2023-27
POWERLINK QUEENSLAND REVENUE PROPOSAL

Project Pack – PUBLIC

CP.02356
Lilyvale Transformers 3 and 4 Replacement

CP.02356 – Lilyvale Transformer 3 and 4 Replacement

Project Status: Approved

1. Network Requirement

Lilyvale Substation, located approximately 50km from Emerald, plays a critical role in the supply of electricity to customers in Queensland's Central West region, as well as the Blackwater and Bowen Basin mining areas. Two of the original three 132/66 kV transformers (T3 and T4) are now over 38 years old and are reaching the end of their technical service lives, are no longer supported by the manufacturer, and have limited spares available to rectify a failure if one were to occur.

A Condition Assessment (CA) carried out in 2019 identified that T3 and T4 are exhibiting signs of age-related deterioration, particularly by the condition of their oil and paper insulation, main tank and bushing seals as well as significant oil leaks and corrosion of external fittings[1]. The condition of Transformers 3 and 4 presents an emerging risk to the reliable and safe supply of electricity to customers at Lilyvale, and more broadly into the central west transmission zone.

Powerlink's 2019 Transmission Annual Planning Report forecasts steady peak demand in the area for the next ten years. In order to continue to meet the reliability standard within Powerlink's Transmission Authority, the services currently provided Lilyvale Substation are required for the foreseeable future to meet ongoing customer requirements. Failure to address the existing condition of these assets is likely to result in non-compliance with Powerlink's reliability and safety obligations[6].

2. Recommended Option

As this project is 'Approved', the project need and options have been assessed via a public Regulatory Investment Test for Transmission (RIT-T) consultation process[5].

The preferred option is replacement of two 132/66kV 80MVA transformers with two 160MVA transformers (and full-bay replacement of primary plant in selected bays under project CP.02340) by October 2022. Decommissioning of the remaining 80MVA transformer by December 2027. This option was preferred due to the lowest cost in NPV terms.

The following options were considered in the RIT-T process but not preferred:

- Do nothing – rejected due to non-compliance with reliability standards and safety obligations.
- Replacement of two 132/66kV 80MVA transformers with 100MVA transformers and full-bay replacement of primary plant in selected bays by October 2022. Replacement of the remaining 80MVA transformer with a 100MVA transformer by December 2027.
- No viable non-network options were identified.

The forecast risk monetisation profile of the Lilyvale T2 and T3 is shown in Figure 2-1. As the residual risk is effectively $0 following replacement of both transformers, we see from the chart that the preferred option reduces the risk monetisation by approx. $3m p.a. in 2022. These works will extend the asset life by 40 years.

Where a 'do nothing' scenario is adopted the total risk costs are projected to increase from $1.67 million in 2019 to $11.9 million in 2038. This is predominantly due to reliability of supply risks, financial risk costs associated with replacement of failed assets in an emergency, and safety risks.

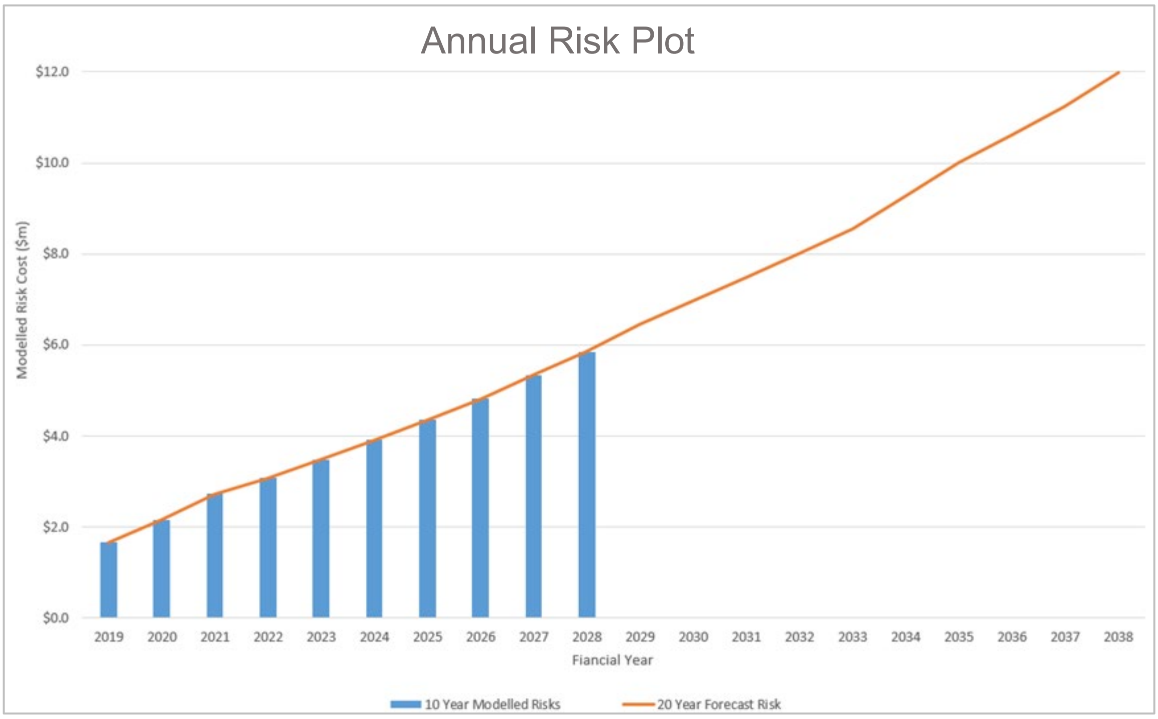

Figure 2-1 Annual Risk Monetisation Profile (Nominal)

3. Cost and Timing

The estimated cost to replace the two 132/66kV 80MVA transformers with two 160MVA transformers is $10.2m ($2018/19)[4].

Target Commissioning Date: June 2023

Note: Following detailed design and project planning, the completion of the preferred option is expected to be delayed due to network access limitations in Central Queensland. Work is continuing on reviewing the implementation strategy, but for the purposes of the Revenue Proposal we have modelled a target commission date of June 2023.

4. Documents in CP.02356 Project Pack

Public Documents

1. Transformers Condition Assessment H015 Lilyvale Substation
2. Lilyvale 132/66kV Transformer and 132kV Bay Reinvestment, Blackwater 132/66kV Transformer Reinvestment – Planning Report
3. Project Scope Report CP.02356 Lilyvale 132/66kV No 3 & 4 Transformers Replacement.
4. CP.02356 Lilyvale 132/66kV No 3 & 4 Transformers Replacement Project Management Plan at Concept Stage
5. Project Assessment Conclusions Report – Maintaining power transfer capability and reliability of supply at Lilyvale

Supporting Documents

6. Asset Reinvestment Criteria - Framework
7. Asset Management Plan 2021

Transformers Condition Assesment H015 Lilyvale Substation

Report requested by:	[redacted]	**Requested Completion Date:**	30/09/2014
Report Prepared by:	[redacted]	**Date of site visit:**	02/07/2014
AUTHOR/S:	[redacted] *Team Leader Primary Design Standards & Asset Investigations*		
Report Approved by:	[redacted] - *Manager DS&AI*	**Report Approval Date:**	16/09/2014
Report Reviewed by:	[redacted]	**Review Date:**	07/01/2016
Issue Approved by:	[redacted]	**Issue Date:**	

Date	Version	Objective ID	Nature of Change	Author	Authorisation
18/08/2014	1.0	A2050093		[redacted]	
07/01/2014	2.0	vA3359638	Small modifications	[redacted]	

IMPORTANT: - This condition assessment report provides an overview of the condition of power transformers (excluding internal transformer inspections) and high level indications of their residual reliable service life. As it is a snapshot in time and subject to the accuracy of the assessment methodology and ongoing in-service operating environment, the comments in this report are valid for 3 years from the date of the site visit stated above.

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1. SUMMARY

A thorough condition assessment was performed on all three (3) 80MVA 132/69/11kV bulk supply transformers installed at H015 Lilyvale Substation to determine their residual service life and any immediate issues that may need to be considered. No internal inspections were performed on the in-service transformers.

Although power transformer condition is monitored closely, the exact point of power transformer failure cannot be accurately predicted. As the consequences associated with catastrophic power transformer failure in electricity transmission are very high in terms of the financial costs, and potential loss of supply, impact on safety of personnel and public and on the environment (fire, gasses, oil disposal, etc.), the asset management strategy employed is to plan and execute replacement before the actual failure occurs.

This is done by assessing condition of the major transformer components and estimating their end of life as well as that of the overall transformer. As the transformer systems and components deteriorate their probabilities of failure increase leading to an increased risk cost and decreased transformer availability. While component repair or replacement may be possible, in many cases they would provide very little or no benefit with regards to the transformer probability of failure. Typically repairs would have to be performed on a number of power transformer components, whilst the major internal components (insulation, core and mechanical enforcement of internal components) cannot be repaired.

This report does not attempt to cover any detailed economic analysis of the viability of rectifying the highlighted issues associated with each transformer but provides a condition assessment of the “key” parameters for each of the three transformers and recommendations for maintenance going forwards.

Transformers T3 and T4:

Apart from having a range of oil leaks with some very significant, poor paintwork and aged oil, both transformers T3 and T4 after 34 years of service appear to have mechanically weak winding paper insulation based on the calculated average cellulose insulation DPv of 250 and 270 respectively. The DPv at the winding hot spots would be even lower by 50 points or more, effectively indicating end of reliable winding paper life. Due to the low DPv value, only minimal maintenance expenditure should be considered for these transformers going forwards in order to extract the last few years of service life, in case of insulation failure on through fault. It may be statistically possible to achieve a further 5 years of service from these transformers with only minimal oil leak attention and no oil change.

It should also be noted that the mechanical stability of the windings can’t be confirmed due to not performing transformer internal inspections but if the DPv is used as an indicator of loss of cellulose mass, there is a loose correlation with residual axial winding clamping pressure. So the calculated DPv values indicate the windings of these transformers to be mechanically weak.

At this stage, replacement of the high voltage terminal bushings is not considered necessary based on DLA/ capacitance test data. It is worthwhile noting that field DLA / capacitance field testing does not detect partial discharge activity which can be well advanced before being detectable.

Transformer T7:

Transformer T7 with 40 years of service has a more reliable average cellulose insulation DPv value of 400, a couple of oil leaks of interest, two potential holes forming towards the bottom of the main tank conservator and a tap changer which has completed close to 300,000 operations. Its paint work is however the worst with cracks appearing in the outer layer on the cooler bank 'A' frame structural supports.

If no action is taken to rectify the failure of the paint system in particular, including the conservator issue, the aging rate of the transformer will accelerate and it already appears in poor physical condition. Moisture can reside under the cracked paint surface on the cooler bank 'A' frame support structures. It would be difficult to see this transformer remaining serviceable for more than 5 years.

It is easier to justify the expense of performing more maintenance on T7 to address the poor paintwork and the oil leaks due to the calculated average cellulose insulation age of 60 percent nameplate age (less than unity aging). Theoretically this transformer's insulation system has 13 years of untapped service life but we must be mindful of other factors such as some ancillary items and fittings that will be coming up for replacement soon which will add to the cost of ownership.

If the oil leaks and paintwork were addressed and the serviceability of the tap changer ensured, it should be possible to achieve more than 5 - 10 additional years of service life from this transformer provided the additional cost of the replacement of ancillary items and fittings that will be necessary over that time are considered economical. This expectation needs to be tempered with the residual mechanical stability of the windings.

Hence it should be noted that the mechanical stability of the windings can't be confirmed due to not having performed transformer internal inspections but if the DPv is used as an indicator of loss of cellulose mass, there is a loose correlation with residual axial winding clamping pressure. So, using the calculated DPv value, the windings of this transformer would have to be considered mechanically stronger than T3 and T4.

At this stage, replacement of the high voltage terminal bushings is not considered necessary but field DLA / capacitance field testing does not detect partial discharge activity which can be well advanced before being detectable via the average insulation quality reading DLA test data.

TABLE 1

Summary of Estimated Residual Life of

Transformer T3, T4 & T7 "Key" Components

Parameter	Estimated Residual Life			Further Comments
	T3	T4	T7	
Anti-corrosion system	5 years for main tank. 5-10 years for cooler bank	10 years for main tank and cooler bank.	10 years for main tank and cooler bank.	Considered as not economic to address.
Winding paper life	3 to 5 years	5 to 7 years	10 to 13 years	Calculated Av age = 38 /36/ 27 years for T3, T4 & T7 respectively.
Winding mechanical stability	Cannot be assessed accurately, but is questionable due to design and exposure.	Cannot be assessed accurately, but is questionable due to design and exposure.	Cannot be assessed accurately, but is questionable due to design and exposure.	Old clamping structures design, lowering of DPv & moisture exchange.
External HV & LV bushings	May need replacement if and when test indicates the need. Expected to be within 5 years.	May need replacement if and when test indicates the need. Expected to be within 5 years.	May need replacement if and when test indicates the need. Expected to be within 5 years.	Bushings exceeded their expected design life.
Insulating Oil	5 to 7 years	5 to 7 years	7 to 10 years.	Assuming no big changes to in-service operating conditions.
Radiators	5 to 10 years	10+ years	10+ years	
Repairs to leaking gaskets.	Required now.	Required now.	Required now, but less oil leaks than on T3 and T4.	Many gasket leaks mean air ingress and therefore moisture exchange between air, oil and paper insulation.
Overall residual life.	**3 to 5 years**	**5 to 7 years. May need to replace bushings.**	**7 to 10 years. May need to replace bushings.** **Mechanical stability is compromised.**	**Assuming on-going maintenance as usual.**

2. INVESTIGATION:

A comprehensive on-site inspection of T3, T4 and T7 was performed on the 2nd July 2014 and the major findings which may impact their serviceability are discussed in this report. The substation Operating Diagram is shown in the figure 1. An examination was also performed on the station services transformers T5 and T6 which are connected to the 11kV tertiary windings of transformers T3 and T4 respectively.

[redacted]

Figure 1: H015 Lilyvale Substation Operating Diagram

2.1 H015 LILYVALE TRANSFORMER T3:

2.1.1 Identification Details:

Transformer T3 details are shown below. It was originally commissioned at Lilyvale substation in January 1980, in conjunction with T4.

- General Electric Co. Rocklea, Brisbane manufacturer.
- Specification C67/78
- YOM = April 1980 (34 years)
- Commissioned 1980
- 40 / 52 / 80 MVA ONAN / ONAF / ODAF
- 132 / 69 / 11 kV
- Serial No. A31K3100/2
- SAP No. 20004680
- Reinhausen OLTC counter = 150,360

2.1.2 On-Site Inspection:

Anti-corrosion System:

This transformer has obviously been repainted in the past and from a search of the available notifications, it was found necessary to revisit the transformer in 2011 to touch-up the main lid flange dome nuts. The repainted coating is badly oxidised as shown in Figure 2 and in some locations like the doors of the on-board cubicles, the paint is delamination off the original OEM coating.

Figure 2: Transformer T3 LV side of the main tank showing the oxidised repainted surfaces.

Figure 3: Transformer T3 HV side of the main tank showing paint delaminating off the cubicle doors.

The cooler bank coating is not showing oxidation to the same degree as on the main tank and some of the pipework. A number of locations on the cooler bank fan motors and mounting brackets have been coated with what appears like cold galvanising to stop local corrosion and holes developing in the end casing of the fan motors.

Whilst there were signs of some minor surface corrosion on some fittings, bolts, and flanges, the metal surface appeared to be in reasonable condition. The numerous oil leaks have probably been providing surface corrosion protection in a range of locations.

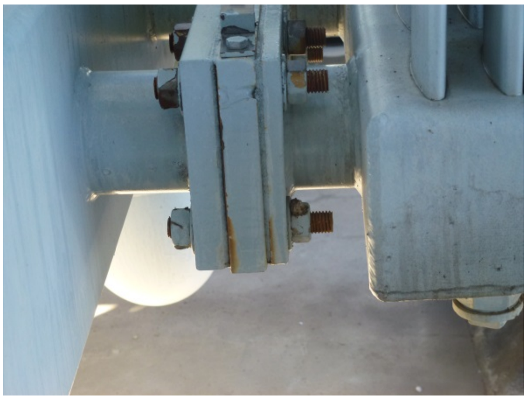


Figure 4: Typical type of minor corrosion visible on the transformer.

Figure 5: Corrosion between the mating flanges of the top main oil pipe between the main tank and the cooler bank.

Corrosion in the location shown in Figure 5 will result in another oil leak as the rust grows inwards under the gasket.

2.1.3 Structural

There were no signs of any structural issues associated with main supports for the cooler bank and main tank but what was noticed was the use of only two holding down bolts in each foot of the cooler bank 'A' Frame support structures. This must have been signed off when the transformer was installed years ago but is not compliant with current design practice.

Figure 6: Cooler bank 'A' Frame structure using only two bolts per foot pad.

No evidence indicating any structural issues related to the condition of foundations or oil containment system was noted.

Structural issues identified with the fire wall were the subject of separate investigation and are not included in this report.

2.1.4 Oil Leaks

This transformer has a welded lid to tank flange, complete with dome nuts, however, there are a number of oil leaks visible on the transformer from other locations, some small and others more significant. From 2004, field staff have tried to address / slow down a number of oil leaks according to the SAP notifications but the leaks still persist. These leaks appeared to be coming from locations such as;

- Tertiary bushings top and / or bottom gaskets,
- HV ‘C’ Phase top bushing seal,
- Oil sampling fittings / valves (ground level gas receiver)
- Valve stem seals,
- Some radiator panels and mounting flanges and / or butterfly valve seals,
- Perhaps some other hatches on the lid which were not visible while the transformer was still in service.

Figure 7: Oil leaks resulting in free oil collecting on the concrete around the main tank on the LV side as well as at the tertiary bushings end.

Figure 8: Oil leaks resulting in free oil collecting on the concrete around the main tank on the HV side.


Figure 9: Oil leaks at tertiary bushings resulting in free oil running down the end of the main tank surface and collecting on the concrete below.

With respect to the cooler bank, there are some minor oil leaks as evidenced by the oil wetness on the concrete immediately below the cooler bank but there were no continuous oil drips evident.

Figure 10: Cooler bank oil leaks around some radiator panel mounting flanges / butterfly valves.

2.1.5 Secondary Systems:

The external black PVC multi-core cables appeared to be in reasonable condition with no signs of excessive surface oxidation / cracking, however, after 34 years, the cables are sure to have taken a set and any significant cable flexing would likely create some insulation damage. The cables have also been previously painted to match the main tank colour but this paint was not designed to adhere to the outer cable PVC surface and as such, some of the paint has been progressively delaminating.

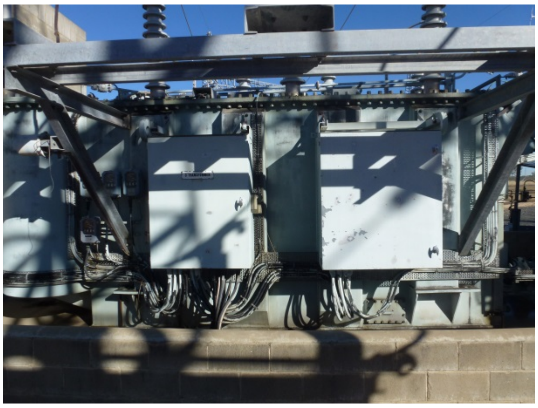



Figure 11: External cabling showing no signs of surface cracking but would have taken a set and should not be subjected to any significant flexing.

The WTIs and OTI instruments appeared to be in fairly good condition and this is possibly due to being replaced in 2011 (WTIs) and 2013 (OTI), as mentioned in the SAP notifications for this transformer.

Figure 12: Kihlstrom temperature measurement instrumentation appears to be in good condition following replacement in later years.

2.1.6 General Comments:

There appeared to be a number of fasteners used for securing items to the main tank either corroded or missing, fasteners used for items such as brackets for holding cables in place and for holding the bracket on which the WTIs are mounted on. These are fairly minor things which are often overlooked from a maintenance perspective since nothing has yet actually fallen loose.

This old transformer design uses a butterfly valve in place of a gate valve adjacent to the main tank on the bottom main oil return pipe. The butterfly valve is not considered reliable for sealing off oil against a positive oil head pressure, especially with the ‘O’ Ring seal material being 34 years old. This could be an issue if the main oil pump were to be replaced.

As mentioned above, this transformer has only one main oil pump which lowers the reliability of its ‘OD’ rating not just because of a possible pump failure (fairly rare) but because of any secondary systems component in that pump control circuitry which has no built in redundancy. This was observed in 2003 when an oil pump failure occurred.

The condition of the surge arresters is uncertain. The zinc-oxide block material does age progressively and is thermally accelerated by passing heavy discharge current. The BIL rating for the LV and TV is higher than the nominal rating in the AS/IEC standard but the BIL rating for the HV is 550kVp instead of 650kVp which means the HV insulation is very dependent on the protective characteristics of the HV surge arresters remaining as per original design.

2.1.7 Oil and Insulation Assessment:

A desktop assessment was performed on the Oil Laboratory test data for this transformer and the following information derived.

2.1.7.1 Oil Quality:

This transformer was designed just prior to Powerlink adopting conservator diaphragms (split conservator tank) in our technical specifications but it was designed and fitted with a Drycol refrigeration unit for continuously dehumidifying the air above the oil in the main conservator as well as for new air entering the conservator. This was eventually replaced with a conventional desiccant breather due to high running maintenance costs.

Figure 13: Main tank conservator original upper and lower mounting flanges for a Drycol refrigeration breather unit.

When last tested, the oil in this transformer had 1.2mg/kg PCB in oil and is therefore classified as “Non Contaminated” for being less than 2mg/kg and does not appear to have been given an oil change over its life.

It was designed just prior to Powerlink adopting conservator diaphragms (split conservator tank) in our technical specifications and therefore has survived with just a desiccant breather maintaining the dryness of the HV oil and insulation system.

The insulating oil would more than likely have been Diala ‘B’ which possessed good natural inhibitors and anti-oxidation stability. From commissioning through to about mid-life (year 2000), the DDF, resistivity and furan levels in particular progressively aged at a faster rate than what was evident from the corresponding oil acidity test results but then seemed to plateau with only marginal additional aging over the next 14 years. There is no measured data for DBPC in the oil tested for this transformer so it does not suggest this slowing down in oil aging was due to an inhibitor being added, however, the oil has aged considerably and will continue to accelerate as the insulation system absorbs more and more moisture from the atmosphere due to the significant oil leaks.

2.1.7.2 Dissolved Gas Analysis:

There are a few “stand-out” aspects to note from the oil DGA test data and they are as follows;

- The insulation mass on the active part appears to have been exposed to higher operating temperatures after about the first 4 years of service which has displayed itself by the abnormally high dissolved carbon dioxide levels.
- The dissolved oxygen levels for a free breathing transformer have remained low for virtually all of its life which would tend to suggest that chemical oxidation of the oil and insulation appears to have been significant for some time. Once the Diala ‘B’ oil’s natural inhibitors were consumed, the aging process would have become more visible.
- There appears to be an on-going OLTC diverter switch tank oil leak into the main tank causing a mildly inflated measurement of thermal gases and traces of acetylene. This is not really worth addressing on its own.

2.1.7.3 Moisture in Insulation:

The percentage of moisture in the insulation was calculated and yielded approximately 2.7% by dry weight. In reality, it may be best to consider the moisture level to be less than 3% but above 2%. This is still an acceptable figure for the insulation system of an unsealed transformer of 34 years, especially considering the transformer has a number of significant oil leaks.

2.1.8 Estimated Residual Life of Transformer:

2.1.8.1 Anti-corrosion System Life

It should be made clear up front that the paint system is not the weak link on the critical path to transformer failure in this specific case. The paper insulation condition as discussed in clause 2.1.8.2 is the most critical element on the critical path to transformer failure in this case. Therefore, one would need to carefully consider the economics of repainting which would only be an option if the significant oil leaks were first repaired.

However, if that is ignored and we consider only the paint system on its own, while the surface paint on the main transformer tank is not in good condition, there is very little rust. The original organic zinc rich primer must still be protecting the steel successfully. Assuming no oil leak repairs were performed, I am sure this transformer in its present state would survive for up to 5 years or so with only minor paint touch-ups along the way. It could be a stretch to expect to leave the transformer “as is” for another 10 years or more since the aging rate of the oil and paper insulation system will accelerate the longer the transformer is left in this state.

If the significant oil leaks were to be repaired, due to the condition of the insulation paper, it would probably not be a wise investment to consider repainting the whole transformer.

2.1.8.2 Insulation Life

Insulation age of this transformer was calculated to be approximately 38 years as shown below in Figure 14. This is slightly above its nameplate age of 34 years and supports the higher than normal dissolved carbon dioxide gas in oil levels over its service life which suggests higher bulk insulation operating temperatures over that time.

