2023-27 POWERLINK QUEENSLAND REVENUE PROPOSAL

Project Pack – PUBLIC

CP.02371 Bouldercombe Transformers 1 and 2 Replacement

CP.02371 – H010 Bouldercombe – Transformers 1 and 2 Replacement

Project Status: Approved

1. Network Need

Bouldercombe Substation, approx. 19km southwest of Rockhampton, is a major transmission node for central Queensland and the sole 132kV injection point for Energy Queensland's Rockhampton distribution area. Bouldercombe Substation contains two aged 275/132kV 200MVA transformers (T1 and T2). An outage on these transformers would leave up to over 200MW of customer load per day at risk[2].

A Condition Assessment (CA) issued in December 2015 identified that T1 and T2, which are both 43 years old (commissioned in 1977), are expected to reach the end of their technical service life in 2020[1]. T1 and T2 are exhibiting the following end of life attributes: HV & LV bushings have exceeded their design life, oil leaks and deteriorated gaskets, areas of corrosion on radiators and structural footings, deteriorating oil quality. The CA found that a series of refit works were required to address these issues and enable T1 and T2 to remain in service.

Energy Queensland forecasts confirm there is an enduring need to maintain electricity supply to the Rockhampton area. The removal or failure of T1 or T2 at Bouldercombe Substation, would violate Powerlink's Transmission Authority reliability obligations (N-1-50MW/maximum 600MWh unserved energy)[2].

Further decline in T1 and T2 asset condition increases the risk of failure that may cause network outages, safety incidents and additional network costs to replace assets under emergency conditions or extended outage times due to limited or no available spares. The CA recommends reinvestment in the asset prior to 2020 to manage these risks and ensure network reliability. Failure to address the existing condition of this asset is likely to result in non-compliance with Powerlink's reliability and safety obligations[7].

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[6].

The preferred option is to replace T1 and T2 with a single 250MVA transformer at Bouldercombe Substation by December 2021[4]. A separate project has been raised to replace primary plant in selected bays, which is referenced in the same RIT-T documentation. This option was preferred due to it being the lowest cost in NPV terms, whilst providing sufficient capacity for load growth and minimum number of site mobilisations.

The following options were identified but not preferred:

- Do Nothing – rejected due to non-compliance with reliability standards.
- Remove T1 & T2 from service – rejected due to non-compliance with reliability standards.
- Replace T1 & T2 like for like – rejected as it did not reflect prudent investment due to a lower forecast load profile than the combined rated capacity.
- Replace T1 & T2 with a single transformer including select primary plant – five options covering various transformer sizes and primary plant staging and timing were considered but not preferred through the RIT-T process.
- Non Network Option – no viable options were identified, and no public submissions were received through the RIT-T process.

The recommended option will extend the asset life by 40 years.

Where a 'Do Nothing' scenario is adopted (see Figure 2-1), the forecast level of risk associated with the asset escalates to over $500k per annum in 2030.

This is predominantly due to network risks (unserved energy) associated with potential outages of T1 and T2[3]. This annual risk profile is expected to escalate rapidly to over $2m from 2039.

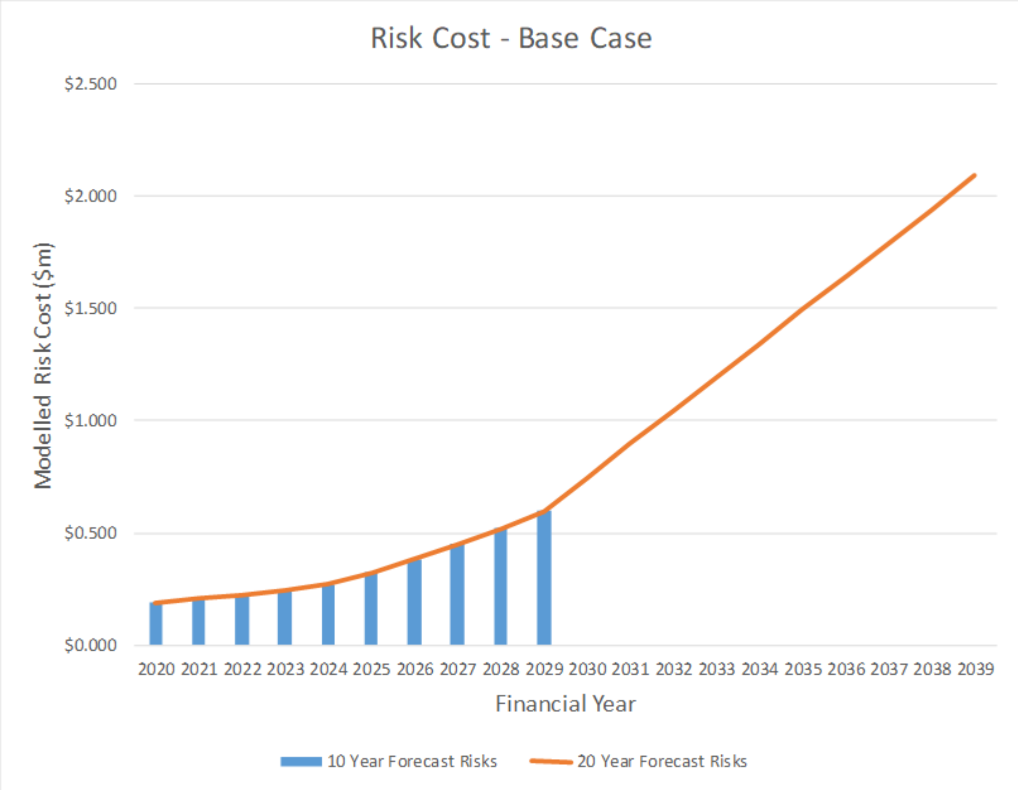

Figure 2-1 Annual Risk Monetisation Profile (Nominal)

3. Cost and Timing

The estimated cost to replace T1 and T2 with a single standard 250MVA transformer is $7.9m ($2018/19 Base)[5].

Target Commissioning Date: December 2021

4. Documents in CP.02371 Project Pack

Public Documents

1. H010 Bouldercombe Transformer T1 & T2 Condition Assessment
2. Bouldercombe Planning Report
3. Base Case Risk Summary Report CP.02371 Bouldercombe 1T and 2T Replacement
4. Project Scope Report CP.02371 H010 Bouldercombe No.1& 2 Transformer Replacement
5. CP.02371 H010 Bouldercombe No.1 & 2 Transformer Replacement Project Management Plan at Concept
6. Project Assessment Conclusions Report – Maintaining power transfer capability and reliability of supply at Bouldercombe Substation

Supporting Documents

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

H010 Bouldercombe Transformer T1 & T2 Condition Assessment

Report requested by:	[redacted]	**Requested Completion Date:**	30/10/2015
Report Prepared by:	[redacted]	**Date of site visit:**	11/06/2015
AUTHOR/S:	[redacted] *Team Leader Primary Design Standards & Asset Investigations*		
Report Approved by:	[redacted] *- Manager DS&AI*	**Report Approval Date:**	
Report Reviewed by:	[redacted]	**Review Date:**	31/12/2015
Issue Approved by:	[redacted]	**Issue Date:**	

Date	Version	Objective ID	Nature of Change	Author	Authorisation
13/10/2015	1.0	A2374963	Original issue	[redacted]	
31/12/2015	2.0	A2420310	Small modifications to standardise and update on bushing condition.	[redacted]	

IMPORTANT: - This condition assessment report provides an overview of the condition of power transformer/s (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

The H010 Bouldercombe substation transformers T1 and T2 are 38 year old English Electric, Rocklea, Brisbane design and in line with the requirements of AM-POL-0056, a condition assessment has been performed towards “end of life” including an on-site visual assessment combined with a desktop analysis of historical oil and insulation test data, maintenance history and through fault data history where available.

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.

As such, no attempt has been made in this report to cover any detailed economic analysis of the viability of rectifying any highlighted issues associated with these transformers. The report provides a condition assessment of the “key” parameters for these transformers and what may need to be actioned if the transformers are to be operational for a further 5 years and beyond.

A summary of the findings is shown in Table 1. Note that the assessment has revealed that Transformer T1 is in marginally better condition than T2 only in terms of the cellulose insulation system residual life.

Transformers T1 and T2 have an assessed “as-is” residual life expectancy of a 2 to 3 years due to the condition of the cooler bank radiator panels. If there is a need to keep both transformers for 10 years with reduced reliability, then the following actions would still need to be considered.

- Replace cooler bank, including cooling fans. Existing main oil pipework and pumps could be reused. (estimate $500,000 plus contractor charges for installing).
- Repair the more serious oil leaks on the main tank. (estimate $150,000 for Contractor).
- New set of bushings (estimate $200,000 plus Contractor charges for installing).

TABLE 1
Summary of Estimated Residual Life of Transformer T1 & T2 "Key" Components

Parameter	Estimated Residual Life		Further Comments
	T1	T2	
Anti-corrosion system	10 years for main tank. 2 to 3 years for cooler bank	10 years for main tank. 2 to 3 years for cooler bank	Recently repainted. Main tank overall in good condition. Cooler bank will present an increasing maintenance issue. (cooler bank may need to be replaced in near future)
Winding paper life	>10 years	10 years	Calculated Av age = 19 / 21 years for T1 & T2 respectively. Wdg Hot spot age = 24 / 27 years for T1 & T2 respectively.
Winding mechanical stability	Cannot be assessed accurately, but is considered questionable due to design used and exposure.	Cannot be assessed accurately, but is considered questionable due to design used and exposure.	Old clamping structures design, lowering of DPv & moisture exchange.
External HV & LV bushings	Need replacement ASAP	Need replacement ASAP	Refer to clause 2.2.7.4 for rational.
Insulating Oil	5+ years	5+ years	Assuming no big changes to in-service operating conditions.
Radiators	2 to 3 years for cooler bank	2 to 3 years for cooler bank	Oval tube / bottom header interface corrosion issues. Some cooling fans may also need to be replaced.
Repairs to leaking gaskets.	Required now.	Required now.	Many gasket leaks mean air ingress and therefore moisture exchange between air, oil and paper insulation.
Overall residual life.	<5 years. The unreliable service can be extended to 10 years if cooler bank is to be replaced and major oil leaks fixed.	<5 years. The unreliable service can be extended to 10 years if cooler bank is to be replaced and major oil leaks fixed.	Assuming on-going maintenance as usual.

2. INVESTIGATION OF TRANSFORMER T1:

A comprehensive on-site inspection of the 200MVA 288/138/19.1kV transformer T1 at H010 Bouldercombe substation was performed on the 11th June 2015 and only the major findings which may impact the serviceability of this transformer and future cost of ownership are discussed in this report.

Figure 1: 200MVA 288/138/19.1kV transformer T1 at H010 Bouldercombe.

2.1 Transformer T1 Identification Details:

According to the information held in SAP, this transformer T1 was originally installed at H010 Bouldercombe substation in 1977 and this aligns with the English Electric factory test report date of February 1977.

The general descriptive details for this transformer are shown below.

Manufacturer	English Electric at Rocklea, Brisbane
Specification	Capricornia Regional Electricity Board Spec No. 973 / 74.
Year of manufacture	Feb 1977 as per FAT test report date. (38 year old)
Commissioned	1977
Winding arrangement	Star-Auto HV-LV and Delta TV
Rating	100/150/200MVA 288/138/19.1kV
Transformer Serial No.	A31F7775 / 2
Powerlink SAP No.	20003743
Tap changer manufacturer	Reinhausen (MR) - Reversing LV terminal Type 3xM1 1200 150B10193W
Tap Changer Serial No.	82170
Tap changer operations	95,213

2.2 Transformer T1 On-site Inspection:

2.2.1 Anti-corrosion System:

More photographs of this transformer are available.

This transformer has obviously been repainted even though there is no information to this effect in the SAP records for this transformer since 1999. Overall, the paint system appears to be in good condition but there are a few localised corrosion issues. The mounting bolts on the TV terminal bushings are corroded and before the corrosion develops to the point where the nuts may not turn on the threaded bolts, the bolts need to be replaced if possible or the rust neutralised and the bolts then coated with a sacrificial zinc coating and then sealed with a lanolin spray coating.

Figure 2: Corrosion of TV mounting bolts and pressure relief vent cover.

Advanced corrosion was noticed on a number of the cooler bank fan motor casings and associated fittings which will more than likely render some of these motors inoperable within 12 months.

Figure 3: Advanced corrosion of cooler bank fan motor casings.

The cooler bank radiator panels are of the old oval tube design inset into top and bottom rectangular box section headers. As usual with this type of design, corrosion issues where the oval tubes enter the headers can cause oil leaks and this was certainly the case with this transformer except the new paint was covering the corrosion but numerous oil leaks were clearly evident.

Figure 4: Corrosion of cooler bank radiator panels where the oval tubes enter the headers causing oil leaks. Note insects (black dots) stuck to the oil film on the side of the bottom header.

The only other location where corrosion was visible was the cooler bank 'A'-frame support structure mounting feet where the welds between the base plate and the vertical leg and web plates were being corroded away.

Figure 5: Corrosion of the cooler bank 'A'-frame support structure mounting feet welds.

This transformer does not have a welded lid to tank but there were no noticeable oil leaks or corrosion in this locality.

Figure 6: No welded lid to main tank but no corrosion visible between mating steel flanges which sandwich the gasket.

2.2.2 Structural:

This transformer has a separate cooler bank mounted on 'A'-frame support structures. The base mounting plate on the 'A'-frame support structure legs has a potential structural issue looming due to corrosion eating away the welds between the base plate and the vertical leg and web plates. While no immediate action is required, this should be programmed for repair within the next 6 months. (Refer to figure 5).
No evidence indicating any structural issues related to the condition of foundations or oil containment system was noted.

2.2.3 Oil Leaks:

From the site inspection, the concrete apron within the oil bunded area around the transformer and cooler bank show residual traces where past oil leaks have been cleaned up but there are still some significant oil leaks at present. These oil leaks are occurring at the following locations;

- The HV 'B'-phase bushing mounting flange gasket to turret.
- Gaskets out of sight on the lid.
- Gasket for the hatch on top of the TV bushing CT chamber.
- Side mounted LV bushing and OLTC chambers.
- Bottom main tank drain valve at TV end.
- HV 'A'-phase bushing oil level indicator.
- Buchholz relay seals.
- Pressure relief device.
- Bottom main tank butterfly valve.
- Cooler bank radiator panel oil drain valves.
- Cooler bank radiator panel oval tube / headers interface.
- Oil leaks in some secondary circuit junction boxes on the transformer lid is allowing oil to leak down inside the multicore cable sheath and spill out onto the Control Cubicle cable gland plate.

A few of the oil leaks listed above are shown in the figures below.

Figure 7: (LHS) Oil leak from the HV 'B'-phase bushing mounting flange gasket to turret. (RHS) Oil leaks from gaskets further up on lid.

Figure 8: (LHS) Oil leak from the hatch gasket on top of the TV bushing CT chamber. (RHS) HV ‘A’-phase bushing oil level indicator oil leak.

Figure 9: Typical oil leaks from the side mounted LV bushing & OLTC chambers. Note the free oil pooling on the ground.

Overall, the oil leaks on this transformer at present cannot be classified as minor since some do require attention as soon as resources are available.

Figure 10: Typical oil leaks from where the oval tubes enter the headers. Note insects (black dots) stuck to the oil film on the side of the bottom header.

2.2.4 Secondary Systems:

After 38 years, the cables are sure to have taken a set and any significant cable flexing (e.g. removal & reconnection) due to replacement of external ancillary items would likely create some insulation damage but if left physically alone, all of the multicore cables should not fail over the next several years (up to 10 years).

Figure 11: The UV stabilisers in the paint covering the external multicore cables will assist in preserving the outer PVC covering.

There were a couple of non-conformances which were noticed if the secondary systems is to be brought up to present day safety and technical standards. There is 400VAC supply connected to the Main Control Cubicle and is terminated on open terminals with no insulating barrier to cover them from accidential contact.

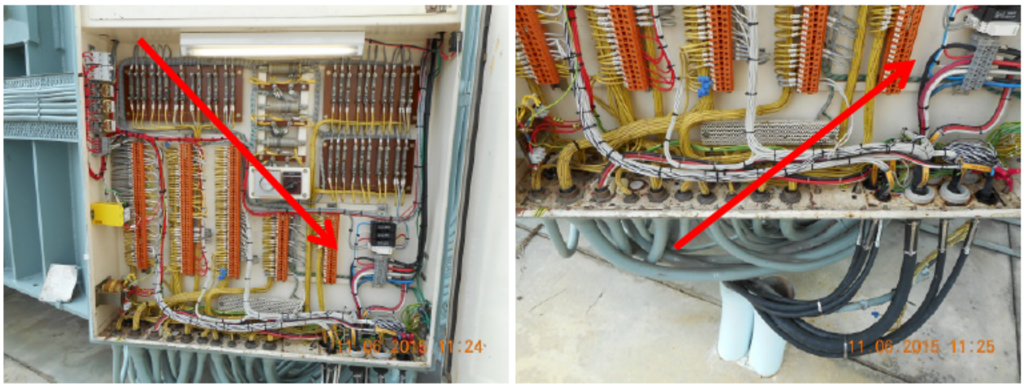

Figure 12: Unprotected 400VAC terminals inside the Main Control Cubicle without safety insulating barrier cover.

There are mercury switches in two of the three winding temperature and one top oil monitoring instruments on the side of the transformer main tank. One of the winding temperature monitoring instruments has already been replaced in 2007 according to the maintenance records.

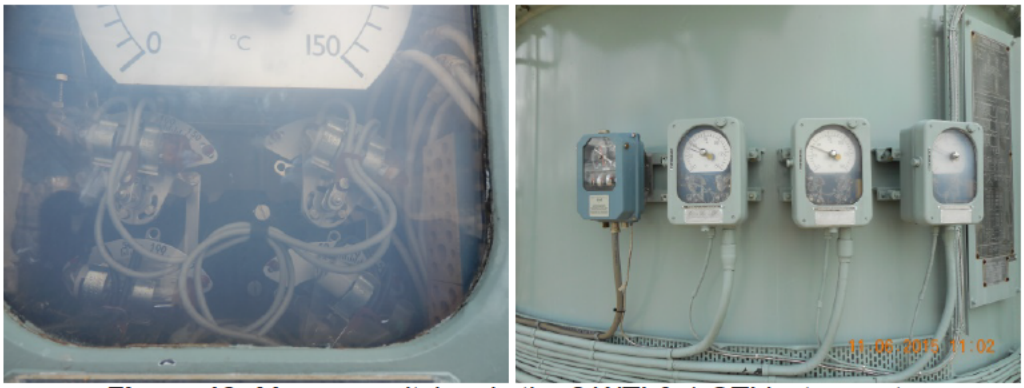

Figure 13: Mercury switches in the 2 WTI & 1 OTI instruments for cooling control and alarm and trip signalling.

As can be seen from figure 13, the viewing windows on the three winding hot spot and one top oil temperature monitoring instruments are somewhat frosty in appearance making reading the instruments difficult. Because of the mercury switches and the frosty viewing windows in the older three instruments, the instruments should be replaced in the near future.

Figure 14: There were no issues noticed inside the Cooler Control Cubicle.

This transformer is fitted with a Reinhausen tap changer comprising three in tank columns, one for each phase, and has performed 95,213 operations, well within its expected life.

Figure 15: Reinhausen tap changer control cubicle for type 3 x M1 1200 150B 10193W.

2.2.5 General Comments:

A summary of the general items associated with this transformer are shown below.

It was rather unusual to find the OLTC conservator divided into three separate chambers all fitted with their own separate oil level indicators with each chamber devoted to each phase. This design may have been seen as an advantage to prevent cross pollution from the failure of one diverter switch to the diverters of other phases (theoretically).

This transformer is fitted with an explosion vent (rupture diaphragm) on a high rise pipe as well as having a pressure relief device (PRD) installed on the HV side of the top main oil pipe which carries hot oil to the cooler bank for cooling. The effectiveness of both the PRD and the high rise explosion vent to rapidly reduce internal pressure adequately is considered to be poor due to the surge impedance of the pipework when confronted with a high frequency transient pressure wave. That is why for the last 30 to 35 years, the PRDs have been installed high up on the main tank side walls.

Figure 16: The explosion vent (rupture diaphragm) at the end of a high rise pipe as well as a PRD on the top main oil pipe between cooler bank and transformer main tank.

2.2.6 Oil and Insulation Assessment:

A desktop assessment was performed using the full history of Oil & Insulation Testing Laboratory test data for this transformer.

