 3 will be replaced with new microwave links, 2 have been identified as no longer required as alternative infrastructure can support the communications network requirements.
Site Security	8	Replace 7
DSS Core Infrastructure	< 2200	To support network, install 3 new head-ends and 30 repeaters.

Table 4: Summary of reasoning for AER program proposal

3.5 Microwave Radio Replacement

In the case of the LEDR-900S microwave radios, the likelihood of failure of the radios is unacceptable, with 11 fault reports being recorded since June 2012 resulting in a rate of 0.8 faults per unit per year. In a majority of instances, these faults have required the replacement of multiple radios, indicating we will need to replace units at a rate of 2 radios (1 link) per year to keep enough spares available to keep the remainder of the units operating.

Energex has proposed replacing 2 links in the first year of the regulatory period to ensure enough spares are available.

Although the failure rates of the Alcatel 9400LX and 9400AWY radios are somewhat less than that of the LEDR-900S radios (0.12 faults per unit per year), with a population of 18 units, we are expecting approximately 2 failures per year. As the equipment age increases, we can expect an acceleration of the current failure rates.

Spares held consist of 3 LEDR-900S radios; 4 Alcatel 9400LX radios; and 4 Alcatel 9400AWY radios. This quantity is insufficient to maintain our existing fleet of radios for more than 6 months in the case of the LEDR-900S radios. Should the current failure rates increase, and a suitable program of replacement is not implemented, then Energex will not have the ability to manage any further faults with these radios.

Appendix 2 highlights some of the recorded faults with the radios since June 2012.

The Powerlink SDH microwave radios are in a similar condition to the Energex radios whereby they are declared End of Life, spares are limited or depleted and there is limited ability to recover from a failure. The proposed replacement programme for the Powerlink SDH microwave radios is discussed further in section 3.14.2.

3.6 Diesel Generators

The diesel generators installed at the Energex radio sites provide backup power in the event of a power failure. In the case of RRDAG a solar site, the diesel generator is supplemental to the solar power supply. In the event of a generator failure and assuming an average amount of cloudy days, the site batteries will eventually discharge, causing a total loss of all services through the site.

The generator at RRDAG currently has the highest runtime of all radio site generators. This generator was installed in 1997, and has had a number of reliability issues in recent years. The generator at Mt Boulder was installed in 2001. It is proposed to replace both of these units in the coming regulatory period.

Figure 1: Typical remote site diesel generator

An example of the potential impacts of a generator failure , fault report STOC-192, where during the ex-tropical cyclone Oswald, total failure of the RRTMB Mt Tamborine site repeater was recorded due to the diesel running out of fuel. During the severe weather event, local mains supply was cut, and unable to be restored. The generator had run for some time, and with access difficulties due to trees and other debris across the roadways, the generator subsequently ran out of fuel. The fault was attributed to a faulty fuel sensor, which was showing 15% fuel, when in fact the correct level was 0%. Had the fault on the fuel sensor not occurred and the alarm raised, then crews could have been dispatched to resolve the issue. Although the reasoning for the failure of the generator was fairly straightforward, it highlighted the impacts associated with a total site failure.

All services at this site were affected, including 7x 110kV and 3 x 33kV protection circuits, substation SCADA, loss of remote management of more than 50 pole mounted switches, and a range of equipment remote management capabilities.

3.7 Site Battery Chargers

At remote sites and depots, owned and operated by Energex, site battery chargers form part of the primary power source for the site. Failure of a battery charger will result in an outage of some of the services for those sites with redundant power supplies and all services operating through the site for installations with a single power supply arrangement. Energex has a legislative requirement to provide a reliable communications path to enable operation of protection functions. In order to meet this obligation, a number of battery chargers have been identified as being at the end of their service life and require replacement.

Two depots have been identified as having battery chargers at end of life (Southport Depot and Raceview Depot). Both sites have non-redundant power supply units and have multiple protection and other services operating through them that depend on the reliable performance of the site power supply. Both of the chargers were manufactured in the 1980's. There are no replaceable parts available for this charger in the event of a failure, and Energex does not hold any spares. Southport charger will be removed as part of a project to relocate the communications equipment from this depot, thus only a single battery charger (Raceview Depot) replacement is necessary for the period.

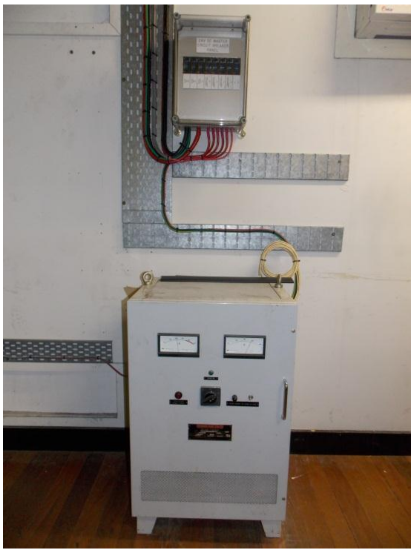

Figure 2: Raceview Depot battery charger – estimated manufacture date 1989

3.8 Batteries

The consequences of a battery bank failure on the communications network are similar to a battery charger failure, with the added risks associated with lead-acid batteries as they age. During the course of this regulatory period, it is anticipated that only one battery bank will be replaced – Raceview Depot. Two remote radio sites, Wilke's Knob Repeater and Mt Perseverance Repeater, will require testing of their battery banks to ensure their performance meets the specifications. At both of these sites, the batteries are within their design life and the risk of failure is small.

3.9 Solar Arrays

Replacement of the solar arrays at the two major solar sites, Flinders Peak Repeater and D'Aguilar Range Repeater, were carried out in the current regulatory period. As such, no major replacements are required to be carried out. A number of minor replacements will need to be carried out, mainly at pole-top repeater sites, as the panels' age increases and the capacities reduce.

The solar regulators at D'Aguilar Range repeater were installed in April 1998 and have had a number of faults in recent years. These regulators will require replacement during the 2015/20 regulatory period.

Figure 3: Solar Regulators – D'Aguilar Range Repeater

Fault Report Number	Date Reported	Site	Fault Details
STOC-178	30/01/2013	RRDAG	Solar regulator failure. Required replacement.
STOC-1134	24/07/2014	RRDAG	Failure of solar regulators 1 and 2. Required replacement.

Table 5: Solar Regulator faults recorded since June 2012

3.10 Towers and Masts

All Energex radio communications towers are inspected at 6 monthly intervals as part of the radio site maintenance schedule. Any minor defects are rectified before they become a major issue. A structural analysis on the tower has however highlighted an issue where the existing equipment has resulted in overloading of the tower. Remedial work such as upgrading footings and reinforcing is required to rectify the problem.

Figure 4: Typical Telecommunications Radio Tower

3.11 Telephone line isolation equipment

The telephone line isolation systems currently in service at some sites do not meet the current industry standards for isolation against earth potential rise. In most of the non-compliant cases, the issue relates to the close proximity of the un-isolated incoming telephone lines to earthed metalwork. This creates a hazard to workers whereby contact could be inadvertently made between the earthed metalwork and the telephone lines.

Although the likelihood of a network fault occurring at the instant contact is made with the telephone lines is small, the consequence should this occur is severe electric shock or death.

In most cases, the hazard can be mitigated by relocation of the telephone isolation equipment to a more suitable location.

For more information, refer to:

AS/NZS 3835.1:2006 Earth potential Rise – Protection of telecommunications network users, personnel and plant – Part 1: Code of practice "Section 7.5 – Mitigation measures applied to Telecommunications Plant"

Figure 5 and Figure 6show examples of telephone line isolation issues.

Figure 5: Non- Compliant isolation – Close Proximity to earthed metalwork (adjacent cabinet)

Figure 6: Isolation cabinet mounted on metal sheeting, and close to GPO and other equipment

3.12 Modems, routers and switches

For modern networking equipment it is necessary to ensure that the equipment remains supported by the manufacturer support to ensure it will correctly operate within the environment. This includes operating correctly with the various management systems that configure the equipment. Energex's management system for the Alcatel IP-MPLS equipment will only support one major revision under the current version, thus Energex needs to replace any items that cannot meet this requirement. As the equipment is declared End of Life no further software revisions are provided and the equipment needs to be replaced before two more major revisions of software occurs.

Energex in its initial submission estimated how much equipment was likely to be declared End of Life by the manufacturers. Since the initial estimate, the manufacturers have issued more notices than Energex had originally planned for. This has resulted in an increased amount of equipment that will be required to be replaced within this regulatory period.

The equipment to be replaced includes the control and processor modules for the 10G MPLS routing equipment, the power supplies, fan modules and interface cards for the 1G MPLS routing equipment. Failure to replace these particular modules when required and a subsequent failure of equipment will result in the unavailability of operationally critical applications and a loss of visibility of the entire distribution network to the system controllers.

3.13 Site Security Infrastructure

At Energex, the radio sites form critical nodes within the telecommunications network. These sites carry many important services including 110kV and 33kV protection circuits, communications for pole mounted plan remote control / indication, SCADA circuits for substation remote control / indication, remote equipment management services and a range of other miscellaneous services. The sites are situated in remote locations with access times to attend site in excess of 2 hours. In the event that loss of services occurs as the result of vandalism or theft, repair times could be extensive extending to days if weather conditions are hampering access to the site. Energex needs to ensure that the site security is commensurate with the risk of failure of the critical services that these sites provide.

The security alarms installed on these sites were installed in the mid 1980's and are based on electronic components and key based systems. The lack of availability of replacement locks utilised at the sites has prompted a review of current security arrangements.

Improved capabilities of modern equipment (motion sensing) could be leveraged to reduce potential impacts from security breaches to the sites.