FOR CALCULATING INSULATION CHEMICAL AGE

Nameplate Age 34 **Years** **Expected Tx Life** 40 **Years**

Furan in Oil 2.37 **Ppm**

Carbon Monoxide 1150 **Ppm**

Carbon Dioxide 9250 **Ppm**

Degree of Polymerisation 250 **DPv Aged Sample**

Degree of Polymerisation 1200 **DPv Newly Commissioned**

CALCULATED INSULATION CHEMICAL AGE

FURAN	DPv	CO	CO2	
38	38	45	39	Years

SIGNS OF ACCELERATED AGING

Figure 14: Calculation of cellulose insulation age using a number of indirect indicators.

Since no actual paper samples were taken from the transformer for this assessment, the paper DP value was based on the dissolved furans in the oil. Obviously this will only give an average DPv figure since the furan data is an average of the total cellulose insulation mass. The DPv of 250 means that the winding hot spot values are likely to be less than this (around 200 or less) and other cooler parts of the windings will be perhaps around the 350 level.

The life expectancy of the transformer is only as good as the weakest link and that is definitely the winding paper in this case (ignoring any unknown winding clamping potential issues). The insulation is close to end of mechanical life and should be considered unreliable into the future.

2.1.8.3 Mechanical Life

Because there was no internal active part inspection performed, there is no way of knowing the state of the winding clamping or winding mechanical stability.

With an average DPv of 250 and even lower in critical areas such as the top ends of the windings (hot spots) where end turns can become displaced during through fault and eventually cause a winding inter-turn short or winding to core/frame short, the probability of failure must be relatively high. The only saving grace is the prospective fault level at the H015 Lilyvale 132kV Bus which is lower than what was used for the transformer design.

2.2 H015 LILYVALE TRANSFORMER T4:

2.2.1 Identification Details:

Transformer T4 details are shown below. It was originally commissioned at Lilyvale substation in January 1980, in conjunction with T3:

- General Electric Co. Rocklea, Brisbane manufacturer.
- Specification C67/78
- YOM = April 1980 (34 years)
- Commissioned 1980
- 40 / 52 / 80 MVA ONAN / ONAF / ODAF
- 132 / 69 / 11 kV
- Serial No. A31K3100/1
- SAP No. 20004681
- Reinhausen OLTC counter = 150,028

2.2.2 On-Site Inspection:

Anti-corrosion System:

This transformer has obviously been repainted in the past and from a search of the available notifications, it was found necessary to revisit the transformer in 2011 to touch-up the main lid flange dome nuts. The repainted coating is badly oxidised as shown in Figure 15.

Figure 15: Transformer T4 LV side of the main tank showing the oxidised repainted surfaces.

Whilst there were signs of some minor surface corrosion on some fittings, bolts, and flanges, the metal surface appeared to be in reasonable condition. The numerous oil leaks have probably been providing surface corrosion protection in a range of locations.

Figure 16: Typical type of minor corrosion visible on the transformer.

Figure 17: Corrosion around the flanges, valve body and PRD.

While the cooler bank paint is also oxidised with minor rusting in some locations, it is not showing oxidation to the same degree as on the main tank, pipework and conservator. A number of locations on the cooler bank fan motors and mounting brackets appear to have been coated with what appears like cold galvanising, to stop local corrosion and holes developing.

Figure 18: Cold galvanising paint applied to fan body, casings and mounting brackets.

Figure 19: Small localised corrosion on cooler bank fittings.

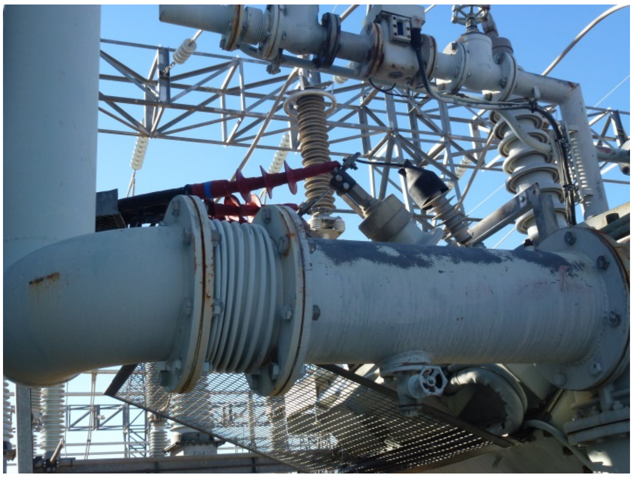


Figure 20: Small localised corrosion on main oil pipe & fittings.

Figure 21: Small localised corrosion on cooler bank fittings.

2.2.3 Structural:

There were no signs of any structural issues associated with main supports for the cooler bank and main tank but what was noticed was the use of only two holding down bolts in each foot of the cooler bank ‘A’ Frame support structures. This must have been signed off when the transformer was installed years ago but would not be our design practice these days.

There were no signs of corrosion of the jacking bolts or the ‘A’ frame base mounting plates even though grouting has been used between the base plates and the top surface of the concrete foundation.

Figure 22: Cooler bank ‘A’ Frame structure using only two bolts per foot pad.

No evidence indicating any structural issues related to the condition of foundations or oil containment system was noted.

Structural issues identified with the fire wall were the subject of a separate investigation and are not included in this report.

2.2.4 Oil Leaks:

This transformer has a welded lid to tank flange, complete with dome nuts, however, there are a number of oil leaks visible on the transformer from other locations, some small and others more significant. From 2003, field staff have tried to address / slow down a number of oil leaks according to the SAP notifications but the leaks still persist. These main leaks appeared to be coming from locations such as:

- The top of one of the Tertiary bushings,
- Oil seals on top of the transformer lid. (refer to Figure 23)
- Isolating valves,
- Some gaskets on the main tank lid which were not visible while the transformer was still in service.

Figure 23: (LH) Oil leaks coming from gaskets on top of the main tank lid were dripping from the flange bolts. (RH) Oil leaks coming from the bolts which hold the cover plate for TV bushing connection access.

Oil was also running down the tank wall in a number of locations. A typical example is shown in Figure 24 (left hand side photo).

Figure 24: (LH) Oil running down the side of the main tank. (RH) Oil was also leaking from seals around the bottom main tank isolating valve.

With respect to the cooler bank, there are some minor oil leaks as evidenced by the oil wetness on the concrete immediately below the cooler bank but there were no continuous oil drips evident.

There were minimal oil leaks on the cooler bank with only two notable traces on the concrete as shown in Figure 25. One leak immediately below the conservator desiccant breather is more likely due to oil bath spillage during maintenance of the breather rather than oil being pushed out due to rapid transformer exhalation due to rapid internal transformer temperature increase.

Figure 25: There were minimal oil leaks on the cooler bank with only two notable traces of oil on the concrete, one being due to maintenance of the breather..

2.2.5 Secondary Systems:

The external black PVC multi-core cables appeared to be in reasonable condition with no signs of excessive surface oxidation / cracking, however, after 34 years, the cables are sure to have taken a set and any significant cable flexing would likely create some insulation damage. The cables have also been previously painted to match the main tank colour but this paint was not designed to adhere to the outer cable PVC surface and as such, some of the paint has been progressively delaminating (refer to Figure 24).

Readability of the WTIs and OTI instruments appeared to be good and this is due to being replaced in more recent times.

Figure 26: Kihlstrom temperature measurement instrumentation appears to be in good condition following some replacements in later years.

2.2.6 General Comments:

This old transformer design uses a butterfly valve in place of a gate valve adjacent to the main tank on the bottom main oil return pipe. The butterfly valve is not considered reliable for sealing off oil against a positive oil head pressure, especially with the ‘O’ Ring seal material being 34 years old. This could be an issue if the main oil pump were to be replaced.

As mentioned above, this transformer has only one main oil pump which lowers the reliability of its 'OD' rating not just because of a possible pump failure (fairly rare) but because of any secondary systems component in that pump control circuitry which has no built in redundancy. This transformer has already experienced "cooling failure" issues.

There seems to have been many issues associated with the cooling system on this transformer from early 2000s onwards. These have comprised cooler fail alarms, abnormal WTI operation or failure, replacement of faulty cooling fans, etc. Some of these ancillary items, which have not already been replaced under maintenance, may have reached the end of serviceable life.

The condition of the surge arresters is uncertain. The zinc-oxide block material does age progressively and is thermally accelerated by passing heavy discharge current. The BIL rating for the LV and TV is higher than the nominal rating in the AS/IEC standard but the BIL rating for the HV is 550kVp instead of 650kVp which means the HV insulation is very dependent on the protective characteristics of the HV surge arresters remaining as per original design.

2.2.7 Oil and Insulation Assessment:

A desktop assessment was performed on the Oil Laboratory test data for this transformer and the following information derived.

2.2.7.1 Oil Quality:

When last tested, the oil in this transformer had 0.2mg/kg PCB in oil and is therefore classified as "Non Contaminated" for being less than 2mg/kg and does not appear to have been given an oil change over its life.

This transformer was designed just prior to Powerlink adopting conservator diaphragms (split conservator tank) in our technical specifications but it was designed and fitted with a Drycol refrigeration unit for continuously dehumidifying the air above the oil in the main conservator as well as for new air entering the conservator. This was eventually replaced with a conventional desiccant breather due to high running maintenance costs.

The insulating oil would more than likely have been Diala 'B' which possessed good natural inhibitors and anti-oxidation stability. From commissioning through to about mid-life, the DDF, resistivity and furan levels in particular progressively aged at a faster rate than what was evident from the corresponding oil acidity test results but then seemed to plateau with only marginal additional aging over the next 14 years. There is no measured data for DBPC in the oil tested for this transformer so it does not suggest this slowing down in oil aging was due to an inhibitor being added, however, the oil has aged considerably and will continue to accelerate as the insulation system absorbs more and more moisture from the atmosphere due to the significant oil leaks.

2.2.7.2 Dissolved Gas Analysis:

There are a few "stand-out" aspects to note from the oil DGA test data and they are as follows:

- The insulation mass on the active part appears to have been exposed to higher operating temperatures which has displayed itself by the abnormally high dissolved carbon dioxide levels.
- The dissolved oxygen levels for a free breathing transformer have remained low for virtually all of its life which would tend to suggest that chemical oxidation of the oil and insulation appears to have been

significant for some time. Once the Diala 'B' oil's natural inhibitors were consumed, the aging process would have become more visible.

- There appears to be the on-going OLTC diverter switch tank oil leak into the main tank causing a mildly inflated measurement of thermal gases and traces of acetylene. This is not really worth addressing on its own.

2.2.7.3 Moisture in Insulation:

The percentage of moisture in the insulation was calculated and yielded approximately 2.7% by dry weight. In reality, it may be best to consider the moisture level to be less than 3% but above 2%. This is still an acceptable figure for the insulation system of an unsealed transformer of 34 years, especially considering the transformer has a number of significant oil leaks.

2.2.8 Estimated Residual Life of Transformer:

2.2.8.1 Anti-corrosion System Life

It should be made clear up front that the paint system is not the weak link on the critical path to transformer failure in this specific case. The paper insulation condition as discussed in clause 2.2.8.2 is the most critical element on the critical path to transformer failure in this case. Therefore, one would need to carefully consider the economics of repainting which would only be an option if the significant oil leaks were first repaired.

However, if that is ignored and we consider only the paint system on its own, while the surface paint on the main transformer tank is not in good condition, there is very little rust. The original organic zinc rich primer must still be protecting the steel successfully. Assuming no oil leak repairs were performed, I am sure from a corrosion point of view that this transformer in its present state would survive for perhaps 5 years or so with only minor paint touch-ups along the way. It could be a stretch to expect to leave the transformer "as is" for another 10 years or more since the aging rate of the oil and paper insulation system will accelerate the longer the transformer is left in this state.

If the significant oil leaks were to be repaired, due to the condition of the insulation paper, it would probably not be a wise investment to consider repainting the whole transformer.

2.2.8.2 Insulation Life

Insulation age of this transformer was calculated to be approximately 36 years as shown below in Figure 27. This is slightly above (but not too bad) its nameplate age of 34 years and supports the higher than normal dissolved carbon dioxide gas in oil levels over its service life which suggests higher bulk insulation operating temperatures over that time.

FOR CALCULATING INSULATION CHEMICAL AGE

Nameplate Age	34	Years	Expected Tx Life	40	Years
Furan in Oil	1.81	ppm			
Carbon Monoxide	1030	ppm			
Carbon Dioxide	7750	ppm			
Degree of Polymerisation	270	DPv Aged Sample			
Degree of Polymerisation	1200	DPv Newly Commissioned			

CALCULATED INSULATION CHEMICAL AGE

FURAN	DPv	CO	CO2	
36	36	43	36	Years

SIGNS OF ACCELERATED AGING

Figure 27: Calculation of cellulose insulation age using a number of indirect indicators.

Since no actual paper samples were taken from the transformer for this assessment, a paper DP value was calculated based on the dissolved furans in the oil. Obviously this will only give an average DPv figure since the furan data is an average of the total cellulose insulation mass. The DPv of 270 means that the winding hot spot values are likely to be less than this (around 200 or less) and other cooler parts of the windings will be perhaps around the 370 level.

The life expectancy of the transformer is only as good as the weakest link and that is considered to be the winding paper in this case (ignoring any unknown winding clamping potential issues). The insulation is close to end of mechanical life and should be considered unreliable into the future.

2.2.8.3 Mechanical Life

Because there was no internal active part inspection performed, there is no way of knowing the state of the winding clamping or winding mechanical stability.

With an average DPv of 270 and even lower in critical areas such as the top ends of the windings (hot spots) where end turns can become displaced during through fault and eventually cause a winding inter-turn short or winding to core/frame short, the probability of failure must be fairly high. The only saving grace is the prospective fault level at the H015 Lilyvale 132kV Bus is lower than what was used for the transformer design.

2.3 H015 LILYVALE TRANSFORMER T7:

2.3.1 Identification Details:

Transformer T7 details are shown below. It was originally commissioned at T023 Rockhampton in 1974 and later relocated to H015 Lilyvale in October 2000.

- English Electric Co. Rocklea, Brisbane manufacturer.
- Specification 708/72
- YOM = July 1974 (40 years)
- Commissioned 1974
- 40 / 52 / 80 MVA ONAN / ONAF / ODAF
- 132 / 69 / 11 kV
- Serial No. A31D4412/1
- SAP No. 20006433
- Reinhausen OLTC counter = 288,599

2.3.2 On-Site Inspection:

Anti-corrosion System:

From first appearances, even though this transformer has obviously been repainted in the past and given touch-ups over time, it appears more run down than its neighbouring T3 & T4, with much more minor distributed surface & fitting corrosion and badly oxidised paint. Extensive cracking in the paint surface was also noticed on the cooler bank ‘A’ frame support structures. This is going to allow captive water pools under the paint to progress corrosion more quickly. This could be expected as it is 6 years older that T3 & T4. Overall, the cooler bank paintwork appeared just as oxidised or worse (cracking in particular locations) than the main tank paint.

Figure 28: (LH) Transformer T7 LV side of the main tank showing the oxidised repainted surfaces. (RH) Surface paint cracking on the cooler bank support structure.

Corrosion in the area of the main tank / lid flanges has previously required the cleaning and recoating with a cold galvanising paint, as shown in Figure 28 & 29. The cold galvanising paint has been applied in a few locations around the transformer as required over time.

Figure 29: The dark strip around the tank / lid flange area is cold galvanising paint to combat the local corrosion.

Figure 30: (LH) Tap changer end showing oxidised paint. (RH) Surface corrosion of weld on TV tank extension. Note also the cold galvanising on the welded lid strap.

It was difficult to accurately determine but there were signs of corrosion on the underside of the main tank conservator which appeared to be the start of two future perforations. Refer to Figure 31 (RH) photo.

Figure 31: (LH) Corrosion of welded tank/lid strap. (RH) Corrosion on the bottom of the conservator appears like two holes forming.

There was visible surface corrosion of the fan motor housings. Maintenance records reveal that there has been fan motor bearing iussues identified in 2004. This could indicate that these old “birds wing” fans are close to their end of reliable life, depending on how often they are needed to operate.

Figure 32: (LH) Corrosion of the fan motor housings. (RH) Corrosion on cable trays.

2.3.3 Structural:

There were no signs of any structural issues associated with main supports for the cooler bank and main tank at this stage but what was noticed was the use of only two holding down bolts in each foot of the cooler bank 'A' Frame support structures. This must have been signed off when the transformer was installed years ago but would not be our design practice these days.

There were no signs of corrosion of the jacking bolts or the 'A' frame base mounting plates even though grouting has been used between the base plates and the top surface of the concrete foundation.

No evidence indicating any structural issues related to the condition of foundations or oil containment system was noted.

Structural issues identified with the fire wall were the subject of separate investigation and are not included in this report.

Figure 33: Cooler bank 'A' Frame structure using only two bolts per foot pad. No visible corrosion

2.3.4 Oil Leaks:

This transformer has a welded lid to tank flange, complete with dome nuts. While this transformer did have some visible signs of oil leaks, they could be classified as relatively minor in comparison to the leaks on adjacent T3 & T4 transformers. From a general overview, there was only one area on the main tank LV side wall where oil residue was tracking down the side from the lid. This is shown in Figure 34. The leak could be coming from the lid flange dome nut seals or the 'B' phase LV bushing flange seal.

Figure 34: Oil run noticed on the LV side of the transformer main tank.

There were minimal oil leaks on the cooler bank with only two notable traces on the concrete as shown in Figure 33.

Figure 35: Relatively few oil leaks noticed on the concrete foundation.

The only one significant oil leak was from the lower main butterfly isolating valve adjacent to the main tank. (Refer to Figures 35). From about 2002, field staff tried to address some previously “bad” oil leaks and also other minor oil leaks and this seems to have been reasonably effective.

The oil leaks appeared to be coming from locations such as;

- Over the welded lid strap in front of the ‘A’ & ‘B’ phase HV bushings.
- Lower main butterfly valve adjacent to the main tank.
- Radiator panel.
- The OLTC conservator oil level sight glass gasket.
- Perhaps some gaskets on the main tank lid which were not visible while the transformer was still in service.

Figure 36: (LH) Oil leak from the lower main butterfly isolating valve adjacent to the main tank, and (RH) from OLTC conservator breather oil bath.

With respect to the cooler bank, there were only a few minor oil leaks as evidenced by the oil wetness on the concrete immediately below the cooler bank but there were no continuous oil drips evident.

2.3.5 Secondary Systems:

The external black painted PVC multi-core cables appeared well aged but still serviceable so long as they are not physically disturbed since after 40 years, the cables are sure to have taken a set and any significant cable flexing would likely create some insulation damage / cracking. Refer to Figure 37.

Figure 37: The painted multicore cables are looking aged but still serviceable.

While there have been some minor issues associated with the Kihlstrom temperature measurement instrumentation, their readability of the WTIs and OTI instruments appeared to be reasonable.

Figure 38: Kihlstrom temperature measurement instrumentation appears to still be readable and functioning.

The main control cubicle was inspected for signs of potential issues but all appeared as expected, with only some minor corrosion around the door sealing lip on the lower edge of the cubicle. There were signs of some recent wiring additions to an otherwise old but clean installation. The replacement of any secondary system components if ever they fail should be fairly straight forward with more modern equivalent items (e.g. old mechanical phase failure relay visible in Figure 39, RH side photo) .

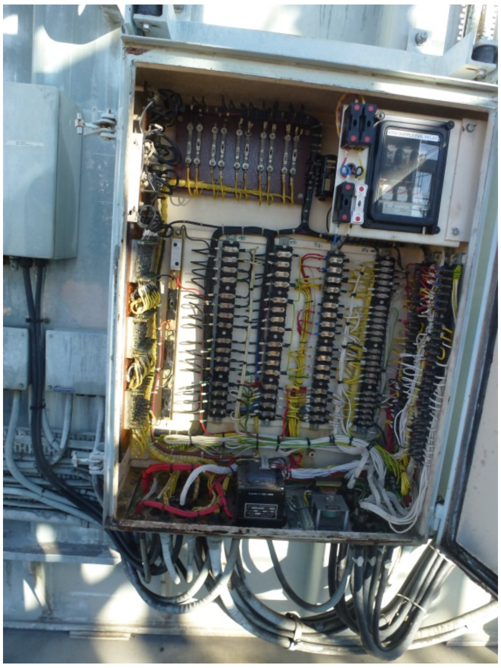


Figure 39: Main Control Cubicle control panel and wiring.

2.3.6 General Comments:

This old transformer design uses a butterfly valve in place of a gate valve adjacent to the main tank on the bottom main oil return pipe. The butterfly valve is not considered reliable for sealing off oil against a positive oil head pressure, especially with the 'O' Ring seal material being 40 years old. This could be an issue if the main oil pump were to be replaced.

As mentioned above, this transformer has only one main oil pump which lowers the reliability of its 'OD' rating not just because of a possible pump failure (fairly rare) but because of any secondary systems component in that pump control circuitry which has no built in redundancy. Some of these ancillary items which have not already been replaced under maintenance may have reached close to end of serviceable life.

The condition of the surge arresters is uncertain. The zinc-oxide block material does age progressively and is thermally accelerated by passing heavy discharge current. The BIL rating for the LV and TV is higher than the nominal rating in the AS/IEC standard but the BIL rating for the HV is 550kVp instead of 650kVp which means the HV insulation is very dependent on the protective characteristics of the HV surge arresters remaining as per original design.

The HV bushings appear to be old Micafil type and if they are the original bushings supplied with the transformer, they will not be reliable for the long term future.

2.3.7 Oil and Insulation Assessment:

A desktop assessment was performed on the Oil Laboratory test data for this transformer and the following information derived.

2.3.7.1 Oil Quality:

When last tested, the oil in this transformer had 4.4mg/kg PCB in oil and is therefore classified as "Contaminated" for being over 2mg/kg.

This transformer was designed prior to Powerlink adopting conservator diaphragms (split conservator tank) in our technical specifications but it was designed and fitted with a Drycol refrigeration unit for continuously dehumidifying the air above the oil in the main conservator as well as for new air entering the conservator. Powerlink's notifications indicate that the Drycol was eventually removed in October 2009, however, Ergon have indicated that T7 was fitted with a conservator bag in the year 2000 as part of its relocation to Lilyvale and this is reflected in the low dissolved oxygen levels in the oil.

The insulating oil would more than likely have been Diala 'B' which possessed good natural inhibitors and anti-oxidation stability. Even with the oil processing that would have been performed as part of the transformer relocation from Rockhampton to Lilyvale substation, the oil aging rate appears to have been fairly similar to that of the Lilyvale transformers T3 & T4 of the same design, with the exception of the dissolved furan level in the oil being about one fifth that of T3 and T4.

Our Oil Laboratory database indicates that this transformer has had passivator added to the oil and the level is still within acceptable limits.

2.3.7.2 Dissolved Gas Analysis:

There are a few "stand-out" aspects to note from the oil DGA test data and they are as follows;

- Since being relocated to Lilyvale, there have been periods where the insulation mass on the active part appears to have been exposed to higher operating temperatures which has displayed itself by the abnormally high dissolved carbon dioxide levels.
- The point in time when the conservator was modified from a Dry Keep system to a conservator air cell is clearly discernible from the dissolved oxygen / nitrogen levels in the oil.
- There appears to be the on-going OLTC diverter switch tank oil leak into the main tank causing a mildly inflated measurement of thermal gases and traces of acetylene. This is not really worth addressing on its own.

2.3.7.3 Moisture in Insulation:

The percentage of moisture in the insulation was calculated and yielded approximately 2.7% by dry weight. In reality, it may be best to consider the moisture level to be less than 3% but above 2%. This is still an acceptable figure for the insulation system of a 40 year old transformer but in this case, was certainly due to being commissioned with a "Dry Keep" unit on the conservator and later having a main tank conservator bag installed after removing the Dry Keep unit. (Refer to clause 2.3.7.1).

2.3.8 Estimated Residual Life of Transformer:

2.3.8.1 Anti-corrosion System Life

This transformer does look in worse physically condition than Lilyvale T3 and T4 based on paint condition and surface corrosion aspects. While this transformer is 40 years old, the winding paper insulation is in reasonable condition for its age and the paper aging rate is slower than for an unsealed transformer so therefore it may be still possible to justify spending money for a thorough repaint if this transformer were to be kept for several more years. This ignores any potential winding stability issues that may exist.

2.3.8.2 Insulation Life

Insulation age of this transformer was calculated to be approximately 27 years as shown below in Figure 40. This is below its nameplate age of 40 years and supports the use of sealed insulation systems on transformers. While the DPv of the winding paper insulation is in better mechanical condition than the Lilyvale T3 and T4 transformers, it should not be ignored when analysing its future life expectancy.