This transformer was manufactured with the main tank oil and tap changer oil sharing the same conservator but with three partial partitions separating four oil volumes, namely main tank oil and the oil for each phase of the OLTC. This still provided common air in the head space above the four separate oil surfaces for the exchange of dissolved gases and moisture between both oil volumes. The use of partial partitions was confirmed on site by observing only one desiccant breather shared by all conservators, as per the transformer general arrangement drawing. Hence the oil and insulation system inside the transformer, and especially in the main tank, had direct contact with the external air via the conservator dehumidifying desiccant breather.

Figure 17: (LHS) Three separate oil level gauges and oil delivery pipes for each OLTC phase. (RHS) One oil level gauge on the end for the main tank oil.

This conservator was originally designed and fitted with a Drycol refrigerant breather for drying the air when entering and while held within the conservator but was later replaced with a conventional desiccant breather. This is obvious from the plumbing shown on the end of the conservator and the English Electric transformer drawings.

2.2.6.1 Oil Quality:

The overall oil quality for this transformer indicates oil is aged but still serviceable and has remained relatively stable over the last 8 years. If this oil aging rate continues and considering that the acidity & dielectric dissipation factor (DDF) are still reasonable for its age, it should be possible for the oil to last for a further 5+ years if operated under similar in-service conditions. The moisture in oil / cellulose insulation will be discussed separately in clause 2.2.6.4.

Our Oil Laboratory test data shows that in 2011, the oil was classified as “non-corrosive” per the IEC test method. The measured level of Polychlorinated biphenyls (PCB) in oil was 1.1ppm in 2003 and is therefore not classified as PCB contaminated.

2.2.6.2 Winding Paper Quality

The measured dissolved furan levels in oil are shown in figure 18. There was a normal progressive increase as the transformer aged, however, there appears to have been some significant transformer loading variations over the past few years. The average trend in the bulk cellulose insulation aging (furan increase) is shown by the red dotted line in this figure.

Because there is normally a variation in insulation temperatures throughout the transformer windings when loaded, at times fairly significant, more localised higher winding insulation temperatures will generate higher than average amounts of furan which must also be considered in the calculation of cellulose insulation age.

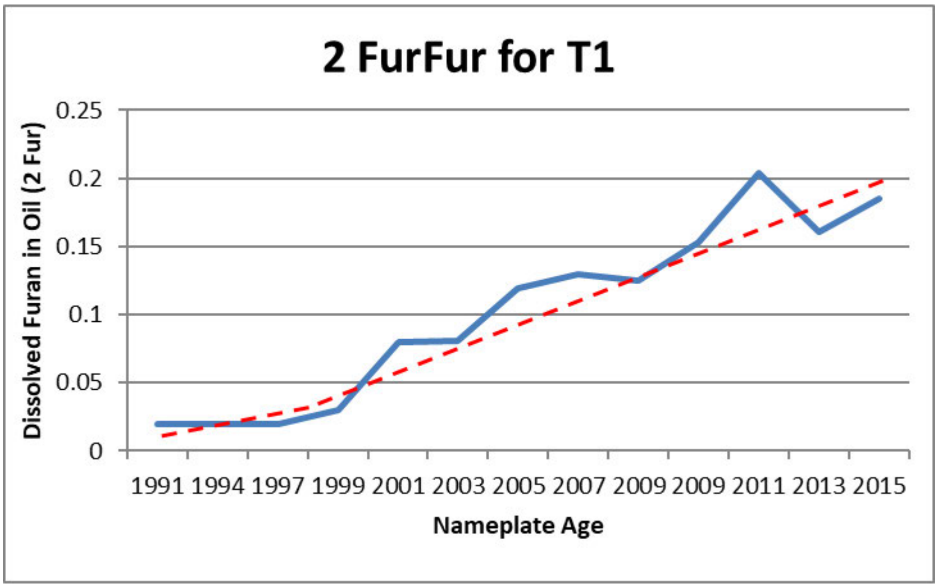

Figure 18: The dissolved furan in oil (mg/kg) has been plotted against transformer nameplate age.

The dissolved furan in oil test data was useful in the calculation of the apparent bulk cellulose insulation DPv as well as the bulk insulation chemical age and these graphs are shown in figures 19 and 21. The average trend in both of these graphs is shown by the red dotted line in these figures. The green dotted line if figure 21 is an approximation for unity cellulose insulation aging rate.

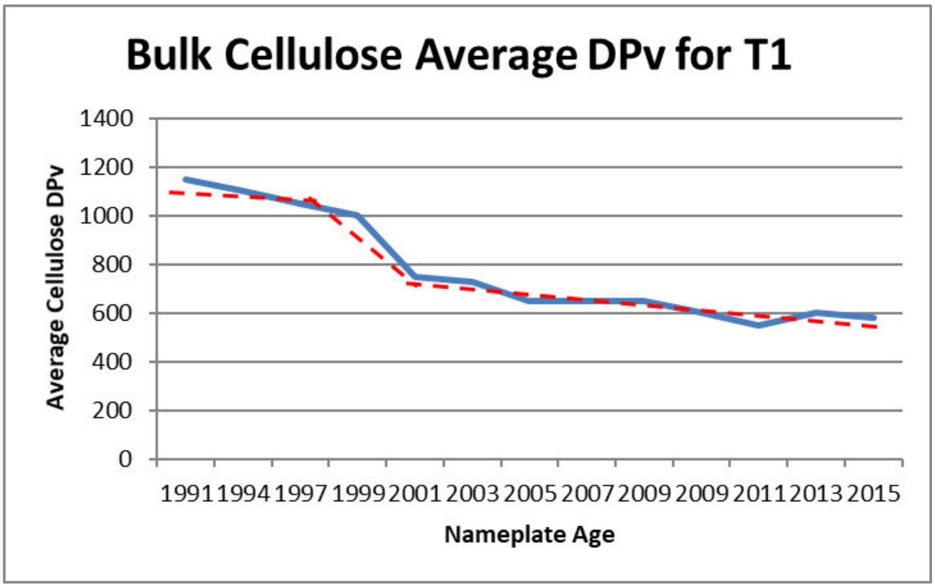

Figure 19: The bulk insulation average DP_v has been plotted against transformer age.

It is only natural that the cellulose insulation DPv tracks roughly the inverse characteristic of the dissolved furan in oil level.

Taking into account the dissolved furan trend, the calculated age of the bulk cellulose insulation is shown in figure 20. It is interesting because the correlation between dissolved furan in oil and insulation aging becomes more obvious when the graphs in figures 18 & 21 are compared. The shape of the insulation aging graph reflects how the transformer has been loaded over the years.

FOR CALCULATING INSULATION CHEMICAL AGE

Nameplate Age	38	Years
Furan in Oil	0.2	ppm
Carbon Monoxide	163	ppm
Carbon Dioxide	1560	ppm
Degree of Polymerisation	540	DPv Aged Sample
Degree of Polymerisation	1200	DPv Newly Commissioned

CALCULATED INSULATION CHEMICAL AGE

FURAN	DPv	CO	CO2	
19	19	8	13	Years

Figure 20: Calculation of the bulk (average) insulation age and comparison with the DP_v level of 540.

The average age of the bulk cellulose insulation system within the transformer is calculated to be approximately 19 years, with a localised winding hot spot insulation age of approximately 24 years. This is less than the 38 year nameplate age and tends to correlate with the low 35C to 40C winding hot spot maximum operating temperatures noted on site on the transformer temperature monitoring instrumentation.

Both the average and localised cellulose insulation in this transformer is still in reasonable condition and if this cellulose insulation aging rate persists, it could last at least a further 10 to15 years.

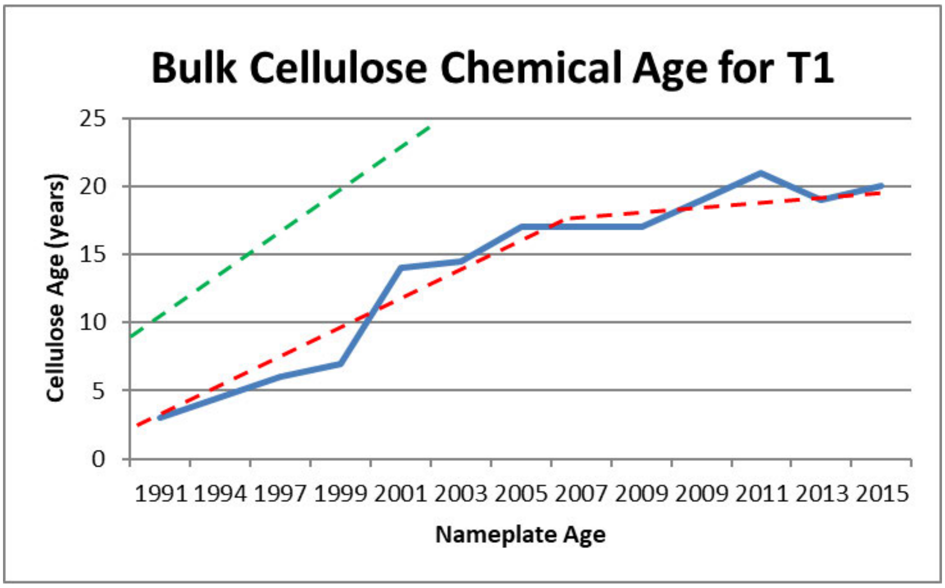

Figure 21: The bulk (average) insulation chemical age has been plotted against transformer nameplate age. The green dotted line represents unity insulation aging rate.

2.2.6.3 Dissolved Gas Analysis:

Apart from signs of the bulk insulation operating at marginally higher temperatures on occasions, the DGA test data up to the last oil sample taken in February 2015 shows no emerging electrical issues.

The DGA does show a small amount of migration of dissolved gases from one or more of the three Reinhausen OLTC diverter switch chambers into the main tank oil environment. This migration was likely to have been via two paths, one being associated with leaks from the OLTC diverter switch cylinders. The other path being due to the common head space (only partial oil partitions) shared by the main tank conservator and the three OLTC conservators. This is not a serious problem in itself provided people who may review such DGA test data in the future understand what they are seeing. What it does do is mask emerging thermal issues / hot spots until the severity of the problem increases sufficiently to generate greater amounts of dissolved thermal fault gases which eventually will become visible above the background stray gases.

This transformer has experienced 12 cooling fail alarms over the last 16 years alone with 9 of these from December 2000 through to around October 2002. These incidents have not caused any visible signs of abnormal heating in the oil test data.

As mentioned earlier in clause 2.2.6, this transformer is not hermetically sealed to atmosphere and this is obvious from the dissolved gas in oil test data.

2.2.6.4 Moisture in Insulation:

Because the oil samples taken from this transformer in 1981, 1983 and 1985 had no oil sample temperature information provided, the laboratory test data over this period was not usable for calculating the moisture in cellulose. Hence figure 22 shows a plot of the calculated percent by dry weight moisture in insulation over most of the transformer's life, starting from 1988. The red dotted line in figure 22 is an attempt to compensate for any erroneous data errors. The calculated average percent moisture in cellulose by dry weight at present is approximately 2.0%.

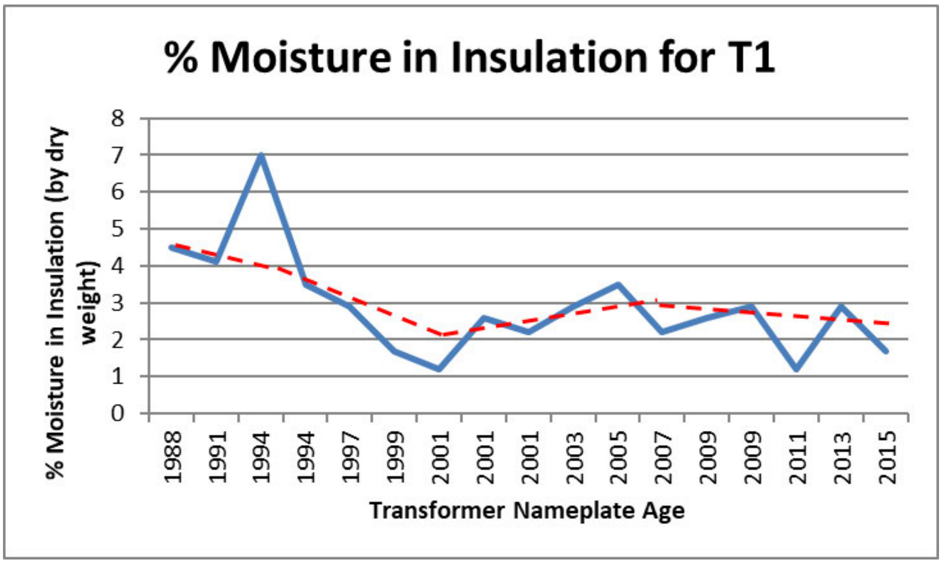

Figure 22: Calculated average of 2.0% moisture in insulation by dry weight.

When this transformer was designed and built, the insulation dryout methods were somewhat poor compared to the standards set by the vapour phase dryout systems used over the last 15 years or more and it was not uncommon to have relatively wet insulation (by today's standards) from new. The measured moisture in insulation level appears to have been slowly reducing from 1988 and this may have been due to the efficiency of the conservator Drycol refrigerant drying system which continuously dried the air above the oil as well as the incoming air as transformer operating temperatures reduced. The Drycol system was removed in 2004 after 27 years of operation.

The origin of the calculated residual moisture in the cellulose insulation can only come from a few sources, namely;

- insulation chemical aging,
- moisture ingress from the atmosphere over the years due to oil leaks or maintenance activities,
- residual moisture from new.

The condition of the desiccant in the conservator air breather appeared serviceable when checked through a tiny viewing window but it was not possible to see a holistic view of the desiccant due to the design of this non-standard breather. It was therefore not possible to verify if there was an air leak in the plumbing between the breather and the conservator. It was also not possible to inspect the breather oil bath condition, or even if the breather was fitted with one.

Figure 23: The conservator desiccant breather design does not allow comprehensive visual inspection for serviceability.

The calculated moisture in insulation at present is still well below the 4% level beyond which can introduce risks of insulation failure under the right combination of specific operating / environmental conditions.

The only way of getting a more accurate measure of the % moisture in insulation is to install an on-line moisture and temperature probe in the main oil stream for a week and analyse the data collected under varying loads / temperatures.

2.2.7 Estimated Residual Life of Transformer:

Table 2 provides a quick summary of the estimated residual life of the "key" transformer components but there is further discussion on these aspects in clause 2.2.7.

TABLE 2
Summary of Estimated Residual Life of Transformer T1 "Key" Components

Parameter	Estimated Residual Life	Further Comments
Anti-corrosion system	10 years for main tank. 2 to 3 years for cooler bank	Recently repainted. Main tank overall in good condition. Cooler bank will present an increasing maintenance issue. (cooler bank may need to be replaced in near future)
Winding paper life	10 - 15 years	Calculated Av age = 19 years Wdg Hot spot age = 24 years
Winding mechanical stability	Cannot be assessed accurately, but is considered questionable due to design used and exposure.	Old clamping structures design, lowering of DPv & moisture exchange.
External HV & LV bushings	LV bushings need replacement ASAP. Restricted access zone established.	Refer to clause 2.2.7.4 for rational.
Insulating Oil	5+ years	Assuming similar in-service operating conditions for the future.
Radiators	2 to 3 years for cooler bank	Oval tube / bottom header interface corrosion issues. Some cooling fans may need replacement.
Repairs to leaking gaskets	Required now.	Many gasket leaks.
Overall residual life	<5 years. The unreliable service can be extended to 10 years if cooler bank is to be replaced and major oil leaks fixed.	If the recommended actions are taken, transformer may remain in service for 10 years, but its reliability will remain low and availability will be decreasing due to the failures of minor components.

2.2.7.1 Anti-corrosion System Life

In general, the main tank could last for a further 10 years or more provided localised corrosion is addressed before it becomes more serious. Some areas will be awkward to access (e.g. main tank / lid mating steel flanges) to neutralise existing corrosion.

Because the cooler bank is exhibiting the usual corrosion issues associated with the radiator panel oval tube / header design, the existing cooler bank life expectancy is limited to a few years with increasing maintenance repair costs.

The corrosion problem with respect to the cooler bank fan motor casings is more serious and will need attention or removal in the not too distant future.

2.2.7.2 Insulation Life

Winding Paper:

The calculated age / mechanical condition of the winding paper suggests that it still has the potential to achieve another conditional 10-15 years of life provided its in-service operating environment does not change significantly.

Insulating Oil:

The quality of the insulating oil is well aged but the oil and cellulose insulation environment should be able to achieve a further 5+ years of service provided its in-service operating environment does not change significantly.

2.2.7.3 Mechanical Life

There has been a significant reduction in moisture in cellulose insulation from the early years through to 2001 after which it slowly increased until 2007 after which it has slowly been reducing again. (refer to figure 22). This moisture migration in and out of the cellulose insulation in the winding clamping structure would have caused some accumulative relaxation in the winding axial clamping pressure and would make it less tolerant to through faults.

Compounding this is the continual loss of cellulose mass while in service as discussed in clause 2.2.6.2 which also causes a relaxation in winding clamping pressure.

A final concern is the clamping assembly design used on this transformer in the early 1970's may not be considered appropriate by today's design standards.

2.2.7.4 Transformer Bushings

The HV and LV bushings installed on this transformer are an oil impregnated paper (OIP) design in porcelain housing. Maintenance records from 2004 show considerable issues involving abnormal HV insulation dielectric loss and capacitance test data started arising from when the bushings reached roughly 27 years of age. Some of the abnormal field test data recorded for dielectric loss angle (DLA) and capacitance were considered at the time as measurement errors but some were not. This prompted the approval in 1999 to oil sample the HV bushings since they were an OIP design but the oil analysis showed no signs of internal partial discharge or thermal problems to account for poor bushing measured DLA and / or capacitance.

As recently as 9th October 2015, additional HV and LV bushing DLA / capacitance field test data is again being reviewed due to some DLA results being outside of the defective limit. Because the LV bushings sit in a separate chamber along with the in-tank column tap changer, this specific oil is being sampled to determine if the oil quality surrounding the bushing tail is contributing to the bushing poor DLA / capacitance field test results.

Additional bushing oil samples were taken in December 2015 from both LV and HV bushings and showed that the partial discharge has indeed occurred in all three LV bushings and that deterioration is most progressed in C phase LV bushing. Due to the concerns for safety of personnel in the event of bushing explosive failure, restricted access zone has been established around this transformer.

The reliable life expectancy of an OIP bushing is about 25 years and therefore these bushings have performed beyond expectations.

The tertiary winding terminal bushings appear to be a more robust hollow porcelain design and should be able to last for a further 10+ years or longer.

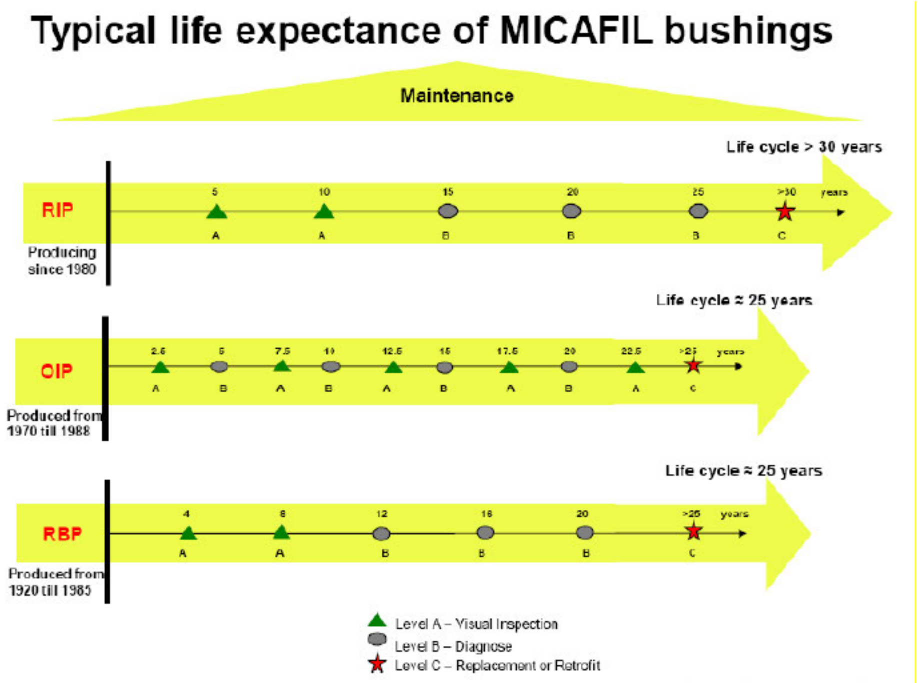

Figure 24: Bushing life expectancy provided by the bushing manufacturer.