Figure 7: Typical remote site security panels

An example of a site security breach occurred at the D'Aguilar Range Repeater on 1 January 2012. The radio site RRDAG is located in a remote area within the D'Aguilar Range National Park. The site is off the main track, approximately 100m, and is not easily visible to passers-by. There is significant infrastructure that is attractive to would-be thieves. This site has had a number of security breaches over its operational lifetime. Approximately 6 years ago, a secondary gate was installed to prevent unauthorised access to the compound perimeter by vehicles. This has reduced the number of incidents; however incidents continue to occur, as described below

On the afternoon of 1/1/2012, two offenders approached the site in a vehicle, and proceeded to gain entry to the compound. The fence was damaged, and one of the offenders was seen in the video climbing on and around the solar arrays, a height of approximately 2.5 metres. In this instance, the only damage was to the fence, and entry was not gained to any of the buildings.

The security breach was only identified by staff on a routine service visit 5 days later. Staff noticed the damage to the fence, and reviewed the video footage to identify the offenders. After a police investigation, the offenders were apprehended and charged.

In this case, no significant damage was done, except to the fence. The offenders were climbing on structures at greater than a safe height, with no fall arrest or safety equipment. The offenders could have been injured or worse. No critical infrastructure was damaged, however the offenders had ample opportunity to do this. No alerts were raised from the existing security system, and our staff only became aware of the incident 5 days later. The existing system had no integration with the cameras, and therefore no proximity sensing capability was available to generate alarms. The alarming capabilities from the existing system were not performing reliably enough to generate accurate alerts in a reasonable timeframe.

Replacing the 30 year old security systems present at these sites will provide enhanced security that will reduce the impact of access breaches by detecting more of the breaches and providing local alarming that would discourage offenders from causing further damage and would provide an indication back to relevant personnel as breaches occur so that any impacts are identified and remediation can proceed as quickly as possible.

Figure 8: Footage from RRDAG tower with offenders circled

3.14 Other at-risk items included in this justification

3.14.1 Replacement of PDH multiplex and associated due to compatibility issues

The Energex PDH multiplex network consists primarily of the Nokia Dynanet family of equipment. The equipment is used to “multiplex” (facilitate combining multiple services onto single pairs of copper or fibre cable) services and carries protection signalling for all voltages, SCADA services and other miscellaneous services. In 2013, Nokia declared the Dynanet equipment end of life. Following this, no spares are available either through the manufacturer or supplier. Energex holds sufficient spares to maintain the existing network in the short term. As equipment fails the spares will be consumed and Energex will need to replace the equipment to generate further spares. This has already been experienced for one variant of the equipment called the DN2. After recent failures the spares holding was reduced to nil for certain cards. A project is proposed to replace some of the equipment in 2015/16, generating the necessary spares to continue with utilisation of the still in-service equipment.

3.14.2 Installation of microwave links due to Powerlink's decommissioning of their SDH radio network

Powerlink currently use a Nera SDH microwave radio link, which carries Energex data between certain radio sites. This equipment was deemed to be end of life some time ago from the manufacturer, and as such is not supported, and no new spares are available. Currently this radio system is operating with few existing spares, with limited ability to restore links in the event of a failure. It is therefore Powerlink's intention to decommission this system in 2017.

These microwave links provide 110kV and 33kV protection circuits, communications for pole mounted plant remote control / indication, SCADA circuits for substation remote control / indication, remote equipment management services and a range of other miscellaneous services. Energex will need to replace these links to continue to provide these services.

Analysis of the current telecommunications network configuration and capabilities has shown that of the five SDH radio links currently in service, three links will require replacement with new microwave radio links, while two links will no longer be required as the communications capability can be maintained by the use of alternate communications bearers such as Energex microwave radio links or optical fibre cable.

3.14.3 DSS Core Infrastructure Stage 5

Further analysis of the DSS Core Infrastructure program has resulted in a reduction on the original proposal. This is attributed to the natural growth of the network which is subsequently providing radio communications access, and an overall reduction in the program of work means that fewer new sites are being installed than those originally planned. Energex still has a requirement to service some existing sites that currently have no remote control available.

The DSS system plays an important role in the Energex distribution network as it allows network operators to have greater visibility of the network, enables faster fault restoration due to remote switching capability, and has the potential to reduce the impact of power system faults to customers.

4 Options

4.1 Impact of Doing Nothing

A consequence of obsolete and aged equipment is the reduced ability to carry out repairs in an efficient manner due to reduced access to spares and technical support. Some equipment failures would result in outage of services including SCADA and protection signalling for extended durations.

Risk of the do nothing approach is quantified in the untreated risk scenarios in Table 6.

Category	Risk Scenario	Consequence	Likelihood	Risk Score
Safety	Telephone line isolation is not installed, Energex field staff or Telecommunications carrier staff working on / using phone service when earth fault occurs and receives an electric shock causing a fatality.	5	2	10 (Low Risk)
Legislated Requirements	Microwave equipment fail and Energex is unable to repair as all spares are exhausted. Loss of 110kV protection circuits with Energex required to notify AEMO via Powerlink who require Energex to reconfigure the network and de-energise circuits.	5	4	20 (High Risk)
Customer Impact	Powerlink decommission their microwave equipment and Energex is unable to provide replacement services. Loss of control of significant numbers of pole mounted switches results in Energex being unable to restore supply efficiently following storm activity	3	5	15 (Moderate Risk)

Table 6: Untreated Risk Assessment Summary – RTU Replacements

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

4.2 Option 1 – Proactively Replace Equipment

This option entails equipment replacements with current generation equipment before in-service failures occur and before spares holdings reduce to unmanageable levels.

The required expenditure for this option over the 2015/16 – 2019/20 regulatory period is provided in the table below.

Description	2015/16	2016/17	2017/18	2018/19	2019/20
Expenditure $m, 2014/15	1.0	1.0	1.5	1.5	1.5

Table 7: Option 1 Expenditure

4.3 Option 2 – Repair only

4.3.1 Summary

“Repair only” is not a practical option as in most cases, components are either not available or difficult to maintain.

In the case of the microwave radios, once the manufacturer ceases production or declares the equipment to be end of life, the individual components become difficult to obtain, therefore limiting our ability to carry out repairs. For example, currently Energex holds very limited quantities of LEDR-900S and Alcatel 9400LX radios, which are insufficient to maintain the radios currently in service.

The LEDR-900S radios are a fractional-E1 type, designed to operate in the 900MHz band only. The ACMA has indicated in their 900MHz Band Plan their intentions to review the current frequency assignments, which will likely result in the revocation of the existing 900MHz licences held by Energex. In order to continue using microwave radio as a transport medium, replacement radios and reassignment of the radio frequency will be required.

4.3.2 Impact analysis

With the existing microwave radio equipment, prior to becoming obsolete, faulty units were repaired where possible and returned to service. As the equipment ages, the ability to repair the equipment reduces to a point where it is either not economical, or not possible to do so.

In all cases listed in this document, “repair only” is not possible due to the inability to obtain spare parts or components.

4.4 Option 3 – Use of Commercial Carriers

4.4.1 Summary

The possibility of using a commercial carrier for communications purposes was considerted. For the majority of equipment replacements no such alternative exists however for microwave radios it is in theory possible.

This option was considered but found not to be practical as:

- Costs exceed those that Energex incurs by providing the service internally;
- No existing carriers currently offer a service that meets Energex requirements; and
- The access control required by Energex cannot be achieved by the use of commercial carriers.

4.4.2 Impact analysis

The use of a commercial carrier is not an option that can be easily implemented. As there are no existing services available that are suitable, this could not be established in an efficient timeframe.

5 Proposed Works

Option 1 is the preferred option to maintain the expected level of reliability and dependability of the Energex telecommunications network. Summarised below is the replacement program for the regulatory period.

Equipment	Sub Type	2015/16 Program	Proposed 2016/17	Proposed 2017/18	Proposed 2018/19	Proposed 2019/20
Microwave Links	Sinewave 900 MHz fractional E1 units	Perseverance to Gatton Peseverance to Lockrose	One link	2 links		
	Alcatel 9400 AWY, 9000 AWY	Mt Gravatt to Lytton Mt Cotton to Cleveland Mt Walker to Gatton	2 links		3 links	1 link
Diesel Generators	Varies			1 site		1 site
Communications Site Chargers	Varies	Raceview depot	1 site	1 site		
Batteries	Varies	Raceview depot				
Solar Arrays	Varies	None	None	D'Aguilar Regulators	None	None
TLIU (Isolation units)	Varies	4 Sites				
Towers and Masts	Varies	RRGHR				
Miscellaneous (incl.VGDL equipment)	Varies					
PDH Multiplex	Dynanet	Remove DN2 RRMGV				
Powerlink SDH shutoff	NA	RRDAG/SSVPK	2 links			
Site Security	Varies	D'Aguilar and Mt Tamborine	2 sites	2 sites	2 sites	

Table 8: Replacement program

6 Required Expenditure

Table 9 below outlines the required expenditure for replacement of obsolete telecommunications equipment over the period 2015/16 to 2019/20. Given the combination of obsolescence and external factors driving this program, the revised program is considered the least cost prudent option available. No other options were considered viable.

$m, 2014/15	2015/16	2016/17	2017/18	2018/19	2019/20
Expenditure	1.0	1.0	1.5	1.5	1.5

Table 9: 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 – Regulation associated with Protection outages that need to be applied for communications links providing communications for protection services

National Electricity Regulator (NER) Schedule S5.1.2.1 (d)

The Network Service Provider must ensure that all protection systems for lines at a voltage above 66 kV, including associated intertripping, are well maintained so as to be available at all times other than for short periods (not greater than eight hours) while the maintenance of a protection system is being carried out.