FOR CALCULATING INSULATION CHEMICAL AGE

Nameplate Age	40	Years	Expected Tx Life	40	Years
Furan in Oil	0.588	ppm			
Carbon Monoxide	1070	ppm			
Carbon Dioxide	6960	ppm			
Degree of Polymerisation	400	DPv Aged Sample			
Degree of Polymerisation	1200	DPv Newly Commissioned			

CALCULATED INSULATION CHEMICAL AGE

FURAN	DPv	CO	CO2	
27	27	43	35	Years

SIGNS OF ACCELERATED AGING

Figure 40: Calculation of cellulose insulation age using a number of indirect indicators.

Since no actual paper samples were taken from the transformer for this assessment, the paper DP value was based on the dissolved furans in the oil.

Obviously this will only give an average DPv figure since the furan data is an average of the total cellulose insulation mass. The DPv of 400 means that the winding hot spot values are likely to be less than this (around 300 or less) and other cooler parts of the windings will be perhaps around the 550 level.

2.3.8.3 Mechanical Life

Because there was no internal active part inspection performed, there is no way of knowing the state of the winding clamping or winding mechanical stability.

With an average DPv of 400 and even allowing for less in critical areas such as the top ends of the windings (hot spots), there is slightly less chance of inter-turn shorts due to better paper mechanical strength but if winding stability is poor, there can be no stopping winding end turns becoming displaced during a significant through fault and eventually cause a winding inter-turn short or winding to core/frame short. The only saving grace is the prospective fault level at the H015 Lilyvale 132kV Bus is lower than what was used for the transformer design.

3.0 CONCLUSION:

3.1 Condition Assessment

The following conclusions can be drawn from the condition assessment of these three transformers at Lilyvale substation.

Oil Leaks:

In terms of oil leaks, T3 is the worst, followed by T4 and then T7.

External Physical Condition:

As would be expected due to its calendar age, T7 is in the worst physical condition, with T3 and T4 being fairly similar but slightly better than T7.

Insulation Residual Life:

The transformer with the most residual insulation life is T7, followed by T4 and then T3.

Winding Mechanical Stability:

This could not be analysed as no internal inspections were performed. If the average DPv (based on dissolved furans) were to be used as a “loose” indicator of loss of insulation mass and hence loss of axial winding clamping pressure, then T7 would be the most stable, followed by T4 and then T3. This obviously is ignoring the severity and frequency of through faults that may have occurred. Hence the term “loose” indicator.

Transformer Bushings:

These transformers were originally fitted with Micafil terminal bushings. No condition assessment was performed on the bushings as part of this condition assessment, however, they should be getting tested routinely for DLA / capacitance as per the requirements of Powerlink’s transformer maintenance policy and any suspected defects raised at that time.

For reference, manufacturers indicate that such bushings have an expected design life of 25 to 30 years as shown in Figure 41. The relative ages of all three transformers are shown below and all exceed the design life by 4 - 10 years.

- Transformer T3 = 34 years old.
- Transformer T4 = 34 years old.
- Transformer T7 = 40 years old.

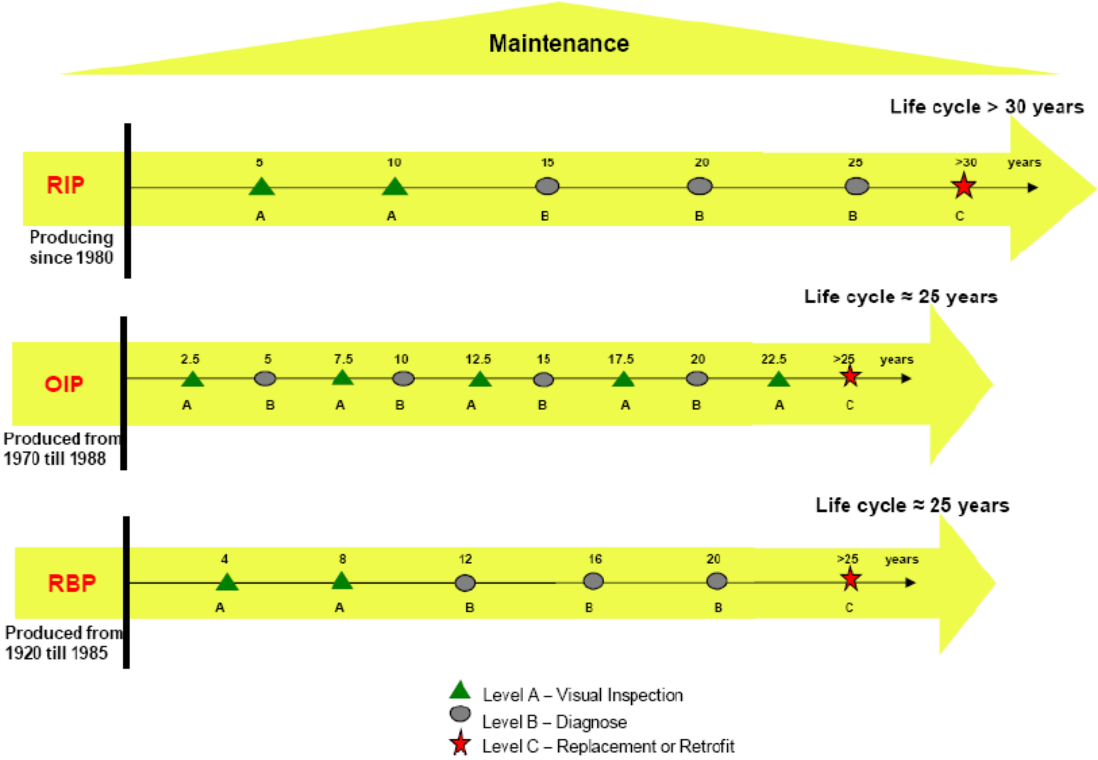
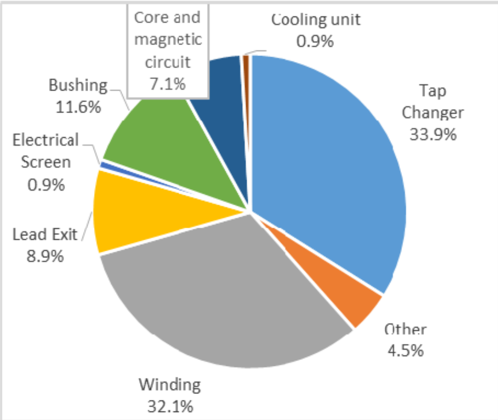
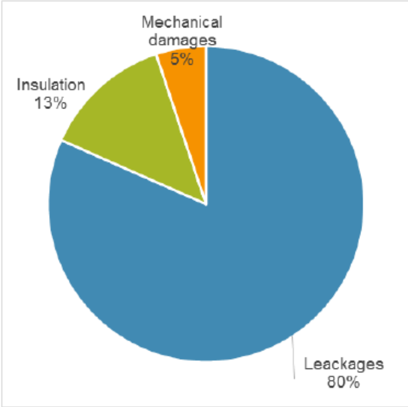


Figure 41: Relative high voltage bushing design life.

Bushing failures can represent approximately 12% of transformer failures but out of this 12%, only 13% is from insulation failure and 80% is from breathing to atmosphere. Refer to Figure 42. The remainder is due to mechanical damage. This means that only about 1.6% of transformer failures are due to the failure of HV bushing insulation. The oil leaks noted around bushing turrets appeared to be coming from gaskets on the main tank side and not from actual HV or LV bushing gaskets so it would appear that the bushings have a low probability of insulation failure and with scheduled periodic field testing for DLA and capacitance, pending bushing insulation failure should be detectable prior to complete insulation failure.



Root causes of transformer failures in German speaking Europe btw. 2000 and 2010 (source: Tenbohlen et. al)



Root causes for overhaul or replacement of a transformer bushing; own data

Figure 42: Transformer failure causes.

3.2 Maintenance Going Forwards:

3.2.1 Transformer T3:

The main issues for transformer T3 going forwards are the more significant oil leaks, the fairly low winding paper insulation DPv, the surface paint which really could do with repainting if the protective oil leaks were stopped and the oil quality which is indicating that the oil will need attention if the transformer was to be kept in service for more than another 5 years.

While the transformer could do with repainting, there could be issues with achieving proper bonding with the parent paintwork if the oil leaks are not addressed first and the parent paint chemically cleaned to fully remove absorbed oil.

The economics of spending over one hundred thousand dollars to fix the serious oil leaks and repaint the transformer which has a low average cellulose insulation DPv of 250 is questionable. To mitigate the financial loss if the transformer insulation should fail in the near future, the transformer could have the serious oil leaks fixed without repainting to reduce the costs. The paint system as is would still maintain the transformer in a serviceable condition for another 5 years at which time the residual transformer life could be reassessed.

It should also be noted that the mechanical stability of the windings can't be confirmed but if the DPv is used as an indicator of loss of cellulose mass, there is a loose correlation with residual axial winding clamping pressure. So if the calculated DPv value is used, ignoring through fault history, transformer T3 would be considered the weakest.

3.2.2 Transformer T4:

The main issues for transformer T4 going forwards are very similar to that of T3. They include oil leaks but not quite as bad as for T3, the fairly low winding paper insulation DPv, the surface paint which requires repainting if the protective oil leaks were stopped and the oil quality which is indicating that the oil will need some attention if the transformer was to be kept in service for more than another 5 years.

Again, while the paint system does need redoing, there could be issues with achieving proper bonding with the parent paintwork if the oil leaks are not addressed first and the parent paint is chemically cleaned to fully remove absorbed oil.

As stated for T3, The economics of spending over one hundred thousand dollars to fix the serious oil leaks and repaint T4 transformer which also has a low average cellulose insulation DPv of 270 is questionable. To mitigate the financial loss if the transformer insulation should fail in the near future, the same approach as concluded for T3 could be considered for T4 where the transformer could have the serious oil leaks fixed without repainting to reduce the costs. The paint system as is would still maintain the transformer in a serviceable condition for another 5 years at which time the residual transformer life could be reassessed.

As for T3, it should also be noted that the mechanical stability of the windings can't be confirmed but if the DPv is used as an indicator of loss of cellulose mass, there is a loose correlation with residual axial winding clamping pressure. So if the calculated DPv value is used and the through fault history ignored, transformer T4 would be considered marginally stronger than T3 but not by much.

3.2.3 Transformer T7:

The main issues for transformer T7 going forwards are slightly different than for T3 and T4. They only include two oil leaks of significance, two holes developing on the bottom of the main tank conservator, the physical condition and paint system of the transformer, a tap changer which has completed nearly 300,000 operations and the poor condition of a number of external fittings and ancillary items on the transformer. The average cellulose insulation DPv of 400 suggests that this transformer has a greater residual insulation life than T3 and T4 which both displayed an average DPv of 250 and 270 respectively. In fact, it has theoretically 13 years of unused insulation life due to a less than unity ageing rate (0.67 times).

As for T3 and T4, it should also be noted that the mechanical stability of the windings can't be confirmed but if the DPv is used as an indicator of loss of cellulose mass, there is a loose correlation with residual axial winding clamping pressure. So using the calculated DPv value and ignoring through fault history, transformer T7 would be considered the strongest out of all three transformers.

It is easier to justify spending more money on T7 to address the poor paintwork, the couple of oil leaks, ensure serviceability of the tap changer and address the holes developing in the conservator due to the calculated extra years of residual insulation life and perceived better winding mechanical stability, however, some ancillary items and fittings will be coming up for replacement soon which will add to the cost.

If these items were address, it should be possible to achieve a further 5 years of service life at which time the residual transformer life could be reassessed.

Technology and Planning – Network Planning

November 2018

Lilyvale 132/66kV Transformer and 132kV Bay Reinvestment

Blackwater 132/66kV Transformer Reinvestment

Planning Report

Prepared by: Grid Planning

Table of Contents

1 Executive summary

Powerlink has reviewed the condition of assets located at Lilyvale and Blackwater substations. 132/66kV transformers at Blackwater and Lilyvale substations and 132kV primary plant at Lilyvale substation have been identified as approaching end of technical life and reinvestment will be required by 2022 to maintain supply reliability to the Central West Queensland zone.

This planning report assesses the enduring need for the functionality provided by the assets under consideration and, where enduring need is established, provides options which will meet the network need. Each option has been evaluated based on their impact on system strength, contributions to maximum fault levels, headroom to accommodate load growth and the level of non-network support which would be required to enable them. Where non-network support would be required to enable a particular option, high level analysis has been carried out to guide potential providers. Operating envelopes of non-network solutions will be confirmed as part of the RIT-T process.

Summary of planning report findings

- There is an enduring need for 132/66kV transformation at Lilyvale and Blackwater substations.
- There is potential to convert each substation from a three to a two transformer site.
- To avoid the need for non-network support across all modelled load growth scenarios, both substations would require two 160MVA transformers or three transformers (maintaining the current configuration at each substation).
- There is an enduring need for the three 132kV feeders between Lilyvale and Blackwater substations.
- If economic, reconfiguration of Lilyvale substation would to the meet the following criteria:
  - If the existing bypass bus is abandoned and the functionality is not replaced, Feeder 7150 and Feeder 7153 are to be located on different buses to ensure that a bus outage does not interrupt supply to Clermont
  - At least once source of 132/66kV transformation is connected to a different bus than the other source(s).
  - At least one of the 132kV feeders to Blackwater is connected to a different bus than the other feeder(s).
  - The existing 275/132kV transformers are connected to different buses to ensure 275kV injection during a 132kV bus outage/contingency.

2 Background

Lilyvale Substation:

Lilyvale Substation is a major transmission connection point in the Central West zone, supplying residential, mining and Aurizon loads via the 132kV and 66kV network. The substation consists of 275kV, 132kV and 66kV (Energy Queensland) switchyards. The substation hosts two 275/132kV transformers and three 132/66kV transformers, and facilitates the connection of two 275kV feeders and six 132kV feeders (refer to Appendix A).

A 132kV transfer bus is connected between Feeder 7150 (Lilyvale to Dysart tee Norwich Park and Bundoora) and Feeder 7153 (Lilyvale to Clermont). The bus is utilised under outages of the Feeder 7153 circuit breaker (CB71532) to ensure supply to the Clermont and Longreach areas, and for outages of the feeder 7150 circuit breaker (CB71502) to maintain system security in the Northern Bowen Basin.

A condition assessment of the substation assets has identified that the three 132/66kV transformers and items of 132kV primary plant are approaching end of technical life and will require reinvestment by 2022. Failure to address these condition issues will result in reduced reliability and increased unsupplied energy in the central west zone. Table 1 shows the affected assets and reinvestment need dates.

Table 1 - Lilyvale substation reinvestment need timings

Lilyvale	
Transformers	Need date
3T	2022
4T	2022
7T	2022
Primary plant	Need date
1T	2021
2T	2021
3T	2021
Feeder 7310	2021
Feeder 789	2021
Feeder 7150	2021
Feeder 7153	2021

Blackwater Substation:

Blackwater Substation provides supply to residential, mining and Aurizon rail traction sites via the Powerlink 132kV and Energy Queensland 66kV networks. The substation consists of 132kV and 66kV (Energy Queensland) switchyards. The substation hosts three 132/66kV transformers and facilitates the connection of seven 132kV feeders (refer to Appendix A).

A condition assessment of the substation assets has identified that two of the 132/66kV transformers are approaching end of technical life and will require reinvestment by 2022. Failure to address these condition issues will result in reduced reliability and increased unsupplied energy in the central west zone. Table 2 shows the affected assets and reinvestment need dates.

Table 2 - Blackwater substation reinvestment need timings

Blackwater	
Transformers	Need date
1T	2022
2T	2022

One line diagrams and aerial views of Lilyvale substation and Blackwater substation can be found in Appendix A.

Supply between substations

132kV feeders 789, 7310 and 7311 facilitate power flow between Lilyvale and Blackwater substations. Flow is predominantly in the direction from Lilyvale to Blackwater. The primary plant at Lilyvale which relates to Feeder 789 and Feeder 7310 has condition issues which need to be addressed by 2021. Table 3 shows the thermal ratings of the three transmission lines.

Table 3 - F789, F7310 and F7311 thermal ratings

Feeder	Normal Rating (MVA)	Emergency Rating (MVA)
789	130.94	156.88
7310	140.15	164.32
7311	136.85	162.85

Geographical Overview

Figure 1 shows the Central West transmission system. The main 275kV transmission backbone (Nebo, Broadsound and Stanwell) facilitates power flow from central to southern Queensland. The 132kV inland network runs in parallel. Lilyvale Substation facilitates 275kV injection into the Powerlink 132kV and Energy Queensland 132kV and 66kV networks. This region of the network hosts a large quantity of generation including increasing levels of renewable and embedded generation. Powerlink's new Bundoora Substation, located on Feeder 7150 between Lilyvale and Dysart substations will be energised in 2018 to facilitate the connection of Lilyvale Solar Farm. Omitted from this diagram is the parallel 66kV network from Lilyvale to Blackwater, supplying Emerald and Comet substations. The Lilyvale 66kV bus is the connection point for German Creek and Oaky Creek non-scheduled generators (waste coal mine gas).

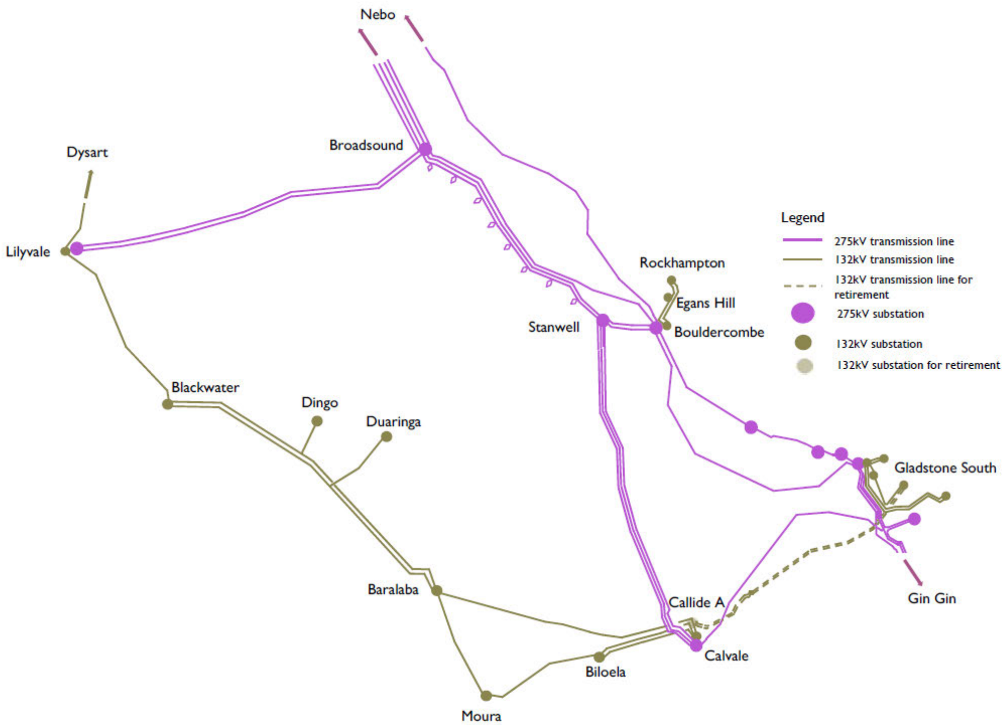


Figure 1 - Central west transmission network

3 Load Forecast and Future Supply Requirements

3.1 Lilyvale and Blackwater 66kV

As shown in Figure 2, the native 66kV load at Blackwater and Lilyvale substations is expected to increase to 113MW and 129MW respectively during the outlook period (to 2027/28).

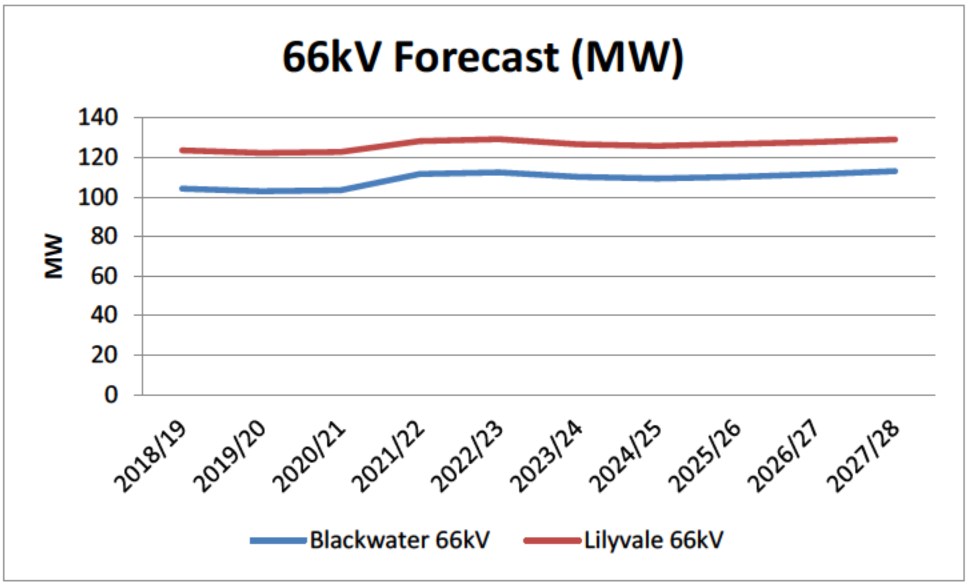


Figure 2 - Blackwater and Lilyvale 66kV forecast to 2027/28

3.2 Embedded generation and renewable energy connections

Non-scheduled embedded generation affects the peak demand and delivered energy at Lilyvale and Blackwater substations. Table 4 shows the existing embedded generation in the 66kV network and metered outputs in 2016/17 (the most recent financial year for which complete data is available).

Table 4 - Embedded generation

Generator	Peak Output 2016/17 (MW)	Delivered Energy 2016/17 (MWh)
German Creek	41.86	300071.48
Oakey Creek	19.47	120284.78

Emerald Solar Farm is committed and is scheduled to be operational in 2018. The solar farm will be connected to Ergon's 66kV network between Lilyvale and Blackwater. It is likely that further renewable generation will commit in the central west zone within the outlook period. The effect of renewable generation on peak demand at Lilyvale and Blackwater substations will need to be monitored however delivered energy at each substation is likely to decrease.

Figure 3 and Figure 4 show the 66kV load duration curves at Lilyvale and Blackwater substations for the financial years 2014/15 to 2016/17. Peak demand and delivered energy at both substations have decreased over this period.