3. CONCLUSIONS FOR TRANSFORMER T1

3.1 Condition Assessment

The following conclusions can be drawn from the condition assessment of the H010 Bouldercombe transformer T1.

3.1.1 Oil Leaks:

There are a number of significant oil leaks which do need attention when resources can be made available and the sooner the better if these transformers are to be kept for longer than 5 years.

More regular monitoring may be required of the cooler bank radiator panels due to existing oil leak issues that will only get worse.

3.1.2 External Physical Condition:

Overall, the paint system appears to be in good condition but there are a few corrosion issues that warrant attention in the near future. These are;

- Corrosion of the mounting bolts on the TV terminal bushings.
- Advanced corrosion on a number of the cooler bank fan motor casings.
- Corrosion where the cooler bank radiator panel oval tubes join the top and bottom rectangular box section headers. The corrosion is not really visible at present due to the excess paint having been placed in these locations but the oil leaks from these locations are evidence of the corrosion.
- Corrosion of the cooler bank ‘A’-frame support structure mounting feet welds.

Repairs to the cooler bank radiator panel oval tubes / bottom header interface is going to be a worsening on-going maintenance issue up until the cooler bank is replaced.

The band aid approach to maintaining the cooler bank in a serviceable condition may be appropriate if the transformer is only required to remain serviceable for up to 5 years.

3.1.3 Insulation Residual Life:

The winding paper insulation residual in-service life is calculated to be approximately 10 to 15 years. After that the paper mechanical strength will be deteriorated to the point where any vibration will cause loss of insulation. Obviously this calculated residual life would depend greatly upon how the transformer will be loaded in the future and the severity of any through faults.

3.1.4 Winding Mechanical Stability:

There have been the usual factors influencing the longevity of the mechanical stability of the windings over the years but this transformer's cellulose insulation system has lost mass at a slower than unity aging rate and as such, the stability of the windings is considered to be slightly more reliable than if the aging rate was equal to unity or greater. However clamping design used in this transformer is known to be subject to the relaxation making this transformer susceptible to sudden failure during or shortly after it is exposed to even minor through faults.

3.1.5 Transformer Bushings:

Because there have been a number of bushing tests performed in the field over the years yielding test data which was later confirmed by oil sampling directly from the top of the bushings to be misleading, the more recent bushing test results obtained recently again triggered the same debate. However the oil samples taken in December confirmed the presence of significant partial discharge. It is possible that electrical tests are more sensitive and can possible detect internal faults before they develop to such extent that their presence is detectable in the oil samples. Unfortunately they are often very sensitive to the pollution on the porcelain housing and weather conditions during test.

3.1.6 Transformer Primary Ancillary Items:

Apart from the serviceability of the HV and LV bushings, there is nothing else of major consequence other than what has already been discussed elsewhere in this report (radiator panels, cooler bank fans, WTI & OTI instruments). There will always be a possibility to have to replace ancillary equipment unexpectedly and this cannot always be forecast.

3.1.7 Transformer Secondary Systems:

The secondary system components are well aged and a number of items have needed to be replaced over the years but the design of the system is relatively simplistic and can be maintained in a serviceable condition without too much trouble, but can contribute to the reduced transformer availability.

One aspect which may need consideration is the need to improve the electrical safety in the Main Control Cubicle by installing an insulating barrier in front of the live 400VAC terminals, to align with existing design standards.

4. INVESTIGATION OF TRANSFORMER T2:

A comprehensive on-site inspection of the 200MVA 288/138/19.1kV transformer T2 at H010 Bouldercombe substation was performed on the 11th June 2015 and only the major findings which may impact the serviceability of this transformer and future cost of ownership are discussed in this report.

Figure 25: 200MVA 288/138/19.1kV transformer T2 at H010 Bouldercombe.

4.1 Transformer T2 Identification Details:

This transformer T2 was originally installed and energised at H010 Bouldercombe substation in 1977. Based on the transformer and serial number it was factory tested in January 1977.

The general descriptive details for this transformer are shown below.

Manufacturer	English Electric at Rocklea, Brisbane
Specification	Capricornia Regional Electricity Board Spec No. 973 / 74.
Year of manufacture	January 1977 as per FAT test report date. (38 year old)
Commissioned	1976
Winding arrangement	Star-Auto HV-LV and Delta TV
Rating	100/150/200MVA 288/138/19.1kV
Transformer Serial No.	A31F7775 / 1
Powerlink SAP No.	20003744
Tap changer manufacturer	Reinhausen (MR) - Reversing LV terminal Type 3xM1 1200 150B10193W
Tap changer serial No.	82169
Tap changer operations	95,282

4.2 Transformer T2 On-site Inspection:

4.2.1 Anti-corrosion System:

More photographs of this transformer available.

This transformer has obviously been repainted even though there is no information to this effect in the SAP records for this transformer since 1999. Overall, the paint system appears to be in good condition but there are a few localised corrosion issues. The mounting bolts on the TV terminal bushings are corroded and before the corrosion develops to the point where the nuts may not turn on the threaded bolts, the bolts need to be replaced if possible or the rust neutralised and the bolts then coated with a sacrificial zinc coating and then sealed with a lanolin spray coating.

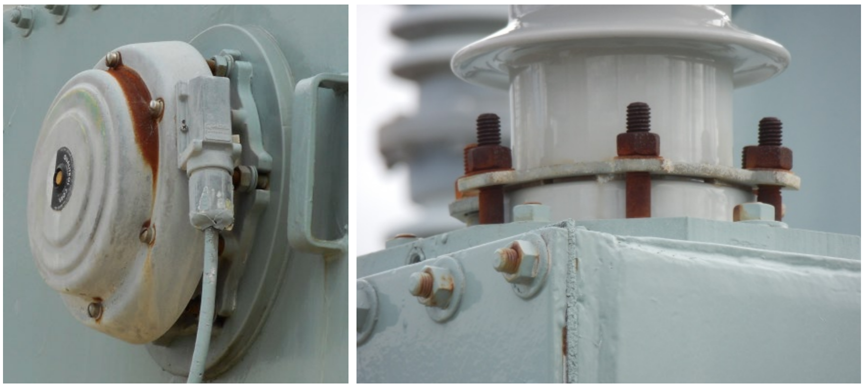

Figure 26: Corrosion of TV mounting bolts and pressure relief vent cover.

Advanced corrosion was noticed on a number of the cooler bank fan motor casings and associated fittings which will more than likely render some of these motors inoperable within 12 months.

Figure 27: Advanced corrosion of cooler bank fan motor casings.

The cooler bank radiator panels are of the old oval tube design inset into top and bottom rectangular box section headers. As usual with this type of design, corrosion issues where the oval tubes enter the headers can cause oil leaks and this was certainly the case with this transformer except the new paint was covering the corrosion but numerous oil leaks were clearly evident.

Figure 28: Corrosion of cooler bank radiator panels where the oval tubes enter the headers causing oil leaks.

There were also signs of corrosion on some of the radiator panel bottom headers along the welded joint between the header base plate and the vertical sides. The likely causes are residue corrosion not fully removed / neutralised prior to the repainting process combined with the fact that the paint film thickness would be inherently thinner in this location and beads of water would come to rest on this lower shoulder when raining.

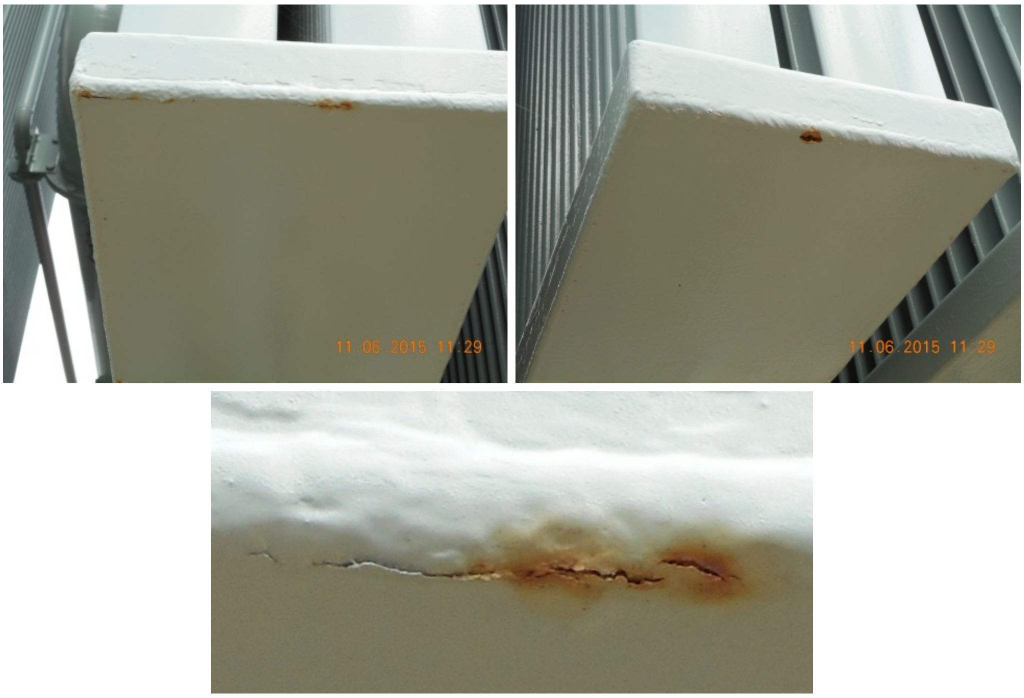

Figure 29: Corrosion of cooler bank radiator panels where the oval tubes enter the headers causing oil leaks.

Signs of corrosion were also visible where the main tank and lid steel flanges are bolted together on a nitrile gasket. It would have been virtually impossible to remove all residual rust from this location prior to repainting without lifting the lid off the main tank base and that would be a very expensive exercise. It was therefore inevitable that signs of rust would again become visible in this location. If this corrosion becomes more serious, transformer oil will eventually start to leak past the gasket but this may then slow down or stop the corrosion by limiting the available oxygen needed for the corrosion process.

Other areas such as on horizontal main tank stiffener plates near the base of the transformer were showing corrosion occurring under the paint coating causing the paint film to bubble up and break away. The paint delamination combined with the horizontal surface which can collect water makes for an ideal site for the corrosion to propagate. The observed corrosion in this location is not considered serious at this stage but should be treated.

Figure 30: (LHS) Corrosion between the main tank and lid mating steel flanges. (RHS) Corrosion on a horizontal main tank stiffener plate.

Whilst there was no serious corrosion around the mounting feet of the cooler bank 'A'-frame support structures, there were signs that corrosion was active beneath the paint coating.

Figure 31: Corrosion occurring beneath the paint of the cooler bank 'A'-frame support structure mounting feet.

This transformer does not have a welded lid to tank but there were no noticeable oil leaks or corrosion in this locality.

Figure 32: No welded lid to main tank but corrosion is visible in some locations as well as oil leaks.

4.2.2 Structural:

This transformer has a separate cooler bank mounted on 'A'-frame support structures. No structural issues were identified. No evidence indicating any structural issues related to the condition of foundations or oil containment system was noted.

4.2.3 Oil Leaks:

From the site inspection, the concrete apron within the oil bunded area around the transformer and cooler bank show residual traces where past oil leaks have been cleaned up but there are still some significant oil leaks at present. These oil leaks are occurring at the following locations;

- HV 'B'-phase bushing oil level indicator.
- Gasket for the hatch on top of the TV bushing CT chamber.
- Main tank to lid gasket along HV side.
- OLTC conservator.
- Buchholz Relay.
- Side mounted LV bushing and OLTC chambers.
- Main tank 200NB top gate valve.
- HV 'C'-phase bushing turret to main tank lid gasket.
- Cooler bank radiator panel oval tube / headers interface.

A few of the oil leaks listed above are shown in the figures below.

Figure 33: (LHS) Oil leak from the hatch gasket on top of the TV bushing CT chamber. (RHS) HV 'B'-phase bushing oil level indicator oil leak.

Figure 34: Typical oil leaks from the side mounted LV bushing & OLTC chambers. Note the free oil pooling on the ground.

Figure 35: (LHS) 'C'-phase bushing turret to lid gasket oil leak. (RHS) Cooler bank top header gate valve oil leak.

Figure 36: Typical oil leaks from where the oval tubes enter the headers.

Overall, the oil leaks on this transformer at present can't be classified as minor since some do require attention as soon as resources are available.

4.2.4 Secondary Systems:

After 38 years, the cables are sure to have taken a set and any significant cable flexing (e.g. removal & reconnection) due to replacement of external ancillary items would likely create some insulation damage but if left physically alone, all of the multicore cables should not fail over the next five years.

Figure 37: The UV stabilisers in the paint covering the external multicore cables will assist in preserving the outer PVC covering.

There were a couple of non-conformances which were noticed if the secondary systems is to be brought up to present day safety and technical standards. There is 400VAC supply connected to the Main Control Cubicle and is terminated on open terminals with no insulating barrier to cover them from accidential contact.

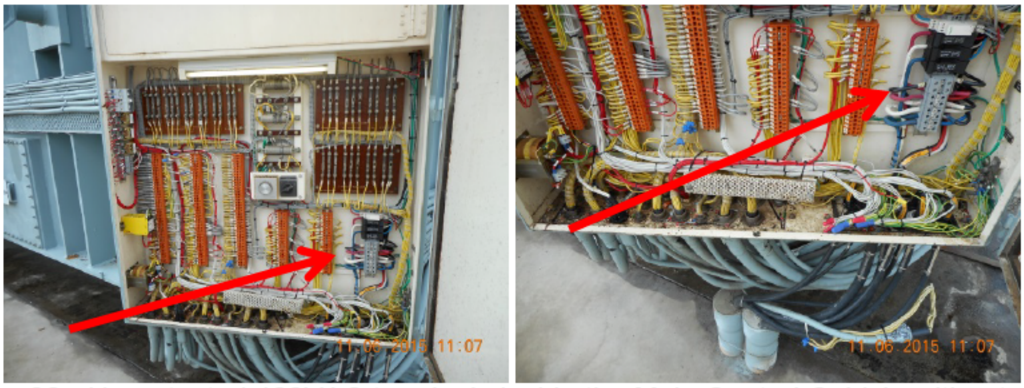

Figure 38: Unprotected 400VAC terminals inside the Main Control Cubicle without safety insulating barrier cover.

There are mercury switches in two of the three winding temperature and one top oil monitoring instruments on the side of the transformer main tank. There have been a lot of issues with one or all of these instruments according to the maintenance records, resulting in the HV winding hot spot temperature instrument being replaced.

Figure 39: Mercury switches in the 2 WTI & 1 OTI instruments for cooling control and alarm and trip signalling.

As can be seen from figure 40, the viewing windows are still serviceable for reading the three winding hot spot and one top oil temperature monitoring instruments. Because of the mercury switches in the older three instruments and the issues experienced to date, these three old instruments should be replaced in the near future.

Figure 40: There were no issues noticed inside the Cooler Control Cubicle.

This transformer is fitted with a Reinhausen tap changer comprising three in tank columns, one for each phase, and has performed 95,282 operations, well within its expected life.

Figure 41: Reinhausen tap changer control cubicle for type 3 x M1 1200 150B 10193W.

4.2.5 General Comments:

A summary of the general items associated with this transformer are shown below.

It was rather unusual to find the OLTC conservator divided into three separate chambers all fitted with their own separate oil level indicators with each chamber devoted to each phase. This design may have been seen as an advantage to prevent cross pollution from the failure of one diverter switch to the diverters of other phases (theoretically).

This transformer is fitted with an explosion vent (rupture diaphragm) on a high rise pipe as well as having a pressure relief device (PRD) installed on the HV side of the top main oil pipe which carries hot oil to the cooler bank for cooling. The effectiveness of both the PRD and the high rise explosion vent to rapidly reduce internal pressure adequately is considered to be poor due to the surge impedance of the pipework when confronted with a high frequency transient pressure wave. That is why for the last 30 to 35 years, the PRDs have been installed high up on the main tank side walls.

Figure 42: The explosion vent (rupture diaphragm) at the end of a high rise pipe as well as a PRD on the top main oil pipe between cooler bank and transformer main tank.

4.2.6 Oil and Insulation Assessment:

A desktop assessment was performed using the full history of Oil & Insulation Testing Laboratory test data for this transformer.

This transformer was manufactured with the main tank oil and tap changer oil sharing the same conservator but with three partial partitions separating four oil volumes, namely main tank oil and the oil for each phase of the OLTC. This still provided common air in the head space above the four separate oil surfaces for the exchange of dissolved gases and moisture between both oil volumes. The use of partial partitions was confirmed on site by observing only one desiccant breather shared by all conservators, as per the transformer general arrangement drawing. Hence the oil and insulation system inside the transformer, and especially in the main tank, had direct contact with the external air via the conservator dehumidifying desiccant breather.

Figure 43: (LHS) Three separate oil level gauges and oil delivery pipes for each OLTC phase. (RHS) One oil level gauge on the end for the main tank oil.

This conservator was originally designed and fitted with a Drycol refrigerant breather for drying the air when entering and while held within the conservator but was later replaced with a conventional desiccant breather. This is obvious from the plumbing shown on the end of the conservator and the English Electric transformer drawings.

4.2.6.1 Oil Quality:

The overall oil quality for this transformer looks aged but still serviceable and has remained relatively stable over the last 8 years. If this oil aging rate continues and considering that the acidity & dielectric dissipation factor (DDF) are still reasonable for its age, it should be possible for the oil to last for a further 5+ years if operated under similar in-service conditions. The moisture in oil / cellulose insulation will be discussed separately in clause 4.2.6.4.

Our Oil Laboratory test data shows that in 2012, the oil was classified as “non-corrosive” per the IEC test method. The measured PCB in oil level was 2.0ppm in 2003 and is therefore classified as PCB contaminated (non-contaminated is < 2.0ppm level).

4.2.6.2 Winding Paper Quality

The measured dissolved furan levels in oil are shown in figure 45. There was a normal progressive increase as the transformer aged. The average trend in the bulk cellulose insulation aging (furan increase) is shown by the red dotted line in this figure.

Because there is normally a variation in insulation temperatures throughout the transformer windings when loaded, at times fairly significant, more localised higher winding insulation temperatures will generate higher than average amounts of furan which must also be considered in the calculation of cellulose insulation age.

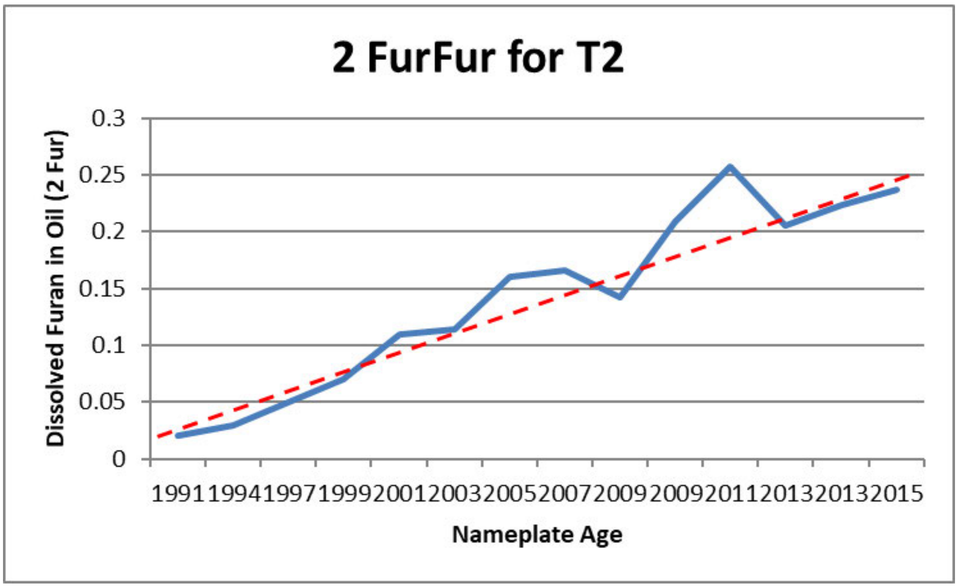

Figure 44: The dissolved furan in oil (mg/kg) has been plotted against transformer nameplate age.