AEMO security guide lines

16. Protection System Outages

If a Registered Participant becomes aware that any relevant protection system or control system is defective or unavailable for service, that Registered Participant must advise AEMO. If AEMO considers it to be a threat to power system security, AEMO may direct that the equipment protected or operated by the relevant protection system or control system be taken out of operation or operated as AEMO directs.

16.1. Total Outage of Protection Schemes

If all the primary protection schemes on a transmission element are removed from service the transmission line is normally removed from service. An exception to this may arise if the outage of the transmission line would interrupt supply and adequate backup protection is available to maintain system security. Situations of this kind should be resolved between the NSP and AEMO.

16.2. Planned Outage of One Protection of a Duplicated Scheme

Normally the power system equipment can remain in service

The duration of the outage should be kept to a minimum and not greater than eight hours unless agreed by AEMO and the relevant NSPs. Refer NER Schedule S5.1.2.1 (d).

If the protection remains unserviceable after 8 hours and provided there is agreement between AEMO and the relevant NSPs for the outage to continue, then follow the approach as for unplanned outages.

16.3. Unplanned Outage of One Protection of a Duplicated Scheme

The Rules (refer S5.1.2.1 (d)) may be interpreted to apply to planned outages for maintenance purposes and the following clarifies the approach for unplanned outages of one protection of a duplicated scheme.

Normally the transmission element can remain in service provided that the NSP provides reasonable assurance that the remaining protection will clear a fault in primary protection timeframe; and

The protection repair is being progressed with the intention of returning the duplicate protection to service as soon as possible.

If these conditions are not met then the affected transmission element must be taken out of service.

16.4. Degraded Clearing Times

Degraded or longer clearing times can result during outages of protection signalling or inter-tripping equipment. Degraded clearing times can also result if high speed primary protection such as distance or pilot wire protection is taken out of service and the alternative protection is a slower directional over current scheme. Temporary protection schemes can also result in longer clearing times. The effect of this on system security needs to be assessed in consultation with the TNSP.

Where there is a risk to system security and any of the following apply:

- High speed clearance of some faults is no longer possible.
- There are periods when the risk of fault on the power system is high.
- The degraded clearing times are to apply for extended periods.

Then:

- The power system must be operated to more restrictive limits which correspond to the longer clearing times, or;
- The protection settings must be reduced to provide faster clearing times. If this leads to loss of discrimination, operating limits must be reduced to correspond with the possibility of inappropriate operation, or;
- The affected transmission element must be taken out of service.

16.5. Outage of Additional Non- Duplicated Protection Schemes

Protection schemes required for the detection of special low probability events such as Directional Earth Fault Comparison schemes, designed to detect high impedance faults which may occur during bushfires, may be taken out of service, and the primary plant left in service. This action may only be taken provided the risk of this type of fault is not high and the outage is of short duration, that is, less than 8 hours unless agreed by AEMO and the relevant NSPs.

Outages of other types of protection schemes which may not be duplicated, such as transformer Buchholz or differential protection, should be treated in a similar way.

16.6. Outage of Signalling Systems

Outages of signalling systems such as fast zone two blocking can cause loss of discrimination and suitable remedial measures should be agreed with the TNSP. These measures may include the temporary application of a block or removal of the fast zone two tripping feature.

Outages of accelerated inter-tripping on one protection scheme of a duplicated scheme normally will not result in loss of zone one clearing times on the protected transmission element and thus should not impact on system security.

Outages of direct or accelerated inter-tripping associated with Circuit Breaker Fail protection in “breaker and a half” switchyards may require opening of coupler circuit breakers provided this does not cause additional security problems.

Provided the system security issues have been adequately addressed the affected primary plant can remain in service.

16.7. Transfer Limit Reductions due to Protection Outages

Outages of protection or associated signalling equipment can lead to a reduction in transient stability transfer limits.

Various types of protection schemes designed to enhance system stability such as single pole tripping and reclosing or power swing blocking could also result in a reduction of safe power transfer limits if they are not available. Changes to these limits will be agreed between AEMO and the appropriate TNSP.

16.8. System Protection Services

Under frequency protection is designed to return system frequency to normal following multiple generation contingencies. The National Electricity Rules requires 60% of the total load of a region to be connected to under frequency protection. This protection is distributed across the region and taking the under frequency scheme out of service at one substation has little effect on the overall scheme and the security of the power system.

Under voltage schemes are designed to protect smaller areas within the power system from under voltages during contingencies. The outage of these schemes will impact on the security of the power system but only for a limited number of contingencies. The outage will need to be assessed against other planned outages of system equipment and any known risk factors such as weather conditions.

There are special control schemes and devices that allow higher Inter-Regional and Intra-Regional transfer levels when they are in service. Outages of these schemes will be assessed to determine if new constraints need to be applied to the associated transfer limits.

16.9. NEM Rules Requirements

The National Electricity Rules Clause 4.3.1 defines the responsibility AEMO has for system security.

Clause4.6.2. AEMO is required to co-ordinate, in consultation with Network Service Providers, the protection of power system plant which could affect power system security.

Clause 4.6.5 defines AEMO’s responsibility to determine, in consultation with the Network Service Providers, the best course of action to adopt for partial, or complete, removal from service of the protection equipment protecting transmission lines. The NSP must comply with AEMO’s determination unless in their reasonable opinion it would threaten the safety of any person or cause material damage.

Clause 4.8.2 defines a registered participant’s responsibility to advise AEMO of any relevant protection or control system that is defective or unavailable. If there is risk to system security AEMO can direct the affected plant to be taken out of service or to be operated in an appropriate manner. The Registered participant must comply with a direction given by AEMO

Appendix 2 – Reported microwave radio faults by radio type since June 2012

Fault Report Number	Date Reported	Radio Link Affected	Fault Details
Radio Type: Sinewave LEDR-900S			
STOC-1278	29/09/2014	RRWKB - SSNGI	Main radio failed due to loose DC connections, Standby radio failed with low RF output. Standby radio was replaced.
STOC-1051	17/06/2014	RRTMB - SSJBB	RRTMB - Main radio receiver deaf. Required replacement. SSJBB - Standby radio complete fail. Required replacement.
STOC-1939	15/01/2013	RRFPK - SSBDS	Radios at both sites failed due to over temperature.
STOC-1942	18/12/2013	DPRVW-RRFPK-SSBDS	Radios at all three sites failed due to over temperature
STOC-1413	16/11/2014	RRWKB - SSNGI	SSNGI - Standby radio failed, won't power up. Link missing standby radio due to no available spares.
STOC-1364	11/11/2014	RRPER - SSLRE	SSLRE - Radios failed due to over temperature following a local power failure during storm.
STOC-1864	22/04/2015	RRPER - SSGBS	RRPER - Standby radio deaf (no RX), Main radio passing errors. Both radios required replacement.
STOC-878	31/03/2014	RRPER - SSWHH	Radios have low RSSI at both ends. Antenna fault.
STOC-316	26/04/2013	RRCTN - SSRPT	Main radios at both sites required replacement due to errors on link. Due to RSSI being OK, radios did not attempt to switch to Standby radios.
STOC-154	11/01/2013	RRFPK - SSBDS	Main radio at SSBDS was faulty. Manual switch to Standby radio and link was restored. Replace faulty radio.
STOC-357	23/05/2013	RRPER - SSPRG	Services on this link are reported faulty. Radios at SSPRG were faulty and required replacement.

Fault Report Number	Date Reported	Radio Link Affected	Fault Details
Radio Type: Alcatel 9400LX Series			
STOC-1607	30/01/2015	DPGTN - RRYRM	Fault reported as a service fail on one tributary of the radio link. Investigation shows that one E1 interface on radio has failed. At this stage, unable to repair. Radio is operating at 3 x E1 capacity.
STOC-917	19/04/2014	DPGTN - RRPER	RRPER - Transmit fault - radio required a reboot.

Appendix 3 – Other Supporting Information

Site Security Systems:

ENA DOC 015-2006 National Guidelines for Prevention of Unauthorised Access to Electricity Infrastructure

BMS00375 – Substation Security – Key Tactical and Operational Requirements – Version 3 Released 16/01/2015

Microwave Radio Replacements:

ACMA – Five-Year Spectrum Outlook 2014-18 – Release Date: September 2014

http://www.acma.gov.au/Industry/Spectrum/Spectrum-projects/5-Year-Spectrum-Outlook/fiveyear-spectrum-outlook-1

Alcatel LX Series Digital Microwave Radio Links

https://support.alcatel-lucent.com/portal/productContent.do?productId=null&entryId=1-0000000002421&type=alpha

Alcatel AWY Series Digital Microwave Radio Links

https://support.alcatel-lucent.com/portal/productContent.do?productId=&entryId=1-0000000002420

GE Digital – LEDR 900S Microwave Radios

http://www.wirelessdata.com.au/media/downloads/44/Notice%20of%20MFG%20Change%20LEDR%20Series.pdf

Nokia PDH Replacements:

Nokia Dynanet family – End of Life Notice

Miscellaneous Documentation:

Energex Telecommunications Strategic Plan 2015-2020

http://thesource/np/ott/Documents/TelecommunicationsStrategicPlan2015-20.pdf

Appendix 4 – Proposed work under the DSS Core Infrastructure Stage 5 Project

Proposed Headend Sites			
No.	**Site**	**Address**	**Site Owner**
1	SSCLM - Energex Substation Coolum	Greenoak Dr & Yungar St Coolum.	Energex
2	SSGVN - Energex Substation Gavin	Smith St, Gaven	Energex
3	RREHL - Enoggera Hill Repeater	Tyarrabee Rd, Enoggera	Dept. of Defence
Proposed Repeater Sites			
No.	**Site**	**Address**	**Site Owner**
1	Pole X18665-B	Guanaba Rd, Mount Tamborine	Energex
2	Optus tower	Mona Dr, Jimboomba	Optus
3	Optus tower	Laheys Lookout Rd, Mt Tamborine	Optus
4	Optus or Telstra near SP753829	Off Boonah-Rathdowney Rd, Rathdowney	Optus or Telstra
5	Solar repeater	Off East Egypt Rd, Fordsdale	Private property
6	Solar repeater	Off Ingoldsby Rd, Ingoldsby	Private property
7	Solar repeater	Off Kandanga Creek Rd, Kandanga.	Private property
8	Solar repeater	Old Mill Rd, Sheep Station Creek	Private property
9	SP777630	Harper Rd, Barney View	Energex pole on private property
10	Solar Repeater	Eastern Branch Creek Rd, Kin Kin	Private property
11	SP15578-D	Mt Stradbroke, Off Larkhill Boundary Rd, Glamorgan Vale	Energex
12	SP4642-E	Brocks Rd, Currumbin Valley	Energex
13	Private power pole	Glastonbury Rd, Glastonbury	Private property