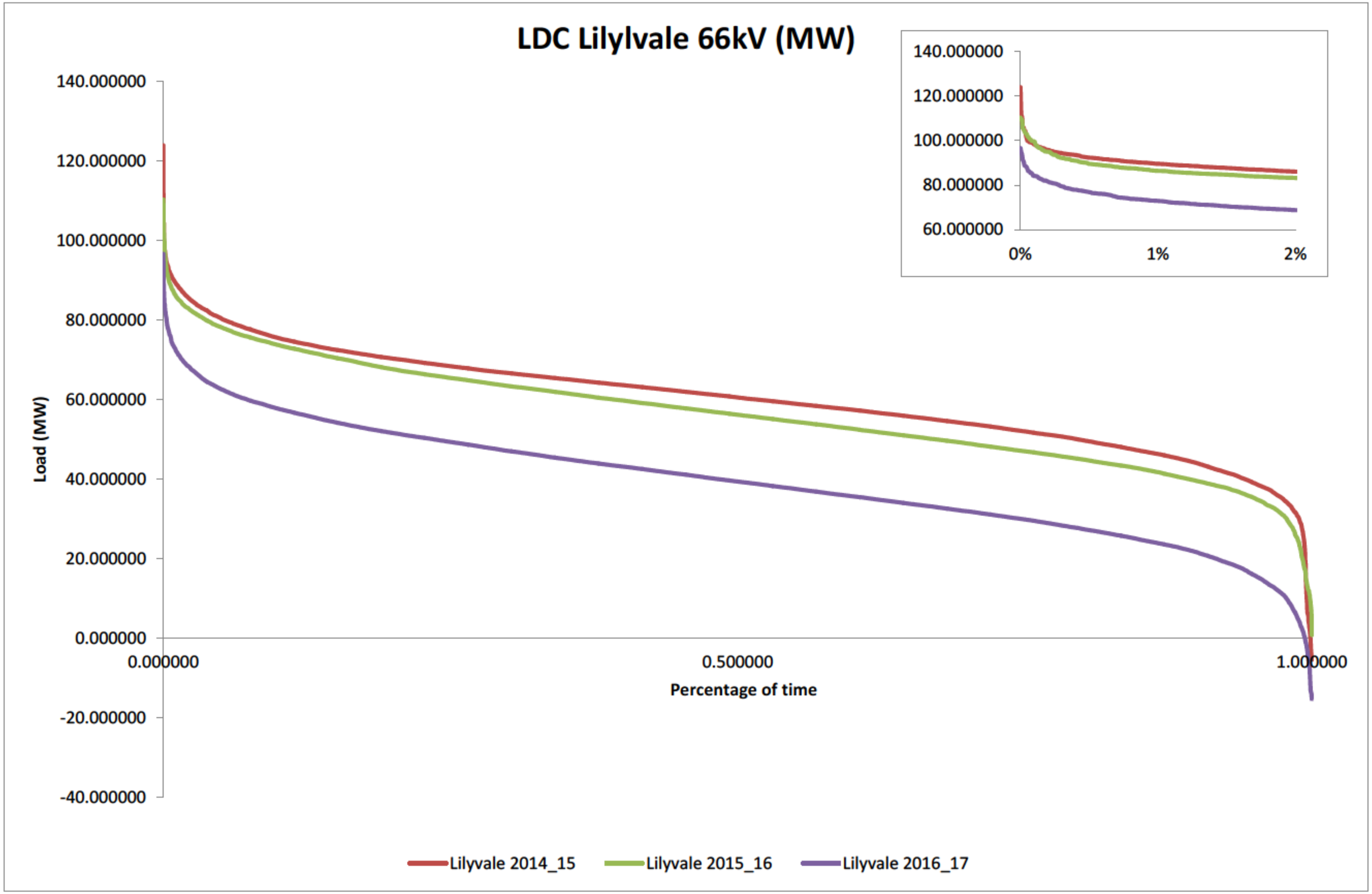


Figure 3 - Load Duration Curve (LDC), Lilyvale 66kV

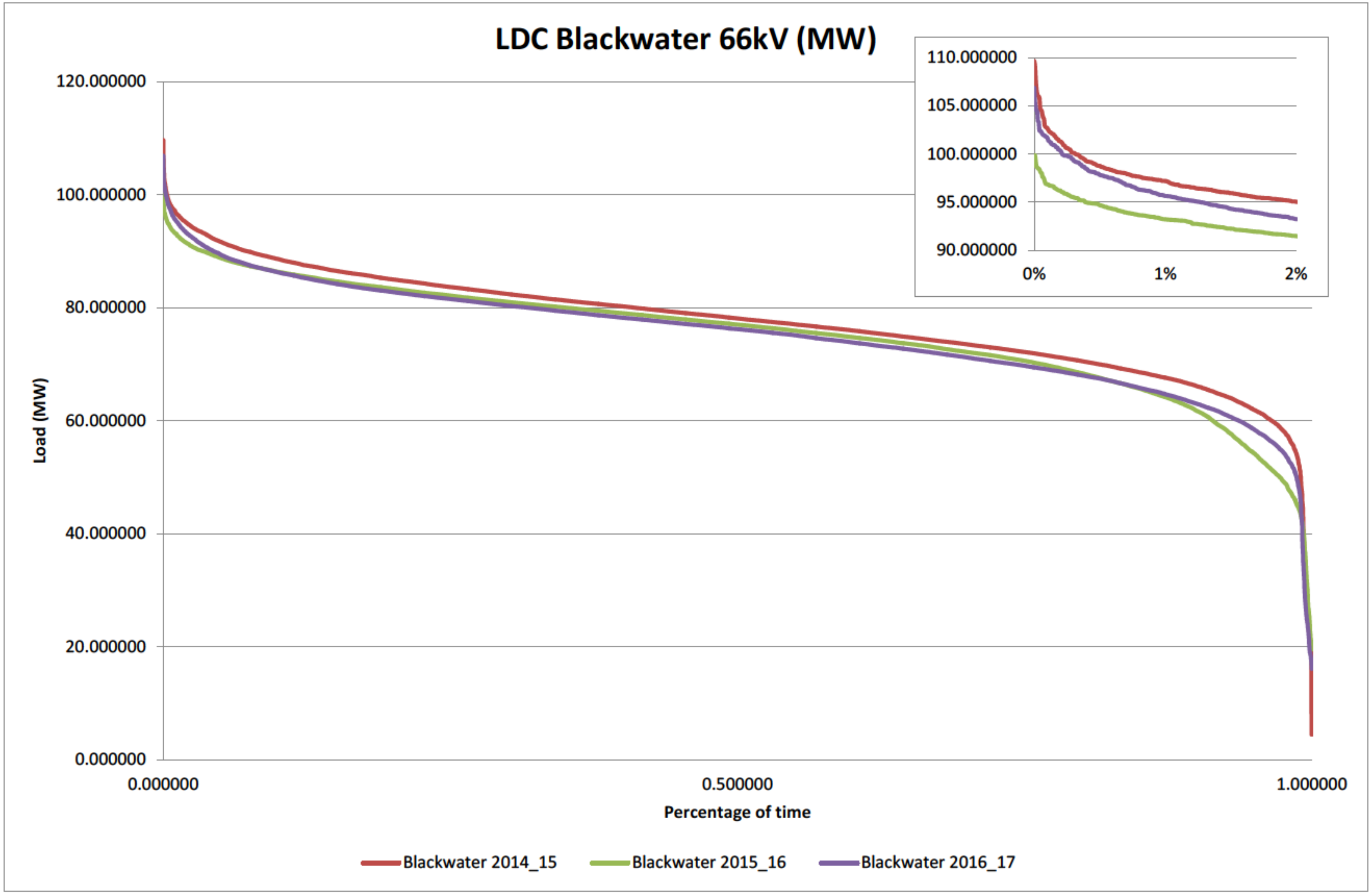


Figure 4 - Load Duration Curve (LDC), Blackwater 66kV

3.3 132kV flow between Lilyvale and Blackwater

Lilyvale and Blackwater substations are connected via three 132kV feeders and a parallel 66kV Ergon network which supplies Emerald and Comet substations. Figure 5 shows the total load (66kV and 132kV) forecast at each substation in the outlook period (to 2027/28). The total load at Lilyvale and Blackwater substations is expected to increase by 3% and 7% respectively.

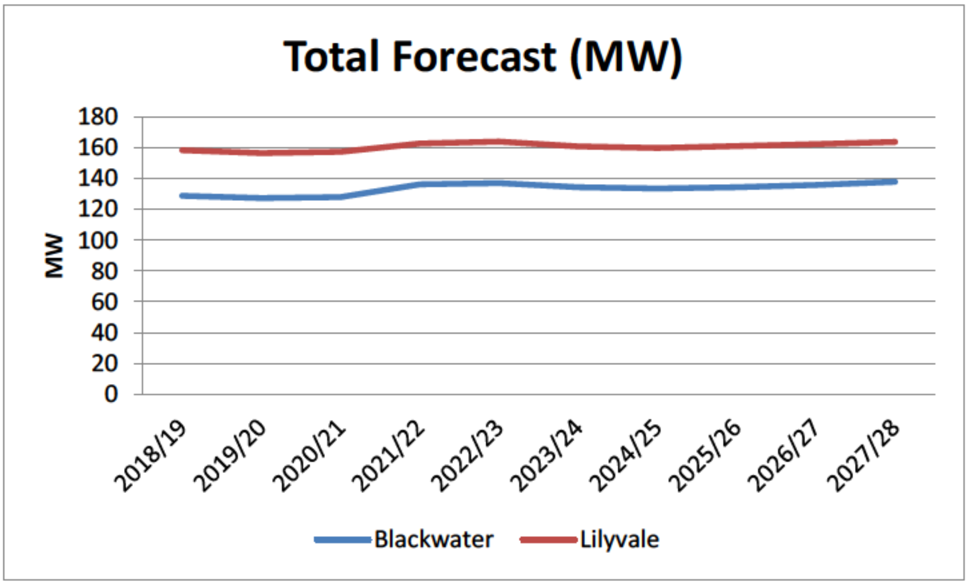


Figure 5 - Blackwater and Lilyvale 132kV and 66kV forecast to 2027/28

There are three 132kV feeders between Lilyvale and Blackwater substations. Figure 6 shows that flow between Lilyvale and Blackwater substations peaked at 216MVA in the 2017/18 financial year. If one of the 132kV feeders (Feeder 789 or Feeder 7310) is retired, this level of flow could not be supported on one feeder if a contingency occurs. There would be periods during which load would need to be shed system intact to reduce flows to an acceptable level which would violate Powerlink's Transmission Authority.

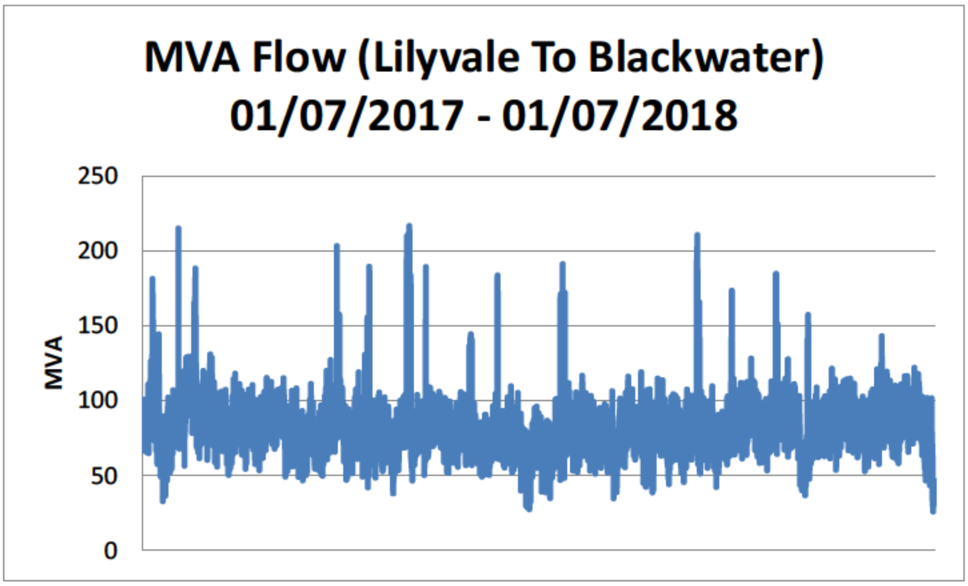


Figure 6 - MVA flow between Lilyvale and Blackwater

F7113 from Baralaba to Blackwater is scheduled to be decommissioned in 2018/19 at which time power flow from Lilyvale towards Blackwater is expected to increase, and support from Baralaba will decrease.

There is an enduring need for Feeder 789 and Feeder 7310 and reinvestment in the related primary plant at Lilyvale is required.

4 Proposed Options to Address the Identified Need

4.1 132/66kV Lilyvale Transformers

Condition assessments undertaken by Powerlink Asset Strategies have identified that all three 132/66kV 80MVA transformers at Lilyvale Substation will reach end of life by 2022.

Planning studies have shown that there is an enduring need for the functionality provided by these transformers; i.e. the need to provide reliable 66kV supply to the Lilyvale and Blackwater region.

Identified options that meet the network need include:

- **Option 1 – three 132/66kV transformers**
  1a) 3 x 80MVA
  1b) 3 x 100MVA
- **Option 2 – two 132/66kV transformers**
  2a) 2 x 80MVA
  2b) 2 x 100MVA
  2c) 2 x 160MVA
- **Option 3 – one 132/66kV transformer**
  3a) 1 x 160MVA

These options have been assessed based on their impact on system strength, contributions to maximum fault levels, headroom to accommodate load growth and the level of non-network support which would be required to enable them under different load growth scenarios.

4.1.1 System Strength - Minimum and Available Fault Levels

Under AEMO's System Strength Impact Assessment Guidelines, system strength is measured by the available synchronous fault level at a connection point. This measure is referred to as Available Fault Level (AFL). In general, a reduction in AFL at Lilyvale 66kV (and/or Blackwater 66kV) will reduce the amount of non-synchronous (renewable) generation that can be hosted in the 66kV network between Lilyvale and Blackwater without project specific system strength remediation.

Emerald Solar Farm is committed and will connect to the 66kV network between Blackwater and Lilyvale in 2018/19. Changes in AFL at the Lilyvale and Blackwater 66kV buses will be reflected at Emerald Solar Farm. The selection of a transformer option at Lilyvale that results in a negative AFL at Emerald Solar Farm would impact the operation and compliance of the solar farm. A positive AFL would need to be reinstated by a network or non-network solution.

The existing AFL at Emerald Solar Farm is ~70 MVA (system intact) and ~55MVA (during a single contingency). Table 5 shows the modelled AFL on the Lilyvale 66kV bus and the Emerald Solar Farm 66kV connection point for the different Lilyvale transformer options.

Table 5 – AFL, Lilyvale 66kV

Lilyvale 66kV Transformers	Lilyvale 66kV AFL		Mt Emerald 66kV AFL	
	System Intact	Single Contingency	System Intact	Single Contingency
Existing	473.43	378.17	68.08	55.84
3x100MVA	495.25	388.96	69.84	57.46
2x80MVA	411.22	281.41	62.99	49.32
2x100MVA	441.09	316.71	65.48	53.43
2x160MVA	513.16	396.16	71.36	58.87
1x160MVA	424.63	-17.38	64.11	-74.40

Installation of a single 160MVA transformer at Lilyvale substation would require a network or non-network solution to raise the AFL at Lilyvale 66kV and Emerald Solar Farm to above 0MVA.

Changes to generation and network configuration will affect system strength calculations. The process used to assess AFL is relatively new and is still evolving. Consequently, exact requirements will be confirmed with non-network proponents during the RIT-T process and these figures should only be used as a guide.

4.1.2 Maximum Fault Levels

Lilyvale 66kV bus is rated for a maximum fault current of 13.1kA. When reinvesting in primary plant at Lilyvale 132kV, Powerlink must consider the Energy Queensland primary plant fault current limits. Table 6 shows the modelled maximum fault levels for the different Lilyvale transformer options.

Table 6 - Maximum fault levels, Lilyvale 66kV

Option	Transformer Arrangement	Maximum fault levels	
		3 phase	L-G
1a	3 x 80MVA	9155.74	11420.97
1b	3 x 100MVA	10813.33	13939.53
2a	2 x 80MVA	7453.16	9062.35
2b	2 x 100MVA	9083.8	11451.66
2c	2 x 160MVA	10722.25	13665.3
3	1 x 160MVA	7776.23	9522.04

Option 1b and Option 2c will likely increase the fault level above the maximum fault level rating. Should either of these options be selected, there will likely be a need for a current limiting device such as a Neutral Earthing Resistor (NER) or Neutral Earthing Reactor (NEX) to be installed with the transformers to restrict the line to ground fault current.

The need to do work on Energy Queensland's network due to increased 66kV fault levels, and costed options to perform this work, will be confirmed through joint planning.

4.1.3 Headroom

Table 7 shows the headroom each of the Lilyvale transformer options would yield, using the peak 2016/17 66kV load at Lilyvale (96.65MW) and the load growth scenarios which were developed using Powerlink's 2018 TAPR connection point forecasts.

Table 7 - Headroom, Lilyvale 66kV

				Capacity - Forecast		
Option	Transformer Arrangement	N-1 Capacity (MW)	N-1 Headroom to 2016/17 Peak	Headroom (Low Forecast - 95MW)	Headroom (Medium Forecast - 105MW)	Headroom (High Forecast - 145MW)
1a	3 x 80MVA	152	57%	60%	45%	5%
1b	3 x 100MVA	190	97%	100%	81%	31%
2a	2 x 80MVA	76	-21%	-20%	-28%	-48%
2b	2 x 100MVA	95	-2%	0%	-10%	-34%
2c	2 x 160MVA	152	57%	60%	45%	5%
3	1 x 160MVA	0	N/A	N/A	N/A	N/A

4.1.4 Non network support

Table 8 indicates the amount of non-network support that would be required at Lilyvale substation to enable each of the Lilyvale transformer options, for each of the three load growth scenarios which were developed using Powerlink's 2018 TAPR connection point forecasts.

Table 8 - Non-network support requirements, Lilyvale 66kV

		Non-network (Low forecast)		Non-network (Medium forecast)		Non-network (High forecast)	
Option	Transformer Arrangement	MW	MWh	MW	MWh	MW	MWh
1a	3 x 80MVA						
1b	3 x 100MVA						
2a	2 x 80MVA					35	725
2b	2 x 100MVA					15	250
2c	2 x 160MVA						
3	1 x 160MVA	70	1675	80	1850	110	2575

These levels of non-network support would restrict load at risk for a single contingency to a maximum of 50MW and energy at risk for a single contingency to a maximum of 600MWh, therefore satisfying Powerlink N-1-50MW/600MWh reliability standard. The exact operating envelope for a non-network solution will be confirmed with non-network proponents during the RIT-T process and these figures should only be used as a guide. Non-network solutions may include, but are not limited to local generation or demand side management initiatives in the area, and would be required to be available on a firm basis.

4.2 132kV Lilyvale Substation Arrangement

4.2.1 Clermont bypass bus

A bypass arrangement exists between 132kV feeders 7150 (Lilyvale to Dysart Tee Norwich Park and Bundoora) and 7153 (Lilyvale to Clermont). This is used predominantly by Energy Queensland to maintain supply to Clermont during outages of the feeder 7153 circuit breaker. Energy Queensland (Ergon) has confirmed that there is an enduring need for the functionality provided by this bypass bus. The existing configuration of the bypass bus is shown in Figure 7.

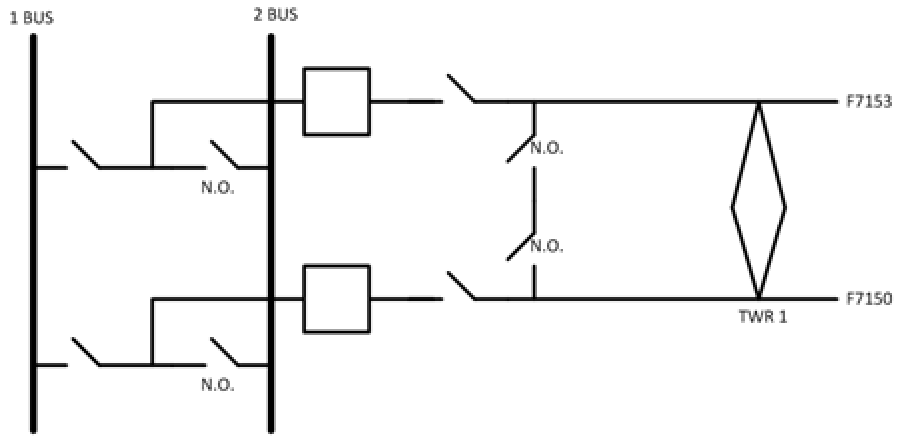


Figure 7 - Clermont bypass, Lilyvale substation

The Connection of Lilyvale Solar Farm to F7150 at Bundoora Substation will result in a system normal four ended configuration which will result in increased operational and protection complexities. The situation will be further complicated when the bypass bus is in operation because this will result in a five ended feeder. The five ended feeder connects three separate customers: Aurizon at Norwich Park, Lilyvale Solar Farm and Energy Queensland at Clermont.

To maintain the functionality of the bypass arrangement, the following options have been identified:

- Maintaining the current configuration
- Double breaker Bay for Feeder 7153
- Bypass bus using a Blackwater feeder.

Maintaining the current configuration, allows for reliable supply and flexibility for the Clermont and Dysart feeder. However to utilise the bypass bus, a short outage is required to transfer the load. Additionally a complex control and protection system is required to ensure the five ended configuration is adequately protected.

A double breaker arrangement similar to Feeder 7188 Gin Gin to Korenan tee would provide online load transfer and reduce operational complexity. This comes at the additional cost of a 132kV bay and circuit breaker. These costs would have to be agreed to by Energy Queensland.

Alternatively, the 132kV yard could be reconfigured to facilitate the bypass using one of the feeders from Lilyvale to Blackwater. This would reduce the operational complexity and maintain current supply arrangements and ongoing costs. To realise this option, extensive reconfiguration of the incoming feeders, including re-arrangement of the towers/poles, may be required.

4.2.2 Lilyvale 132kV bus arrangement

The Lilyvale 132kV bus is configured in a disconnector selectable arrangement. Whilst the disconnector selectable arrangement provides greater operational flexibility and increased reliability to radial loads at Clermont and Gregory, it comes at the cost of additional isolators and greater complexity with secondary system design and maintenance.

In addition to being economic, a reconfiguration of Lilyvale Substation would need to ensure that:

- If the existing bypass bus is abandoned and the functionality is not replaced, Feeder 7150 and Feeder 7153 are located on different buses to ensure that a bus outage does not interrupt supply to Clermont.
- At least one source of 132/66kV transformation is connected to a different bus than the other source(s).
- At least one of the 132kV feeders to Blackwater is connected to a different bus than the other feeder(s).
- The existing 275/132kV transformers are connected to different buses to ensure 275kV injection during a 132kV bus outage/contingency.

4.3 132/66kV Blackwater Transformers

Condition assessments undertaken by Powerlink Asset Strategies have identified that both 132/66kV 80MVA transformers at Blackwater substation, and associated station supply transformers, will reach end of technical life by 2022. 132/66kV 160MVA transformer 7T at Blackwater Substation has no condition issues and will be retained.

Operationally only two of the three transformers on site are loaded at any time. Due to instability of the 66kV Energy Queensland Bus Zone Relay, 2T is normally not energised in order to reduce the 66kV fault level and stabilise protection. Following a contingency of either 1T or 7T, 2T is energised which guarantees that a minimum of 160MVA of 132/66kV transformation is in service.

Planning studies have shown that there is an enduring need for the functionality provided by these transformers; i.e. the need to provide reliable 66kV supply to the Lilyvale and Blackwater region.

Identified (including the existing 160MVA transformer) options to meet the need are:

- **Option 1 – three 132/66kV transformers**
  1a) 2 x 80MVA, 1 x 160MVA
  1b) 2 x 100MVA, 1 x 160MVA
- **Option 2 – two 132/66kV transformers**
  2a) 1 x 80MVA, 1 x 160MVA
  2b) 1 x 100MVA, 1 x 160MVA
  2c) 2 x 160MVA
- **Option 3 – one 132/66kV transformer**
  3a) 1 x 160MVA

These options have been assessed based on their impact on system strength, contributions to maximum fault levels, headroom to accommodate load growth and the level of non-network support which would be required to enable them.

4.3.1 System Strength – Minimum and Available Fault Levels:

Under AEMO's System Strength Impact Assessment Guidelines, system strength is measured by the available synchronous fault level at a connection point. This measure is referred to as Available Fault Level (AFL). In general, a reduction in AFL at Lilyvale (and/or Blackwater) will reduce the amount of non-synchronous (renewable) generation that can be accommodated in the 66kV network between Lilyvale and Blackwater without project specific system strength remediation.

Emerald Solar Farm is connected to the 66kV network between Blackwater and Lilyvale. Changes in AFL at the Lilyvale and Blackwater 66kV buses will be reflected at Emerald Solar Farm. The selection of a transformer option for Blackwater substation that results in a negative AFL would impact the operation and compliance of the solar farm. A positive AFL would need to be reinstated by a network or non-network solution.

The existing AFL at Blackwater 66kV is ~430 MVA. Table 9 shows the modelled AFL on the Blackwater 66kV bus for each Blackwater transformer reinvestment option:

Table 9 – AFL, Blackwater 66kV

Blackwater 66kV Transformers	Blackwater 66kV AFL		Mt Emerald 66kV AFL	
	System Intact	Single Contingency	System Intact	Single Contingency
Existing	431.28	295.30	68.08	55.84
2x100MVA, 1x160MVA	433.90	293.88	68.31	56.04
1x80MVA, 1x160MVA	418.55	297.63	67.14	55.04
1x100MVA, 1x160MVA	421.66	297.52	67.36	55.22
2x160MVA	432.35	294.86	68.17	55.91
1x160MVA	390.20	44.54	65.41	-7.62

Installation of a single 160MVA transformer at Blackwater substation would require a network or non-network solution to raise the AFL at Lilyvale 66kV and Emerald Solar Farm to 0MVA.

Changes to generation and network configuration will affect system strength calculations. The process used to assess AFL is relatively new and is still evolving. Consequently, exact requirements will be confirmed with non-network proponents during the RIT-T process and these figures should only be used as a guide.

4.3.2 Maximum Fault Levels:

Blackwater 66kV bus is rated for a maximum fault current of 10kA. When reinvesting in primary plant at Blackwater 132kV, Powerlink must consider the Energy Queensland primary plant fault current limits. Table 10 shows the modelled maximum fault levels for the different transformer reinvestment options.

Table 10 - Maximum fault levels, Blackwater 66kV

Option	Transformer Arrangement	Maximum fault levels	
		3 phase	L-G
1a	2 x 80MVA, 1 x 160MVA	7134.05	9371.01
1b	2 x 100MVA, 1 x 160MVA	7561.51	10088.87
2a	1 x 80MVA, 1 x 160MVA	6473.83	8370.12
2b	1 x 100MVA, 1 x 160MVA	6801.41	8894.16
2c	2 x 160MVA	7201.92	9474.85
3	1 x 160MVA	5493.62	6965.86

Option 1b will likely increase the fault level above the maximum fault level rating. Should this option be selected, there will likely be a need for a current limiting device such as a Neutral Earthing Resistor (NER) or Neutral Earthing Reactor (NEX) to be installed with the transformers to restrict the line to ground fault current.