The dissolved furan in oil test data was useful in the calculation of the apparent bulk cellulose insulation DPv as well as the bulk insulation chemical age and these graphs are shown in figures 45 and 47. The average trend in both of these graphs is shown by the red dotted line in these figures. The green dotted line if figure 47 is an approximation for unity cellulose insulation aging rate.

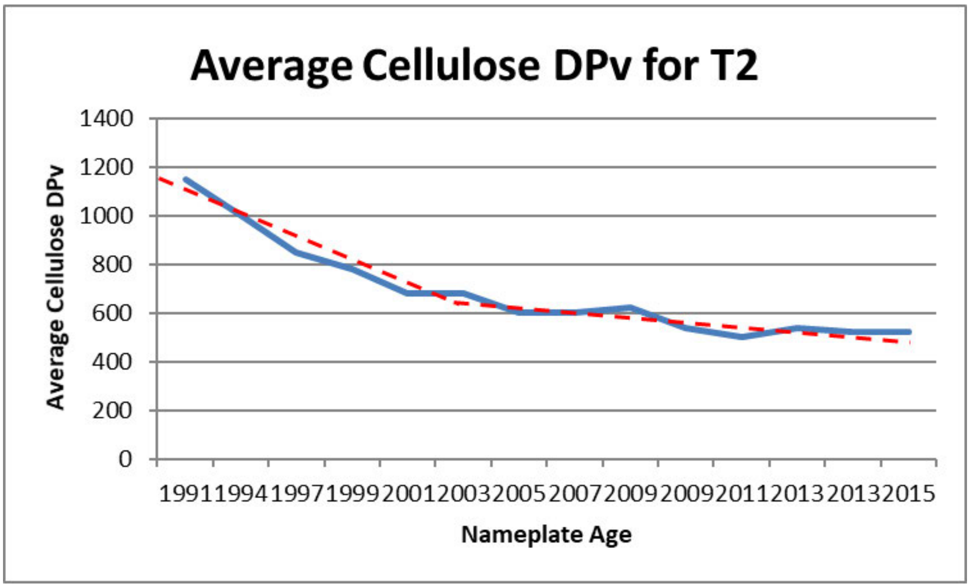

Figure 45: The bulk insulation average DP_v has been plotted against transformer age.

It is only natural that the cellulose insulation DPv tracks roughly the inverse characteristic of the dissolved furan in oil level. Note the natural slowing down in loss of DPv as the transformer ages, which simulates more of the characteristic shape observed in technical publications for DPv.

Taking into account the dissolved furan trend, the calculated age of the bulk cellulose insulation is shown in figure 47. It is interesting because the correlation between dissolved furan in oil and insulation aging becomes more obvious when the graphs in figures 44 & 47 are compared. The shape of the insulation aging graph reflects how the transformer has been loaded over the years.

FOR CALCULATING INSULATION CHEMICAL AGE

Nameplate Age	38	Years
Furan in Oil	0.25	ppm
Carbon Monoxide	153	ppm
Carbon Dioxide	1930	ppm
Degree of Polymerisation	500	DPv Aged Sample
Degree of Polymerisation	1200	DPv Newly Commissioned

CALCULATED INSULATION CHEMICAL AGE

FURAN	DPv	CO	CO2	
21	21	6	16	Years

Figure 46: Calculation of the bulk (average) insulation age and comparison with the DP_v level of 500.

The average age of the bulk cellulose insulation system within the transformer is calculated to be approximately 21 years, with a localised winding hot spot insulation age of approximately 27 years. The calculated insulation age for T2 is slightly greater than the corresponding 19 years and 24 years calculated for T1 at H010 Bouldercombe but still far less than the 38 year nameplate age.

Both the average and localised cellulose insulation in this transformer is still in reasonable condition and if this cellulose insulation aging rate persists, it could last at least a further 10 years.

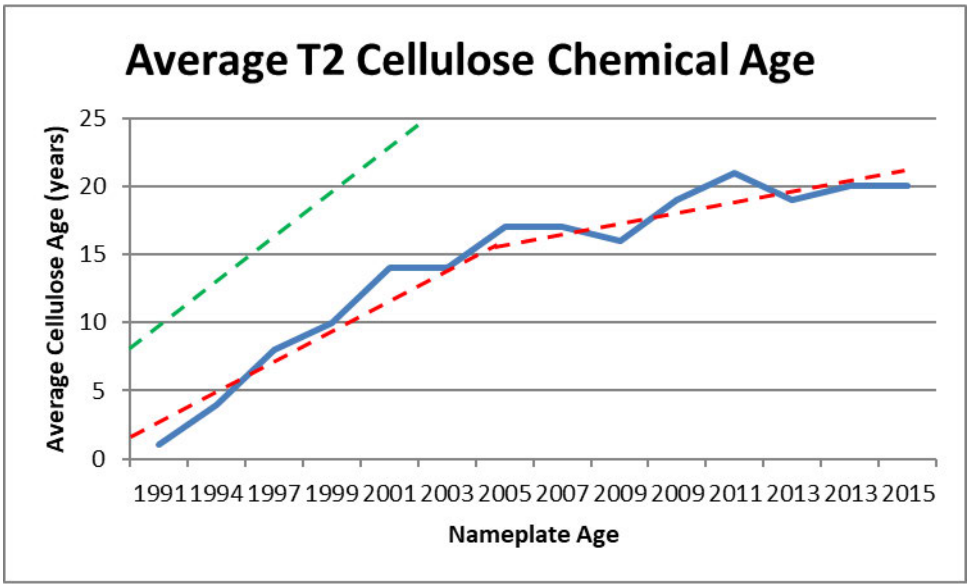

Figure 47: The bulk (average) insulation chemical age has been plotted against transformer nameplate age. The green dotted line represents unity insulation aging rate.

4.2.6.3 Dissolved Gas Analysis:

Apart from signs of the bulk insulation operating at marginally higher temperatures on occasions, the DGA test data up to the last oil sample taken in February 2015 shows no emerging electrical issues.

The DGA does show a small amount of migration of dissolved gases from one or more of the three Reinhausen OLTC diverter switch chambers into the main tank oil environment. This migration was likely to have been via two paths, one being associated with leaks from the OLTC diverter switch cylinders. The other path being due to the common head space (only partial oil partitions) shared by the main tank conservator and the three OLTC conservators. This is not a serious problem in itself provided people who may review such DGA test data in the future understand what they are seeing. What it does do is mask emerging thermal issues / hot spots until the severity of the problem increases sufficiently to generate greater amounts of dissolved thermal fault gases which eventually will become visible above the background stray gases.

This transformer has experienced 10 cooling fail alarms over the last 14 years alone with 6 of these from July 2011. These incidents have not caused any visible signs of abnormal heating in the oil test data. As mentioned earlier in clause 4.2.6, this transformer is not hermetically sealed to atmosphere and this is obvious from the dissolved gas in oil test data.

4.2.6.4 Moisture in Insulation:

Because the oil samples taken from this transformer in 1981, 1982 and 1983 had no oil sample temperature information provided, the laboratory test data over this period was not usable for calculating the moisture in cellulose. Hence figure 48 shows a plot of the calculated percent by dry weight moisture in insulation over most of the transformer's life, starting from 1984. The red dotted line in figure 49 is an attempt to compensate for any erroneous data errors. The calculated average percent moisture in cellulose by dry weight at present is approximately 2.0% and the moisture profile over the years appears to follow fairly closely, for similar reasons, the moisture profile of T1 which is shown in figure 22 in this report.

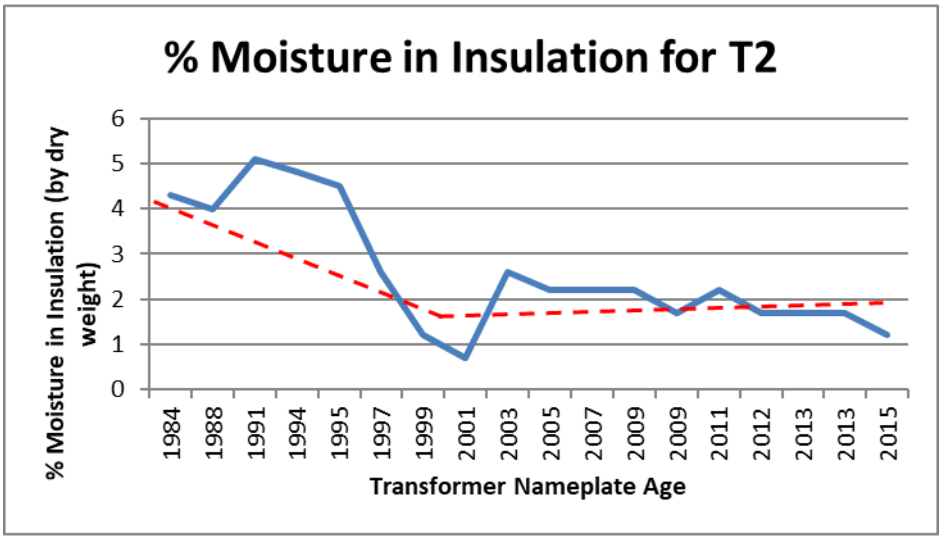

Figure 48: Calculated average of 2.0% moisture in insulation by dry weight.

When this transformer was designed and built, the insulation dryout methods were somewhat poor compared to the standards set by the vapour phase dryout systems used over the last 15 years or more and it was not uncommon to have relatively wet insulation (by today's standards) from new. The measured moisture in insulation level appears to have been slowly reducing from 1984 and this may have been due to the efficiency of the conservator Drycol refrigerant drying system which continuously dried the air above the oil as well as the incoming air as transformer operating temperatures reduced. Maintenance records do not say but it is likely that the Drycol system on this transformer was removed around the same time as the removal of the Drycol system on T1, which was in 2004 after 27 years of operation.

The origin of the calculated residual moisture in the cellulose insulation can only come from a few sources, namely;

- insulation chemical aging,
- moisture ingress from the atmosphere over the years due to oil leaks or maintenance activities,
- residual moisture from new.

The condition of the desiccant in the conservator air breather appeared serviceable when checked through a tiny viewing window but it was not possible to see a holistic view of the desiccant due to the design of this non-standard breather. It was therefore not possible to verify if there was an air leak in the plumbing between the breather and the conservator. It was also not possible to inspect the breather oil bath condition, or even if the breather was fitted with one.

Figure 49: The conservator desiccant breather design does not allow comprehensive visual inspection for serviceability.

The calculated moisture in insulation at present is still well below the 4% level beyond which can introduce risks of insulation failure under the right combination of specific operating / environmental conditions.

The only way of getting a more accurate measure of the % moisture in insulation is to install an on-line moisture and temperature probe in the main oil stream for a week and analyse the data collected under varying loads / temperatures.

4.2.7 Estimated Residual Life of Transformer:

Table 3 provides a quick summary of the estimated residual life of the "key" transformer components but there is further discussion on these aspects in clause 4.2.7.

TABLE 3
Summary of Estimated Residual Life of Transformer T2 "Key" Components

Parameter	Estimated Residual Life	Further Comments
Anti-corrosion system	10 years for main tank. 2 to 3 years for cooler bank	Recently repainted. Main tank overall in good condition. Cooler bank will present an increasing maintenance issue. (cooler bank may need to be replaced in near future)
Winding paper life	10 years	Calculated Av age = 21 years Wdg Hot spot age = 27 years
Winding mechanical stability	Cannot be assessed accurately, but is considered questionable due to design used and exposure.	Old clamping structures design, lowering of DPv & moisture exchange.
External HV & LV bushings	LV bushing B phase oil sample provides clear indication of advanced partial discharge. Restricted access zone is established.	Refer to clause 4.2.7.4 for rational.
Insulating Oil	5+ years	Assumed similar in-service operating conditions for the future.
Radiators	2 to 3 years for cooler bank	Oval tube / bottom header interface corrosion issues. Some cooling fans may need replacement.
Repairs to leaking gaskets	Required now.	Many gasket leaks.
Overall residual life	<5 years. The unreliable service can be extended to 10 years if cooler bank is to be replaced and major oil leaks fixed.	If the recommended actions are taken, transformer may remain in service for 10 years, but its reliability will remain low and availability will be decreasing due to the failures of minor components.

4.2.7.1 Anti-corrosion System Life

In general, the main tank could last for a further 10 years or more provided localised corrosion is addressed before it becomes more serious. Some areas will be awkward to access (e.g. main tank / lid mating steel flanges) to neutralise existing corrosion.

Because the cooler bank is exhibiting the usual corrosion issues associated with the radiator panel oval tube / header design which has already necessitated oil leak repairs, the existing cooler bank life expectancy is limited to a few years with increasing maintenance repair costs.

The corrosion problem with respect to the cooler bank fan motor casings is more serious and will need attention or removal in the not too distant future.

4.2.7.2 Insulation Life

Winding Paper:

The calculated age / mechanical condition of the winding paper suggests that it still has the potential to achieve another conditional 10 years of life provided its in-service operating environment does not change significantly (for the worse).

Insulating Oil:
The quality of the insulating oil is well aged but the oil and cellulose insulation environment should be able to achieve a further 5+ years of service provided its in-service operating environment does not change significantly (for the worse).

4.2.7.3 Mechanical Life

There has been a significant reduction in moisture in cellulose insulation from the early years through to 2001 after which it has remained fairly stable. (refer to figure 49). This moisture migration in and out of the cellulose insulation in the winding clamping structure would have caused some accumulative relaxation in the winding axial clamping pressure and would make it less tolerant to through faults.

Compounding this is the continual loss of cellulose mass while in service as discussed in clause 4.2.6.2 which also causes a relaxation in winding clamping pressure. A final concern is the clamping assembly design used on this transformer in the early 1970's may not be considered appropriate by today's design standards.

Because the calculated average DPV of the cellulose insulation is still at a reasonable level, the residual life expectancy of the core and coils (active part) should be better than for other transformers of a similar age which are closer to end of insulation life.

4.2.7.4 Transformer Bushings

The HV and LV bushings installed on this transformer are an oil impregnated paper (OIP) design. Maintenance records from 2004 do not show the same issues with poor HV insulation dielectric loss and capacitance test data as compared to the same bushings on transformer T1. The recent tests showed very high reading of DLA measurement for B phase LV bushing and the oil samples taken also indicated progressed partial discharged in this bushing. Due to the concerns for safety of personnel in the event of bushing explosive failure, restricted access zone has been established around this transformer.

The reliable life expectancy of an OIP bushing is about 25 years and therefore these bushings have performed beyond expectations.

The tertiary winding terminal bushings appear to be a more robust hollow porcelain design and should be able to last for a further 10+ years or longer.

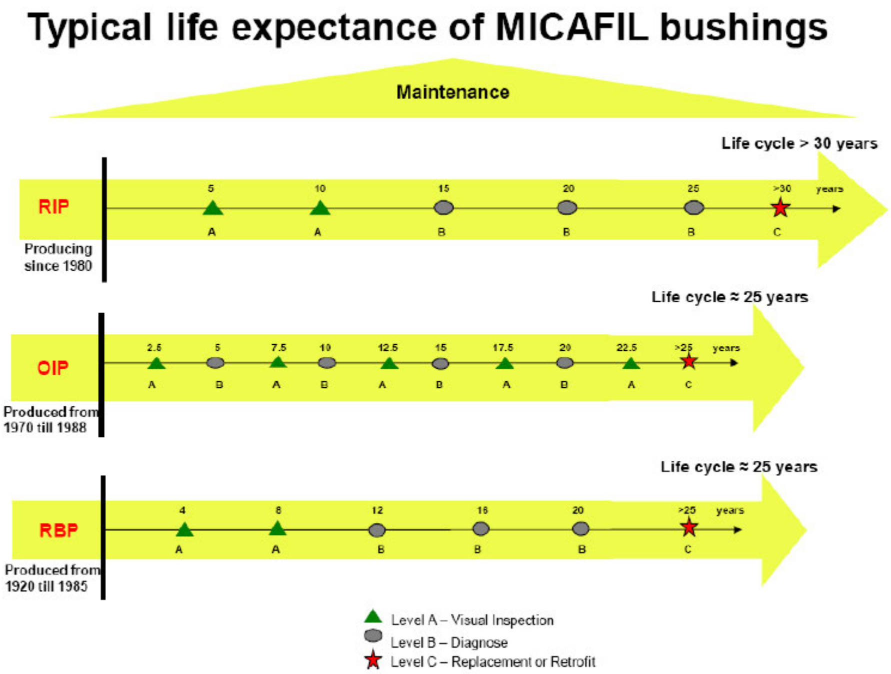

Figure 50: Bushing life expectancy provided by the bushing manufacturer.

5. CONCLUSIONS FOR TRANSFORMER T2

5.1 Condition Assessment

The following conclusions can be drawn from the condition assessment of the H010 Bouldercombe transformer T2.

5.1.1 Oil Leaks:

There are a number of significant oil leaks which do need attention when resources can be made available and the sooner the better if these transformers are to be kept for a further 10 years.

More regular monitoring may be required of the cooler bank radiator panels due to existing oil leak issues that will only get worse.

5.1.2 External Physical Condition:

Overall, the paint system appears to be in good condition but there are a few corrosion issues that warrant attention in the near future. These are;

- Corrosion of the mounting bolts on the TV terminal bushings.
- Advanced corrosion on a number of the cooler bank fan motor casings.
- Corrosion where the cooler bank radiator panel oval tubes join the top and bottom rectangular box section headers. The corrosion is not really visible at present due to the excess paint having been placed in these locations but the oil leaks from these locations are evidence of the corrosion.
- Corrosion between main tank and lid flanges.
- Corrosion of main tank horizontal stiffener plates.

Repairs to the cooler bank radiator panel oval tubes / bottom header interface is going to be a worsening on-going maintenance issue up until the cooler bank is replaced.

The band aid approach to maintaining the cooler bank in a serviceable condition may be appropriate if the transformer is only required to remain serviceable for up to 5 years.

5.1.3 Insulation Residual Life:

The winding paper insulation residual in-service life is calculated to be approximately 10 years before it would deteriorate to a point where it would be considered mechanically unacceptable for reliable in service operation. Obviously this calculated residual life would depend greatly upon how the transformer was loaded in the future and the severity of any through faults.

5.1.4 Winding Mechanical Stability:

There have been the usual factors influencing the longevity of the mechanical stability of the windings over the years but this transformer's cellulose insulation system has lost mass at a slower than unity aging rate and as such, the stability of the windings is considered to be slightly more reliable than if the aging rate was equal to unity or greater. However clamping design used in this transformer is known to be subject to the relaxation making this transformer susceptible to sudden failure during or shortly after it is exposed to even minor through faults.

5.1.5 Transformer Bushings:

Because there have been a number of bushing tests performed in the field over the years yielding test data which was later confirmed by oil sampling directly from the top of the bushings to be misleading, the more recent bushing test results obtained this month are again triggering the same debate. Until repeat bushing oil samples are taken to conclusively show if the electrical test data is "real", their true condition is uncertain but suspect.

5.1.6 Transformer Primary Ancillary Items:

Apart from the serviceability of the HV and LV bushings, there is nothing else of major consequence other than what has already been discussed elsewhere in this report (radiator panels, cooler bank fans, WTI & OTI instruments). There will always be a possibility to have to replace ancillary equipment unexpectedly and this cannot always be forecast.

The OLTC has had a number of issues with 'C'-phase diverter switch and the tap changer not wanting to change tap position so maintenance costs associated with keeping the OLTC serviceable may be going to increase in coming years even though it the number of tap change operations is still relatively low.

5.1.7 Transformer Secondary Systems:

The secondary system components are well aged and a number of items have needed to be replaced over the years but the design of the system is relatively simplistic and can be maintained in a serviceable condition without too much trouble, but can contribute to the reduced transformer availability.

One aspect which may need consideration is whether Powerlink wishes to improve the electrical safety in the Main Control Cubicle by installing an insulating barrier in front of the live 400VAC terminals, to align with our existing design standards.

Technology and Planning – Network Planning

March 2018

Bouldercombe Planning Statement

Prepared by: Grid Planning

A2860125

Table of Contents

1 Executive summary

Bouldercombe is a major transmission node in the central Queensland region, marshalling a number of 275kV circuits from Nebo, Stanwell and Broadsound to the North and Raglan and Calliope River to the south. Three 275/132kV transformers provide the sole 132kV injection to the area, supplying Energy Queensland at Rockhampton, Egans Hill and Pandoin, as well as the Stanwell Power Station auxiliary supply and Aurizon loads at Wycarbah and Grantleigh.