Proposed Repeater Sites			
No.	**Site**	**Address**	**Site Owner**
14	SP788748	Rosedene Farm, Mt Sylvia Rd, West Haldon	Energex
15	SP48987-A	Off Sandy Creek Rd & O'Meara Rd, Downsfield	Energex
16	P308951	Paulsens Rd, Kin Kin	Energex
17	P46709-A	Beenham Valley Rd, Beenham Valley	Energex
18	P39677	Shadbolt Rd, Cedar Pocket	Energex
19	P763408	Adjacent Reservoir, Beehive Rd, Amity Point, Stradbroke Island	Energex
20	P46156-C	Near water reservoir, Rutledge St, Coolangatta	Energex
21	P1408792	Ocean View Rd, Ocean View	Energex
22	P50619-B	Lamington National Park Rd, O'Reilly	Energex
23	P263079	Biddaddaba Creek Rd, Biddaddaba	Energex
24	SP796093	Wivenhoe - Somerset Rd, Dundas	Energex
25	SP4152-A	Lockyer View Rd, Wivenhoe Pocket	Energex
26	SP1461-C	Off Esk - Kilcoy Rd, Caboonbah	Energex
27	P14564-C	Jacaranda Av, Logan Central	Energex
28	SP755346	Mt. Dunsinane, Off Veresdale Scrub School Rd, Veresdale Scrub	Energex
29	P110631	Greenhill Rd, Munruben	Energex
30	SSNGI	Caboolture - Bribie Island Rd, Ningi	Energex

PUBLIC

Energex

RTU Replacement Program

Asset Management Division

energex

positive energy

Energex

RTU 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.

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Corporate Communications
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BRISBANE QLD 4001

Executive Summary

The purpose of this document is to outline the required expenditure for replacement of Remote Terminal Units (RTUs) over the forthcoming 5 year period. This is not accounted for in the modelled REPEX programs. During the 2010 – 2015 regulatory control period, replacement of obsolete RTU hardware had largely been achieved as part of substation augmentation works with 149 units replaced. In the 2015-2020 period, due to Energex's reduced augmentation program there is a requirement to action the required replacements as a stand alone REPEX program.

The objectives of this program are to:

- Mitigate to As Low As Reasonably Practicable the safety risks to staff and the community associated issues with voltage regulation present in RTUs running older software versions;
- Maintain customer voltage levels within statutory tolerances; and
- Mitigate the business risks associated with plant damage by implementing automated overload management control algorithms.

Energex has an extensive System Control And Data Acquisition (SCADA) network that contributes to safe, compliant and sustainable customer outcomes by enabling operator remote control of distribution network plant. The SCADA network is a complex arrangement of computer servers called Remote Terminal Units (RTU) and other communications infrastructure. It facilitates automation of functions such as voltage control, network overload management and automated switching following contingency events. These are key to Energex meeting legislated obligations with regards to customer quality of supply per National Electricity Rule requirements, security of supply requirements per Energex's Distribution Authority, and to mitigate business risks associated with damage resulting from overload of critical electrical infrastructure such as power transformers and underground cables. Planned replacement of obsolete RTU hardware mitigates the risks associated with in-service failures. The significant number of older units in service and the accelerating failure rates experienced to date confirms requirements for this replacement program.

Longer term Energex intends to transition to a Commercial Off The Shelf RTU. A separate initiative detailed in the Energex submission will select a replacement for the current RTU utilised by Energex and modify and integrate necessary systems to allow its use. Due to immediate issues and risks with current obsolete RTU assets, Energex is unable to defer replacement of obsolete units until a commercial product is available for use.

Addressing feedback from the AER in its preliminary decision, Energex has revised this program to remove from scope items deemed lower risk. The revised expenditure required is $4.0 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	1.46	1.46	1.46	1.46	1.46	7.3
Energex revised	0.6	0.8	0.8	0.9	0.9	4.0

Contents

1 Introduction

The purpose of this document is to seek endorsement to add the Remote Terminal Unit (RTU) replacement program for the 2015 to 2020 regulatory period to the program of work.

This program is important due to need to ensure the ongoing performance of the RTU fleet and ensure that:

- Operators retain control of network elements.
- Critical automatic functions like volt-var regulation, network overload management and auto change over continue to work in an optimal manner and
- Old software with known failure modes and other inadequacies is removed from the network.

Upgrading the equipment will also enable the utilisation of improved communications links, enabling faster real-time data updates and control responses for operators. This will also enable increasing levels of data to be collected, allowing Energex to collect and report more information on the 11kV network and potentially on the low voltage network. With increasing penetration of distributed generation (rooftop solar) this will become increasingly important for effective planning, asset management.

The proposed program covers the replacement of obsolete RTUs with the current technology for both hardware and software.

Changes from the original proposal

The original proposal to the AER for the RTU replacement was for $7.3 million.

Energex is committed to the delivery of sustainable outcomes for customers and the business with no compromise to existing safety and legislative compliance. 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

The revised program presented where items with lower risk have been removed and a change from the original proposal to seek an investment of $4.0 million over the five year period.

2 Drivers

Obsolescence is the major driver for the replacement of SCADA RTUs. Once the software or hardware of the equipment becomes obsolete, various risk factors begin to increase until ongoing use of the equipment is considered as intolerable. The following sections provide a summary of these issues.

2.1 Reliability

Each in-service failure significantly impacts Energex until such time as the unit is repaired leading to loss of:

- Operator monitoring and control
- Substation automation functions implemented by the RTU (e.g. volt-var regulation, autochangeover, plant overload protection, etc.); and
- Load control

Most components of SCADA RTUs cannot be purchased new. Spares holdings currently consist of units that have been removed from service elsewhere and are likely to provide only limited service life before failing.

The latest generation equipment cannot be used to replace failed equipment following in service failure scenarios without extended outage times, due to physical size differences and configuration differences (both physical and logical interface differences).

2.2 Management of engineering knowledge risk.

The numbers of staff with expert knowledge of the existing in-house legacy system is decreasing over time. Training of new staff in the intricacies of the old system is not economical.

2.3 Inability to leverage the capabilities of latest hardware and software

The inability of obsolete RTUs to leverage the capabilities of the latest hardware and software will significantly impact the ability of to deliver efficiencies into the future.

Obsolete RTUs cannot take full advantage of IP-based networks for SCADA communications, in order to provide faster updates and control to operators and enable the SCADA units to provide more data about the state of the network. Similarly they cannot support the latest versions of substation automation functions such as volt-var regulation (VVR5 software) and network overload mitigation software (NOMS) software.

Obsolete RTUs will also not be able to support new features under development, such as:

- RTU Monitoring and Management that will enable integrated monitoring and management of both network and SCADA system resources form a common operations centre
- Enhanced, network-based time synchronisation, which will improve the quality of post-incident diagnostic data provided to engineering staff

2.4 Legislative

Energex has to meet various compliance obligations including maintaining voltage to customers within the statutory limits of The Queensland Electricity Regulation 2006, s13. The latest VVR5 software overcomes various issues that previous version of the software has exhibited.

2.5 Dependability

Energex is implementing automatic management capability such that the RTU fleet will be monitored by a computing solution and alarms generated will be sent direct to relevant staff. The arrangements are being developed for the current plat forms only. For obsolete RTU equipment failures cannot be detected and rectified as quickly for obsolete RTUs as for current equipment

2.6 Flexibility

The latest versions of automation applications allow certain types of configuration changes to be made “on the fly” without having to invoke the full configuration change process – with significant labour savings. The solution has been developed on the latest generation of operating system (V5), so only those with V5 software can take advantage of this improvement.

3 Supporting Analysis

3.1 Existing Fleet

Figure 1 below gives the hardware age profile of the existing RTU fleet. On average Energex gets 12 years from an RTU and as such units installed before 2007 will be 12 years or older by 2020.