It is possible that Energy Queensland will have to upgrade the 66kV Bus Zone protection due to the increased fault levels associated with larger capacity transformers (Option 1b).

The need to do work on Energy Queensland's network due to increased 66kV fault levels, and costed solutions, will be confirmed through joint planning.

4.3.3 Headroom

Table 11 shows the headroom each Blackwater transformer option would provide, using the peak 2016/17 66kV load at Blackwater (107MW) and the load growth scenarios which were developed using Powerlink's 2018 TAPR connection point forecasts.

Table 11 - Headroom, Blackwater 66kV

				N-1 Headroom to forecast		
Option	Transformer Arrangement	N-1 Capacity (MW)	N-1 Headroom to 2016/17 Peak	Headroom (Low Forecast - 105MW)	Headroom (Medium Forecast - 120MW)	Headroom (High Forecast - 160MW)
1a	2 x 80MVA, 1 x 160MVA	152	42%	45%	27%	-5%
1b	2 x 100MVA, 1 x 160MVA	190	78%	81%	58%	19%
2a	1 x 80MVA, 1 x 160MVA	76	-29%	-28%	-37%	-53%
2b	1 x 100MVA, 1 x 160MVA	95	-11%	-10%	-21%	-41%
2c	2 x 160MVA	152	42%	45%	27%	-5%
3	1 x 160MVA	0	N/A	N/A	N/A	N/A

4.3.4 Non-network support

Table 12 indicates the amount of non-network support that would be required at Blackwater Substation to enable each of the Blackwater transformer options, for each of the three load growth scenarios which were developed using Powerlink's 2018 TAPR connection point forecasts.

Table 12 - Non-network support, Blackwater 66kV

		Non-network (Low forecast)		Non-network (Medium forecast)		Non-network (High forecast)	
Option	Transformer Arrangement	MW	MWh	MW	MWh	MW	MWh
1a	2 x 80MVA, 1 x 160MVA						
1b	2 x 100MVA, 1 x 160MVA						
2a	1 x 80MVA, 1 x 160MVA	20	350	30	650	65	1500
2b	1 x 100MVA, 1 x 160MVA			10	175	50	1025
2c	2 x 160MVA						
3	1 x 160MVA	95	2200	105	2500	145	3350

These levels of non-network support would restrict load at risk for a single contingency to a maximum of 50MW and energy at risk for a single contingency to a maximum of 600MWh, therefore satisfying Powerlink N-1-50MW/600MWh reliability standard. The exact operating envelope for a non-network solution will be confirmed with non-network proponents during the RIT-T process and these figures should only be used as a guide. Non-network solutions may include, but are not limited to local generation or demand side management initiatives in the area, and would be required to be available on a firm basis.

5 Summary of Options

The matrices below show how well each option meets against the assessed criteria. Also included is an assessment of whether operational flexibility (the ability to schedule outages for maintenance) is affected.

The traffic light assessment was carried out using the following criteria:

	Increase / maintain	Reduce by up to 20%	Reduce by >20%
Future renewable generation			
	>0MVA	<0MVA	
AFL for committed renewables			
	< Bay Rating	> Bay Rating	
Maximum Fault Level			
	>40%	20%-40%	<20%
N-1 Headroom (Medium Forecast)			
	No	Yes	
NNS Required (Medium Forecast)			
	Maintained	Reduced	
Operational Flexibility			

5.1.1 Lilyvale substation

	Lilyvale 132/66kV transformer arrangement					
	3x80MVA	3x100MVA	2x80MVA	2x100MVA	2x160MVA	1x160MVA
Future renewable generation						
AFL for committed renewables						
Maximum Fault Level						
Headroom / N-1						
NNS Required						
Operational Flexibility						

5.1.2 Blackwater substation

	Blackwater 132/66kV transformer arrangement					
	2x80MVA 1x160MVA	2x100MVA 1x160MVA	1x80MVA 1x160MVA	1x100MVA 1x160MVA	2x160MVA	1x160MVA
Future renewable generation						
AFL for committed renewables						
Maximum Fault Level						
Headroom / N-1						
NNS Required						
Operational Flexibility						

6 Conclusion

Powerlink has reviewed the condition of assets located at Lilyvale and Blackwater substations. 132/66kV transformers at Blackwater and Lilyvale substations and 132kV primary plant at Lilyvale Substation have been identified as approaching end of technical life and reinvestment will be required by 2022 to maintain reliability and supply to the Central West Queensland zone.

The key findings of this report are:

- There is potential to convert each substation from a three to a two transformer site.
- To avoid the need for non-network support across all modelled load growth scenarios, both substations would require two 160MVA transformers or three transformers (maintaining the current configuration at each substation).
- There is an enduring need for the three 132kV feeders between Lilyvale and Blackwater.
- If economic, reconfiguration of Lilyvale substation would need to the meet the following criteria:
  - If the existing bypass bus is abandoned and the functionality is not replaced, Feeder 7150 and Feeder 7153 are located on different buses to ensure that a bus outage does not interrupt supply to Clermont
  - At least once source of 132/66kV transformation is connected to a different bus than the other source(s).
  - At least one of the 132kV feeders to Blackwater is connected to a different bus than the other feeder(s).
  - The existing 275/132kV transformers are connected to different buses to ensure 275kV injection during a 132kV bus outage/contingency.

All of the options presented (some of which require non-network support) will meet the network need; i.e. maintaining reliable supply to the Lilyvale and Blackwater area. Economic analysis will determine Powerlink's proposed option.

Levels of non-network support and AFL remediation will be confirmed with non-network proponents as the RIT-T progresses.

7 References

1. A3359638 – *" Transformer Condition Assessment H015 Lilyvale Substation"*
2. A2371191 – *"Transformer T1 & T2 Condition Assessment T032 Blackwater Substation"*
3. A2837427 – *"Condition Assessment Report Lilyvale – H015"*
4. 2017 – *Powerlink Transmission Annual Planning Report*
5. *AEMO – System Strength Impact Assessment Guidelines – V0.1, 5 March 2018 "For Consultation"*

8 Appendix A

[redacted]

[redacted]

PSS®E System Diagram:

[redacted]

Project Scope Report

CP.02356

Lilyvale 132/66kV No 3 & 4 Transformers Replacement

Concept Estimate - Version 3

Document Control

Change Record

Issue Date	Revision	Prepared by	Reviewed by	Approved by	Background
8 Oct 2020	V3	[redacted]	[redacted]	[redacted]	New metering points to be established on transformer HV side
29 Nov 2019	V2	[redacted]	Historical	Historical	Post RIT-T, remove obsolete options
18 Dec 2018	V1	[redacted]	Historical	Historical	Initial issue

Related Documents

Issue Date	Responsible Person	Objective Document Name
15 Jan 2016	[redacted]	H015 Lilyvale Transformers T3, T4 & T7 Condition Assessment Report V2 [A2050093]
15 Mar 2018	[redacted]	H015 Lilyvale Substation Condition Assessment Report V1 [A2837427]
Nov 2018	[redacted]	H015 Lilyvale Substation Replacement Requirements [A3028445]

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Strategist - HV Asset Strategies	[redacted]	[redacted]
Planner - Main/Regional Grid	[redacted]	[redacted]
Project Manager	[redacted]	[redacted]

Project Details

1. Project Need

H015 Lilyvale is a 275/132kV substation located in central Queensland approximately 50km from Emerald. It was established in 1980 to provide 275kV injection into the Bowen Basin and Blackwater regions to service mining load growth. Lilyvale is a major transmission connection point in the central west and Gladstone transmission network and provides connections to Aurizon and Energy Queensland at 132kV and 66kV.

The 132kV switchyard includes three 132/66kV 80MVA transformers which provide connections to Energy Queensland servicing coal mines and communities in the surrounding region.

The 132/66kV 3T and 4T transformers are from the original substation installation and have been subjected to high cyclic and continuous loads for many years. At over 38 years of age these units are displaying significant condition issues typical of transformers of that age.

A condition assessment has identified that 4T is in marginally better condition than 3T and in terms of residual life each transformer has a life expectancy of less than 5 years. Their reliability is limited by mechanical integrity, which is likely to fail if tested by through-fault of significant magnitude or duration.

Network studies confirm an ongoing need for 132/66kV transformation at Lilyvale substation and therefore there is a need for corrective action. There is potential to convert the site to a two132/66kV transformer configuration, with a minimum of two 160MVA transformers are required.

The objective of this project is to carry out replacement of transformers 3T & 4T by June 2021.

2. Project Scope

2.1. Original Scope

The following scope presents a functional overview of the desired outcomes of the project. The proposed solution presented in the estimate must be developed with reference to the remaining sections of this Project Scope Report, in particular *Section 1.7 Matters to Consider*.

Briefly, the project involves replacing the existing 3T & 4T 80MVA 132/66/11kV transformers at H015 Lilyvale, decommissioning, removal and disposal of the recovered transformers.

2.2. Concurrent Works

This project is to be delivered concurrently with project CP.02340 which includes selective replacement of primary plant at H015 Lilyvale substation.

2.3. Options - H015 Lilyvale Substation Works

Three credible scenarios which considered ultimate substation arrangements of either three, two or one 132/66kV transformers were identified as potential future configurations for Lilyvale substation.

The outcome of the associated Regulatory Investment Test for Transmission (RIT-T) and external consultation identified Option 1(c) to be the least cost alternative and therefore the preferred option.

The option is based upon an ultimate two transformer arrangement and the scope involves replacement of the 3T and 4T transformers with 2x new 132/66/11kV 160MVA transformers. Decommissioning of the third transformer (7T) is planned for a future project and excluded from the scope.

Only Stage 1 works are to be implemented under the CP.02356 project.

Table 1 - Options summary

Option	Scope Requirements	Comm. Date
	Stage I Options - Project CP.02356	
1(a)	Replace 3T & 4T transformers with 80MVA transformers	June 2021
1(b)	Replace 3T & 4T transformers with 100MVA transformers	June 2021
1(c)	Replace 3T & 4T transformers with 160MVA transformers	June 2021
2	Replace 3T & 4T transformers with one 160MVA transformer and engage non-network support	June 2021
	Stage II Options - Future Project(s)	
3(a)	Replace 7T transformer with 80MVA transformer	2031
3(b)	Replace 7T transformer with 100MVA transformer	2031
3(c)	Replace 7T transformer with 160MVA transformer	2031
4	Decommission 7T transformer	2031

The scope requirements for each of the options are summarised in Appendix 1.

2.4. Substation Works - H015 Lilyvale

Option 1(c) - Replacement of both 3T & 4T transformers

Within the scope of works, design, procure, construct and commission the in situ replacement of:

- 3T & 4T transformers with 2x new 160MVA 132/66/11kV transformers, with on-load tap changer, cooling facilities and associated surge arrestors for all voltage levels;
- install Neutral Earthing Resistors/Reactors to limit ground fault current;
- establish new transformer foundations for 3T & 4T;
- upgrade oil containment system to current Powerlink standard allowing as needed for increased transformer oil quantity;
- integrate existing drainage systems to new oil containment system; and

- establish HV and LV connections to the existing transformer bay infrastructure.

Auxiliary supply works:

- transfer or replace the existing 5T & 6T station services transformers 11kV cables to the tertiary winding of the new transformers.

Other works:

- decommission the old 3T & 4T transformers, recover and dispose of decommissioned units;
- demolish and remove the existing 3T & 4T transformer foundations and oil containment system;
- confirm, or otherwise, presence of asbestos containing materials and PCB oil contamination and dispose of affected materials accordingly;
- modify secondary systems as required;
- locate the metering installation points to the 132kV side for the new transformers and upgrade metering to current Powerlink standard;
- carry out all required tests to confirm compliance for the new metering installations including an overall accuracy measurement;
- create new NMIs for the new meters; and
- update drawing records, SAP, configuration files, etc. accordingly.

2.5. Variations to Scope (post project approval)

- Ver. 3 - include installation of revenue metering to HV side of replacement transformers. Section 1.3.4 is amended accordingly.

3. Project Timing

3.1. Site Access Date

H015 Lilyvale is an existing Powerlink owned substation, and access is available immediately.

3.2. Commissioning Date

The latest date for the commissioning of the new assets included in this scope and the decommissioning and removal of redundant assets is 30 June 2021.

4. (Proposed) High Level Line Requirements

Not applicable

5. (Proposed) High Level Substation Requirements

Item	Requirement
Project Management	Meet all relevant Powerlink Standards.
Civil Design	
Electrical Design	
Protection Design	
Automation Design	
Telecommunications Design	
Construction	
Commissioning	

6. Matters to Consider

The following issues are important to consider during the implementation of this project:

- the estimate should consider the implications of relevant workplace health & safety legislation in delivering the proposed solution, and identify any alternative solutions that meet the functional requirements included in the scope whilst having the potential to facilitate improvements in safety during construction, or as built, and:
  - include an assessment of the risks associated with each option identified, after all available and applicable mitigating actions have been implemented; and
  - include an allowance for any specific safety related activities required in the delivery phase of the project.
- any existing assets to be removed and disposed of as part of this scope must be identified within the estimate together with the residual asset values at time of disposal;
- plant and equipment identified as suitable to be recovered for use as spares or returned to stores should be packaged and transported to an appropriate storage location, with a suitable allowance for the cost included in the estimate; and
- a high level project implementation plan including staging and outage plans (as per Section 1.10) should be considered as part of the estimate.

7. Asset Management Requirements

Equipment shall be in accordance with Powerlink equipment strategies.

Unless otherwise advised [redacted] will be the Project Sponsor for this project. The Project Sponsor must be included in any discussions with any other areas of Strategy & Business Development.

[redacted] will provide the primary customer interface with Energy Queensland. The Project Sponsor should be kept informed of any discussions with the customer.

8. Asset Ownership

The works detailed in this project will be Powerlink Queensland assets.

Lilyvale includes 132kV and 66kV connection interfaces between the Powerlink and Energy Queensland networks. Ownership and interface boundaries that apply are described in the relevant C&AA, and in summary are:

H015 Lilyvale 132kV

The Energy Queensland connection point for the Clermont feeder F7153 is the landing beam; and

H015 Lilyvale 66kV

The Energy Queensland connection point is the transformer 66kV bushing. Due to legacy connection arrangements, Powerlink owns related 66kV assets, including disconnectors, earth switches, surge arrestors and instrument transformers.

9. System Operation Issues

Operational issues that should be considered as part of the scope and estimate include:

- interaction of project outage plan with other outage requirements;
- likely impact of project outages upon grid support arrangements; and
- likely impact of project outages upon the optical fibre network.

10. Options

An estimate is required for each of the four options as described in Section 1.3 above. The estimates are to be developed on the basis that Stage 1 and Stage 2 works are to be delivered under separate standalone projects.

11. Asset Depreciation

As a result of this project, accelerated depreciation will be applied to the assets to be replaced or decommissioned. The estimate is to include a summary table of the affected assets and associated current book value.

12. Division of Responsibilities

A division of responsibilities document will be required as changes are anticipated for interface boundaries with Energy Queensland.

The Project Manager will be required to draft the document after project approval and consult with the Project Sponsor to arrange sign-off between Powerlink and the relevant customer.

13. Related Projects

Project No.	Project Description	Planned Comm Date	Comment
Pre-requisite Projects			
Co-requisite Projects			
CP.02340	H015 Lilyvale Selected Primary Plant Replacement	Oct 2022	
Other Related Projects			

14. Project Drawing

[redacted]

15. Property & Easement Information

15.1. Established Site - H015 Lilyvale

15.2. Site Accessibility

H015 Lilyvale is an existing substation site and site access is availability immediately.

15.3. Issues Regarding Site Location

No issues regarding the site location identified at this stage.

APPENDIX 1: LILYVALE 132/66kV No 3 & 4 TRANSFORMER REPLACEMENT

H015 LILYVALE SUBSTATION REPLACEMENT REQUIREMENTS

DIAMETER	DESCRIPTION	START UP	REQUIREMENTS			CP.02340 - PRIMARY PLANT REPLACEMENT												CP.02356 - TRANSFORMER REPLACEMENT			
			INCLUSIONS		EXCLUSIONS	OPTIONS												OPTIONS			
			Mandatory	Optional		1		2		3		4		5		6		1	2	3	4
						In Situ Replacements		Selected Full Bay Replacements		In Situ Replacements		Selected Full Bay Replacements		In Situ Replacements		Selected Full Bay Replacements		Replace 3T & 4T	Replace 3T & Decomm 4T	Replace 7T	Decomm 7T
						Stg I	Stg II	Stg I	Stg II	Stg I	Stg II	Stg I	Stg II	Stg I	Stg II	Stg I	Stg II	1(a) 2x 80MVA 1(b) 2x 100MVA 1(c) 2x 160MVA	1x 160MVA	3(a) 1x 80MVA 3(b) 1x 100MVA 3(c) 1x 160MVA	
	(Book Value)									(=Opt 1 Stg 1)		(=Opt 2 Stg 1)					(=Opt 4 Stg 2)				
Assumptions:- 1. Project dependencies						CP.02340 and CP.02356 to be delivered concurrently												CP.02340 and CP.02356 to be delivered concurrently			
2. Ultimate Transformer Arrangement						3x 132/66kV Tx (3T, 4T & 7T)				2x 132/66kV Tx (3T & 4T, decomm 7T)				1x 132/66kV Tx (3T, decomm 4T & 7T)				2x or 3x 132/66kV Tx	1x or 2x 132/66kV Tx	2x or 3x 132/66kV Tx	1x or 2x 132/66kV Tx
=C01 BC 501	CB (Mitsubishi)	1985	R			R		R		R		R		R		R					
	ES	1983/04		●			R	R			R	R			R	R					
	ISOL	1968/04		●			R	R			R	R			R	R					
	CT	1983	R			R		R		R		R		R		R					
	S&F - CB and CTs		R			R	R	R		R	R	R		R	R	R					
=C01 1T	CB (ABB)	2004			●																
	ES	1984/04		●			R	R			R	R			R	R					
	ISOL	1984/04		●			R	R			R	R			R	R					
	CT	2004			●																
	CVT	1984	R			R		R		R		R		R		R					
	SA	2004			●																
	S&F				●		R	R			R	R			R	R					
=C01 F850	H015-C01-850	2004			●																
=C02 - 2T	CB (Mitsubishi)	1984	R			R		R		R		R		R		R					
	ES	1975/04		●			R	R			R	R			R	R					
	ISOL	1975/04		●			R	R			R	R			R	R					
	CT	1983	R			R		R		R		R		R		R					
	CVT	1983	R			R		R		R		R		R		R					
	SA	2004		●				R				R				R					
	S&F - CB, CTs and VTs		R			R	R	R		R	R	R		R	R	R					
=C02 - 593 (Spare)	ES	1983		●			R	R			R	R			R	R					
	ISOL	1983		●			R	R			R	R			R	R					
	S&F			●			R	R			R	R			R	R					
=C03 833	H015-C03-833	2004			●																
=D01 - F7311 (Blackwater)	H015-D01-7311	2004			●																
=D02 - F7310 (Blackwater)	CB (Mitsubishi)	1986	R			R		R		R		R		R		R					
	CT	1985	R			R		R		R		R		R		R					
	ES (Siemens)	1977		●			R	R			R	R			R	R					
	ISOL (Siemens)	1981		●			R	R			R	R			R	R					
	CVT (Haefely)	1985	R			R		R		R		R		R		R					
	S&F		R	●		R	R	R		R	R	R		R	R	R					
=D03 - 3T	CB (Sprecher+Schuh)	1986	R			R		R		R		R		R		R					
	CT- A phase (B & C ok)	1984/99/00	R			R		R		R		R		R		R					
	ES	1984		●			R	R			R	R			R	R					
	ISOL	1985		●			R	R			R	R			R	R					
	SA	1985	R			R		R		R		R		R		R					
	S&F - CB	1986	R			R	R	R		R	R	R		R	R	R					
	3T (132/66kV)	1980	R															R	R		
	Establish NER/NEX installation																	Y			
	5T (11kV/415VAC)	2011		●																	
=D04 - F789 (Blackwater)	CB (Sprecher+Schuh)	1986	R			R		R		R		R		R		R					
	CT	1985	R			R		R		R		R		R		R					
	ES	1977		●			R	R			R	R			R	R					
	ISOL	1981		●			R	R			R	R			R	R					
	CVT	1985	R			R		R		R		R		R		R					
	SA	1985		●			R	R			R	R			R	R					
	S&F- CB & CTs	1985	R			R	R	R		R	R	R		R	R	R					
=D05 - 4T	CB (Sprecher+Schuh)	1981	R			R		R		R		R		D		D					
	CT	1980	R			R		R		R		R		D		D					
	ES	1984		●			R	R			R	R		D		D					
	ISOL	1985		●			R	R			R	R		D		D					
	SA	1985	R			R		R		R		R		D		D					
	S&F - CB & CTs	1986	R			R	R	R		R	R	R		D		D					
	4T (132/66kV)	1980	R															R	D		
	Establish NER/NEX installation																	Y			
	6T (11kV/415VAC)	2011		●															D		
=D06 - F7153 (Clermont)	CB (Sprecher+Schuh)	1981	R			R		R		R		R		R		R					
	CT	1997/08		●			R	R			R	R			R	R					
	ES	1977		●			R	R			R	R			R	R					
	ISOL	1981		●			R	R			R	R			R	R					
	CVT	2011/13		●				R				R				R					
	SA	1985		●			R	R			R	R			R	R					
	S&F- CB	1985	R			R	R	R		R	R	R		R	R	R					
=D07 - F7150 (Dysart)	CB (Mitsubishi)	1981	R			R		R		R		R		R		R					
	CT	1980/97/05	R			R		R		R		R		R		R					
	ES	1977		●			R	R			R	R			R	R					
	ISOL	1981		●			R	R			R	R			R	R					
	CVT - A phase (B & C ok)	1984/13	R					R				R				R					
	SA	1980		●			R	R			R	R			R	R					
	S&F - CB, CT & CVT	1980	R			R	R	R		R	R	R		R	R	R					
=D08 - 1T	CB (ABB)	2004			●																
	CT	2004			●																
	ES	2004			●																
	ISOL	2004			●																
	CVT	1983	R			R		R		R		R		R		R					
	SA	2004			●																
	S&F - CVTs	2004	R			R		R		R		R		R		R					
=D09 - 7T ($136k)	H015-D09-447	1977/00/01		●			R		R		D		D		D		D				
	Establish NER/NEX installation																			Y	
($100k)	7T (132/66kV)	1974		●																R	D
=D10 - 2T	CB (ABB)	2004			●																
	CT	2004			●																
	ES	2004			●																
	ISOL	2004			●																
	CVT	1983	R			R		R		R		R		R		R					
	SA	2004			●																
	S&F - CVTs	2004	R			R		R		R		R		R		R					
=D12 - 1CAP	H015-D12-481	2002			●																
=D13 - BC	H015-D13-401	2007			●																
=D51 - F7171 (Gregory)	H015-D51-7171	2013			●																
=E01 - 7T	H015-E01-347	1986/99/01		●			R		R		D		D		D		D				
=E05 - 3T	CT	2015			●																
	ES	2000		●				R				R				R					
	ISOL	1977		●			R	R			R	R			R	R					
	CVT - C phase	2013		●				R				R				R					
	EMVT - A&B phase	1980	R			R		R		R		R		R		R					
	SA	2000	R			R		R		R		R		R		R					
	S&F							R				R				R					
=E07 - 4T	CT	2015			●									D		D					
	ES	1977		●			R	R			R	R		D		D					
	ISOL	1981		●			R	R			R	R		D		D					
	EMVT	1977		●			R	R			R	R		D		D					
	SA	1977	R			R		R		R		R		D		D					
	S&F							R				R		D		D					
=132kV Bus	CVT	2007			●																
	ES	2007			●																
	S&F				●																
=275kV Bus	CVT	2004			●																
	ES	2004			●																
	S&F - lattice bus supports		●			●		●		●		●		●		●					
Non-Bay	Oil Containment Sys - replace			●														R	R	R	R
	275/132kV strung bus				●																
	275/132kV OHEW				●																
	132kV DC supply				●																
	275kV DC supply - replace 125V & 50V batteries		R			R		R		R		R		R		R					
	Local AC supply incl diesel and AC C/O				●																
	Perimeter switchyard fence - address compliance issues		●			●		●		●		●		●		●					
	Establish replacement station services supply			●															Y		

Notes:

●	Corrective action
D	Decomm issioning
R	Replacement
Y	New asset establishment
(yellow)	CA review required

CP.02356 Lilyvale 132/66kV No 3 & 4 Transformers Replacement

Project Management Plan at Concept Stage

Record ID	A2977668	
Authored by	Project Manager	[redacted]
Reviewed by	Manager Projects	[redacted]
Approved by	General Manager	[redacted]

Version History

Version	Date	Section(s)	Summary of amendment
1	1/03/2019	1-4	Development

Table of Contents

1. Executive Summary

Project background

H015 Lilyvale is a 275/132kV substation located in central Queensland approximately 50km from Emerald. It was established in 1980 to provide 275kV injection into the Bowen Basin and Blackwater regions to service mining load growth.