Condition assessments have been undertaken on the Bouldercombe 275kV and 132kV primary plant, the two 200MVA 275/132kV transformers and 132kV built sections 1154 and 1155 (Rockhampton-Bouldercombe). These condition assessments carried out on plant that has been in service for more than 40 years revealed condition based drivers and plant that is approaching the end of its technical life.

The following feeders and transformers associated with the diameters identified in the condition assessment were technically assessed from a planning perspective, to determine whether there is an enduring need.

275kV switchyard:

- Feeder 848 Bouldercombe –Stanwell
- Feeder 849 Bouldercombe – Stanwell
- Feeder 820 Bouldercombe - Broadsound
- Feeder 821 Bouldercombe - Nebo
- Feeder 811 Bouldercombe - Raglan
- Feeder 812 Bouldercombe - Calliope River

132kV switchyard:

- Feeder 7115 Bouldercombe – Pandoin
- Feeder 7170 Bouldercombe –Rocklands (disconnected at Rocklands substation, no load)
- Feeder 7107 Bouldercombe – Rockhampton
- Feeder 7108 Bouldercombe – Rockhampton
- Feeder 7221 Bouldercombe - Egans Hill
- Feeder 7167 Bouldercombe - Stanwell

Power Transformers:

- 275/132kV Transformer T1 and T2 200MVA (T2 has been removed from service due to immediate safety and condition concerns.)

Planning studies have determined that these feeders have an ongoing need to meet the transfer capability in the Bouldercombe area. F7170 Bouldercombe – Rocklands feeder currently has not supplied load since 1/07/2017, and does not service a foreseeable need. Bouldercombe has a need for two transformers, 375MVA T3 (installed in 2012) and an additional transformer with a minimum rating of 250MVA.

These studies have confirmed that to maintain Powerlink’s reliability obligations there is an ongoing requirement for Bouldercombe Substation in its current configuration, excluding the Rocklands feeder. Planning has investigated several alternative options, but they are not considered credible options from a technical and economic perspective.

2 Background

Bouldercombe Substation is located in the Central West region and is a critical part of the 275kV network providing circuits north to Broadsound and Nebo, south to Raglan and Calliope River and west to Stanwell. Bouldercombe 132kV substation provides supply to the Ergon networks through 132/66kV transformation at Rockhampton (T023), Egans Hill (T127) and Pandoin (T061). It also provides 132kV supply to Stanwell Power Station and Aurizon loads via Wycarbah and Grantleigh. The connection to Rocklands substation was terminated on 01/07/2017.

The Bouldercombe 132kV switchyard was established in 1975, and the 275kV switchyard and two 200MVA transformers were established in 1977. Transformer T3 (375MVA) was established in 2012. The 275kV switchyard is based on double bus and a breaker and a half configuration. The 132kV yard is based on a double bus, disconnector selectable configuration with a coupler bay, however there are two individual bus sections (bus 3 and 4) connected via disconnectors to bus 1 and 2.

Bouldercombe 275/132kV Substation is the sole supply to the 132kV network in the area, supplying customer loads via two 275/132kV transformers rated at 375MVA and 200MVA respectively. One 200MVA 275/132kV transformers is currently disconnected and is available as a spare (T2); however its condition is degraded. There is presently no generation connected to Bouldercombe (the 132kV connection to Stanwell is to provide Auxiliary supplies to the Power Station).

2.1 Geographical Overview

Figure 1 shows a geographical view of the Bouldercombe Substation within the Central West zone. The figure shows the existing transmission network in the area but omits the 66kV distribution network.

[redacted]

Figure 1: Geographical view of the Central West area transmission network

2.2 Existing Supply Arrangements of Bouldercombe Substation

The 275kV switchyard at Bouldercombe consists of two 275kV busbars with 5 diameters and is configured as breaker and a half scheme. The switchyard consists of six feeder bays, five coupler bays and three transformer bays. One diameter is partially populated, and could potentially be used to mitigate extended outages.

The 132kV switchyard is based on a double bus, disconnector selectable configuration with a coupler bay, however there are two individual bus sections (bus 3 and 4) connected via disconnectors to bus 1 and 2. The 132kV switchyard consists of 6 feeder bays, three transformer bays and one diameter is currently spare which could potentially be used to mitigate extended outages.

The 132kV switchyard at Bouldercombe Substation facilitates bulk supply for Ergon load, Aurizon loads and auxiliary supply to the Stanwell Power Station. Figures 2 and 3 show the aerial view and connection configuration of the Bouldercombe 275/132kV Substation respectively. The substation consists of three transformer bays with three 275/132kV power transformers, single 275kV feeders to Calliope River, Raglan, Broadsound and Nebo, two 275kV feeders to Stanwell, single 132kV feeders to Stanwell, Pandoin, Rocklands and Egans Hill and two 132kV feeders to Rockhampton.

Figure 2: Aerial view of Bouldercombe Substation

[redacted]

Figure 3: Single line diagram of 275kV Bouldercombe Substation

3 Load Forecast and Future Supply Requirement of H010

Bouldercombe Substation facilities the power flow from Central West zone south to the Gladstone loads and north to the north loads through both the Gladstone Grid section and CQ-NQ grid section. The Gladstone Grid section is made up of Bouldercombe – Calliope River/Larcom Creek circuits and Calvale – Wurdong circuit. The power transfer through this grid section is limited by thermal rating following a critical contingency.

From Figure 5 it can be seen that the utilisation of Gladstone grid section has slightly decreased in 2016, due to increases in Gladstone zone and decreases in southern generation. It can then be expected that once the committed renewable generation is operational in the Far North, Ross and North zones, CQ-NQ may flow more in a Southerly direction and increase the loading on the Gladstone grid section.

The CQ-NQ grid section is made up of the Bouldercombe – Nebo, Broadsound – Nebo andDysart – Eagle Downs (132kV) circuits. The impact of the removal of these feeders causes thermal limitations and reduces the transfer capacity to North Queensland. The secure power transfer through this grid section is limited by both thermal ratings (for a trip a Stanwell to Broadsound 275kV circuit) and voltage stability limitations for a trip of Townsville gas turbine or trip of Stanwell to Broadsound 275kV.

From Figure 4 it can be seen that the utilisation of CQ-NQ grid section has decreased in 2016, mainly due to FNQ and Ross zone generators operating at higher capacity. It can then be expected that once the committed renewable generation is operational, thew utilisation may continue to reduce, particularly during the daylight hours. Although the average utilisation is reducing high power transfers in North Queensland are still expected to meet the peak evening load. Figures 4 and 5 shows the Gladstone and CQ-NQ grid section flow duration curves from 2012 to 2016.

Additional generation in North Queensland may lead to a reversal of flows, with new renewable generation flowing south resulting in thermal overloads, particularly on the 275kV feeders between Bouldercombe and Calliope River. Powerlink has recently approved a project to increase two feeders (Bouldercombe – Raglan and Larcom Creek – Calliope River) from a design temperature of 82°C to 90°C.The removal or reconfiguration of the network across and around this grid section will result in a change to the transfer capacity. Removing circuits will have the effect of reducing the transfer limit, imposing constraints on the amount of generation, impacting market benefits such as dispatch of cheapest fuel generators, and potentially impacting on the ability to supply load in Bouldercombe, the Gladstone zone and southern Queensland zones.

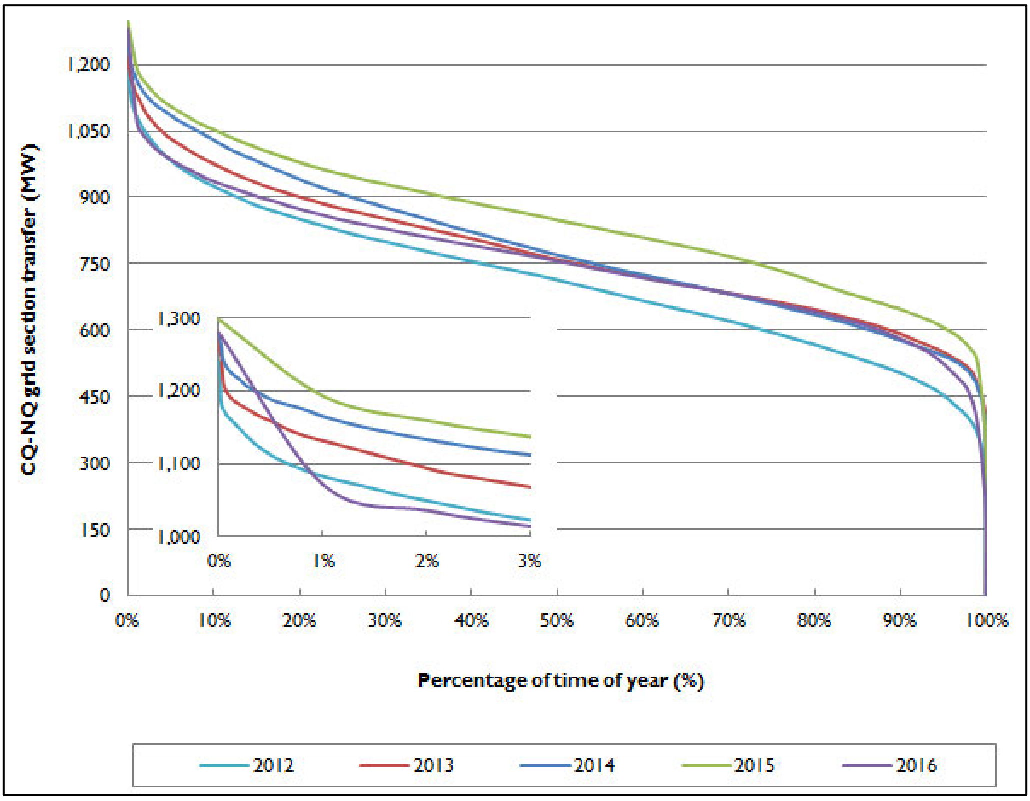

Figure 4: Load Curve for CQ-NQ Grid Section

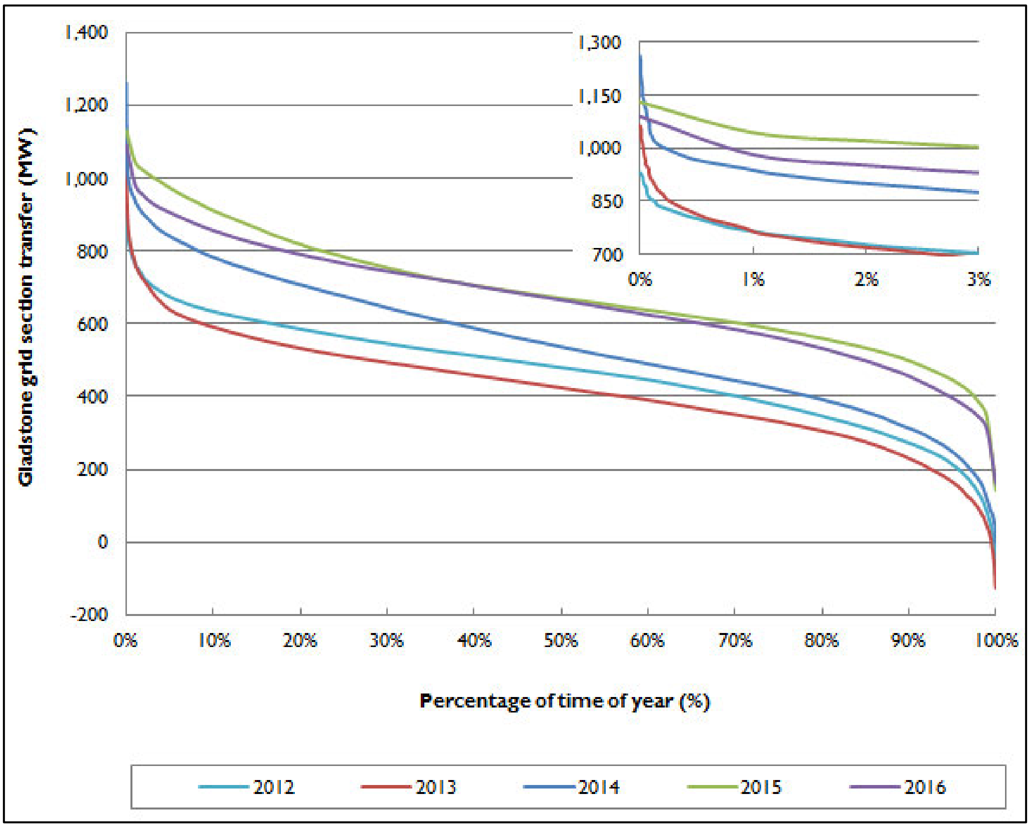

Figure 5: Load Curve for Gladstone Grid Section

Figure 6 shows the historical and forecast summer maximum demand on the 132kV network at Bouldercombe Substation. The forecast indicates a steady demand out to 2026. There are no major additional loads proposed or committed in the Bouldercombe region.

From Figure 6, it can be seen that the historical maximum demand peak was 217MW in 2011/12 and the lowest maximum demand was 192MW in 2016/17. Bouldercombe Substation supplies the 132kV substations of Rockhampton, Paindoin, Egans Hill and via Stanwell the Aurizon Wycarbah and Grantleigh loads. Note that the Rocklands load is included in the historical load but was decommissioned in 2017.

There are several proposals for renewable generation in the Bouldercombe area, however these have been focussed on the Solar PV potential in the region, and none have reached a stage where it is considered committed. As such, whilst generation in the region would reduce demand during daylight hours, it is not expected to change maximum demand which typically occurs outside of daylight hours.

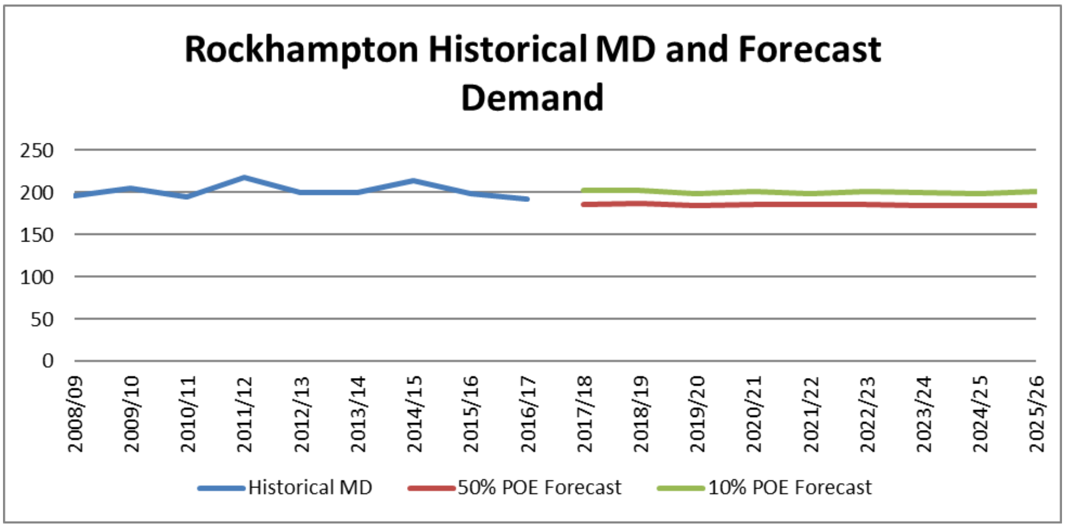

Figure 6: Historical and forecast demand forecast for Bouldercombe Substation

4 Primary plant asset condition

Three separate condition assessment reports capture the age and condition based drivers on the 275/132kV primary plant, transformer and transmission lines reinvestment.

Bouldercombe 275/132kV Substation was established in the mid-1970s and every diameter has some selective primary plant replacement required. Condition issues are apparent on the following plant, with the timeframe in brackets provided for each indicating when the issues require rectification:

- Hitachi 132kV circuit breakers (2-3 years);
- 132kV disconnectors and earth switches (3-5 years);
- Hitachi 275kV circuit breakers (3-5 years);
- 275kV string insulator assemblies (12-24 months);
- 275kV station post insulators (12-24 months); and
- 275kV disconnectors (10-15 years)

A reinvestment timing of 2021 has been proposed for the primary plant replacement (refer reference 1).

The H010 Bouldercombe Substation transformers T1 and T2 are 38 years old. Catastrophic power transformer failure in electricity transmission are very high in terms of financial costs, loss of supply, impact on safety of personnel and public and impact on the environment (fire, gasses, oil disposal, etc.), the asset management strategy employed is to plan and execute replacement before the actual failure occurs. Transformer T1 is in marginally better condition than T2 in terms of estimated residual life. Transformer T1 has a residual life of less than 5 years if left in its current condition, whilst both T1 and T2 could be extended to 10 years if the cooler banks were replaced and oil leaks rectified. Condition issues on transformer T1 require rectification by 2022. Refer to reference 2.

Failure of plant to operate may result in non-credible contingencies such as cascading failure, reduced transfer capabilities and loss of supply. Furthermore, where spare replacement units are not available, there may be prolonged outages while replacement units are incorporated into the existing unit.

5 Transmission line asset condition

Built sections 1154 and 1155, which make up a section of the Bouldercombe – Rockhampton 132kV feeders between Egans Hill and Rockhampton substations, was originally commissioned in 1963 and has now reached the end of its predicted service life. The original structures in Built Sections 1154 & 1155 are part of the original Rockhampton – Callide A 132kV Feeder constructed in 1963, while all other towers were constructed in the 1990's as part of the arrangements to establish the Egans Hill Substation with a 132kV connection to Bouldercombe. As a result the 132kV circuits to Rockhampton are located on both single and double circuit towers varying in age from 22 to 55 years. The condition assessment highlighted that some tower bolts and members and grillage foundations required replacement or rectification by 2020. A reinvestment timing of 2020 for the transmission lines refit has been proposed (refer reference 4).

6 Options Considered

This section highlights options which were considered technically and/or economically feasible and infeasible to address the above identified condition based primary plant issues. The "do nothing" option is discussed first and then three alternative options were assessed as having the potential to meet the required reliability obligations for supply to the Bouldercombe area.

1. Do Nothing
2. Maintain Bouldercombe network configuration
3. Decommission/re-use F7170 feeder connection
4. Non-Network options

Planning is recommending Option 3, as the optimal solution to meet the needs of the Bouldercombe area by 2020-22. Multiple alternative scenarios were assessed but were not considered to be credible options from a technical and economic point of view, such as the removal of additional feeders.

6.1 Do Nothing

Under Queensland legislation, Powerlink has the responsibility to plan for Queensland's future transmission needs, including the interconnection with other networks. These planning obligations are prescribed by Queensland's Electricity Act 1994 (the Act), the National Electricity Rules (NER) and Powerlink's Transmission Authority, issued by the Queensland Government.

The Transmission Authority requires that Powerlink plans and develops the transmission grid in accordance with good electricity practice, with regard to the value end users of electricity place on the quality and reliability of electricity services.

"Do Nothing" would not be an acceptable option as the primary driver (transformer condition) and associated safety, reliability and compliance risks would not be resolved. Furthermore, the "Do Nothing" option would not be consistent with good industry practice and would result in Powerlink breaching their obligations with the requirements of the System Standards of the National Electricity Rules and its Transmission Authority.

6.2 Maintain Bouldercombe Network Configuration

Bouldercombe Substation itself has limited operational flexibility for outages and maintenance outages due to thermal limitations. It has multiple feeder pathways which facilitate flows from the Central West to supply Gladstone and Southern Queensland loads, as well as flows north to Northern Queensland. Central West generation supplies the loads off Bouldercombe 132kV substation and the 275kV network is critical in the power transfer supplying Gladstone and Southern Queensland loads as well as north to the CQ-NQ grid section.

Planning has investigated the viability of the feeder configurations examined in the condition assessment for Bouldercombe. Planning studies indicate that there is an ongoing need for the following feeders to remain in the Queensland network:

- Feeder 848 Bouldercombe –Stanwell
- Feeder 849 Bouldercombe – Stanwell
- Feeder 820 Bouldercombe - Broadsound
- Feeder 821 Bouldercombe - Nebo
- Feeder 811 Bouldercombe - Raglan
- Feeder 812 Bouldercombe - Calliope River
- Feeder 7115 Bouldercombe – Pandoin
- Feeder 7107 Bouldercombe – Rockhampton
- Feeder 7108 Bouldercombe – Rockhampton
- Feeder 7221 Bouldercombe – Egans Hill
- Feeder 7167 Bouldercombe – Stanwell

Except:

- Feeder 7170 Bouldercombe –Rocklands (disconnected at substation, no load)

Several of the 275kV feeders impact the power transfer capability across the Gladstone and CQ-NQ grid section, and under contingency can reduce the transfer capacity significantly (refer reference 3). The maximum power transfer is limited by the transmission elements thermal capacity, voltage stability or maintaining transient stability following a critical contingency. The outage of selected 275kV and 132kV individual feeders violate the thermal capacity requirements.