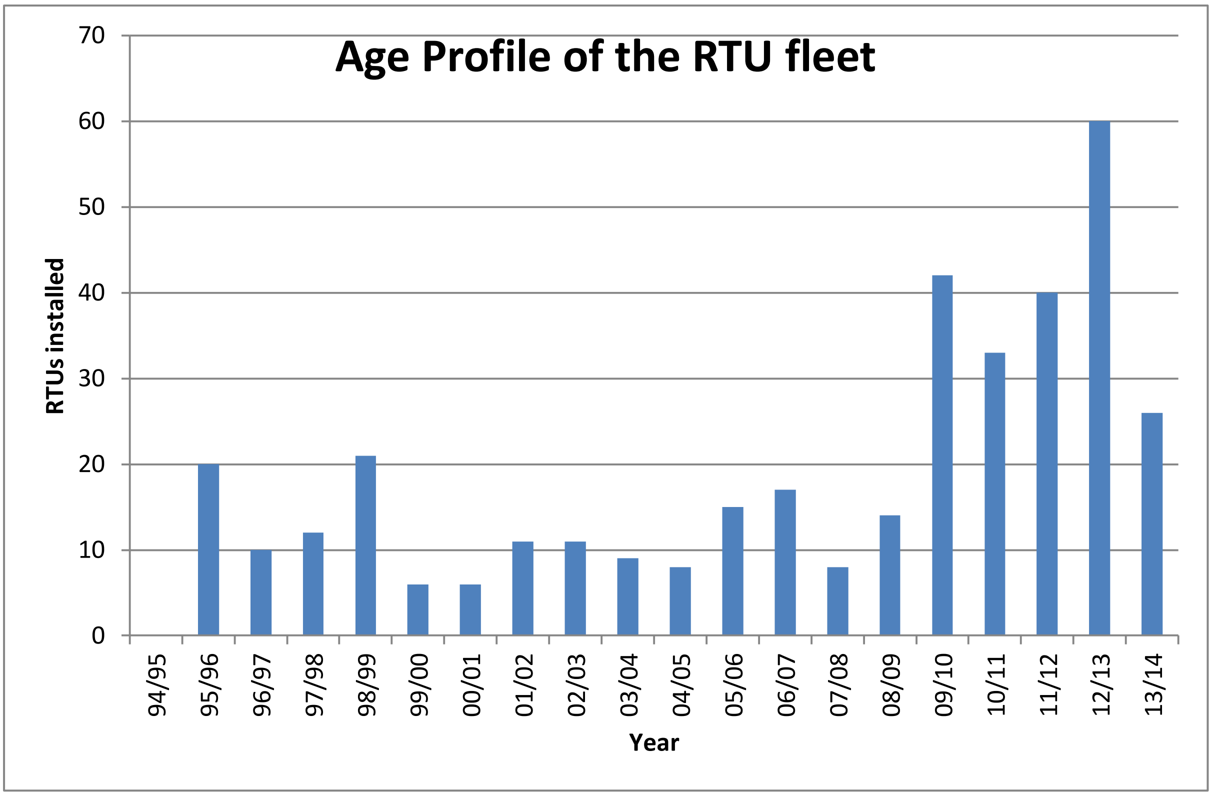

Figure 1 – RTU Age Profile

There are three generations of operating system software in service in the fleet - V2 and V3 (obsolete) and V5 (current). V2 is an in-house operating system. V3 and V5 are based on different versions of [redacted], a commercial operating system. Each major substation automation application has been “ported” from one operating system to the next over time. Later versions of the applications will not run on earlier operating systems, [redacted] Furthermore, later versions of the applications have been developed to include new or enhanced features.

Software / hardware version compatibility also allows for a mix and match approach to deployments. A significant number of sites are running old software on the latest hardware. In most cases this has been done to avoid the need to replace the parallel I/O equipment, and the consequent need for expensive rewiring at the site. In total the fleet as at May 2015 had 46 units with version 3 software running on the latest hardware platform. Refer to Table 1 – Substation RTUs

		Electronics Module						Totals
		SICM2	PC MiniSACS	V2.x	V3	S1.x	P5.0	
Operating System	[redacted]	9	NA	NA	NA	NA	NA	9
	[redacted]	NA	13	6	0	0	0	19
	[redacted]	NA	11	12	0	46	0	69
	[redacted]	NA	0	9	0	112	92	213
Totals		9	24	27	0	158	92	**310**

Table 1 – Substation RTUs

		Electronics Module					Totals
		PC MiniSACS	V2.x	V3	S1.x	P5.0	
Operating System	[redacted]	0	2	0	0	0	2
	[redacted]	0	0	0	3	0	3
	[redacted]	0	0	0	36	0	36
Totals		0	2	0	39	0	**41**

Table 2 – Data Concentrator RTUs

3.2 Failure Rates

Energex is experiencing increasing failure rates for older generation equipment. Figure 2 shows annual failure rates for existing equipment running non-current software versions. The increase since 2011 is attributed to equipment nearing the end of it service life. Energex is utilising spare units that have been removed from other sites to replace faulty equipment.

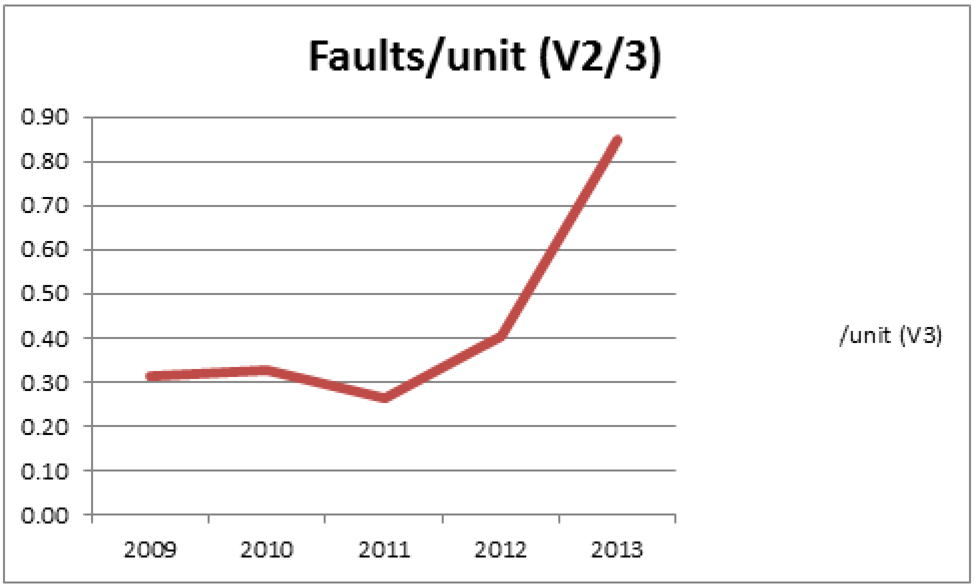

Figure 2 – RTU Failure Rates

3.3 Benefit of the latest voltage regulation software (VVR5)

Energex has experienced voltage regulation issues at substations, resulting in non-compliance with legislated voltage requirements and customer impacts such as over voltage events. Appendix 1 contains examples of such events. The consequence of these events would be reduced through the application of the latest voltage regulation software (VVR5), which in turn requires the latest software to be running on the RTU.

In each of the cases listed a failure in the voltage measurement chain results in a less than actual value for voltage being measured by the RTU. The RTU believing that the voltage has dropped attempts to correct what it sees as low volts by changing tapping to increase the voltage. The result is an over voltage. This failure mode is mitigated by the latest regulation software by having a set of limits that causes the voltage regulation software to detect that issues are occurring and limiting tap changes to a certain range.

3.4 Benefit of IP based SCADA communications

[redacted]

Energex is proposing to resolve this issue for sites that are receiving the core IP-MPLS telecommunications network and have cabling diversity to the site by changing the sites over to IP connectivity. However the RTUs must be running the latest software to take advantage of the IP solution.

4 Options

4.1 Impact of Doing Nothing

The “do nothing” option, or failure to proactively replace obsolete RTUs would result in situations where an increasing likelihood of units failing in service thereby resulting in uncontrolled voltage control of Energex equipment with safety, legislative and customer risks. Spares of various items will no longer be available - in these cases, outages of multiple weeks will be required to restore service, during which remote control of the substation will not be possible.

This outcome is not tolerable to Energex, with untreated risks not considered to be As Low As Reasonably Practicable (ALARP).

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 an RTU to regulate substation voltage results in an overvoltage event to customers, resulting in a house fire and multiple fatalities	6	2	12 (Moderate Risk)
Legislated Requirements	Failure of an RTU to regulate substation voltage results in an overvoltage event to customers requiring notification to the regulator	4	3	12 (Moderate Risk)
Customer Impact	Failure of an RTU to regulate substation voltage results in an overvoltage event to customers results in damage to customer equipment	4	3	12 (Moderate Risk)

Table 3: Untreated Risk Assessment Summary – RTU Replacements

4.2 Option 1 – Bring all Old Operating System Versions to Current and Replace Obsolete Hardware

4.2.1 Summary

This option proposes to bring all units running old operating system versions to current operating system versions and replace the hardware of any of these units that are obsolete. This program is a compromise from Energex's original proposal with all lower risk elements of the program being removed. This will reduce the cost of the program and incur an increase in risk compared to the original proposal.

Under the revised proposal in total 88 installations would be targeted. On current data, 33 RTUs will be upgraded under existing and proposed projects, leaving 55 RTUs to be upgraded under this programme.

4.2.2 Impact analysis

This option would leave in service 18 RTUs with old hardware in the network.

Additional risk would arise from leaving obsolete hardware in service with likelihood of in service failure (noting that spare hardware will be available for replacement as the total number of removals will ensure that enough spare units are available to replace all in service).

This option would:

- Allow the latest software to be deployed if required to any RTU in the fleet.
- Allow SPARQ solutions to cease support for old software (but support of new software on the old hardware will still be required).

The preferred risk mitigation strategy is for Energex to continue with RTU replacements, but to limit replacements to those considered essential bearing in mind a new RTU strategy based on commercially available equipment is being developed (Refer SCADA COTS RTU Selection Business Case).

Note: This risk mitigation strategy has been "implied" in the past, but must now be made "explicit". In recent years, a large proportion of this REPEX has been performed in augmentation works. This has been driven in some cases by the augmentation works needing to upgrade RTUs or Energex identified that a significant cost savings could be achieved by bundling upgrades works into an Augmentation project. In the 2010-2015 AER period, Energex completed 149 RTU upgrades of some type under augmentation projects. With the proposed reductions in augmentation expenditure in the next regulatory period the opportunity to perform REPEX work such as RTU replacements in augmentation projects is reducing. There is still an opportunity to minimise spend by coordinating RTU replacements with other REPEX works such as switchgear replacements and obsolete relay replacements, but the programs will be present in REPEX programs.