Lilyvale is a major transmission connection point in the central west and Gladstone transmission network, supplying residential, mining and Aurizon loads via the 132kV and 66kV networks. The substation consists of 275kV, 132kV and 66kV (Energy Queensland) switchyards. It hosts two 275/132kV transformers and three 132/66kV transformers, and facilitates the connection of two 275kV feeders and six 132kV feeders.

Plant from the original substation establishment is now over 35 years of age. The majority of both 132kV and 275kV circuit breakers have condition issues, the manufacturers no longer provide support for the equipment and spares holdings are limited. There are several 132kV and 275kV instrument transformers from the original establishment that are at end of technical service life with most having developed oil leaks. This equipment is porcelain housing type and there is increased risk of explosive failure. Corrective action is required.

Planning studies have determined that for Powerlink to meet planning criteria and regulatory obligations, there is an ongoing need for all connecting feeders to satisfy the transfer capability in the Lilyvale area and for the 132/66kV transformation. There is potential to convert the site to a two, or possibly one, 132/66kV transformer configuration. To avoid the need for non-network support a minimum of two 160MVA transformers are required.

Project objective

The objective of this project is to carry out replacement of transformers 3T and 4T by June 2021 in conjunction with CP.02340 Lilyvale Selected Primary Replacement project.

Project delivery strategy is based as follows:

- Design and Construction and optional FAT by SPA
- Transformer and HV Plant (period order items) procured from preferred suppliers by Powerlink.
- Optional FAT, SAT and Commissioning by MSP

A high level project staging plan and project schedule have develop based on Option 1 where both transformers 3T and 4T are replaced with either 100MVA or 160MVA transformers.

For the 132kV yard, Construction of new bay strategy is preferred due to reduced outages duration on feeders and transformers for the replacement works. This is achieved by construction of the new bay while the existing feeders or transformers are in service. On completion of the new construction, the existing bay connections are cutover and the new bay tested and commissioned in a much shorter 3 week outage duration.

Both projects CP.02340 and CP.02356 have been staged to achieve the network asset need (mitigate the potential risk of failure) by replacing the relevant CTs by December 2021. This includes performing temporary works on F7150 in June 2020.

The expected project commissioning date for this project is 25 June 2021.

2. Project Definition

2.1 Project Scope

This project shall be delivered concurrently with project CP.02340 which includes the replacement of selected primary plant at H015 Lilyvale. The scope for CP.02356 will involve the replacement of 3T & 4T with either a single or two new transformers with an additional pricing option to decommission 7T.

Six options were identified, however only four were scoped and estimated. The options with 80MVA transformers were excluded as these are non-standard size units currently procured and installed by Powerlink.

Option	Scope Requirements	Comm. Date
Stage I Options - Project CP.02356		
1(a) (excluded)	Replace 3T & 4T transformers with 80MVA transformers	June 2021
1(b)	Replace 3T & 4T transformers with 100MVA transformers	June 2021
1(c)	Replace 3T & 4T transformers with 160MVA transformers	June 2021
2	Replace 3T & 4T transformers with one 160MVA transformer and engage non-network support	June 2021
Stage II Options - Future Project(s)		
3(a) (excluded)	Replace 7T transformer with 80MVA transformer	2031
3(b)	Replace 7T transformer with 100MVA transformer	2031
3(c)	Replace 7T transformer with 160MVA transformer	2031
4	Decommission 7T transformer	2031

2.1.1 Substations: Option 1 - Replacement of both 3T & 4T transformers

The option 1 strategy involves replacement of both transformers with 2x new 132/66/11kV transformers. Two alternative transformer capacities are to be considered and a separate estimate provided for each, including -

1(b) 2x 100MVA 132/66/11kV transformers, to Powerlink standard transformer specifications;

1(c) 2x 160MVA 132/66/11kV transformers to Powerlink standard transformer specifications.

For options 1(b) and 1(c), design, procure, construct and commission the in situ replacement of:

- 3T & 4T transformers with 2x new 132/66/11kV transformers, with on-load tap changer, cooling facilities and associated surge arrestors for all voltage levels;
- for Options 1 (b) & 1 (c) - install Neutral Earthing Resistors/Reactors to limit ground fault current;
- Note: The cost associated with this item to be separately identifiable within the overall estimate.
- establish new transformer foundations for 3T & 4T;
- upgrade oil containment system to current Powerlink standard allowing as needed for increased transformer oil quantity;
- integrate existing drainage systems to new oil containment system; and
- establish HV and LV connections to the existing transformer bay infrastructure.

Auxiliary supply works for options 1(b) and 1(c):

- transfer or replace the existing 5T & 6T station services transformers 11kV cables to the tertiary winding of the new transformers; and

Other works applicable for options 1(b) and 1(c):

- decommission the old 3T & 4T transformers, recover and dispose of decommissioned units;
- demolish and remove the existing 3T & 4T transformer foundations and oil containment system;
- confirm, or otherwise, presence of asbestos containing materials and PCB oil contamination and dispose of affected materials accordingly;
- modify secondary systems as required;
- upgrade metering to current Powerlink standard; and
- update drawing records, SAP, configuration files, etc. accordingly.

2.1.2 Substation: Option 2 - Replacement of 3T & 4T transformers with a single 160MVA transformer and engage non-network support

The Option 2 strategy involves replacement of both transformers with a single 160MVA 132/66/11kV transformer and engagement of non-network support.

Design, procure, construct and commission the in situ replacement of:

- 3T transformer with a 160MVA 132/66/11kV transformer, with on-load tap changer, cooling facilities and associated surge arrestors for all voltage levels;
- install Neutral Earthing Resistor/Reactor to limit ground fault current;
- Note: The cost associated with this item to be separately identifiable within the overall estimate.
- establish new transformer foundation 3T;
- upgrade oil containment system to current Powerlink standard allowing as needed for increased transformer oil quantity;
- integrate existing drainage systems to new oil containment system; and
- establish HV and LV connections to existing transformer bay infrastructure.

Auxiliary supply works:

- transfer or replace the existing 5T station services transformer (on 3T) 11kV cable to the new transformer tertiary winding; and
- establish a new station services supply (e.g. high burden VT arrangement) to replace 6T transformer which is to be decommissioned with the decommissioning of 4T transformer.

Other works:

- decommission the old 3T, 4T and 6T station services transformer (on 4T), recover and dispose of decommissioned units;
- demolish and remove the existing 3T, 4T and 6T station services transformer (on 4T) foundations and oil containment system;
- confirm, or otherwise, presence of asbestos containing materials and PCB oil contamination and dispose of affected materials accordingly;
- modify secondary systems as required;
- upgrade metering to current Powerlink standard; and
- update drawing records, SAP, configuration files, etc, accordingly.

2.1.3 Substation: Option 3 - Replacement of 7T transformer

The option 3 strategy involves replacement of 7T transformer with 1x new 132/66/11kV transformer. Two alternative transformer capacities are to be considered and a separate estimate provided for each, including -

3(b) 1x 100MVA 132/66/11kV transformers, to Powerlink standard transformer specifications;

3(c) 1x 160MVA 132/66/11kV transformers, to Powerlink standard transformer specifications;

Design, procure, construct and commission the in situ replacement of:

- 7T transformer with 1x new 132/66/11kV transformer, with on-load tap changer, cooling facilities and associated surge arrestors for all voltage levels;
- for Options 3 (b) & (c) - install Neutral Earthing Resistor/Reactor to limit ground fault current;
- Note: The cost associated with this item to be separately identifiable within the overall estimate.
- establish new transformer foundations for 7T;
- upgrade oil containment system to current Powerlink standard allowing as needed for increased transformer oil quantity;
- integrate existing drainage systems to new oil containment system; and
- establish HV and LV connections to the existing transformer bay infrastructure.

Other works:

- decommission the old 7T transformer, recover and dispose of decommissioned unit;
- demolish and remove the existing 7T transformer foundation and oil containment system;
- confirm, or otherwise, presence of asbestos containing materials and PCB oil contamination and dispose of affected materials accordingly;
- modify secondary systems as required;
- upgrade metering to current Powerlink standard; and
- update drawing records, SAP, configuration files, etc. accordingly.

2.1.4 Substation: Option 4 - Decommissioning of 7T transformer

The option 4 strategy involves the decommissioning and removal of 7T transformer and includes -

- decommission the old 7T transformer, recover and dispose of decommissioned unit;
- demolish and remove the existing 7T transformer foundation and oil containment system;
- confirm, or otherwise, presence of asbestos containing materials and PCB oil contamination and dispose of affected materials accordingly;
- modify secondary systems as required;
- upgrade metering to current Powerlink standard; and
- update drawing records, SAP, configuration files, etc. accordingly.

2.1.5 Transmission Lines

Not applicable

2.1.6 Telecommunications

Not applicable

2.1.7 Revenue Metering

Not applicable

2.1.8 Other Project Works

CP.02340 H015 Lilyvale Selected Primary Plant Replacement

2.2 Exclusions

Exclusions as follow:

- Ergon's transformer connection 66kV works.
- Upgrade or uprating of Ergon's assets due to implementation of this project.
- No allowance to repair or upgrade existing access tracks to substation and existing roads within substation.
- No allowance for management of unsuitable ground conditions during foundation works. This would be regarded as a latent condition.
- No Allowance for Non Regulated Work Impacts, namely scope, cost and time.

2.3 Assumptions

Assumptions as follow:

- Delivered in conjunction with CP02340 Lilyvale Selected Primary Plant Replacement. Delay in approval of CP.02340 will impact the delivery strategy, cost and timing of project CP02356.
- Implementation strategy based on construction of new bay with transformer and associated plant and thereafter cutover of existing connection to the new bay.
    - Bay D02 available for T3
    - Bay D11 (currently vacant) available for new T4 transformer bay with 66kV underground cable connection to Ergon 66kV yard. Change in this strategy shall require the project staging to be revised.

  Note: new bay strategy is preferred due to reduced outages duration on feeders and transformers for the replacement works. This is achieved by construction of the new bay while the existing feeders or transformers are in service. On completion of the new construction, the connections from the existing bays are cutover, tested and commissioned in a much shorter 2 to 3 week outage duration.
- Outages available for the cutover of the primary connections of the new transformers T3 and T4.
- Re-use existing secondary system infrastructure (e.g. marshalling kiosks, protection and control panels, and cables from marshalling kiosk to building).
- Modifications to Ergon assets will be performed within the required timeframes to avoid delaying Powerlink works.

2.4 Project Interaction

Project Number and Description	Interaction (Pre-requisite/Co-requisite/dependent/Related)	Planned Commissioning Date	Comment
CP.02340 H015 Lilyvale Selected Primary Plant Replacement	Concurrent	June 2021	Delivered concurrently with CP.02356. CP.02340 will be completed by Dec 2022.
CP.02369 Blackwater Transformer 1 & 2 Replacement	Concurrent	Jun 2021	Part of project CP.02356 will overlap with CP.02369.

2.5 Project Risk

Project risks identified during Project Concept phase are as follows:

Risks	Impact	Likelihood	Mitigation Strategy / Amount
Project Staging: Additional design due to complexity of staged works. Change in staging strategy	Medium	Medium	Confirm staging as soon as project is approved for execution.
Availability of Bay D11 for new Transformer connection into the 132kV yard	Medium	Medium	Seek pre-approval funds to commence with single line diagram by Primary System Design
Availability or change of outages and subsequent impact on project staging	Medium	Medium	Ongoing discussion and management with NetOps.
Availability of MSP resources as follows: o 132kV Feeder F7150 – replace CTs by MSP – June 2020 o 275kV bay C1 – Testing and commissioning works by MSP – June 2020 to July 2020 o 275kV bay C2 – Testing and commissioning works by MSP –July 2020 to August 2020 o T3 and F7310 – Test, cutover and commissioning by MSP – April 2021 o T4 and F789 – Test, cutover and commissioning by MSP – May 2021 o F7153 - Test, cutover and commissioning by MSP – October 2021 o F7150 - Test, cutover and commissioning by MSP – July 2022	Medium	Medium	Engage resources as soon as practically possible. Ongoing discussion and management with MSP.
Delivery of transformer and HV plant as required	Low	Low	Seek pre-approval funds to place orders with suppliers

Project based on approximately 15% risk allowance with 10% banding giving a total risk of 25% of based value.

3. Project Financials

3.1 Project Estimate

3.1.1 Estimate Summary

	Option 1b (Replace T3 and T4 with 100MVA, excludes NER)		Option 1c (Replace T3 and T4 with 160MVA, excludes NER)		Option 2 (Replace T3 and T4 with one 160MVA, excludes NER)		Option 3b (Replace T7 with 100MVA in 2031, excludes NER)		Option 3c (Replace T7 with 160MVA in 2031, excludes NER)		Option 4 (Decommission T7 in 2031)	
	Un-Escalated	Escalated	Un-Escalated	Escalated	Un-Escalated	Escalated	Un-Escalated	Escalated	Un-Escalated	Escalated	Un-Escalated	Escalated
Base Estimate	9,345,280	10,229,549	10,229,920	11,197,895	6,884,607	7,536,042	5,899,841	9,651,876	6,342,021	10,375,263	1,078,744	1,764,777
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Total Proposed Contingency	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Total Proposed Approval	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

	Option 1b & 1c NER		*Option 2, 3b & 3c NER*	
	Un-Escalated	Escalated	Un-Escalated	Escalated
Base Estimate	283,164	309,958	164,082	179,608
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Total Proposed Contingency	[redacted]	[redacted]	[redacted]	[redacted]
Total Proposed Approval	[redacted]	[redacted]	[redacted]	[redacted]

3.1.2 Asset Write-Off Table

CP.02356 Asset Write-off's. Values current at 30th June 2016

Functional Loc.	Description	Asset	Sub number	Book val.	% Write-off	Write-off Value
H015-D03-443-	132kV 3 TRANSF BAY	104999	0	113,087.11	100%	113,087.11
H015-D05-444-	132kV 4 TRANSF BAY	105003	0	113,087.11	100%	113,087.11
H015-D09-447-	132kV 7 TRANSF BAY	105011	0	318,127.80	100%	318,127.80
H015-SSS-447-	132kV 7 TRANSF BAY	123210	0	324,070.30	100%	324,070.30
H015-T03-3TRF	3 TRANSFORMER	105030	0	244,437.07	100%	244,437.07
H015-T04-4TRF	4 TRANSFORMER	105031	0	244,437.07	100%	244,437.07
					Total	1,357,246.46

CP.02356 Asset Write-off's. Values current at 30th June 2019

Functional Loc.	Description	Asset	Sub number	Book val.	% Write-off	Write-off Value
H015-SIN	SUBSTATION INFRASTRUCTURE	105026	0	480243.58	22%	$ 105,653.59
H015-T03-3TRF	3 TRANSFORMER	105030	0	104,552.51	100%	$104,552.51
H015-T04-4TRF	4 TRANSFORMER	105031	0	104,552.51	100%	$104,552.51
H015-T07-7TRF	7 TRANSFORMER	105660	0	99926.47	100%	$ 99,926.47
					Total	$ 414,685.08

3.2 Approved Released Budget

To be advised.

3.3 Planned Costs (Forecasted Cash Flow)

During Project Execution, project planned cost are managed in SAP.

4. Project Planning Strategy

4.1 Milestones

The following milestones are required by the project team to deliver the project:

Milestones	Planned Dates
Project Approval (issue of PAN) – Partial Approval	3/6/2019
Project Approval (issue of PAN) – Full Approval	06/1/2020
Site Access - to carry out investigations, inspections, etc	As required as this is an existing substation site
Site Possession - to carry out construction works	
Expected Project Commissioning Date – CP.02369	30/06/2021

Other project delivery milestones for combined CP.02340 and CP.02356 (based on Option 1 - replacement of both3T and 4T transformers with 2x new 132/66/11kV transformers) are as follows:

- Issue Transformer Tender: September 2019
- SPA ITT (Design and Construct):
  - Issue ITT: October 2019
  - Accept Tender: December 2019

- 2021 Site Works:
  - 275kV bay C1 and C2 – Construction works by SPA: March 2020 to June 2020
  - 132kV Feeder F7150 – replace CTs by MSP – June 2020 (Temporary works to meet asset need)
  - 275kV bay C1 – Testing and commissioning works by MSP – June 2020 to July 2020
  - 275kV bay C2 – Testing and commissioning works by MSP –July 2020 to August 2020
  - New bays for T3, F7310, T4 and F78:
    - Construction by SPA – June2020 to February 2021
    - T3 and F7310 – Test, cutover and commissioning by MSP – April 2021
    - T4 and F789 – Test, cutover and commissioning by MSP – May 2021
  - New bay for F7153
    - Demo and construction by SPA – June 2021 to September 2021
    - F7153 - Test, cutover and commissioning by MSP – October 2021
- 2022 Site Works:
  - New bay for F7150
    - Demo and construction by SPA – March 2022 to June 2022
    - F7150 - Test, cutover and commissioning by MSP – July 2022

4.2 Project Staging

A high level Project Staging has been developed for the combined works on Project CP.02340 and CP.02356 at Lilyvale Substation.

Substation Strategies has identified the following HV plant that needs to be replaced by December 2021:

Functional Loc.	Description	Equipment	Description	Manufacturer	Model number	Manuf Serial No.
H015-D05-444--4TRFCTA	132KV CT A	20004547	CURRENT TRANSFORMER	STANGER DICKSON	B66581/1	C0526
H015-D05-444--4TRFCTC	132KV CT C	20004566	CURRENT TRANSFORMER	STANGER DICKSON	B66581/1	C0521
H015-D05-444--4TRFCTB	132KV CT B	20004567	CURRENT TRANSFORMER	STANGER DICKSON	B66581/1	C0518
H015-C01-501--5012CTA	1 COUPLER CB CT A	20004569	CURRENT TRANSFORMER	HAEFELY	IOSK300/1050	830329
H015-C01-501--5012CTB	1 COUPLER CB CT B	20004570	CURRENT TRANSFORMER	HAEFELY	IOSK300/1050	830328
H015-C01-501--5012CTC	1 COUPLER CB CT C	20004574	CURRENT TRANSFORMER	HAEFELY	IOSK300/1050	830318
H015-C02-542--5422CTA	CB CT A	20004571	CURRENT TRANSFORMER	HAEFELY	IOSK300/1050	830330
H015-C02-542--5422CTC	CB CT C	20004572	CURRENT TRANSFORMER	HAEFELY	IOSK300/1050	830312
H015-C02-542--5422CTB	CB CT B	20004573	CURRENT TRANSFORMER	HAEFELY	IOSK300/1050	830314
H015-D07-7150-7150CTB	FDR CT B	20005448	CURRENT TRANSFORMER	MODERN PRODUCTS	H427/82/2 ITEM 2A	M2267
H015-D02-7310-7310CTC	7310 BLACKWATER 132kV CT C	20004554	CURRENT TRANSFORMER	MODERN PRODUCTS	MODEL325	M2562
H015-D02-7310-7310CTB	7310 BLACKWATER 132kV CT B	20004555	CURRENT TRANSFORMER	MODERN PRODUCTS	MODEL325	M2561
H015-D02-7310-7310CTA	7310 BLACKWATER 132kV CT A	20004556	CURRENT TRANSFORMER	MODERN PRODUCTS	MODEL325	M2560
H015-D03-443--3TRFCTA	132KV CT A	20004561	CURRENT TRANSFORMER	TYREE	06/145/57	S4065

Both projects has been staged to achieve the above network asset need by replacing the relevant CTs by December 2021 as follows:

- Replacing CT (B phase only) in situ on F7150 upfront in June 2020. This replacement is temporary as the existing bay for F7150 will then be replaced later in 2022.
- Performing the 275kV primary plant replacement works in 2020
- Performing the 132kV primary plant (excluding F7150) and transformer works from June 2020 to October 2021.
- Performing 132kV primary plant works (F7150) in 2022. The CTs in the existing bay is not at risk as this was done upfront to mitigate the potential risk of failure.

4.3 Project Schedule

Based on Option 1 - replacement of both 3T and 4T transformers with 2x new 132/66/11kV transformers, a high level proposed Project Schedule has been developed for the combined works on Project CP.02340 and CP.02356 at Lilyvale Substation.

4.4 Network Impacts and Outage Planning

The high level project staging and high level project schedule (based on Option 1) has been developed in consultation with NetOps. A bay replacement approach has been considered as an effective delivery plan to minimum number and duration of outages.

The following have been identified as critical items that will require ongoing management including restoration or return to service plans:

- F7153
- F7150
- Staging and replacement methodology shall require the 275kV yard to be unmeshed to gain access to the relevant primary plant.

NetOps have advised that outages in Summer (from October to following March) are unlikely, hence the project schedule have been developed based on outages during 'shoulder' and winter period from April to September. For all outages, a return to service (RTS) plan shall be required.

For 275kV works, NetOps have advised that the 132kV network between T022 Callide to H015 Lilyvale and Moranbah to Nebo needs to be intact to maintain security of the network.

4.5 Project Delivery Strategy

Strategy to deliver the project as follows:

- Design and Construction and optional FAT by SPA
- Transformer and HV Plant (period order items) procured from preferred suppliers by Powerlink.
- Optional FAT, SAT and Commissioning by MSP

Description	*Responsibility*							
	Main Site				*Remote End(s)*			
	Powerlink	*Contractor*	*MSP – O&SD*	*MSP - Ergon*	*Powerlink*	*Contractor*	*MSP – O&SD*	*MSP*
Primary Design Systems (PSD):								
Earthworks (Not applicable)	☐	☐	☐	☐	☐	☐	☐	☐
Civil and Structural	☐	☒	☐	☐	☐	☐	☐	☐
Electrical	☐	☒	☐	☐	☐	☐	☐	☐
Transmission Lines (Not Applicable)	☐	☐	☐	☐	☐	☐	☐	☐
Secondary Systems Design (SSD):								
Protection	☒	☐	☐	☐	☐	☐	☐	☐
Automation (Circuitry and Systems Configurations)	☐	☒	☐	☐	☐	☐	☐	☐
Construction:								
Earthworks (Not Applicable)	☐	☐	☐	☐	☐	☐	☐	☐
Civil	☐	☒	☐	☐	☐	☐	☐	☐
Construction (support structures, plant and equipment installation and demolition Works)	☐	☒	☐	☐	☐	☐	☐	☐
Secondary Systems Installation	☐	☒	☒	☐	☐	☐	☐	☐

Description	*Responsibility*							
	Main Site				*Remote End(s)*			
	Powerlink	*Contractor*	*MSP – O&SD*	*MSP - Ergon*	*Powerlink*	*Contractor*	*MSP – O&SD*	*MSP*
(loose panels installation, panel modification, IED replacement, etc)								
Telecommunication Construction (including fibres)	☐	☒	☒	☐	☐	☐	☐	☐
Transmission Lines - New Lines	☐	☐	☐	☐	☐	☐	☐	☐
Testing and Commissioning:								
Factory Acceptance Test	☐	☒	☐	☐	☐	☐	☐	☐
Site Acceptance Test (partial)	☐	☒	☒	☐	☐	☐	☐	☐
System Cut Over and Commissioning	☐	☐	☒	☐	☐	☐	☐	☐
Other:								
Revenue Metering site works	☐	☐	☐	☐	☐	☐	☐	☐
Transformer Install (Transformer Vendor)	☐	☒	☐	☐	☐	☐	☐	☐

4.6 Procurement Strategy

The procurement strategy for services and selected items are listed below. All other services and items shall be procured in accordance with Powerlink's Procurement Standard.

Description	Procurement Method
Services:	
SPA – DC with optional T	ITT - Substation Panel Arrangement (SPA)
MSP – Ergon	RFQ – Service Level Agreement
Primary Plant and Equipment:	
HV Plant and Equipment	Period Contractors
Structures	Supplied by SPA Contractor
Hardware and fittings	Supplied by SPA Contractor
Transformers	ITT – Standing Offer arrangement with preferred/preapproved suppliers
Secondary Systems Equipment:	
IEDs	Period Contract
Panels, Kiosks, Boards	Supplied by SPA Contractor
Secondary Cables	Supplied by SPA Contractor

References

Document name and hyperlink	Version	Date
Project Scope Report – Concept Estimate	Version 1	18/12/18
Project Staging Plan 132kV	1	19/02/19
Project Schedule	1	1/03/19

Powerlink Queensland

Project Assessment Conclusions Report

25 October 2019

Maintaining power transfer capability and reliability of supply at Lilyvale

Document Purpose

For the benefit of those not familiar with the National Electricity Rules (the Rules) and the National Electricity Market (NEM), Powerlink offers the following clarifications on the purpose and intent of this document:

1. The Rules require Powerlink to carry out forward planning to identify future reliability of supply requirements and consult with interested parties on the proposed solution as part of the Regulatory Investment Test for Transmission (RIT-T). This includes replacement of network assets in addition to augmentations of the transmission network.
2. Powerlink must identify, evaluate and compare network and non-network options (including, but not limited to, generation and demand side management) to identify the '*preferred option*' which can address future network requirements at the lowest net cost to electricity consumers. This assessment compares the net present value (NPV) of all credible options to identify the option that provides the greatest economic benefits to the market.
3. This document contains the results of this evaluation, and a final recommended solution to address the condition risks arising from the ageing transformers and primary plant at Lilyvale Substation by October 2022.