All options were analysed with feasible generation patterns, and under these conditions thermal overloads were apparent. Low northerly flow CQ-NQ, low Gladstone flow with 4 units at Gladstone on and medium CQ-SQ flow was analysed. Under these conditions, thermal issues are apparent throughout the Bouldercombe area under critical contingencies. These thermal limitations are expected to worsen if Gladstone generation is reduced further (low Gladstone generation results in higher transfer through the Gladstone grid section), as well the commissioning of committed renewables in North Queensland may push flows in a southerly direction on the CQ-NQ cut-set to meet the Gladstone and Southern Queensland loads. The effects of this generation dispatch, will see further thermal limitations under critical contingencies, such as Calvale –Wurdong or Larcom Creek –Calliope River.

Modelled generation dispatch:

Generation dispatched from Bulli area

- Braemar

Maximise the generation in Central West area

- Stanwell
- Callide B

Reduced capacity generation in Gladstone area

- Gladstone

The 132kV network from Bouldercombe supports the Aurizon and Ergon loads. All feeders are single circuit except Rockhampton, which is double circuit. The removal of any of these feeders will result in a violation of Powerlink’s reliability obligations.

Powerlink’s reliability obligations specifies that the maximum load at risk must not exceed 50MW and no more than 600MWh of energy is to be lost at one time following a credible contingency event. To meet this criteria, there is a need for two transformers at Bouldercombe Substation, the existing T3 (375MVA) and an additional transformer.

Currently T1 200MVA is energised and T2 200MVA has been decommissioned to address immediate safety risks arising from its condition. Both transformers have condition based drivers indicating reinvestment is required in 2022, hence T2, whilst it has been kept on site as a spare cannot be relied upon without further works. The energised T3 375MVA transformer can sufficiently support the loads supplied from the Bouldercombe 132kV network. However, to meet the required reliability obligations an additional 275/132kV transformer with a minimum rating of 250MVA is required.

6.3 Disconnection of Bouldercombe – Rocklands F7170

Planning studies confirm there is no foreseeable need for Feeder 7170. The Aurizon load at Rocklands was decommissioned in 2017. One potential future reuse for Feeder 7170 between Bouldercombe – Rocklands (concrete pole line built in 1986), which is a , for the replacement of F7107 Bouldercombe-Rockhampton single steel tower line built in 1977, which is 10 years older. This option would reduce the requirement for the primary plant associated with this element whilst not limiting any functionality and operational capacity; and has potential economic and network strategic benefits.

6.4 Non-Network options

Bouldercombe Substation solely supplies the power flow to the loads at Rockhampton, Pandoin, Egans Hill and Stanwell; as well as the Aurizon load at Wycarbah and Grantleigh via Stanwell. A non-network solution for Bouldercombe would need to provide an additional 132kV injection to ensure supply to these loads, specifically by considering the transformer size, configuration and consolidation of T1 and T2. The non-network solutions would require injection at either Bouldercombe, or closer to the loads on the Energy Queensland 66kV network, of over 200MW. This is required to ensure compliance with Powerlink's planning criteria. Table 1 highlights the historical flow of 132kV feeders from Bouldercombe between 2017/2018 (excluding Rocklands feeder 7170). Note that due to diversity on the feeders, the sum of the individual feeders exceeds 250MW.

Table 1. Historical maximum flow on 132kV feeders 2017/2018

Feeder	Max MW
F7115	48.2
F7107	57.7
F7108	57.7
F7221	67.4
F7167	38.2

7 Recommendations

Powerlink has reviewed the condition of the primary plant and transformers at the Bouldercombe Substation. The T1 and T2 275/132kV transformers and primary plant will reach end of technical service life by 2021.

It is recommended that all feeders remain in-service to meet Powerlink's reliability and security obligations, expect Feeder 7170 to Rocklands. This connection is no longer required to supply Aurizon load.

It has been recommended that the existing 375MVA transformer (T3) as well as an additional transformer with a minimum rating of 250MVA is required to ensure Powerlink's reliability obligations are met. Retaining a two 275/132kV transformer substation will allow Powerlink to continue to meet its required reliability obligations (N-1-50MW/600MWh).

Powerlink is currently unaware of any feasible alternative options to minimise or eliminate the load at risk at Tully but will, as part of the formal RIT-T consultation process, seek non-network solutions that can contribute significantly to ensuring it continues to meet its reliability of supply obligations.

8 References

1. "H010 Bouldercombe Electrical Condition Assessment V3", Powerlink, A2375188, 2015.
2. "Condition Assessment Report Rockhampton Egans Hill 132kV BS 1154 & 1155" Powerlink, A2382302, 2015.
3. Transmission Annual Planning Report 2017
4. "H10 Bouldercombe T1 & T2 Transformer Condition Assessment Report" Powerlink, A2374963, 2015.

Base Case Risk
Summary Report

CP.02371 Bouldercombe 1T and 2T Replacement

Version Number	Objective ID	Date	Description
1.0	A3374267	09/06/2020	Original document.

1 Purpose

The purpose of this report is to quantify the base case risk cost profiles and maintenance costs for 275/132kV transformers 1T and 2T at Bouldercombe substation. These are being replaced with a single 275/132kV transformer under approved project CP.02371.

Base case risk costs and maintenance costs have been analysed over a ten year study horizon.

2 Key Assumptions

In calculating the potential unserved energy (USE) arising from a failure of the ageing transformers at Bouldercombe, the following modelling assumptions have been made:

- historical load profiles have been used when assessing the likelihood of unserved energy under concurrent failure events;
- unserved energy generally accrues under concurrent failure events, and consideration has been given to potential feeder trip events within the wider Rockhampton area; and
- The most relevant VCR values published within the AER's 2019 Value of Customer Reliability Review Final Report have been used resulting in a VCR of $25,560/MWh.

3 Base Case Risk Analysis

3.1 Risk Categories

Four main categories of risk are assessed within Powerlink's risk approach; safety, network, financial and environmental.

3.2 Transformer Analysis

This section analyses the risks presented by the relevant transformers at Redbank Plains Substation.

Table 1: Risks associated with at risk transformers

	Mode of failure	
Equipment	**Peaceful**	**Explosive**
Transformer	Network risks (unserved energy). Financial risks to respond to transformer failures in an emergency manner.	Network risks (unserved energy) primarily associated with substation de-energisation in the event of a transformer fire. Safety risks to on-site personnel. Financial risks to replace failed and damaged equipment in an emergency manner.

3.2.1 Transformers – Risk Cost by Year

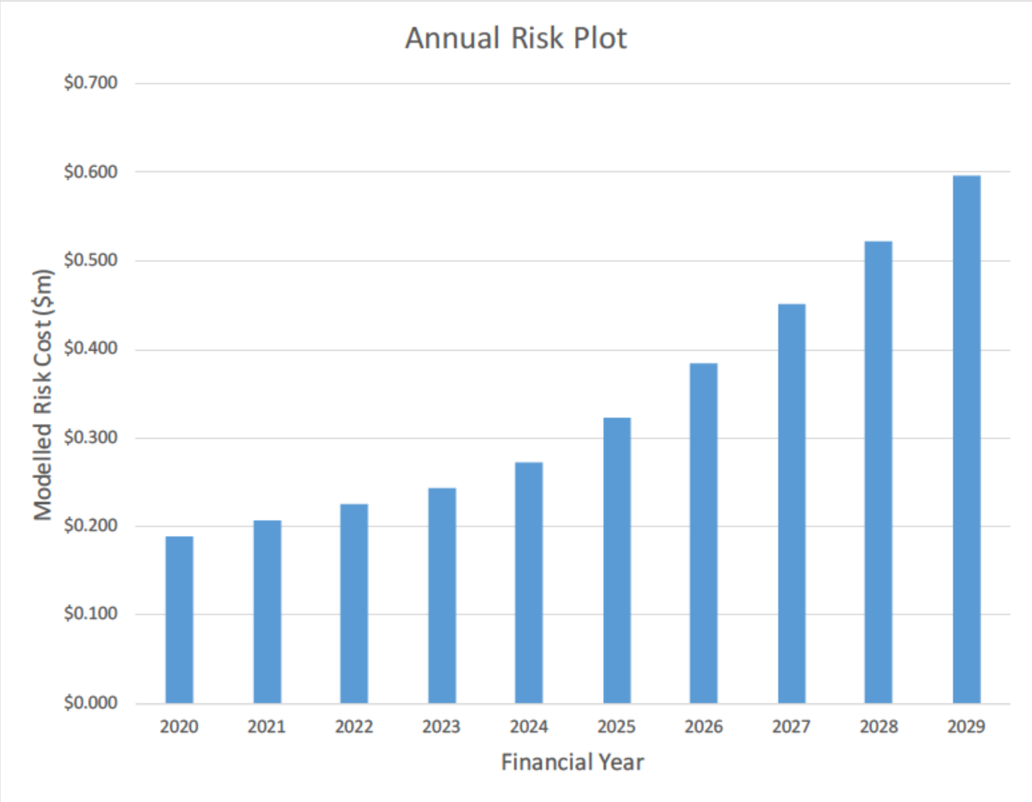

Figure 1: Transformers risk (10 years)

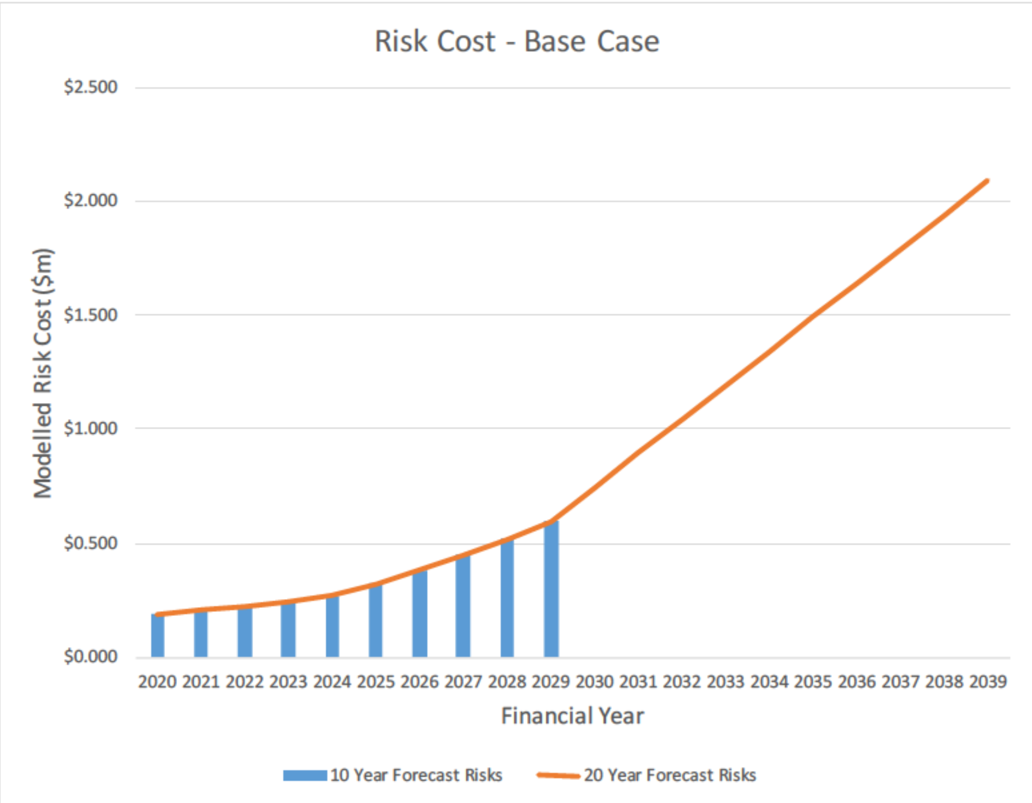

Figure 2: Transformers risk (10 and 20 years)

3.2.2 Transformers – Risk Breakdown by Risk Category

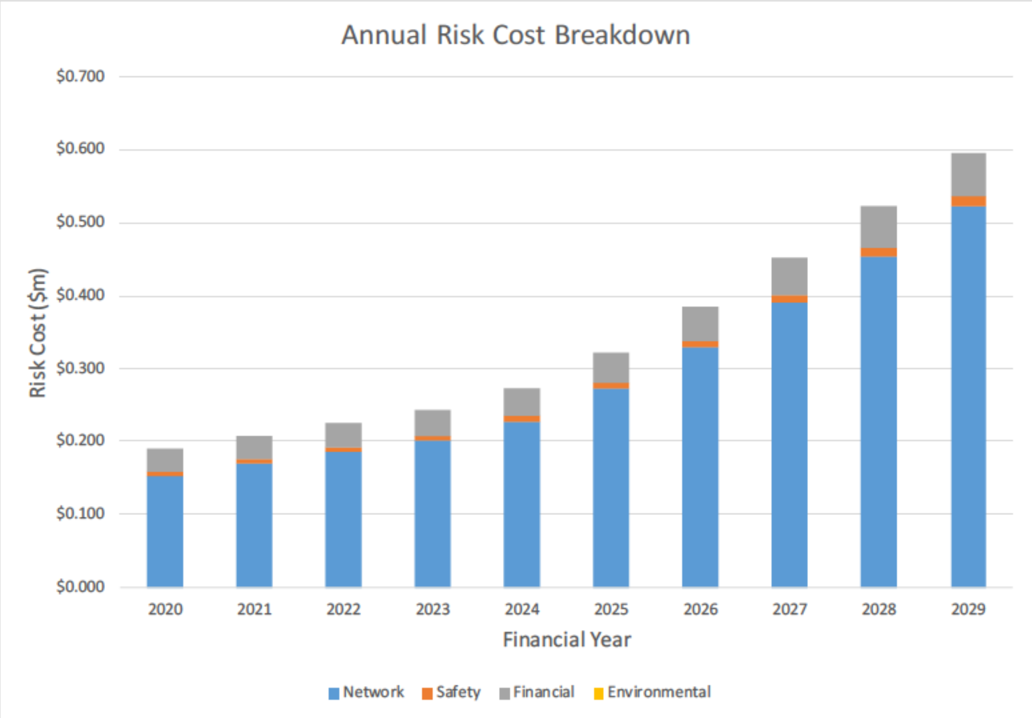

Figure 3: Transformers risk by category

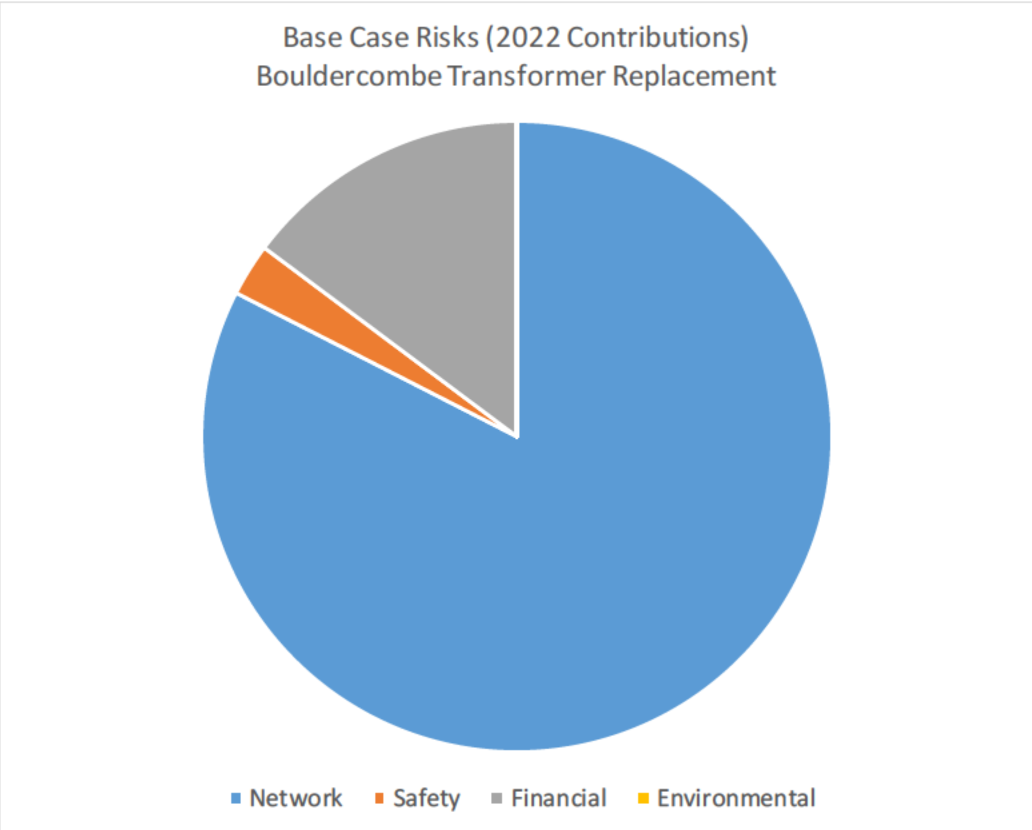

Figure 4: Transformers 2022 risk by category

3.3 Base case risk statement

The main risks for the Bouldercombe transformers under the base case are associated with network risks (unserved energy) associated with failure of the transformers. There is also a component of financial risk to replace damaged equipment and safety risks to personnel.

4 Input participation

A sensitivity analysis was carried out to determine the participation factors for key inputs into the risk cost models (i.e. which inputs affect the risk costs the most).

The sensitivity analysis shows the effect of changing an input value on the modelled risk cost. For example, if VCR is increased by 10%, total risk will increase by around 81.4% of this change (i.e. 8.14%).

Table 2: Input values, transformer model

Item	Value	Unit
Probability of personnel within substation	0.4	Ratio
Probability of personnel adjacent to transformer	0.9	Ratio
Equivalent cost of serious injury	1	$M
ALARP disproportionality factor (substation personnel)	3	Ratio
VCR	25,560	$/MWh
Emergency transformer replacement time (with spare)	6	Weeks
Likelihood of major fire given transformer explosion	0.2	Ratio
Time required to de-energisation site during major fire	72	Hours
Emergency transformer/bushing replacement labour/switching cost	0.5	$M
Media and communication costs	0.3	$M

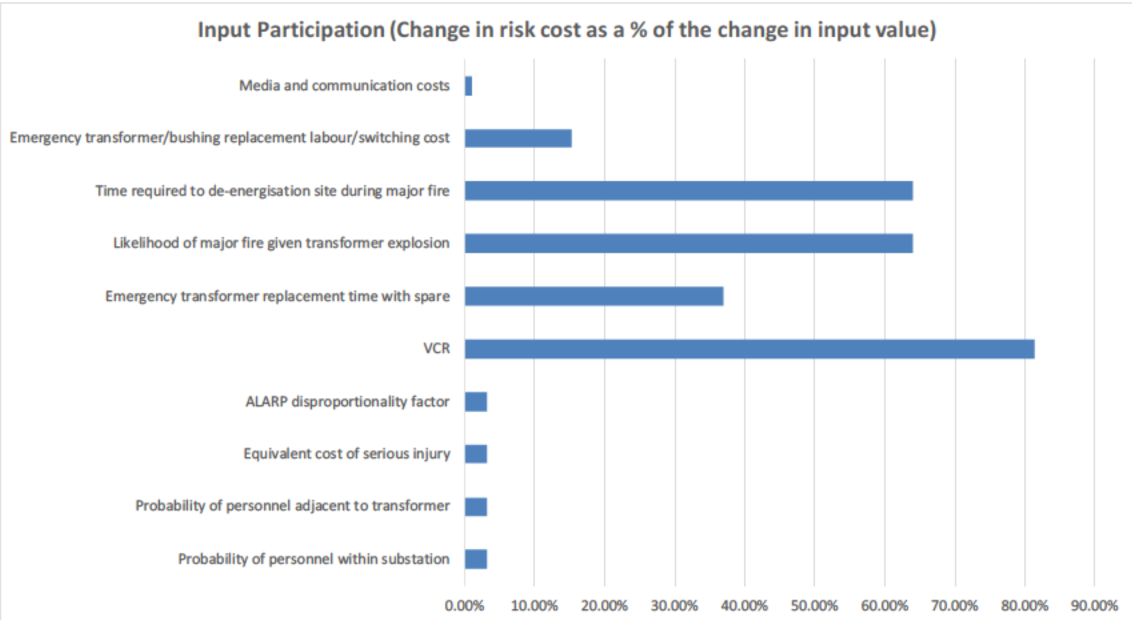

Figure 5: Participation factors, transformer model

Project Scope Report

CP.02371

H010 Bouldercombe No.1 & 2

Transformer Replacement

Concept Estimate - Version 4

Document Control

Change Record

Issue Date	Responsible Person	Objective Document Name	Background
21 Mar 2019	[redacted]	Project Scope Report - CP.02371 H010 Bouldercombe No. 1 & 2 Transformer Replacement	Ver. 4 - Full Approval, obsolete options removed
9 Aug 2018	[redacted]	Project Scope Report - CP.02371 H010 Bouldercombe No. 1 & 2 Transformer Replacement	Ver. 3 - incorporate Tx refurb options
27 Jul 2018	[redacted]	Project Scope Report - CP.02371 H010 Bouldercombe No. 1 & 2 Transformer Replacement	Ver. 2 - RIT-T Concept initial issue
2 Nov 2015	[redacted]	Project Scope Report - CP.02371 H010 Bouldercombe No. 1 & 2 Transformer Replacement	Ver. 1 - Proposal initial issue

Related Documents

Issue Date	Responsible Person	Objective Document Name
31 Dec 2015	[redacted]	H010 Bouldercombe Transformer T1 & T2 Condition Assessment [A2420310]
30 Oct 2015	[redacted]	H010 Bouldercombe Electrical Condition Assessment V3 [A2375188]
Jul 2018	[redacted]	H010 Bouldercombe Substation Replacement Requirements [A2908354]

1. PROJECT DETAILS

1.1. Project Need

Bouldercombe substation is a major transmission node in the Central Queensland region, marshalling a number of 275kV circuits from Nebo, Stanwell and Broadsound to the north and Raglan and Calliope River to the south. Three 275/132kV transformers provide the sole 132kV injection to the area, supplying Energy Queensland at Rockhampton, Egans Hill and Pandoin, as well as the Stanwell Power Station auxiliary supply and Aurizon loads at Wycarbah and Grantleigh.