The following table provides a summary of the treated risks addressed by this option.

Category	Risk Scenario	Consequence	Likelihood	Risk Score
Safety	Failure of an RTU to regulate substation voltage results in an overvoltage event to customers, resulting in a house fire and multiple fatalities	6	1	6 (Low Risk)
Legislated Requirements	Failure of an RTU to regulate substation voltage results in an overvoltage event to customers requiring notification to the regulator	4	1	4 (Very Low Risk)
Customer Impact	Failure of an RTU to regulate substation voltage results in an overvoltage event to customers results in damage to customer equipment	4	1	4 (Very Low Risk)

Table 4: Treated Risk Assessment Summary – RTU Replacements

Description	2015/16	2016/17	2017/18	2018/19	2019/20
Option 1 ($m)	0.6	0.8	0.8	0.9	0.9

Table 5: Program Requirement Breakdown – RTU

4.3 Option 2 – Bring all Obsolete Operating Systems and Hardware to Supported Versions

4.3.1 Summary

This option proposes to bring all units with obsolete operating systems or with obsolete hardware to supported operating systems and hardware. This option would replace or upgrade all RTUs with obsolete hardware or software, targeting 106 installations. The original program was for the replacement of 79 units

4.3.2 Impact analysis

This option would:

- Allow the latest software to be deployed if required to any RTU in the fleet
- Allow SPARQ solutions to cease support for old software
- Remove the need to retain spares for obsolete hardware
- Allow all units to be monitored with the proposed management monitoring software

Description	2015/16	2016/17	2017/18	2018/19	2019/20
Option 2 ($m)	1.46	1.46	1.46	1.46	1.46

Table 6: Expenditure – Option 2

4.4 Option 3 – Replace only obsolete substation RTU hardware leaving obsolete operating systems in service

4.4.1 Summary

By not replacing equipment running obsolete operating systems, the organisation would have to commit to back-porting the latest versions of substation automation applications to older platforms. This would significantly reduce the total number of RTUs to be replaced. In total 60 installations would be targeted. On current data, 26 RTUs will be upgraded under existing and proposed projects that are already identified in other programs, leaving 32 RTUs to be upgraded under this programme.

4.4.2 Impact analysis

This option would have a significant negative impact on the organisation. Energex would retain 46 units operating on old software versions. This would have the following risks and impacts:

- A productivity penalty would arise from the need for SPARQ to continue support (bug fixes, etc.) for old software. Also the flexibility that the latest software packages provide to tailor settings without the need to go through the complete RTU change process would not be realised.
- Energex would carry the risk of not meeting our obligations to regulate voltage to within legislated levels due to having older voltage regulation software's with known issues left in the network.
- Also safety risk associated with the old voltage regulation software would not be ALARP (As Low As Reasonably Practical)

This option has the following advantages:

- All obsolete hardware removed from the network allowing spares of older units to be disposed of, reducing the overhead of managing the spares,
- Removal of all obsolete hardware should halt the trend of increasing failure rates.

Description	2015/16	2016/17	2017/18	2018/19	2019/20
Option 3 ($m)	0.6	0.6	0.6	0.6	0.6

Table 7: Expenditure – Option 3

5 Proposed Works

It is proposed to implement Option 1 to replace 55 RTU units over the 2015/16 – 2019/20 period under this program. Whilst, in the absence of funding restraints, 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 embodied in Option 1, while not compromising on its treatment of safety risks.

This includes the replacement of all PC MiniSACS, V2 and V2.5 hardware, and upgrade all S1 RTUs running old software at a cost of $4.0 million.

6 Required Expenditure

Table 8 below outlines the required expenditure for Option 1, which is the preferred RTU replacement program in this business case.

$m, 2014/15	2015/16	2016/17	2017/18	2018/19	2019/20
Energex Revised Proposal	0.6	0.8	0.8	0.9	0.9

Table 8: 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 – Voltage regulation incidents

Sub	Report	INC	STOC Ref	Date	Summary
SSSMF	SR12-19			May-12	SICM1 involved (cold weather)
SSIBS	SR12-19			15/05/2012	SICM1 involved (cold weather)
SSMTN		INC-115842		May-13	Significant incident with damage
SSIBS			STOC-1100	8-9/07/2014	SSIBS - TR2 abnormal VVR operation: The following investigations were undertaken by multiple field groups, and TR2 110KV was re-energised on Tuesday 8/07/2014 and the 33kV re-energised on Wednesday 9/07/2014. No cause identified, issue with VVR interface hardware or SACS hardware suspected.

PUBLIC

Energex

Obsolete SCADA Equipment

Asset Management Division

energex

positive energy

Energex

Obsolete SCADA Equipment 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.

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Executive Summary

SCADA (Supervisory Control And Data Acquisition) is a system which operates using coded signals over communication channels so as to provide control of remote equipment used to operate the Energex network. Energex relies upon its SCADA systems to manage the distribution network more efficiently and with much greater speed than it could without it. Through remote control and monitoring, the network can be operated at lower cost and with fewer risks (e.g. able to remotely isolate electricity supply in emergency much faster than if a crew needed to travel to a nearby site).

The product life-cycle of commercial off-the-shelf equipment for the type of elements which comprise the SCADA system is typically very short by distribution industry expectations – more akin to the life-cycle of the information technology industry than the power industry.

Energex has already extended the life of elements of its SCADA systems well beyond generally accepted life-spans, deferring the cost of works associated with replacements. Accordingly, Energex is now required to replace obsolete elements of its SCADA systems to ensure ongoing compliance with legislative obligations. Failure to do so would place Energex at increasing risk of not being able to meet compliance obligations, particularly with respect to maintaining voltage to customers within statutory limits.

Following feedback from the AER in its preliminary decision, Energex has re-evaluated its capital programs to tolerate more risk than described in the original submission. As a result, the SCADA replacement program is reduced in scope.

The original Energex submission proposed works for an expenditure of $2.2 million. The revised total expenditure required is $1 million 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	0.1	0.2	0.2	0.3	0.2	1.0

Contents

1 Introduction

The purpose of this document is to outline the required expenditure for the Obsolete SCADA program in the period 2015/16 – 2019/20.

This program is important due to the potential risk consequences to the operation of the Energex distribution network if left untreated. The proposed program covers replacement of end of life SCADA equipment which does not fall within the scope of other programs.

Changes from the original proposal

The original proposal to the AER for the Obsolete SCADA program was for $2.2 million over the 2015/16 – 2019/20 regulatory period. Following feedback from the AER in its preliminary decision, Energex has re-evaluated its capital programs to operate with a higher level of risk. Accordingly, the works have been reviewed and items with lower risk have been removed.

The total expenditure proposed for these works is now $1 million.

2 Drivers

Obsolescence is the major driver for the replacement of most SCADA equipment utilised within Energex. As with most IT related equipment, once the software, equipment or components of the equipment become obsolete, various risk factors begin to increase until ongoing use of the equipment is considered intolerable.

The existing Energex network has a range of obsolete SCADA equipment that is ageing. A subset of the equipment in this category either has intolerable risk during in-service failure or has other factors that drive proactive replacement activities. For the remainder of the equipment fail-fix processes are adopted until failure modes or failure rates (where measureable) justify proactive replacement.

Most components cannot be purchased new, spares are units that have been removed from service elsewhere and are likely to only provide limited service life before failing.

If pre-emptive work is not done to replace obsolete SCADA devices prior to failure, when they fail and there are insufficient spares to replace them with like-for-like, the time required to return them to service is significantly increased (in the order of days or weeks instead of hours). This is due to the differences in physical fit, interfaces and configuration between different generations of equipment.

3 Supporting Analysis

3.1 Existing Network/Background

3.1.1 Scope

Assets considered in planning SCADA & automation refurbishment works include:

- Human Machine Interface
- Remote Terminal Units – Large
- Remote Terminal Units - Small
- Intelligent Electrical Device (IED)
- Marshalling Board
- Interfacing Components
- Servers / Data concentrators
- DSA / DSS control equipment
- Software utilised within Control Systems

Following a revised assessment, assets included in this justification are:

- Interfacing components: Analogue Tap position indicator
- Interfacing components: Statistical Metering boards
- Interfacing components: C&I CBD [redacted] RTUs
- Server hardware for data concentrators
- Modem Bank Replacements.

Other asset refurbishments within this same asset class, for Remote Terminal Units, DSS/DSA control equipment and software utilised within control systems, are justified under separate business cases.

A number of key SCADA & automation assets (i.e. central servers) are managed by SPARQ for Energex who fund maintenance or refurbishment as necessary.

Table 1 below shows the proposed program of works for 2015/16 – 2019/20 to address the issues of obsolescence listed in Table 2, which are not dealt with by other works.

Program	Description
Replace Selected statistical metering boards	Statistical metering board has a high risk profile associated with failure and cannot be replaced with later generation equipment on fail in the time available during fail fix. Plan for 2015/16 – 2019/20 is to replace the oldest units of the population and improve ability to support balance of units in service.
Remove Analogue Tap position indicator	Analogue tap position indicator equipment is inaccurate and prone to failure. It is proposed to remove four units representing highest risk on transformers with longest remaining service life from service.
[redacted] RTUs	There are currently seven (7) sites with obsolete [redacted] RTUs that are interfaced to the SCADA system via commercial and industrial concentrator [redacted] This work is to begin the replacement of those installations with current standard hardware.
Replace server hardware for concentrators	Hardware replacement to current supportable platform (standard equipment refresh).
Modem Bank Replacements	Modems and modem banks allow digital transmission on pilot cables and telephone lines. Replacement required due to obsolescence of some models where fix-on-fail approach would result in excessive down times.

Table 1: Program of Works 2015 – 2020

3.1.2 Current Population of SCADA System Equipment

Table 2 below shows the current population of SCADA system equipment considered for replacement.