Contents

Executive Summary

Lilyvale Substation, located approximately 50km from Emerald, plays a critical role in the supply of electricity to customers in Queensland's Central West region, as well as the Blackwater and Bowen Basin mining areas. Planning studies have confirmed there is a long-term requirement to continue to supply the existing electricity services provided by Lilyvale Substation supporting a diverse range of customer needs in the area.

Commissioned over 38 years ago, much of the substation's primary plant, including two of the original three 132/66 kV transformers, are reaching the end of their technical service lives and are no longer supported by the manufacturer, with limited spares available to rectify a failure if one were to occur.

The increasing likelihood of faults arising from the condition of Lilyvale's ageing and obsolete transformers and primary plant remaining in service beyond October 2022, exposes customers to the risks and consequences of an increasingly unreliable electricity supply.

There is a requirement for Powerlink to address these emerging risks. As the identified need for the proposed investment is to meet reliability and service standards specified within Powerlink's Transmission Authority and to ensure Powerlink's ongoing compliance with Schedule 5.1 of the National Electricity Rules (the Rules) and relevant jurisdictional obligations[1], it is classified as a 'reliability corrective action'[2].

This Project Assessment Conclusions Report (PACR) represents the final step in the RIT-T process prescribed under the Rules undertaken by Powerlink to address the condition risks arising from the ageing transformers and primary plant at Lilyvale Substation. It contains the results of the planning investigation and the cost-benefit analysis of credible options compared to a non-credible Base Case where the emerging risks are left to increase over time. In accordance with the RIT-T, the credible option that maximises the net present value (NPV) of economic benefit, or minimises the costs, is recommended as the preferred option.

Credible options considered

Powerlink has developed two credible network options to maintain the existing electricity services, ensuring an ongoing reliable, safe and cost effective supply to customers in the area. The options result in different substation configurations by 2027, with the existing three 132/66kV 80MVA transformers being replaced by three 100MVA transformers in Option 1 and by two 160 MVA transformers in Option 2.

By addressing the condition risks, both options presented allow Powerlink to meet the identified need and continue to meet the reliability and service standards specified within Powerlink's Transmission Authority, Schedule 5.1 of the Rules and relevant jurisdictional obligations.

Powerlink published a Project Specification Consultation Report (PSCR) in May 2019 to address the risks arising from the condition of the ageing transformers and primary plant at Lilyvale Substation.

Interest was shown by three non-network proponents in response to the PSCR, and subsequent discussions were held with two, however the proponents ultimately decided not to progress with formal submissions. As a result, no additional credible options to meet the identified need were identified as part of this RIT-T consultation.

The two credible network options, along with their net present values (NPVs) relative to the Base Case are summarised in Table 1. Option 2 is ranked first of the two credible options, with the highest NPV relative to the Base Case.

[1] Electricity Act 1994, Electrical Safety Act 2002 and Electricity Safety Regulation 2013

[2] The Rules clause 5.10.2, Definitions, reliability corrective action.

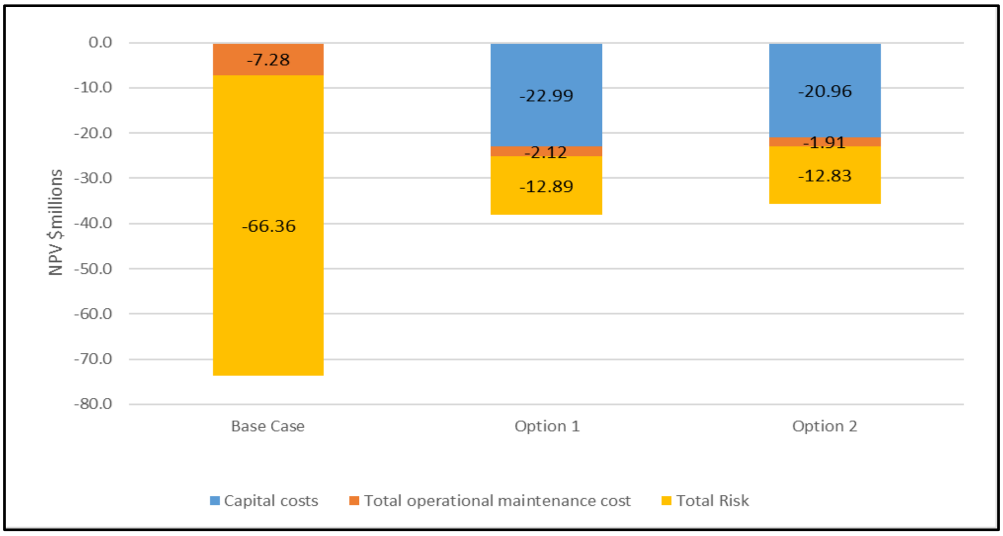
Table 1: Summary of credible RIT-T network options

Option	Description	Total Cost ($m) 2018/19	NPV relative to Base Case ($m) 2018/19	Ranking
Option 1	Replacement of two 132/66kV 80MVA transformers with two 100MVA transformers and full-bay replacement of primary plant in selected bays by October 2022.	25.39*	35.65	**2**
	Replacement of remaining 80MVA transformer with 100MVA transformer by December 2027	8.13†		
	TOTAL	**33.52**		
Option 2	Replacement of two 132/66kV 80MVA transformers with two 160MVA transformers and full-bay replacement of primary plant in selected bays by October 2022.	26.27*	37.95	**1**
	Decommissioning of remaining 80MVA transformer by December 2027	1.96†		
	TOTAL	**28.23**		

*RIT-T Project
†Future modelled projects (operational and capital).

The absolute NPVs of the Base Case and the credible options are negative, shown graphically in Figure 1. All options reduce the total risk and maintenance costs arising from the ageing and obsolete assets at Lilyvale remaining in service, with Option 2 having the largest reduction and reflecting a net economic benefit of $37.95 million compared to the Base Case.

Figure 1: NPV of Base Case and Options ($m, 2018/19)



Evaluation and Conclusion

The RIT-T requires that the proposed preferred option maximises the present value of net economic benefit, or minimises the net cost, to all those who produce, consume and transport electricity in the market.

In accordance with the expedited process for this RIT-T, the PSCR made a draft recommendation to implement Option 2, which delivers a net economic benefit of $37.95m compared to the Base Case.

The RIT-T project for Option 2 involves the replacement of two 132/66kV 80MVA transformers with two 160MVA transformers and the full bay replacement of primary plant in selected bays by October 2022. The substation's third 80MVA transformer will be decommissioned under a separate operational project by December 2027. The indicative capital cost of the RIT-T project for the preferred option is $26.27 million in 2018/19 prices.

Under Option 2, design work would commence in 2020 with the installation of the new transformers and primary plant completed by October 2022.

As the outcomes of the economic analysis contained in this PACR remain unchanged from those published in the PSCR, the draft recommendation has been adopted without change as the final recommendation, and will now be implemented.

1. Introduction

This Project Assessment Conclusions Report (PACR) represents the final step of the RIT-T process[3] prescribed under the National Electricity Rules (the Rules) undertaken by Powerlink to address the condition risks arising from the ageing and obsolete transformers and primary plant at Lilyvale Substation. It follows the publication of the Project Specification Consultation Report (PSCR) in May 2019.

The Project Specification Consultation Report (PSCR):

- described the identified need that Powerlink is seeking to address, together with the assumptions used in identifying this need
- set out the technical characteristics that a non-network option would be required to deliver in order to address the identified need
- described the credible options that Powerlink considered may address the identified need
- discussed specific categories of market benefit that in the case of this RIT-T assessment are unlikely to be material
- presented the Net Present Value (NPV) economic assessment of each of the credible options (as well as the methodologies and assumptions underlying these results) and identified the preferred option and that Powerlink was claiming an exemption from producing a Project Assessment Draft Report (PADR)
- invited submissions and comments, in response to the PSCR and the credible options presented, from Registered Participants, the Australian Energy Market Operator (AEMO), potential non-network providers and any other interested parties.

Powerlink identified Option 2, the replacement of two 132/66kV 80MVA transformers with two 160MVA transformers and the full bay replacement of primary plant in selected bays by October 2022, as the preferred option. The indicative capital cost of the RIT-T project for the preferred option is $26.27 million in 2018/19 prices.

The Rules clause 5.16.4(z1) provides for a Transmission Network Service Provider to claim exemption from producing a PADR for a particular RIT-T application if all of the following conditions are met:

- the estimated capital cost of the preferred option is less than $43 million
- the preferred option is identified in the PSCR noting exemption from publishing a PADR
- the preferred option, or other credible options, do not have a material market benefit, other than benefits associated with changes in involuntary load shedding[4]
- submissions to the PSCR did not identify additional credible options that could deliver a material market benefit.

There were no submissions received in response to the PSCR that closed for consultation on 21 August 2019. As a result, no additional credible options that could deliver a material market benefit have been identified as part of this RIT-T consultation. As the conditions for exemption are now satisfied, Powerlink has not issued a PADR for this RIT-T and is now publishing this PACR, which:

- describes the identified need and the credible options that Powerlink considers address the identified need
- discusses the consultation process followed for this RIT-T together with the reasons why Powerlink is exempt from producing a PADR

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[3] This RIT-T consultation was commenced in May 2019 and has been prepared based on the following documents: National Electricity Rules, Version 121, 2 May 2019 and AER, Application guidelines, Regulatory investment test for transmission, December 2018.

[4] Section 4.3 Project assessment draft report, Exemption from preparing a draft report, AER, Application guidelines, Regulatory investment test for transmission, December 2018

- provides a quantification of costs and reasons why specific classes of market benefit are not material for the purposes of this RIT-T assessment
- provides the results of the net present value (NPV) analysis for each credible option assessed, together with accompanying explanatory statements
- identifies the preferred option for investment by Powerlink and details the technical characteristics and proposed commissioning date of the preferred option.

2. Customer and non-network engagement

Delivering electricity to almost four million Queenslanders, Powerlink recognises the importance of engaging with a diverse range of customers and stakeholders who have the potential to affect, or be affected by, Powerlink's activities and/or investments.

2.1 Powerlink takes a proactive approach to engagement

Powerlink regularly hosts a range of engagement forums and webinars, sharing information with customers and stakeholders in the broader community. These engagement activities help inform the future development of the transmission network and assist Powerlink in providing services that align with the long term interests of customers. Feedback from these activities is also incorporated into a number of publicly available reports.

2.2 Working collaboratively with Powerlink's Customer Panel

Powerlink's Customer Panel provides a face-to-face opportunity for customers and consumer representative bodies to give their input and feedback about Powerlink's decision making, processes and methodologies. It also provides Powerlink with a valuable avenue to keep customers better informed, and to receive feedback about topics of relevance, including RIT-Ts.

The Customer Panel is regularly advised on the publication of Powerlink's RIT-T documents and briefed quarterly on the status of current RIT-T consultations, as well as upcoming RIT-Ts, providing an ongoing opportunity for:

- the Customer Panel to ask questions and provide feedback to further inform RIT-Ts
- Powerlink to better understand the views of customers when undertaking the RIT-T consultation process.

2.3 Transmission Annual Planning Report (TAPR) – the initial stage of public consultation

Powerlink utilises the TAPR as a primary vehicle to engage and understand broader consumer, customer and industry views on key topics as part of the annual Transmission Network Forum (TNF) and to inform its business network and non-network planning objectives. TNF participants encompass a diverse range of stakeholders including customers, landholders, environmental groups, Traditional Owners, government agencies, and industry bodies.

2.3.1 Maintaining transfer capabilities and reliability of supply at Lilyvale

- Powerlink identified in its TAPR from 2016, an expectation that action would be required at Lilyvale Substation to maintain transfer capabilities and reliability of supply to customers in the Central West transmission zone[5].
- The 2018 and 2019 TAPRs also discussed and provided technical information in relation to the identified need of this RIT-T.
- Members of Powerlink's Non-network Engagement Stakeholder Register (NNESR) were directly advised of the publication of the TAPR each year[6], including the accompanying compendium of potential non-network solution opportunities (Appendix F), which sets out

[5] This relates to the standard geographic definitions (zones) identified within the TAPR.
[6] More recently this also included the publication of a TAPR template containing detailed technical data for the connection point at Lilyvale Substation.

the indicative non-network requirements to meet the identified need at Lilyvale Substation. The NNESR were also advised of the publication of the PSCR for this RIT-T.

- The Customer Panel was advised of the upcoming RIT-T consultation for Lilyvale Substation in December 2018.

2.4 Powerlink applies a consistent approach to the RIT-T stakeholder engagement process

Powerlink undertakes a considered and consistent approach to ensure an appropriate level of stakeholder engagement is undertaken for each individual RIT-T. Please visit Powerlink's website for detailed information on the types of engagement activities, which may be undertaken during the consultation process. These activities focus on enhancing the value and outcomes of the RIT-T engagement process for customers and non-network providers. Powerlink welcomes feedback from all stakeholders to improve the RIT-T stakeholder engagement process.

3. Identified need

This section provides an overview of the existing arrangements at Lilyvale Substation and describes the increasing risk to reliability of supply to customers in the Central West transmission zone due to the assessed deteriorated condition of the transformers and selected primary plant assets at the substation.

3.1 Geographical and network need

Lilyvale Substation was established in 1980 to supply the mining load in the Bowen Basin and Blackwater Regions of Central Queensland. It connects the generation points in Central Queensland to the Blackwater and Bowen Basin mining regions, providing the main 275kV injection into western Central Queensland. This region of the network, in which Lilyvale is an integral node, also hosts a significant quantity of generation including levels of renewable and embedded generation.

Lilyvale Substation operates as a major transmission connection point supplying the Central Queensland distribution region owned and operated by Ergon Energy, mining and rail traction loads. The 66kV network fed from Lilyvale also supplies several direct connect mining customers that operate large draglines resulting in significant load fluctuations. The Central West transmission zone is shown in Figure 3.1.

Figure 3.1: Central West transmission zone

3.2 Description of asset condition and risks

Powerlink has undertaken a comprehensive condition assessment of the transformers and primary plant at Lilyvale Substation. This has identified that a significant amount of equipment is exhibiting age-related deterioration issues and reaching the end of its technical service life, with an increasing risk of failure.

This deteriorated primary plant is requiring additional maintenance and displaying reduced performance due to increased failures and an increased number of outages for repairs. The time taken for repairs is increasing significantly, as much of this plant is no longer supported by the manufacturer, with only limited spares available.

Notwithstanding the assessed condition of the asset, Powerlink’s ongoing operational maintenance practices are designed to monitor plant condition and ensure any emerging safety risks are proactively managed.

Power Transformers

Commissioned over 38 years ago, the original 132/66kV transformers are all exhibiting signs of age-related deterioration, particularly by the condition of their oil and paper insulation, main tank and bushing seals as well as the corrosion of external fittings. Transformers 3 and 4 are assessed to be in a more deteriorated condition than Transformer 7 and provide an emerging risk to the reliable and safe supply of electricity to customers at Lilyvale, and more broadly into the central west transmission zone.

Protective galvanised coatings have begun to break down on several components including radiators, connecting pipework, control system cabinets, bushing mountings and flanges. The sealing integrity of numerous joints and valves has been compromised, resulting in an increased observation of oil leaks at radiators, bushings and the conservator tank.

Analysis has also shown the transformers’ winding paper insulation has deteriorated and is nearing the end of its technical service life, with approximately three years of reliable operation remaining for Transformers 3 and 4. While Transformer 7 has experienced some insulating paper degradation, the measurements indicate there are approximately eight years remaining before it will reach the end of its technical service life.

The design of the winding clamping mechanism used in these older transformers also results in a loss of residual clamping pressure as the paper deteriorates, reducing the overall resilience of the transformers to through faults. The failure of transformer insulation during a through fault can have major consequences to reliability of supply, safety and the environment because of the potential for oil loss and fire.

A number of components on Transformers 3 and 4 have been repaired and/or replaced due to numerous failures.

The age and design of the transformers also means that replacements for many key components are now no longer available; hence, obsolescence has also become an issue with ongoing maintenance of the transformers.

Primary Plant

At-risk primary plant comprises circuit breakers, current and voltage transformers, isolators, earth switches and surge arrestors.

Circuit Breakers

Installed in the 1980s, the substation’s ageing circuit breakers are no longer supported by their manufacturers and sourcing spare parts has become a major issue. Low air pressure in the breakers’ compressor systems has resulted in a number of outages, while the wiring inside several mechanism boxes has cracked due to UV penetration through the boxes’ sight glasses. SF6 gas leaks have also become a major issue on four circuit breakers procured in 1985, with the supplier no longer manufacturing HV circuit breakers.

The deteriorated state of these original circuit breakers has resulted in an increasing frequency of unplanned outages and prolonged repair times due to the lack of spares and no manufacturer support. These circuit breakers also contain friable asbestos that requires additional safety precautions when working on the units.

With limited spares available from the manufacturers, it is becoming increasingly difficult for Powerlink to service this ageing population of circuit breakers more broadly across the Powerlink transmission network.

Current and Voltage Transformers

Insulation breakdown and oil leaks pose the biggest risk to the ongoing operation of the ageing current and voltage transformers at Lilyvale Substation. The ageing process has the most significant impact on the integrity of the various seals. The deteriorated state of the aged seals has led to moisture ingress into the insulating oil causing it to breakdown. As the transformer's insulating oil breaks down, it releases a combination of combustible gases and loses its insulating properties.

The moisture migrates into the paper insulation causing its rapid degradation. The insulating paper degradation combined with continuing degradation of the oil ultimately results in the occurrence of partial discharges across insulation, which can result in arcing in the presence of highly combustible gases, leading to an increased probability of catastrophic failure. The oil is contained within porcelain housings, which can rupture when failure occurs, resulting in safety risks, reliability of supply impacts, and potential damage to adjacent equipment and plant requiring repairs and incurring financial costs.

3.3 Consequences of Lilyvale primary plant and transformer failures

Poor asset condition increases the risk and frequency of faults, while obsolescence increases the time needed for Powerlink to undertake any necessary repairs prolonging the return to service time. The potential in-service failure of ageing and obsolete transformers and primary plant at Lilyvale presents Powerlink with a range of unacceptable safety, network and financial risks, and the inability to meet legislative obligations and customer service standards.

The condition and consequences of failure of the main at-risk items of equipment is summarised in Table 3.1.

Table 3.1: Lilyvale at-risk assets and consequences of failure

Equipment	Condition/Issue	Consequence of failure
Circuit Breakers	• Loss of pneumatic pressure • Release of SF6 gas into the atmosphere • Frequent maintenance required to add SF6 to ensure the CB remains functional • Limited availability of spares	• Failure to operate or slow clearance times resulting in safety and supply risks • Extended time to restore supply to customers due to a limited availability of spares • Potential environmental impacts • Increased maintenance resulting in less reliable and more costly supply to customers
Current Transformers	• Degraded oil and paper insulation inside porcelain housings • Oil leaks.	• Significant safety, financial, environmental and loss of supply risks • Potential for explosive failure modes leading to damage of other equipment and extended loss of supply

Equipment	Condition/Issue	Consequence of failure
Voltage Transformers	• Degraded oil and paper insulation inside porcelain housings • Oil leaks and overheating	• Significant safety, financial, environmental and loss of supply risks • Potential for explosive failure modes leading to damage of other equipment and loss of supply • Loss of protection signals resulting in disconnection of supply • Breach of metering requirements[7]
Power Transformers	• Degraded oil and paper insulation • Deteriorated cooling fans and radiators • Significant oil leaks. • Reduced clamping pressure due to clamp design • Loss of insulating paper strength • Limited availability of spares	• Increased susceptibility of power transformer failure during through faults leading to loss of supply with long return to service time. • Risk of fire and environmental damage.

Notwithstanding the assessed condition of the asset, Powerlink's ongoing operational maintenance practices are designed to monitor plant condition and ensure any emerging safety risks are proactively managed.

3.4 Description of identified need

With peak demand forecast to remain steady in the area for the next ten years[8], it is vital that Powerlink maintains supply to satisfy this demand and meet its reliability obligations under its Transmission Authority, the Electricity Act 1994 and the Rules[9].

It follows that the increasing likelihood of faults arising from the deteriorated condition of the at-risk transformers and primary plant remaining in service at Lilyvale Substation compels Powerlink to take action if it is to continue to meet its regulatory obligations and the standards for reliability of supply set out in the Rules.

Powerlink's Transmission Authority requires it to plan and develop the transmission network "in accordance with good electricity industry practice, having regard to the value that end users of electricity place on the quality and reliability of electricity services". It allows load to be interrupted during a critical single network contingency, provided the maximum load and energy will not exceed 50MW at any one time, or will not be more than 600MWh in aggregate[10].

In order to continue to meet the reliability standard within Powerlink's Transmission Authority, the services currently provided Lilyvale Substation are required for the foreseeable future to meet ongoing customer requirements.

Under the Electricity Act 1994, Powerlink is required to "operate, maintain (including repair and replace if necessary) and protect its transmission grid to ensure the adequate, economic reliable and safe transmission of electricity"[11]. The condition of the ageing assets at Lilyvale requires Powerlink to take action to either repair, replace or remove them, while taking into consideration the enduring need for the services they provide, to ensure compliance with the Electricity Act 1994.

The Electrical Safety Act 2002 also requires Powerlink to operate its network in a manner that ensures electrical risk to a person or property has been eliminated, so far as is reasonably

[7] Chapter 7, Part D, Metering Installation and Schedule 7.2 Metering Provider, AER
[8] Powerlink Transmission Annual Planning Report 2019
[9] Transmission Authority Number T01/98, as amended 30 June 2014; Electricity Act 1994; The Rules, Schedule 5.1a System Standards and Schedule 5.1.2 Network Reliability
[10] Transmission Authority No. T01/98, section 6.2(c)
[11] Electricity Act 1994, Chapter 2, Part 4, S34(1)(a)

practicable; or if it is not reasonably practicable to eliminate electrical risk to the person or property, the risk has been minimised so far as is reasonably practicable[12].

As the proposed investment is to meet reliability and service standards specified within applicable regulatory instruments, and to ensure Powerlink's ongoing compliance with its Transmission Authority and Schedule 5.1 of the Rules, it is classified as a "reliability corrective action", under the RIT-T[13].

A reliability corrective action differs from that of an increase in producer and consumer surplus (market-benefit) driven need in that the preferred option may have a negative net economic outcome because it is required to meet an externally imposed obligation on the network business.

3.5 Rules, Jurisdictional and Legislative Compliance

The consequences of Lilyvale's Transformers 3 and 4 and at-risk primary plant remaining in service beyond 2022, without corrective action, would result in Powerlink being exposed to an unacceptable risk of breaching a number of its jurisdictional network, safety, environmental and Rules' obligations - resulting in poor customer, safety and environmental outcomes.

Allowing the ageing and obsolete transformers to remain in service beyond 2022 without corrective action increases the potential risk of catastrophic failure. This would lead to a breach of Powerlink's obligations under the Electrical Safety Act 2002, the Electrical Safety Regulations 2013, Work Health and Safety Act 2011and Environmental Protection Act 1994, as well as its service standards under the Electricity Act 1994 and it's Queensland Transmission Authority[14].

Similarly, the failure of the circuit breakers to operate or clear faults in sufficient time to avoid damage to the power system could leave Powerlink unable to comply with Schedule 5.1 of the Rules[15], or meet its public safety and supply obligations to its customers. Corrective action is also required to prevent the failure of deteriorated current and voltage transformers, in order to ensure the safety of personnel, and that the plant operates as designed in accordance with the requirements of the Electrical Safety Regulations 2013 Part 1 Section 3 and Part 9 Section 198.

Removing the deteriorated assets from service will in many cases eliminate the risk of breaching these obligations. However, removing the assets from the Powerlink network without a suitable network or non-network alternative will result in Powerlink not complying with the Rules or its Transmission Authority, as discussed below.