The three 275/132kV transformers include 2 x 200MVA (1T & 2T) units from the original site establishment and one 375MVA unit (3T) that was established in 2012. 1T & 2T were installed in 1976/77 and at over 40 years of age are displaying significant condition issues typical of transformers of that age.

A condition assessment has identified that 1T is in marginally better condition than 2T 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. Consequently corrective action is required.

Planning studies have determined Bouldercombe has an ongoing need for two transformers, 375MVA 3T (installed in 2012) and an additional transformer with a minimum rating of 250MVA.

The objective of this project is to replace both transformer 1 and transformer 2 by June 2021.

1.2. Project Contacts

Project Sponsor	[redacted]	[redacted]
Manager Connections Contracts (Ergon)	[redacted]	[redacted]
Manager Connections Contracts (Aurizon & Stanwell)	[redacted]	[redacted]
Project Portfolio Optimisation Team	[redacted]	[redacted]
Strategist - HV Asset Strategies	[redacted]	[redacted]
Planner - Main/Regional Grid	[redacted]	[redacted]
Project Manager	[redacted]	[redacted]

1.3. Project Scope

1.3.1. 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 1T & 2T 200MVA 275/132/19.1kV transformers at H010 Bouldercombe with a single new 250MVA 275/132/19.1kV transformer, and decommissioning, removal and disposal of the recovered transformers.

1.3.2. Concurrent Works

This project is to be delivered concurrently with project CP.02350 which includes selective replacement of primary plant at H010 Bouldercombe substation.

1.3.3. Options - H010 Bouldercombe Substation Works

Four credible options including a base case and the three comparative alternatives were identified to address project CP.02371 need.

The outcome of the associated Regulatory Investment Test for Transmission (RIT-T) and external consultation identified Option 3 (a) to be the least cost alternative and therefore the preferred option.

Table 1 - Options summary

Option	Scope Requirements	Comm. Date
Base Case	Life Extension 1T & 2T	Jun 2021
1	Life Extension 2T	Jun 2021
2	Like for Like Replacement	Jun 2021
3 (a)	Single Transformer Replacement - standard 250MVA	Jun 2021
3 (b)	Single Transformer Replacement - non-standard 250MVA	Jun 2021
3 (c)	Single Transformer Replacement - standard 375MVA	Jun 2021

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

1.3.4. Substation Works - H010 Bouldercombe Substation Works

Option 3 (a) strategy involves replacement of 1T & 2T transformers with a single new 250MVA 275/132/19.1kV transformer, to Powerlink standard transformer specifications. Within the scope of works -

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

- 2T transformer with on-load tap changer, cooling facilities and associated surge arrestors for all voltage levels
- establish new transformer foundation;
- 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;

- establish HV and LV connections to new transformer bay infrastructure concurrently established under the *H010 Bouldercombe Substation Replacement Project CP.02350*;

Auxiliary supply works:

- reinstate 5T station services transformer and associated local AC supply (temporarily removed from service under OR.02129);
- establish a new 500kVA station services transformer connected to 3T tertiary winding;
- integrate existing AC changeover board etc. with new station services transformer;
- decommission and recover the temporary diesel generator installation arrangement established under OR.02129;
- demolish and remove existing 4T station services transformer including foundations;

Other works:

- decommission the old 1T & 2T transformers, recover and dispose of decommissioned units;
- demolish and remove the existing 1T & 2T 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; and
- update drawing records, SAP, config files, etc. accordingly.

1.3.5. Variations to Scope (post project approval)

Not applicable

1.4. Project Timing

1.4.1. Site Access Date

H010 Bouldercombe is an existing Powerlink owned substation, and access is available immediately.

1.4.2. 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.

1.5. (Proposed) High Level Line Requirements

Not applicable

1.6. (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	

1.7. 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.

1.8. 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.

1.9. Asset Ownership

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

1.10. 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.

1.11. Options

Not applicable.

1.12. Division of Responsibilities

A division of responsibilities document will not be required for this project.

1.13. Related Projects

Project No.	Project Description	Planned Comm Date	Comment
Pre-requisite Projects			
Co-requisite Projects			
CP.02350	H010 Bouldercombe Primary Plant Replacement	Dec 2021	
Other Related Projects			

1.14. Project Drawing

[redacted]

2. PROPERTY & EASEMENT INFORMATION

2.1. Established Site – H010 Bouldercombe

2.1.1. Site Accessibility

H010 Bouldercombe is an existing substation site and site access is availability immediately.

2.1.2. Issues Regarding Site Location

No Issues regarding the site location identified at this stage.

APPENDIX 1: BOULDERCOMBE TRANSFORMER 1 & 2 REPLACEMENT

H010 BOULDERCOMBE SUBSTATION REPLACEMENT REQUIREMENTS

DIAMETER	DESCRIPTION	START UP	REQUIREMENTS			CP.02350 - PRIMARY PLANT REPLACEMENT			CP.02371 - TRANSFORMER REPLACEMENT					
			INCLUSIONS		EXCLUSIONS	OPTIONS			OPTIONS					
			Mandatory	Optional		0	1	2	0	1	2	3 (a)	3 (b)	3 (c)
Asset Book Value						Life Extension with Deferred Replacements	Life Extension & In Situ Replacements	Selected Full Bay Replacements	1T & 2T Life Extension	2T Life Extension	1T & 2T Like for Like Replacement	2T Replacement - 250MVA (Std)	2T Replacement - 250MVA (Non-Std)	2T Replacement - 375MVA
Assumptions						Projects CP.02350 and CP.02371 to be delivered concurrently			Projects CP.02350 and CP.02371 to be delivered concurrently					
=D01 - BC 4012	CB & CT's (Hitachi)		R			R	R	R						
	ISOL (Stanger)		●			●	●	R						
	S&F - replace rusted nuts & bolts		●			●	●	R						
=D02 - F7167	CB & CT's (GE-Hitachi)	2004		●				R						
Stanwell	SA	2009	●			●	●	R						
	ES	2009	●			●	●	R						
	ISOL	2009	●			●	●	R						
	CVT	2013		●				R						
	S&F - replace rusted nuts & bolts		●			●	●	R						
=D03 - 1T	CB & CT's (Hitachi)	1974	R			R	R	R						
	ES (Stanger)	1977	●			●	●	R						
	ISOL (Stanger)	1977	●			●	●	R						
	EMVT	1977	R			R	R	R						
	S&F - replace rusted nuts & bolts		●			●	●	R						
=D04 - Spare	Decommision and remove		●			●	●	●						
=D05 - F7115	CB & CT's (Hitachi)		R			R	R	R						
Pandoin	SA	2001/2010		●				R						
	ES (Stanger)		●			●	●	R						
	ISOL (Stanger)		●			●	●	R						
	EMVT	1977	R			R	R	R						
	S&F - replace rusted nuts & bolts		●			●	●	R						
=D06 - 2T	CB & CT's (Hitachi)		R			R	R	R						
	ES (Stanger)		●			●	●	R						
	ISOL (Stanger)		●			●	●	R						
	EMVT	1977	R			R	R	R						
	S&F - replace rusted nuts & bolts		●			●	●	R						
=D07 - Spare (F7170)	CB & CT's (Hitachi)		R			R	R	R						
Ex- Rocklands	SA	2000		●				R						
	ES (Stanger)		●			●	●	R						
	ISOL (Stanger)		●			●	●	R						
	CVT	1977	R			R	R	R						
	S&F - replace rusted nuts & bolts		●			●	●	R						
=D08 - F7221	CB & CT's (Hitachi)		R			R	R	R						
Egans Hill	SA	2001		●				R						
	ES (Stanger)		●			●	●	R						
	ISOL (Stanger)		●			●	●	R						
	CVT	1977	R			R	R	R						
	S&F - replace rusted nuts & bolts		●			●	●	R						
=D09 - F7108	CB & CT's (Hitachi)		R			R	R	R						
Rockhampton	SA	2000		●				R						
	ES (Stanger)		●			●	●	R						
	ISOL (Stanger)		●			●	●	R						
	EMVT	1977	R			R	R	R						
	S&F - replace rusted nuts & bolts		●			●	●	R						
=D010 - Bus Section	Decommission and bridge isolators		●			●	●	R						
=D011 - F7107	CB (Asea)	1996	R			R	R	R						
Rockhampton	CT	1983	●			●	R	R						
	SA	1996	●			●	●	R						
	ES (Stanger)	1996	●			●	●	R						
	ISOL (Stanger)	1996	●			●	●	R						
	CVT	1964	R			R	R	R						
	S&F - replace rusted nuts & bolts		●			●	●	R						
=D012 - 3T	CB & CT's (Mitsubishi)	2012			●									
	ES	2012			●									
	ISOL	2012			●									
	CVT	2012			●									
=1&2 Bus 1&2 BU4	EMVT	1974	R			R	R	R						
	ES (Stanger 1999)	1999	●			●	●	R						
	S&F - replace rusted nuts & bolts		●			●	●	R						
=3&4 Bus 3&4 BU4	ES (Stanger 1999)	1999	●			●	●	R						
	S&F - replace rusted nuts & bolts		●			●	●	R						
=C02 BC 502	CB (Mitsubishi)	1993	R			R	R	R						
	ISOL	1993	●			●	R	R						
	ES	1993	●			●	R	R						
	CT	2015		●				R						
$64k	S&F - replace rusted nuts & bolts		●			●	●	R						
=C02 541 1T	CB (Mitsubishi)	1993	R			R	R	R						
	ISOL	1977/1993	●			●	R	R						
	ES	1977/1993	●			●	R	R						
	CT	2015		●				R						
	CVT	2013		●				R						
	SA	1999		●		R	R	R						
$88k	S&F - replace rusted nuts & bolts		●			●	●	R						
	1T		R						●	●	R	●	●	●
=C02 F821	CB & CT's (Hitachi)		R			R	R	R						
Nebo	ISOL	1993	●			●	R	R						
	ES	1993	●			●	R	R						
	CVT	2011		●				R						
	SA	2002		●				R						
$95k	S&F - replace rusted nuts & bolts		●			●	●	R						
=C03 BC 503	CB & CT's (Mitsubishi)	2012		●				R						
	ISOL	1977	●			●	R	R						
	ES	1977	●			●	R	R						
$64k	S&F - replace rusted nuts & bolts		●			●	●	R						
=C03 F811	CB & CT's (Hitachi)	1975	R			R	R	R						
Raglan	ISOL	1977	●			●	R	R						
	ES	1977	●			●	R	R						
	CVT (Asea)	1977	R			R	R	R						
	SA	2002		●				R						
	S&F - replace rusted nuts & bolts		●			●	●	R						
=C03 F820	CB (Merlyn G)		R			R	R	R						
Broadsound	ISOL	1977	●			●	R	R						
	ES	1977	●			●	R	R						
	CT	2002		●				R						
	CVT (Asea)	1977	R			R	R	R						
	SA	2002		●				R						
	S&F - replace rusted nuts & bolts		●			●	●	R						
=C04 BC 504	CB (ABB HPL300)	1994	R			R	R	R						
	ISOL	1994	●			●	R	R						
	ES	1994	●			●	R	R						
	CT	2013		●				R						
$366k	S&F - replace rusted nuts & bolts		●			●	●	R						

H010 BOULDERCOMBE SUBSTATION REPLACEMENT REQUIREMENTS

DIAMETER	DESCRIPTION	START UP	REQUIREMENTS			CP.02350 - PRIMARY PLANT REPLACEMENT			CP.02371 - TRANSFORMER REPLACEMENT					
			INCLUSIONS		EXCLUSIONS	OPTIONS			OPTIONS					
			Mandatory	Optional		0	1	2	0	1	2	3 (a)	3 (b)	3 (c)
Asset Book Value						Life Extension with Deferred Replacements	Life Extension & In Situ Replacements	Selected Full Bay Replacements	1T & 2T Life Extension	2T Life Extension	1T & 2T Like for Like Replacement	2T Replacement - 250MVA (Std)	2T Replacement - 250MVA (Non-Std)	2T Replacement - 375MVA
Assumptions						Projects CP.02350 and CP.02371 to be delivered concurrently			Projects CP.02350 and CP.02371 to be delivered concurrently					
=C04 542 2T	CB & CT's (Hitachi)		R			R	R	R						
	ISOL	1993	●			●	R	R						
	ES	1993	●			●	R	R						
	CVT	2011		●				R						
	SA	1999		●		R	R	R						
	S&F - replace rusted nuts & bolts		●			●		R						
	2T		R						●	●	R	R	R	R
=C04 F849	CB (ABB HPL300)	1994	R			R	R	R						
Stanwell	ISOL	1994	●			●	R	R						
	ES	1994	●			●	R	R						
	CT	2015		●				R						
	CVT	2013		●				R						
$495k	S&F - replace rusted nuts & bolts		●			●	●	R						
=C05 BC 505	CB & CT's (Hitachi)		R			R	R	R						
	ISOL	1977	●			●	R	R						
	ES	1977	●			●	R	R						
	S&F - replace rusted nuts & bolts		●			●	●	R						
=C05 F812	CB & CT's (Hitachi)		R			R	R	R						
Calliope	ISOL	1977	●			●	R	R						
	ES	1977	●			●	R	R						
	CVT (Asea)	1977	R			R	R	R						
	SA	2002		●				R						
	S&F - replace rusted nuts & bolts		●			●	●	R						
=C05 F848	CB & CT's (Hitachi)		R			R	R	R						
Stanwell	ISOL	1977	●			●	R	R						
	ES	1977	●			●	R	R						
	CVT (Asea)	1977	R			R	R	R						
	S&F - replace rusted nuts & bolts		●			●	●	R						
=C06 BC 506	CB (ABB)	2012			●									
	ISOL	2012			●									
	ES	2012			●									
$1.8m	CT	2012			●									
=C06 543 3T	CB (Hitachi)	2012			●									
	ISOL	2012			●									
	ES	2012			●									
	CT	2012			●									
	CVT	2012			●									
	SA	2012			●									
$2.6m	3T	2012			●									
=1&2 Bus 1&2 BU4	CVT (Asea)	1977	R			R	R	R						
	ES	1977	●			●	R	R						
	S&F - replace rusted nuts & bolts		●			●	●	R						
Non-Bay	Oil Containment Sys - replace ?			●					R	R	R	R	R	R
	275kV strung bus hardware/insulators - replace		R			R	R	R						
	275/132kV OHEW hardware/insulators - replace		R			R	R	R						
	275kV station post insulators C02-C05 - replace		R			R	R	R						
	132kV tx feeders hardware/insulators - replace		R			R	R	R						
	Local AC supply - reconfig/establish permanent installation		●						●	●	●	●	●	●
	Perimeter switchyard fence - replace		R			R	R	R						

Notes:

●	Corrective action
R	Replacement
(yellow)	CA review required

CP.02371 H010 Bouldercombe No.1 & 2 Transformer Replacement
Project Management Plan at Concept

Record ID	A2979228	
Authored by	Project Manager	[redacted]
Reviewed by	Team Leader Projects	[redacted]
Approved by	Manager Projects	[redacted]

Version History

Version	Date	Section(s)	Summary of amendment
1	6/09/2018	1-4	Development - Concept Estimate

Table of Contents

1. Executive Summary

Project background

Bouldercombe substation is a major transmission node in the Central Queensland region, marshalling a number of 275kV circuits from Nebo, Stanwell and Broadsound to the north and Raglan and Calliope River to the south. Three 275/132kV transformers provide the sole 132kV injection to the area, supplying Energy Queensland at Rockhampton, Egans Hill and Pandoin, as well as the Stanwell Power Station auxiliary supply and Aurizon loads at Wycarbah and Grantleigh.

The three 275/132kV transformers include 2 x 200MVA (1T & 2T) units from the original site establishment and one 375MVA unit (3T) that was established in 2012. 1T & 2T were installed in 1976/77 and at over 40 years of age are displaying significant condition issues typical of transformers of that age.

A condition assessment has identified that 1T is in marginally better condition than 2T 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. Consequently corrective action is required.

Planning studies have determined Bouldercombe has an ongoing need for two transformers, 375MVA 3T (installed in 2012) and an additional transformer with a minimum rating of 250MVA.

Project objective

The objective of this project is to replace both transformer 1 and transformer 2 by June 2021.

	Date
Project Scope Report (version 3)	27/07/2018
Project Proposal and Project Estimate	14/09/2018
Project Approval Advice (PAA) - date received	TBA

2. Project Definition

2.1 Project Scope

Six options, which include a base case and the five comparative alternatives, have been identified to address project CP.02371 need. Estimates are required to inform feasibility and cost assessments that will form the basis for external consultation under the Regulatory Investment Test for Transmission (RIT-T).

Option	Scope Requirements	Comm. Date
Base Case	Life Extension 1T & 2T	Jun 2021
1	Life Extension 2T	Jun 2021
2	Like for Like Replacement	Jun 2021
3 (a)	Single Transformer Replacement - standard 250MVA	Jun 2021
3 (b)	Single Transformer Replacement - non-standard 250MVA	Jun 2021
3 (c)	Single Transformer Replacement - standard 375MVA	Jun 2021

2.1.1 Substations

Base Case Option - Life Extension 1T & 2T Transformers

The base case option strategy involves targeted refurbishment actions and component replacements to address oil leaks, corrosion issues and emerging reliability issues.

1T Transformer refurbishment works:

- replace cooler bank including fans;
- replace gaskets and valve seals for oil pumps and associated pipework;
- repair all oil leaks including main tank, bushing cable box and main cover flange;
- filter and process oil including degas and dehumidify;
- replace HV and tertiary winding bushings; and
- refurbish the tap changer

2T Transformer refurbishment works:

- replace cooler bank including fans;
- replace gaskets and valve seals for oil pumps and associated pipework;
- repair all oil leaks including main tank, bushing cable box and main cover flange;
- drain and replace oil;
- replace HV, LV and tertiary winding bushings; and
- refurbish the tap changer.

Auxiliary supply works:

- retain existing station services transformers 4T & 5T and associated AC supplies -
  - reinstate 5T station services transformer and associated local AC supply; and
  - decommission and recover the temporary diesel generator installation arrangement established under OR.02129;

Other works:

- upgrade oil containment system to current Powerlink standard;
- modify secondary systems as required; and
- update drawing records, SAP, config files, etc. accordingly.

Option 1 - Life Extension 2T Transformer

Option 1 strategy involves targeted refurbishment actions and component replacements for 2T transformer, and the decommissioning and removal of 1T transformer.