Equipment	Product	Amount in Service 2015	Obsolescence Status
Interface component	Statistical metering board - Derives voltage, current and power analogues from VT and CT signals using analogue processing	145	Obsolete
	Analogue tap position indicator - Derives tap position analogue from radial switch	22	Obsolete
Servers / Data concentrators	[redacted]	3	Current
	[redacted]	10	Current
	[redacted]	5	Obsolete hardware (Hardware refresh needed)
Others	[redacted]	7	Obsolescent

Table 2: Population of SCADA System Equipment

3.2 Network Requirements

3.2.1 Replace selected statistical metering boards

One of the legacy interfacing components used by Energex SCADA still in service is the Statistical Metering board. These units are over-represented in field fault reports given the comparatively small population still in service – four in the last 12 months with only 145 in service (refer Table 4).[1]

Removal of these units from service is planned in order to avoid the need for a reactive program at the time they become completely unsupportable.

There are two generations of the Statistical Metering Board - Type 1 and Type 2:

[1] Note that age is well in excess of the typical 10-15 year service life for industrial electronics.

- *"The initial version of the Statistical Metering Board (Type 1) included a 5x over-scale capability on current, combined with peak-hold on current and dip-hold on voltage…*
- *The current version of the Statistical Metering Board (Type 2) includes a 2x over-scale capability on current, and dispenses with peak-hold and dip-hold."* [2]

It is expected that five of the Statistical Metering Type 1 interface units will be replaced with the program for replacement of obsolete RTUs.

There will still be many other sites where the cost to replace these boards with the current standard interface without an accompanying change of primary plant will be too high. As indicated by Table 2, the population being targeted is quite small in relation to the overall population of obsolete interface modules. This is with the aim of preserving the cost savings originally achieved through replacement of the core RTU processing unit while deferring the need to perform extensive re-testing of altered field wiring.

The proposed solution is to:

- Replace four of the Type 1 boards which are considered at highest risk of problems, and which are not likely to be replaced in the short term with switchgear replacements with either the current standard interface (SICM2B) or with a Statistical Meter Type 2 board.
- Use the recovered Type 1 boards to bolster spares holdings to support the balance of remaining Type 1 boards until they are replaced by other works.
- Refresh the circuit board design of the Statistical Meter Type 2 board to enable manufacture of replacement Statistical Meter Type 2 boards, so they can be supported until they are removed from service.

Item	Quantity installed	No. of sites where is installed	Introduced	End of manufacture	Minimum age of in-service units
Statistical Metering Board Type 1 (TS100)	36	34	Early 1985	Circa 1992	23 years old
Statistical Metering Board Type 2 (SC12073)	109	88	Circa 1992	September 2006	9 years old

Table 3: Statistical Metering board details

[2] CONTROL SYSTEM ANALOGS - AN OVERVIEW document ID 93032801, 18 June 1993

Incident report reference	Title of incident report (substation & problem)	Created
SCS-2659	[redacted] incorrect MW and MVAR readings	02/12/2014 15:07
SCS-2338	[redacted] - Transformer analogues fluctuating	19/09/2014 01:06
SCS-2007	[redacted] - Abnormal Voltage Incident TR2	09/07/2014 06:23
SCS-1537	[redacted]- TR2A volts approx. 200V higher than TR2B and TR1, on closed bus.	22/04/2014 14:10

Table 4: Sample of recent recorded faults history – Faults in 2014 involving Statistical Metering Boards

3.2.2 Remove analogue Tap Position Indicator (TPI) units from service

The Voltage regulation in bulk and zone substations is primarily achieved through the setting of the ratio of the primary to secondary windings of the substation voltage transformers.

To enable automatic regulation of the voltage, and consequently compliance with the statutory regulations on voltage supplied to Energex customers, the Volt-Var Regulation (VVR) automation application needs to dynamically adjust the transformer ratio.

Effective control of this transformer ratio requires measurement of the current tap position of the transformer.

In a number of older sites, a resistive divider device (the Analogue TPI) is used to detect the current tap position. This means of detection was replaced in the standard building blocks with a digital tap position indicator design in 1981 due to issues with the Analogue TPI units.

Most Energex substation power transformers have been converted to digital TPI units through a combination of replacements and refurbishment as part of other works.

The selective replacement of Analogue TPI units with the current standard digital TPI is proposed for the sites where: the remaining service life of the transformer and the load it is servicing warrant the modification and there is a history of issues and the RTU installed is not a candidate for near-term replacement. The nominated sites are identified in Table 5, selected from the full list (Table 6) with reference to the age of transformer (Table 7). The candidate list will be reviewed as part of the project initiation works.

A number of the claims against Energex listed in the response to AER Question EGX005 Q2 “Asset failures and incidents – claims” provide an indication of the potential customer impacts from overvoltage incidents.

Site	RTU type currently installed	Affected Transformers
[redacted]	[redacted]	TR2 and TR3
[redacted]	[redacted]	TR1,TR2 and TR3
[redacted]	[redacted]	TR1 and TR2
[redacted]	[redacted]	TR1 and TR2

Table 5: List of sites proposed for replacement of analogue TPI with digital TPI

Site	RTU type currently installed	Affected Transformers	2015 10 PoE Load (MVA) Winter/ Summer[3]	Notes
[redacted]	[redacted]	TR2 and TR3	25.4/37.0	TR1 replaced 2006
[redacted]	[redacted]	TR2	24.3/24.6	
[redacted]	[redacted]	TR1 and TR2	26.0/26.4	
[redacted]	[redacted]	TR1,TR2 and TR3	19.3/29.4	
[redacted]	[redacted]	TR1 and TR2	29.9/33.9	
[redacted]	[redacted]	TR1 and TR2	15.6/20.1	
[redacted]	[redacted]	TR1 and TR2	17.8/28.1	
[redacted]	[redacted]	TR1 , TR2 and TR3	5.7/6.9	
[redacted]	[redacted]	TR1 , TR2 and TR3		The associated paper mill is closed, however future of the site is still being determined so omitted from consideration.
[redacted]	[redacted]	TR1 and TR2	-	Not included in DAPR so 10PoE not provided.

Table 6: Sites where Analogue TPI is currently installed

[3] DAPR 2014-2015 Volume 2

Site ID / Location	Slot	Plant No	Installation Date	Manufacturer	Manufactured Date	Rated Output
[redacted]	TR1	TR73018	03/05/1978	[redacted]	1966	12500
[redacted]	TR2	TR73017	03/05/1978	[redacted]	1966	12500
[redacted]	TR1	TR73267	01/01/1968	[redacted]	1968	15000
[redacted]	TR2	TR73268	01/01/1968	[redacted]	1968	15000
[redacted]	TR1	TR6237	11/11/1960	[redacted]	1960	5000
[redacted]	TR2	TR7289	11/11/1962	[redacted]	1962	5000
[redacted]	TR3	TR11762	11/11/1967	[redacted]	1967	5000
[redacted]	TR2	TR18403	11/11/1976	[redacted]	1976	12500
[redacted]	TR3	TR18402	11/11/1976	[redacted]	1976	12500
[redacted]	TR2	TR74615	19/10/1972	[redacted]	1972	12500
[redacted]	TR1	TR37572	19/12/1989	[redacted]	1989	15000
[redacted]	TR2	TR18408	11/11/1976	[redacted]	1976	12500
[redacted]	TR1	TR70121	04/05/1978	[redacted]	1965	12500
[redacted]	TR2	TR74022	04/05/1978	[redacted]	1970	12500
[redacted]	TR1	TR72730	12/04/1988	[redacted]	1964	12500
[redacted]	TR2	TR72732	06/01/1988	[redacted]	1964	12500
[redacted]	TR1	TR3125	10/08/1989	[redacted]	1949	3000
[redacted]	TR2	TR3862	11/11/1956	[redacted]	1954	3000
[redacted]	TR3	TR3257	11/11/1955	[redacted]	1950	3000
[redacted]	TR1	TR35410	30/10/1988	[redacted]	1988	15000
[redacted]	TR2	TR35411	30/11/1988	[redacted]	1988	15000
[redacted]	TR3	TR35412	10/10/1988	[redacted]	1988	15000

Table 7: Details of Power transformers where Analogue TPI is currently installed

3.2.3 Replace [redacted] RTUs in CBD Commercial & Industrial (C&I) Substations

Seven of the Energex Commercial & Industrial (C&I) substations located in the Brisbane CBD are reliant upon very old interface devices for remote monitoring and control.

These present an increasing risk failure of in-service equipment that is no longer supported and past normal in-service lifespan of 12-15 years.

The replacement of these installations with current standard SCADA interface units is proposed.

Table 8 below identifies the equipment in question and a sample of the facilities serviced by these items.

Site	Location	Date of install	Equipment Age (years)	Facility at risk	Sample of sites impacted if out of service	Ref
[redacted]	[redacted]	1996	19	[redacted]	[redacted]	5273-A4-CIO-A
[redacted]	[redacted]	1989	26	[redacted]	[redacted]	5273-A4-CIO-A
[redacted]	[redacted]	1989	26	[redacted]	[redacted]	5273-A4-CIO-A
[redacted]	[redacted]	Pre-1996	19+	[redacted]	[redacted]	5273-A4-CIO-A
[redacted]	[redacted]	1989	26	[redacted]	[redacted]	5273-A4-CIO-A

					[redacted]	
[redacted]	[redacted]	1999	16	[redacted]	[redacted]	5273-A4-CIO-A 11027-A3
[redacted]	[redacted]	Pre-1996	19+	[redacted]	[redacted]	5273-A4-CIO-A 10857-A3

Table 8: [redacted] RTUs in CBD C&I substations

3.2.4 Replace server hardware for concentrators

The Energex SCADA & automation network is very dependent on a number of central data concentrators.