The removal of the power transformers or any of the circuit breakers, or other affected primary plant, at Lilyvale will result in the need for load shedding to ensure that the system is able to be operated without breaching clause 4.2.2(d) of the Rules:

> *"all other plant forming part of or impacting on the power system is being operated within the relevant operating ratings (accounting for time dependency in the case of emergency ratings) as defined by the relevant Network Service Providers in accordance with schedule 5.1."*

The load shedding requirement under an intact system, as well as for a credible contingency, would result in breaches of Powerlink's Transmission Authority T01/98 clause 6.2 (c), where Powerlink must plan and develop its transmission network such that:

> *"the power transfer available through the power system will be such that the forecast of electricity that is not able to be supplied during the most critical single network element outage will not exceed:*
>
> *(i) 50 megawatts at any one time; or*
>
> *(ii) 600 megawatt-hours in aggregate."*

---

[12] Electrical Safety Act 2002 sections 10 and 29

[13] The Rules clause 5.10.2, Definitions, reliability corrective action.

[14] *Section 29, Electrical Safety Act 2002*; *Part 1, Section 3, and Part 9, Section 198, Electrical Safety Regulations 2013; Section 19, Work Health and Safety Act 2011*; *Chapter 7, Part 1, Division1 Section 319(1), Environmental Protection Act 1994*; *Section 34 (1)a Electricity Act 1994*; Queensland Transmission Authority T01/98

[15] The Rules Schedule 5.1.9 Protection systems and fault clearance times

By addressing the risks arising from the condition of ageing and obsolete assets at Lilyvale, Powerlink is seeking to ensure it can continue to safely deliver an adequate, economic, and reliable supply of electricity to its customers into the future.

4. Submissions received

There were no formal submissions received in response to the PSCR that was open for consultation until the 21 August 2019.

Interest was shown by three non-network proponents in response to the PSCR, with subsequent discussions being held with two. However, the proponents ultimately decided not to progress with any formal submissions. As a result, no additional credible options to meet the identified need were identified as part of this RIT-T consultation.

5. Credible options assessed in this RIT-T

Powerlink has developed two credible network options to address the identified need for maintaining power transfer capabilities and reliability of supply at Lilyvale Substation. In both options, work commences for the RIT-T project in 2020, with commissioning in October 2022.

- Option 1: Replacement of two 132/66kV 80MVA transformers with 100MVA transformers and full-bay replacement of primary plant in selected bays by October 2022. Replacement of the remaining 80MVA transformer with a 100MVA transformer by December 2027. The RIT-T portion of this option would be completed by October 2022 at a cost of $25.39 million in 2018/19 prices.
- Option 2: Replacement of two 132/66kV 80MVA transformers with two 160MVA transformers and full-bay replacement of primary plant in selected bays by October 2022. Decommissioning of the remaining 80MVA transformer by December 2027. The RIT-T project component portion of this option would be completed by October 2022 at a cost of $26.27 million in 2018/19 prices.

Due to the higher rating of the new transformers installed under Option 2, Transformer 7 will not be replaced at the end of its technical service life in 2027, resulting in a configuration consisting of two, 160MVA 132/66kV transformers at Lilyvale instead of three. Option 1 however will result in a substation configuration consisting of three 132/66kV 100MVA transformers in 2027.

Table 5.1 provides a summary of the options, along with indicative capital and annual operational and maintenance costs.

Table 5.1: Summary of credible options

Option	Description	Indicative project costs ($million, 2018/19)	Indicative annual average O&M costs ($million, 2018/19)
Option 1	Replacement of 3 and 4 power transformers with two 100MVA transformers and full replacement of 132kV and 275kV primary plant in selected bays by October 2022*	25.39*	0.16
	Replacement of 7 transformer with a third 100MVA transformer and full replacement of primary plant in associated bays by December 2027†	8.13†	

Option	Description	Indicative project costs ($million, 2018/19)	Indicative annual average O&M costs ($million, 2018/19)
Option 2	Replacement of 3 and 4 power transformers with two 160MVA transformers and full replacement of 132kV and 275kV primary plant in selected bays by October 2022*	26.27*	0.14
	Decommissioning of transformer 7 by December 2027†	1.96†	

*Proposed RIT-T project
†Future modelled projects (operational and capital)

All credible options address the major risks resulting from the deteriorated condition of ageing transformers and primary plant at Lilyvale Substation and allow Powerlink to maintain compliance with obligations specified in its Transmission Authority, Schedule 5.1 of the Rules and applicable regulatory instruments. None of these options has been discussed by the Australian Energy Market Operator (AEMO) in its most recent National Transmission Network Development Plan (NTNDP)[16].

5.1 Material inter-network impact

Powerlink does not consider that any of the credible options being considered will have a material inter-network impact, based on AEMO's screening criteria[17].

6. Materiality of market benefits

The Rules require that all categories of market benefits identified in relation to a RIT-T be quantified, unless the Transmission Network Service Provider (TNSP) can demonstrate that a specific category (or categories) is unlikely to be material.

6.1 Market benefits that are material for this RIT-T assessment

Powerlink considers that changes in involuntary load shedding (i.e. the reduction in expected unserved energy) between the options, set out in this PSCR, may impact the ranking of the credible options under consideration and that this class of market benefit could be material. Consequently, these benefits have been quantified and included within the cost benefit and risk cost analysis as network risk.

6.2 Market benefits that are not material for this RIT-T assessment

The AER has recognised a number of classes of market benefits may not be material in the RIT-T assessment and so do not need to be estimated[18]. Other than market benefits associated with involuntary load shedding, Powerlink does not consider any other category of market benefits to be material, and had not estimated them as part of this RIT-T.

More information on consideration of individual classes of market benefits can be found in the PSCR.

[16] Clause 5.16.4(b) (4) of the Rules requires Powerlink to advise whether the identified need and or solutions are included in the most recent NTNDP. The 2018 NTNDP is currently the most recent NTNDP.
[17] In accordance with Rules clause 5.16.4(b) (6) (ii). AEMO has published guidelines for assessing whether a credible option is expected to have a material inter-network impact.
[18] AER, Application guidelines, Regulatory investment test for transmission, December 2018.

7. Base Case

7.1 Modelling a Base Case under the RIT-T

Consistent with the RIT-T Application Guidelines the assessment undertaken in this PACR[19] compares the costs and benefits of credible options to address the risks arising from an identified need, with a Base Case[20].

As characterised in the RIT-T Application Guidelines, the Base Case itself is not a credible option to meet the identified need. Specifically, the Base Case reflects a state of the world in which the condition of the ageing asset is only addressed through standard operational activities, with escalating safety, financial, environmental and network risks.

To develop the Base Case, the existing condition issues associated with an asset are managed by undertaking operational maintenance only, which results in an increase in risk levels as the condition of the asset deteriorates over time. These increasing risk levels are assigned a monetary value that is used to evaluate the credible options designed to offset or mitigate these risk costs.

The Base Case therefore includes the costs of work associated with operational maintenance (i.e. routine, condition-based and corrective maintenance) and the risk costs associated with the irreparable failure of the asset. The costs associated with irreparable failures are modelled in the risk cost analysis and are not included in the corrective maintenance costs.

The Base Case acts as a benchmark and provides a clear reference point in the cost benefit analysis to compare and rank the credible options against, over the same timeframe.

7.2 Lilyvale Base Case risk costs

Powerlink has developed a risk modelling methodology consistent with the RIT-T Application Guidelines. An overview document of the methodology is available on Powerlink's website[21] and this has been used to calculate the risk costs of the Lilyvale Base Case. The document includes the modelling methodology and general assumptions underpinning the analysis.

7.2.1 Base Case assumptions

In calculating the potential unserved energy (USE) arising from a failure of the ageing and obsolete transformers and primary plant at Lilyvale, the following modelling assumptions specific to the Lilyvale network configuration have been made:

- A suitable spare transformer is available as an emergency replacement in the event of non-repairable failure of one of the aged transformers.
- The downstream Ergon Energy 66kV distribution network supplying the greater Lilyvale and Blackwater area is available to provide a level of backup supply in the event of equipment failure.
- Embedded generation within the area operates while Lilyvale Substation remains energised to reduce the impacts of unserved energy in the event of equipment failures.
- Historical load profiles and embedded generation patterns have been used when assessing the likelihood of unserved energy under concurrent failure events.
- Peak demand for the greater Lilyvale load area consistent with medium demand forecasts published within Powerlink's 2018 Transmission Annual Planning Report have been used[22].
- Unserved energy generally accrues under concurrent failure events, and consideration has been given to potential feeder trip events within the wider Lilyvale area.
- The Lilyvale load comprises of a mix of load types, including open cut mining, underground mining, traction loads, and residential township. The network risk cost models have used

[19] The economic assessment was also presented in the PSCR.
[20] AER, Application guidelines, Regulatory investment test for transmission, December 2018.
[21] The risk costs are calculated using the principles set out in the Powerlink document, Overview of Asset Risk Cost Methodology, May 2019.
[22] The forecast remains unchanged in the 2019 TAPR.

the Queensland regional Value of Customer Reliability (VCR) published within AEMO 2014 Value of Customer Reliability Review Final Report ($39,710/MWh).

- Powerlink's business response to mitigating unserved energy under prolonged supply outage events has been incorporated within the risk cost modelling.

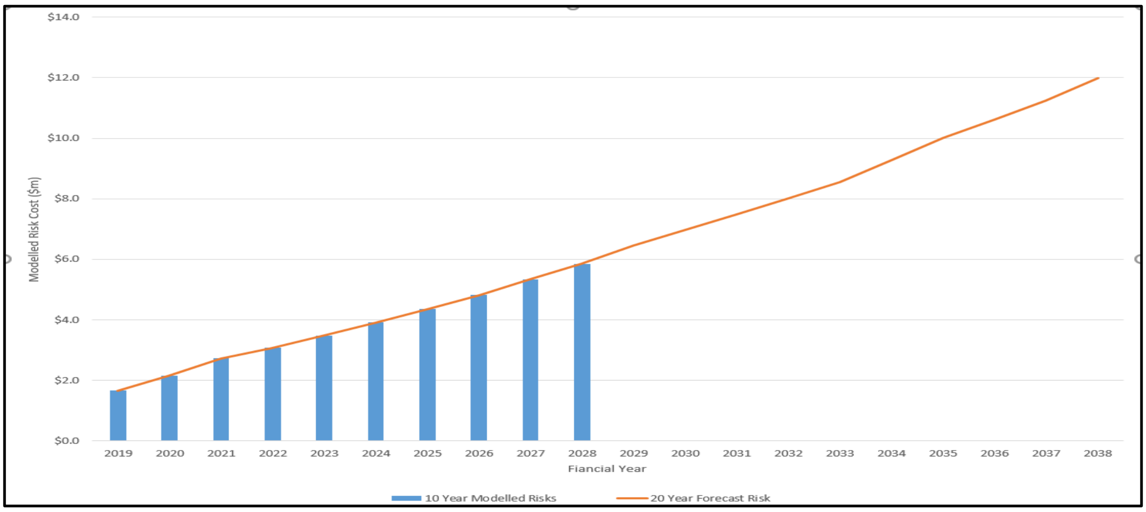
7.2.2 Base Case risk costs

The main areas of risk cost are network risks that involve reliability of supply through the failure of the deteriorated primary plant and transformers modelled as probability weighted unserved energy[23], financial risk costs associated mostly with the replacement of failed assets in an emergency and safety risks. These risks increase over time as the condition of assets further deteriorates and the likelihood of failure rises.

Based upon the assessed condition of the ageing transformers and primary plant at Lilyvale, the total risk costs are projected to increase from $1.67 million in 2019 to $11.9 million in 2038.

The 20-year forecast of risk costs for the Base Case is shown in Figure 7.1.

Figure 7.1: Modelled Base Case risk costs



7.3 Modelling of Risk in Options

Each option is specifically scoped to mitigate the major risks arising in the Base Case in order to maintain compliance with all statutory requirements. The residual risk is calculated for each option based upon the individual implementation strategy of the option. This is included with the capital and operational maintenance cost of each option to develop the NPV inputs.

8. General modelling approach adopted for net benefit analysis

8.1 Analysis period

The RIT-T analysis has been undertaken over a 20-year period, from 2019 to 2038. A 20-year period takes into account the size and complexity of the replacement primary plant and transformer investment.

For all options, there will be remaining asset life by 2038, at which point a terminal value is calculated to account for capital costs under each credible option.

[23] Unserved Energy is modelled using a Value of Customer Reliability (VCR) consistent with that published by AEMO in their *Value of Customer Reliability Review, Final Report*, September 2014.

8.2 Discount rate

Under the RIT-T, a commercial discount rate is applied to calculate the NPV of costs and benefits of credible options. Powerlink has adopted a real, pre-tax commercial discount rate of 5.90%[24] as the central assumption for the NPV analysis presented in this report.

Powerlink has tested the sensitivity of the results to changes in this discount rate assumption, and specifically to the adoption of a lower bound discount rate of 3.47%[25] and an upper bound discount rate of 8.33% (i.e. a symmetrical upwards adjustment).

8.3 Description of reasonable scenarios

The RIT-T analysis is required to incorporate a number of different reasonable scenarios, which are used to estimate market benefits. The number and choice of reasonable scenarios must be appropriate to the credible options under consideration.

The choice of reasonable scenarios must reflect any variables or parameters likely to affect the ranking of the credible options, where the identified need is reliability corrective action[26].

Powerlink has considered capital costs and discount rate sensitivities individually and in combination and found that these variables do not affect the relative rankings of credible options or identification of the preferred option. As sensitivities (both individually and in combination) do not affect ranking results, Powerlink has elected to present one central scenario in Table 8.1.

Table 8.1: Reasonable scenario assumed

Key variable/parameter	Central scenario
Capital costs	100% of central capital cost estimate
Discount rate	5.90%

9. Cost benefit analysis and identification of the preferred option

9.1 NPV Analysis

Table 9.1 outlines the net present value for each credible option and the corresponding ranking of each credible option, relative to the Base Case.

Table 9.1: NPV of credible options ($m, 2018/19)

Option	Central Scenario NPV relative to Base Case ($m)	Ranking
Option 1 Replacement of two 132/66kV 80MVA transformers with two 100MVA transformers and full-bay replacement of primary plant in selected bays by October 2022. Replacement of remaining 80MVA transformer with 100MVA transformer by December 2027	35.65	2

[24] This indicative commercial discount rate has been calculated on the assumptions that a private investment in the electricity sector would hold an investment grade credit rating and have a return on equity equal to an average firm on the Australian stock exchange, as well as a debt gearing ratio equal to an average firm on the Australian stock exchange.

[25] A discount rate of 3.47% is based on the AER's Final Decision for Powerlink's 2017-2022 transmission determination, which allowed a nominal vanilla WACC of 6.0% and forecast inflation of 2.45% that implies a real discount rate of 3.47%. See AER, *Final Decision: Powerlink transmission determination 2017-2022 | Attachment 3 – Rate of return*, April 2017, p 9.

[26] AER, *Final Regulatory Investment Test for Transmission*, June 2010, version 1, paragraph 16, p. 7

Option	Central Scenario NPV relative to Base Case ($m)	Ranking
Option 2 Replacement of two 132/66kV 80MVA transformers with two 160MVA transformers and full-bay replacement of primary plant in selected bays by October 2022. Decommissioning of remaining 80MVA transformer by December 2027	37.95	1

Both credible options will address the identified need on an enduring basis. Option 2 is ranked first, with Option 1 being $2.3 million more expensive compared to Option 2 in NPV terms.

Option 2 is identified as the preferred option as it maximises the net economic benefit relative to the Base Case.

Figure 9.1: NPV of Base Case and Options ($m, 2018/19)

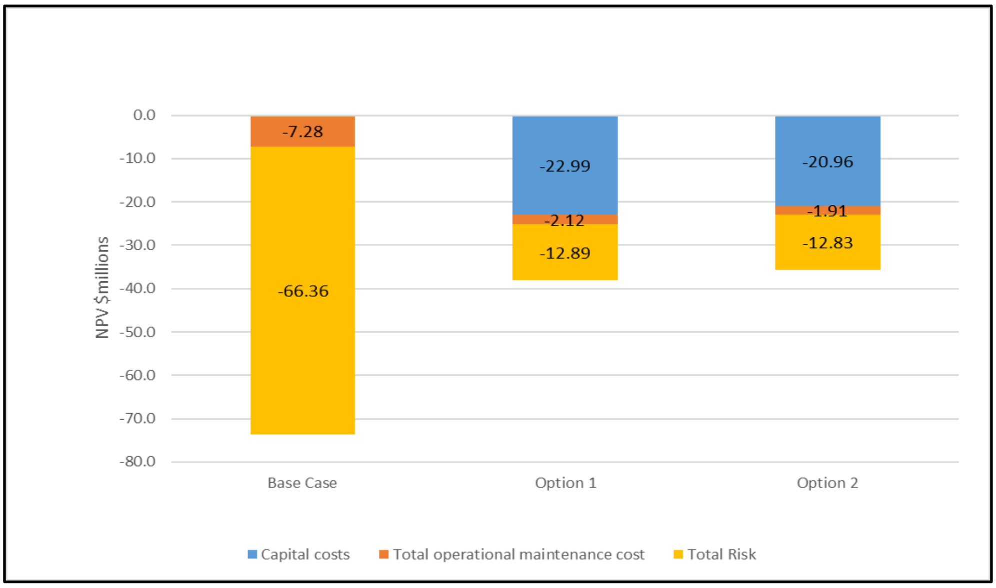


Figure 9.1 sets out the breakdown of capital cost, operational maintenance cost and total risk cost for each option in NPV terms under the central scenario. It illustrates that the capital investment for the two credible options, that address risks arising from the transformers and primary plant at Lilyvale Substation, will result in benefits from a reduction in risk costs, as well as a reduction in operational maintenance costs when compared to the Base Case. Note that the non-credible Base Case consists of operational maintenance and total risk costs and does not include any capital expenditure.

The reduction in operational maintenance costs is similar for both Option 1 and Option 2, though there is a greater reduction in Option 2, as the ultimate configuration for Option 2 results in only two 132/66kV transformers from 2027 instead of three as for Option 1.

Similarly, the reduction in risk costs is comparable between the options, resulting in a slightly greater reduction in Option 2; mostly due to less financial and safety risks associated with the ultimate two 132/66 kV transformer configuration.

9.2 Sensitivity analysis

Powerlink has investigated the following sensitivities on key assumptions:

- a range from 3.47% to 8.33% for discount rate
- a range from 75% to 125% for capital expenditure estimates
- a range from 75% to 125% for operational maintenance expenditure estimates
- a range from 75% to 125% for total risk cost estimates.

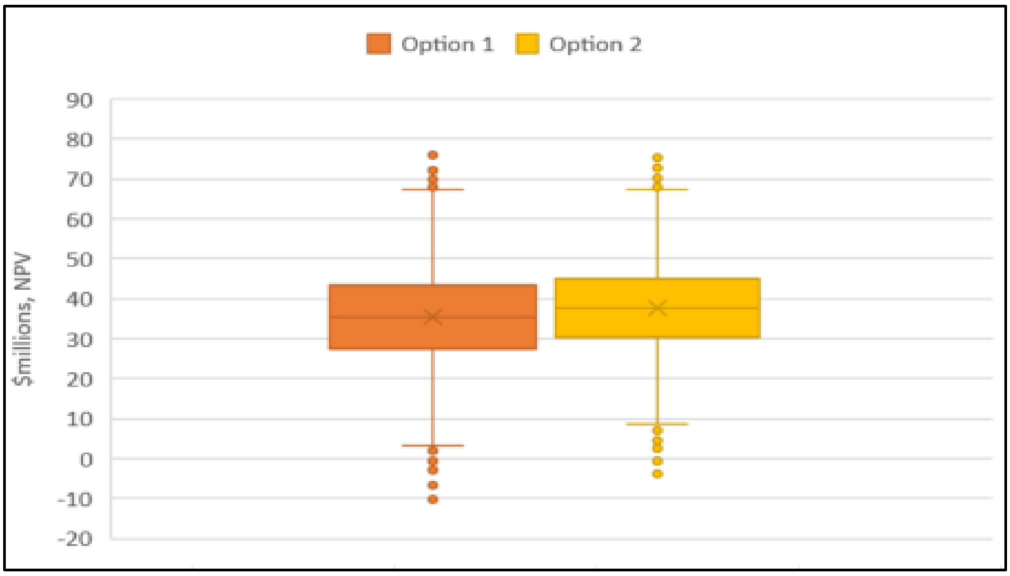
Sensitivity analysis for the NPV relative to the Base Case shows that varying the discount rate, capital expenditure, operational maintenance expenditure and total risk costs has no impact on option rank, and hence which is the preferred option.

9.3 Sensitivity to multiple key assumptions

A Monte Carlo Simulation was performed with multiple input parameters (including capital cost, discount rate, operational maintenance cost, corrective maintenance cost and total risk costs) generated for the calculation of NPV for each option. This process is repeated over 5000 iterations, each time using a different set of random variable from the probability function. The sensitivity analysis output is presented as a distribution of possible NPVs for each option, as illustrated in Figure 9.2.

The Monte Carlo simulation results identify that Option 2 has slightly less statistical dispersion in comparison with Option 1 and its mean and median is the higher of the two options. This confirms Option 2 as the preferred option and shows it to be robust over a range of input parameters in combination.

Figure 9.2: NPV sensitivity analysis of multiple key assumptions relative to the Base Case



10. Preferred option

Based on the conclusions drawn from the NPV analysis and the Rules requirements relating to the proposed replacement of transmission network assets, it is recommended that Option 2 be implemented to address the risks arising from the deteriorated condition of the ageing transformers and primary plant at Lilyvale Substation. Implementing this option will provide an ongoing safe and reliable electricity supply to customers in the area and ensure continued compliance with applicable regulatory instruments and the Rules.

The result of the cost benefit analysis indicates that Option 2 has the highest net economic benefit over the 20-year analysis period. Sensitivity testing shows that the analysis is robust to variations in the capital cost, operational maintenance cost, discount rate and risk cost assumptions. Option 2 is therefore considered to satisfy the requirements of the RIT-T and is the preferred option.

11. Conclusions

The following conclusions have been drawn from the analysis presented in this report:

- Powerlink has identified condition risks arising from the ageing transformers and primary plant at Lilyvale Substation.
- TNSPs must maintain (including repair and replace if necessary) their transmission network to ensure the adequate, economic, reliable and safe transmission of electricity, including the ability to meet peak demand if a major element of the network was to fail.

- The increasing likelihood of faults arising from the condition of the ageing transformers and primary plant compels Powerlink to undertake reliability corrective actions at Lilyvale Substation if it is to continue meeting the reliability standards set out in its Transmission Authority and to ensure ongoing compliance with the Rules and relevant jurisdictional obligations.
- Studies were undertaken to evaluate two credible options. The two credible options were evaluated in accordance with the AER's RIT-T.
- Powerlink published a PSCR in May 2019 requesting submissions from Registered Participants, AEMO and interested parties on the credible options presented, including alternative credible non-network options, which could address the condition risks arising from the transformers and primary plant at Lilyvale Substation.
- The PSCR also identified the preferred option and that Powerlink was adopting the expedited process for this RIT-T, claiming exemption from producing a PADR as allowed for under the Rules Clause 5.16.4(z1) for investments of this nature.
- There were no formal submissions received in response to the PSCR, which was open for consultation until 21 August 2019. As a result, no additional credible options that could deliver a material market benefit have been identified as part of this RIT-T consultation. The conditions specified under the Rules for exemption have now been fulfilled.
- The result of the cost benefit analysis under the RIT-T identified that Option 2 is the least cost solution, providing the greatest economic benefit, over the 20 year analysis period. Sensitivity testing showed the analysis is robust to variations in discount rate, capital expenditure, operational maintenance expenditure and risk cost assumptions. As a result, Option 2 is considered to satisfy the RIT-T.
- The outcomes of the economic analysis contained in this PACR remain unchanged from those published in the PSCR. Consequently, the draft recommendation has been adopted without change as the final recommendation and will now be implemented.

12. Final Recommendation

Based on the conclusions drawn from the NPV analysis and the Rules requirements relating to the proposed replacement of transmission network assets, it is recommended that Option 2 be implemented to address the risks arising from the condition of the ageing transformers and primary plant at Lilyvale Substation. Option 2 allows Powerlink to continue to maintain compliance with its Transmission Authority, Schedule 5.1 of the Rules and other applicable regulatory instruments, while delivering a net economic benefit of $37.95m compared to the Base Case.

Option 2 involves the replacement of two 132/66kV 80MVA transformers with two 160MVA transformers and the full bay replacement of primary plant in selected bays by October 2022. The substation's third 80MVA transformer will be decommissioned by December 2027 under a separate operational project.

The indicative capital cost of the RIT-T project for the preferred option is $26.27 million in 2018/19 prices. Powerlink is the proponent of this network solution.

Under Option 2, design work would commence in 2020 with the installation of the new transformers and primary plant completed by October 2022.

Powerlink will now proceed with the necessary processes to implement this recommendation.

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