In the same way that the hardware of IT servers requires refresh to mitigate in-service failures, these units should be refreshed every 5-7 years.

In order to manage the risks associated with failure of these units, replacement with current platform hardware is required.

3.2.5 [redacted] Replacements

[redacted]

[redacted]

While Energex is actively moving away from dependence on this system, the migration will take a considerable amount of time, particularly with the reduced funding available for the deployment of the IP-MPLS network. Until that migration is complete, the business function provided by these backup links is still required.

A managed replacement program of 5 units per year initially is proposed, with the number of units per year reduced to reach a balanced sustainable replacement program.

3.3 Required Replacements

The complete history of installations is not available for all of these assets and as such a reliable Repex model is unavailable. The table below summarises the justification for the replacement programs with available details of equipment performance.

Equipment	Anticipated amount in Service 2015	Anticipated amount in Service 2021	2015/20 AER program revised proposal
Statistical Metering Interface Type 1 Boards	36	32	Selective replacement to reduce number in service, recover additional spares, refresh board design or Type 2 to extend supportable lifespan.
Analogue Tap position indicator	22	13	Replacing at four sites with current standard interface where the remaining service life of the transformer and the load it is servicing warrant the modification, there is a history of issues and the RTU installed is not a candidate for near-term replacement.
[redacted]RTU CBD C&I Interface units	7	2	Replace majority with current standard interface.
Server hardware for concentrators	5 interface units (old hardware)	5 interface units (new hardware)	A managed replacement program with average of 1 unit per year.
Modem Bank Modems	28 old	25 new, 3 old	Replacement of obsolete modems with supported modems, average of 5 units per year.

Table 9: Summary of reasoning for the proposed replacement programs

4 Options

4.1 Impact of Doing Nothing

The “do nothing” option, or failure to proactively replace obsolete SCADA equipment would result in an increasing likelihood of units failing resulting in uncontrolled voltage control of Energex equipment resulting in safety, legislative and customer risks. This outcome is not tolerable to Energex, with untreated risks not considered to be As Low As Reasonably Practicable (ALARP).

Risk of the do nothing approach is quantified in the untreated risk scenarios in Table 10.

Category	Risk Scenario	Consequence	Likelihood	Risk Score
Safety	Failure of the statistical metering board causes the RTU to incorrectly increase tap settings, causing overvoltage to customers resulting in a house fire and multiple fatalities. C&I [redacted] RTU failure cause failure of substation batteries at a C&I site to remain undetected, inhibiting protection trip operations resulting in significant plant damage and multiple fatalities following a high voltage fault	6	1	6 (Low Risk)
Legislated Requirements	A failure of substation measurement equipment causes the RTU to incorrectly increase tap settings, causing an overvoltage event requiring notification reporting to the regulator	4	3	12 (Moderate Risk)
Customer Impact	A failure of substation measurement equipment causes the RTU to incorrectly increase tap settings, causing overvoltage to customers resulting in damage to customer equipment	4	3	12 (Moderate Risk)

Table 10: Untreated Risk Assessment Summary – Obsolete SCADA Equipment

4.2 Option 1 – Replace Equipment Proactively (recommended)

This option involves proactive replacement of at-risk equipment focused on continued ability to support the deployed system (ability to rapidly replace failed units) and reduction of in-service failures.

Below is noted the program for 2015/16 and the proposed program for the remaining years of the regulatory period.

Equipment	Project Subtotal	2015/16 Program	Proposed 2016/17	Proposed 2017/18	Proposed 2018/19	Proposed 2019/20
Statistical Metering Board	**$313,909**	$15,695	$31,391	$62,782	$94,173	$109,868
Analogue Tap position indicator	**$277,240**	$0	$138,620	$0	$138,620	$0
[redacted] **CBD C&I Interface units**	**$240,491**	$12,025	$24,049	$48,098	$72,147	$84,172
Server hardware for concentrators	**$125,444**	$41,815	$41,815	$41,815	$0	$0
Modem Bank Modems	**$72,806**	$24,269	$24,269	$24,269	$0	$0
Program Totals	$1,029,890	$93,804	$260,144	$176,964	$304,940	$194,040

4.3 Option 2 – Defer Works to Align with Capital Projects

4.3.1 Summary

With the expected reduced capital works for 2015-2020 compared to 2010-2015, this option would take a far longer period to deploy the modifications, resulting in progressively higher risks of increased in-service failures and consequent impacts on business costs, compliance requirements and customers.

4.3.2 Impact analysis

This option would result in a continued increase in risk to the correct operation of the SCADA & automation network as these items age.

This may result in a “spike” in unplanned asset management costs and impacts on other planned works (through redirection of resources) if left to such time as a major retrofit or expansion occurs at the site in question.

5 Proposed Works

It is proposed to implement Option 1 to in the 2015/16 – 2019/20 period under this program.

The proposed works are:

- Selective replacement of Statistical Metering Boards
- Analogue Tap position indicator removal
- Replacement of [redacted] CBD C&I Interface units
- Refresh of Server hardware for concentrators
- Replacement of Modem Bank Modems

For details of each element of the works refer to sections 3.2.1 to 3.2.5.

The following table provides a summary of the treated risks.

Category	Risk Scenario	Consequence	Likelihood	Risk Score
Safety	Failure of the statistical metering board causes the RTU to incorrectly increase tap settings, causing overvoltage to customers resulting in a house fire and multiple fatalities.	6	1	6 (Low Risk)
Legislated Requirements	A failure of substation measurement equipment causes the RTU to incorrectly increase tap settings, causing an overvoltage event requiring notification reporting to the regulator	4	1	4 (Very Low Risk)
Customer Impact	A failure of substation measurement equipment causes the RTU to incorrectly increase tap settings, causing overvoltage to customers resulting in damage to customer equipment	4	2	8 (Low Risk)

Table 11: Treated Risk Assessment Summary – Obsolete SCADA Equipment

6 Required Expenditure

Table 12 below outlines the required expenditure for the replacement program

$m, 2014/15	2015/16	2016/17	2017/18	2018/19	2019/20	Total
Energex Revised Proposal	0.1	0.2	0.2	0.3	0.2	1.0

Table 12: Replacement 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 2 – Statistical Metering Type2 Interface board installations

Site Code	Control Scheme	Interface Device No	Hardware Channel Default	Status
[redacted]	[redacted]	MB-SM1	Statistical Metering Board (new - 2 x FSC)	Commissioned Record
[redacted]	[redacted]	MB-SM1	Statistical Metering Board (new - 2 x FSC)	Commissioned Record
[redacted]	[redacted]	MB-SM1	Statistical Metering Board (new - 2 x FSC)	Commissioned Record
[redacted]	[redacted]	MB-SM1	Statistical Metering Board (new - 2 x FSC)	Commissioned Record
[redacted]	[redacted]	MB-SM2	Statistical Metering Board (new - 2 x FSC)	Commissioned Record
[redacted]	[redacted]	MB-SM1	Statistical Metering Board (new - 2 x FSC)	Commissioned Record
[redacted]	[redacted]	MB-SM1	Statistical Metering Board (new - 2 x FSC)	Commissioned Record
[redacted]	[redacted]	MB-SM2	Statistical Metering Board (new - 2 x FSC)	Commissioned Record
[redacted]	[redacted]	MB-SM1	Statistical Metering Board (new - 2 x FSC)	Commissioned Record
[redacted]	[redacted]	MB-SM2	Statistical Metering Board (new - 2 x FSC)	Commissioned Record
[redacted]	[redacted]	MB-SM1	Statistical Metering Board (new - 2 x FSC)	Commissioned Record
[redacted]	[redacted]	MB-SM1	Statistical Metering Board (new - 2 x FSC)	Commissioned Record
[redacted]	[redacted]	MB-SM1	Statistical Metering Board (new - 2 x FSC)	Commissioned Record
[redacted]	[redacted]	MB-SM1	Statistical Metering Board (new - 2 x FSC)	Commissioned Record
[redacted]	[redacted]	MB-SM1	Statistical Metering Board (new - 2 x FSC)	Commissioned Record
[redacted]	[redacted]	MB-SM1	Statistical Metering Board (new - 2 x FSC)	Commissioned Record
[redacted]	[redacted]	MB-SM1	Statistical Metering Board (new - 2 x FSC)	Commissioned Record
[redacted]	[redacted]	MB-SM1	Statistical Metering Board (new - 2 x FSC)	Commissioned Record
[redacted]	[redacted]	MB-SM1	Statistical Metering Board (new - 2 x FSC)	Commissioned Record
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[redacted]	[redacted]	MB-SM1	Statistical Metering Board (new - 2 x FSC)	Commissioned Record
[redacted]	[redacted]	MB-SM2	Statistical Metering Board (new - 2 x FSC)	Commissioned Record
[redacted]	[redacted]	MB-SM1	Statistical Metering Board (new - 2 x FSC)	Commissioned Record
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[redacted]	[redacted]	MB-SM1	Statistical Metering Board (new - 2 x FSC)	Commissioned Record
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[redacted]	[redacted]	MB-SM1	Statistical Metering Board (new - 2 x FSC)	Commissioned Record
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[redacted]	[redacted]	MB-SM2	Statistical Metering Board (new - 2 x FSC)	Commissioned Record
[redacted]	[redacted]	MB-SM1	Statistical Metering Board (new - 2 x FSC)	Commissioned Record
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[redacted]	[redacted]	MB-SM2	Statistical Metering Board (new - 2 x FSC)	Commissioned Record
[redacted]	[redacted]	MB-SM3	Statistical Metering Board (new - 2 x FSC)	Commissioned Record
[redacted]	[redacted]	MB-SM1	Statistical Metering Board (new - 2 x FSC)	Commissioned Record
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