1T Transformer works:

- decommission 1T transformer, recover and dispose of decommissioned unit;
- demolish and remove foundations;
- confirm, or otherwise, presence of asbestos containing materials and PCB oil contamination and dispose of affected materials accordingly;

2T Transformer refurbishment works:

- replace cooler bank including fans;
- replace gaskets and valve seals for oil pumps and associated pipework;
- repair all oil leaks including main tank, bushing cable box and main cover flange;
- drain and replace oil;
- replace HV, LV and tertiary winding bushings; and
- refurbish the tap changer.

Auxiliary supply works:

- reinstate 5T station services transformer and associated local AC supply (temporarily removed from service under OR.02129);
- establish a new 500kVA station services transformer connected to 3T tertiary winding;
- integrate existing AC changeover board etc. with new station services transformer;
- decommission and recover the temporary diesel generator installation arrangement established under OR.02129;
- demolish and remove existing 4T station services transformer including foundations;

Other works:

- upgrade oil containment system to current Powerlink standard;
- modify secondary systems as required; and
- update drawing records, SAP, config files, etc. accordingly.

Option 2 - Like for Like Replacement

The option 2 strategy involves like for like replacement of both transformers with 2x 200MVA 275/132/19.1kV transformers.

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

- 1T & 2T transformers with 2x 200MVA 275/132/19.1kV transformers, with on-load tap changer, cooling facilities and associated surge arrestors for all voltage levels;
- establish new transformer foundations;
- 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;
- establish HV and LV connections to new transformer bay infrastructure concurrently established under the *H010 Bouldercombe Substation Replacement Project CP.02350*;

Auxiliary supply works:

- retain existing station services transformers 4T & 5T and associated AC supplies -
  - reinstate 5T station services transformer and associated local AC supply; and
  - decommission and recover the temporary diesel generator installation arrangement established under OR.02129;

Other works:

- decommission the old 1T & 2T transformers, recover and dispose of decommissioned units;
- demolish and remove the existing 1T & 2T 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; and
- update drawing records, SAP, config files, etc. accordingly.

Option 3 - Replacement with Single Transformer 3 Options

The Option 3 strategy involves replacement of both transformers with a single transformer. Three alternative transformers are to be considered and a separate estimate provided for each, including -

(a) 1x 250MVA 275/132/19.1kV transformer, to Powerlink standard transformer specifications;

(b) 1x 250MVA 275/132/19.1kV transformer, custom designed and impedance matched to the existing 3T 375MVA transformer; and

(c) 1x 375MVA 275/132/19.1kV transformer to Powerlink standard transformer specifications.

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

- 2T transformer with on-load tap changer, cooling facilities and associated surge arrestors for all voltage levels
- establish new transformer foundations;
- 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;
- establish HV and LV connections to new transformer bay infrastructure concurrently established under the *H010 Bouldercombe Substation Replacement Project CP.02350*;

Auxiliary supply works:

- reinstate 5T station services transformer and associated local AC supply (temporarily removed from service under OR.02129);
- establish a new 500kVA station services transformer connected to 3T tertiary winding;
- integrate existing AC changeover board etc. with new station services transformer;
- decommission and recover the temporary diesel generator installation arrangement established under OR.02129;
- demolish and remove existing 4T station services transformer including foundations;

Other works:

- decommission the old 1T & 2T transformers, recover and dispose of decommissioned units;
- demolish and remove the existing 1T & 2T 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; and
- update drawing records, SAP, config files, etc. accordingly.

2.1.2 Transmission Lines / Transmission Lines Refit

- NA

2.1.3 Telecommunications

- NA

2.1.4 Revenue Metering

- The project includes the modification of revenue metering.

2.1.5 Other Project Works

- This project is to be delivered concurrently with project CP.02350 which includes selective replacement of primary plant at H010 Bouldercombe substation.

2.2 Exclusions

Exclusions as follow:

- Transformer bay works (undertaken under CP.02350 primary plant replacement) and impacts from other projects.
- No allowance to repair or upgrade current roadways.
- Telecommunication Works or Transmission Line Works
- No allowance for unsuitable material during foundation rebuilds.

2.3 Assumptions

Assumptions as follow:

- PAN issued to undertake detailed design advices no later than 14/10/2018.
- PAN issued to purchase Transformer no later than 14/11/2018.
- PLQ Resource availability.
- Project timeline as follows -

  Target Approval (Conditional) Oct 2018

  Target Approval (Full) April 2019

  Target Completion Jun 2021
- The two new 200MVA 275/132/19.1kV transformers will fit on the existing footings;
- The condition of the existing transformers footings is suitable for taking the new transformers if this option is chosen.

2.4 Project Interaction

Project Number and Description	Interaction (Pre-requisite/Co-requisite/dependent/Related)	Planned Commissioning Date	Comment
CP.02350 Bouldercombe Primary Plant Replacement	Concurrent	Dec 2021	

2.5 Project Risk

During Project Execution, project risks are recorded managed in PWA Server.

Project risks identified during <u>Project Concept</u> phase are [redacted]

3. Project Financials

3.1 Project Estimate

3.1.1 Estimate Summary

Base Case Life Extension 1T & 2T

Estimate Components		Un-Escalated	Escalated
Base Estimate		7,158,080	8,038,524
Proposed Released Budget		7,158,080	8,038,524
Accuracy Banding (C)	[redacted]	[redacted]	[redacted]
Risk Allowance (D)	%	Inc above	Inc above
Total Proposed Contingency	%	[redacted]	[redacted]
Total Proposed Approval		[redacted]	[redacted]

Option 1 Life Extension 2T

Estimate Components		Un-Escalated	Escalated
Base Estimate		5,289,826	5,940,475
Proposed Released Budget		5,289,826	5,940,475
Accuracy Banding (C)	[redacted]	[redacted]	[redacted]
Risk Allowance (D)	%	Inc above	Inc above
Total Proposed Contingency	%	[redacted]	[redacted]
Total Proposed Approval		[redacted]	[redacted]

Option 2 Like for Like Replacement

Estimate Components		Un-Escalated	Escalated
Base Estimate		11,402,524	12,805,034
Proposed Released Budget		11,402,524	12,805,034
Accuracy Banding (C)	[redacted]	[redacted]	[redacted]
Risk Allowance (D)	%	Inc above	Inc above
Total Proposed Contingency	%	[redacted]	[redacted]
Total Proposed Approval		[redacted]	[redacted]

Option 3 (a) Single Transformer Replacement - standard 250MVA

Estimate Components		Un-Escalated	Escalated
Base Estimate		7,895,257	8,866,374
Proposed Released Budget		7,895,257	8,866,374
Accuracy Banding (C)	[redacted]	[redacted]	[redacted]
Risk Allowance (D)	%	Inc above	Inc above
Total Proposed Contingency	%	[redacted]	[redacted]
Total Proposed Approval		[redacted]	[redacted]

Option 3 (b) Single Transformer Replacement - non-standard 250MVA

Estimate Components		Un-Escalated	Escalated
Base Estimate		8,090,311	9,085,419
Proposed Released Budget		8,090,311	9,085,419
Accuracy Banding (C)	[redacted]	[redacted]	[redacted]
Risk Allowance (D)	%	Inc above	Inc above
Total Proposed Contingency	%	[redacted]	[redacted]
Total Proposed Approval		[redacted]	[redacted]

Option 3 (c) Single Transformer Replacement - standard 375MVA

Estimate Components		Un-Escalated	Escalated
Base Estimate		8,408,357	9,442,585
Proposed Released Budget		8,408,357	9,442,585
Accuracy Banding (C)	[redacted]	[redacted]	[redacted]
Risk Allowance (D)	%	Inc above	Inc above
Total Proposed Contingency	%	[redacted]	[redacted]
Total Proposed Approval		[redacted]	[redacted]

3.1.2 Asset Write-Off Table

CP.02371 Asset Write-off. Values current at 30th June 2019

Functional Loc.	Description	Asset	Book val.	Write-off %	Write-off Value	Currency
H010-C02-541-	275kV 1 TRANSF BAY	104724	87,688.32	0%	$ -	AUD
H010-C04-542-	275kV 2 TRANSF BAY	104736	500,944.01	0%	$ -	AUD
H010-SIN	SUBSTATION INFRASTRUCTURE	104776	752,584.32	0%	$ -	AUD
H010-T01-1TRF	1 TRANSFORMER	104778	240,765.40	100%	$ 240,765.40	AUD
H010-T02-2TRF	2 TRANSFORMER	104779	240,765.40	100%	$ 240,765.40	AUD
				Total	$ 481,530.80	AUD

3.2 Approved Released Budget

The approved release budget to execute the project is as follows: $11.0m

3.3 Planned Costs (Forecasted Cash Flow)

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

Project Cash flow: Base Case Life Extension 1T & 2T

Financial year	Base $	Escalated $
Financial Year 2018/2019	2,250,000	2,250,000
Financial Year 2019/2020	2,579,040	3,019,262
Financial Year 2020/2021	2,329,040	2,769,261

Project Cash flow: Option 1 Life Extension 2T

Financial year	Base $	Escalated $
Financial Year 2018/2019	2,250,000	2,250,000
Financial Year 2019/2020	1,644,913	1,970,237
Financial Year 2020/2021	1,394,914	1,724,237

Project Cash flow: Option 2 Like for Like Replacement

Financial year	Base $	Escalated $
Financial Year 2018/2019	2,250,000	2,250,000
Financial Year 2019/2020	4,701,262	5,433,020
Financial Year 2020/2021	4,451,262	5,122,014

Project Cash flow: Option 3 (a) Single Transformer Replacement - standard 250MVA

Financial year	Base $	Escalated $
Financial Year 2018/2019	2,250,000	2,250,000
Financial Year 2019/2020	3,331,385	3,842,356
Financial Year 2020/2021	2,313,872	2,774,018

Project Cash flow: Option 3 (b) Single Transformer Replacement - non-standard 250MVA

Financial year	Base $	Escalated $
Financial Year 2018/2019	2,250,000	2,250,000
Financial Year 2019/2020	3,045,156	3,542,710
Financial Year 2020/2021	2,795,155	3,292,710

Project Cash flow: Option 3 (c) Single Transformer Replacement - standard 375MVA

Financial year	Base $	Escalated $
Financial Year 2018/2019	2,250,000	2,250,000
Financial Year 2019/2020	3,204,179	3,721,293
Financial Year 2020/2021	2,954,179	3,471,290

Un-escalated Estimate Summary

Base Case Life Extension 1T & 2T

Asset Class	Asset Life	Total
Line Works	50	N/A
Primary Plant	40	6,654,501
Secondary Systems	15	475,106
Network Operations	12	28,473
Total		**7,158,080**

Option 1 Life Extension 2T

Asset Class	Asset Life	Total
Line Works	50	N/A
Primary Plant	40	4,741,561
Secondary Systems	15	519,688
Network Operations	12	28,577
Total		**5,289,826**

Option 2 like for Like Replacement

Asset Class	Asset Life	Total
Line Works	50	N/A
Primary Plant	40	10,815,631
Secondary Systems	15	559,451
Network Operations	12	27,442
Total		**11,402,524**

Option 3 (a) Single Transformer Replacement - standard 250MVA

Asset Class	Asset Life	Total
Line Works	50	N/A
Primary Plant	40	7,316,138
Secondary Systems	15	551,243
Network Operations	12	27,877
Total		**7,895,257**

Option 3 (b) Single Transformer Replacement - non-standard 250MVA

Asset Class	Asset Life	Total
Line Works	50	N/A
Primary Plant	40	7,509,195
Secondary Systems	15	553,143
Network Operations	12	27,973
Total		**8,090,311**

Option 3 (c) Single Transformer Replacement - standard 375MVA

Asset Class	Asset Life	Total
Line Works	50	N/A
Primary Plant	40	7,832,282
Secondary Systems	15	548,345
Network Operations	12	27,730
Total		**8,408,357**

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)	TBA
Signed Connection Agreement	NA
Design information from Ergon/Energex/Customer	NA
Site Access - to carry out investigations, inspections, etc	11/11/2018
Site Possession - to carry out construction works	01/07/2019
Ergon/Energex/Customer works complete and ready for connection	NA
Project Commissioning Date	30/06/2021

4.2 Project Staging

The high level project staging are as follows:

Stage	Activity/Stage Description	High Level Timing
Not applicable	Design and Procurement	Nov 2018 – June 2019
1	Construction 132kV Demolition	TBA
2	Construction Build Transformer Foundation	TBA
3	Foundation Curing	TBA
4	Install Transformers	TBA
5	Commission	TBA
6	Commission Load Tests	TBA

4.3 Project Schedule

Project timing shall be managed using a Project Schedule.

4.4 Network Impacts and Outage Planning

- Feeder 7167 Stanwell Critical Supply.
- No Current Operational issues.
- Currently TX2 disconnected.

4.5 Project Delivery Strategy

Strategy to deliver the project as follows:

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	☒	☒	☐	☐	☐	☐	☐	☐
Civil and Structural	☒	☒	☐	☐	☐	☐	☐	☐
Electrical	☒	☐	☐	☐	☐	☐	☐	☐
Transmission Lines	☒	☐	☐	☐	☐	☐	☐	☐
Secondary Systems Design (SSD):								
Protection	☒	☒	☐	☐	☐	☐	☐	☐
Automation (Circuitry and Systems Configurations)	☒	☒	☐	☐	☐	☐	☐	☐
Construction:								
Earthworks	☐	☒	☐	☐	☐	☐	☐	☐
Civil	☐	☒	☐	☐	☐	☐	☐	☐
Construction (support structures, plant and equipment installation and demolition Works)	☐	☒	☒	☐	☐	☐	☐	☐
Secondary Systems Installation (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	☐	☒	☐	☐	☐	☐	☐	☐

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 – C / CT / DCT / D	ITT - Substation Panel Arrangement (SPA)
Optical Fibre System	Shortform ITT – Standing Offer arrangement with preferred/preapproved suppliers
MSP – OSD	RFQ
MSP – Ergon	RFQ – Service Level Agreement
Primary Plant and Equipment:	
HV Plant and Equipment	Period Contractors
Structures	ITT – Standing Offer arrangement with preferred/preapproved suppliers
Hardware and fittings	ITT – Standing Offer arrangement with preferred/preapproved suppliers
Transformers	ITT – Standing Offer arrangement with preferred/preapproved suppliers
Reactors	ITT – Standing Offer arrangement with preferred/preapproved suppliers
Diesel Generators	ITT – Standing Offer arrangement with preferred/preapproved suppliers
Capacitor Bank	ITT – Standing Offer arrangement with preferred/preapproved suppliers
Secondary Systems Equipment:	
IEDs	Period Contract
Panels, Kiosks, Boards and building fit-out	Shortform ITT – Standing Offer arrangement with preferred/preapproved suppliers

5. References

Document name and hyperlink	Version	Date
Project Scope Report	3	09/08/18
Project Concept (Proposal)	1	06/09/19
Project Staging Plan 132kV	1	06/09/18
Project Staging Plan 275kV	1	06/09/18
Project Outage Plan	TBA	
Project Schedule	1	06/09/18
Project Schedule Concept Schedule Procurement and Design	1	06/09/18

Powerlink Queensland

Project Assessment Conclusions Report

13 February 2019

Maintaining power transfer capability and reliability of supply at Bouldercombe Substation

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 primary plant condition risks at Bouldercombe Substation from December 2021.

Contents

Executive Summary

Located approximately 19 kilometres south-west of Rockhampton and established in 1975, Bouldercombe Substation is a major transmission node for Central Queensland, marshalling a number of 275kV circuits from Nebo and Broadsound to the north, Stanwell in the west and Raglan and Calliope River to the south.

It also provides the sole 132kV injection source for the area, supplying Ergon Energy (part of the Energy Queensland Group) at Rockhampton, Egans Hill and Pandoin, as well as Stanwell Power Station's auxiliary supply and customers directly connected to Powerlink's network.

Transformers 1 and 2, along with the original circuit breakers, disconnectors, earth switches and instrument transformers at Bouldercombe Substation are nearing the end of their technical service lives, with manufacturers no longer providing technical support or carrying spares for many of the items.

Powerlink's obligations as a Transmission Network Supply Provider (TNSP)[1] require it to maintain (including repair and replace if necessary) its transmission grid 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 ageing and obsolete plant at Bouldercombe Substation remaining in service, presents Powerlink with a range of operational and safety risks, as well as compliance issues, requiring resolution. Since consideration for this investment is driven by an obligation in the National Electricity Rules (the Rules), it is a 'reliability corrective action' under the Regulatory Investment Test for Transmission (RIT-T).

This Project Assessment Conclusions Report (PACR) represents the final step of the RIT-T process prescribed under the Rules undertaken by Powerlink to address the condition risks arising from ageing primary plant at Bouldercombe Substation. It contains the results of the planning investigation and cost-benefit analysis of credible options. In accordance with the RIT-T, the credible option that maximises the present value of net economic benefits is recommended for implementation.

Credible options considered

Powerlink identified six credible network options to address the identified need, as presented in Table 1.

[1] Schedule 5.1a System Standards and 5.1.2 Network Reliability of the Rules, Electricity Act 1994 and Queensland Transmission Authority T01/98

Table 1: Summary of credible options

Option	Description	Indicative capital cost ($million, 2018/19)	Indicative annual O&M costs ($million, 2018/19)
Base Option Standard 250MVA transformer with staged replacement of primary plant by December 2031	Install a new 250MVA transformer Decommission Transformers 1 & 2 Life extend or replace selected primary plant by December 2021*	26.77*	0.14
	Replace balance of ageing plant by December 2031†	16.96†	
Option 1 Standard 250MVA transformer with staged replacement of primary plant by December 2041	Install a new 250MVA transformer, decommission transformers 1 & 2, life extend or replace selected primary plant by December 2021*	26.98*	0.14
	Replace balance of ageing plant by December 2041†	15.95†	
Option 2 Install standard 250MVA transformer with upfront replacement of all primary plant in selected bays by December 2021	Install a new 250MVA transformer, decommission transformers 1 & 2 and single stage replacement of all plant in selected bays by December 2021*	30.60*	0.12
Option 3 Standard 375MVA transformer with staged replacement of primary plant by December 2031	Install a new 375MVA transformer, decommission transformers 1 & 2 and life extend or replace selected primary plant by December 2021*	27.28*	0.14
	Replace balance of ageing plant by December 2031†	16.96†	
Option 4 Standard 375MVA transformer with staged replacement of primary plant by December 2041	Install a new 375MVA transformer, decommission transformers 1 & 2 and life extend or replace selected primary plant by December 2021*	27.49*	0.14
	Replace balance of ageing plant by December 2041†	15.95†	
Option 5 Standard 375MVA transformer with upfront replacement of all primary plant in selected bays by December 2021	Install a new 375MVA transformer, decommission transformers 1 & 2 and single stage replacement of all primary plant in selected bays by December 2021*	31.12*	0.12

*Proposed RIT-T project
†Modelled project

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 Project Specification Consultation Report (PSCR), published in October 2018, made a draft recommendation to implement Option 2. Option 2 involves the installation of a standard 250MVA transformer and the upfront replacement of all primary plant in selected bays by December 2021. The estimated capital cost of this option is $30.6 million in 2018/19 prices. Powerlink is the proponent of the proposed network project.

There were no submissions received in response to the PSCR.

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[2] prescribed under the Rules undertaken by Powerlink to address the condition risks arising from the ageing primary plant at Bouldercombe Substation. It follows the publication of the Project Specification Consultation Report (PSCR) published in October 2018 that adopted the expedited process for this RIT-T, as allowed for under the Rules for investments of this nature.

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 specific RIT-T assessment are unlikely to be material
- identified Option 2 as the preferred option and that Powerlink was claiming an exemption from producing a Project Assessment Draft Report (PADR).

Option 2 involves the installation of a standard 250MVA transformer and the upfront replacement of all primary plant in selected bays by December 2021. The estimated capital cost of this option is $30.6 million in 2018/19 prices.

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

- the estimated capital cost of the preferred option is less than $41 million
- the preferred option has been identified in the PSCR noting exemption from publishing a PADR
- the preferred option, or other credible options, do not have a material market benefit
- 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 on 25 January 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 all of the conditions are now satisfied, Powerlink has not issued a PADR for this RIT-T and is publishing this PACR, which:

- describes the identified need and the credible options that Powerlink considers may address the identified need
- 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 estimated commissioning date of the preferred option
- describes the consultation process followed for this RIT-T together with the reasons why Powerlink is exempt from producing a PADR.

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[2] This RIT-T consultation has been prepared based on the following documents: *National Electricity Rules, Version 113*, 5 October 2018 and AER, *Final Regulatory Investment Test for Transmission Application Guidelines*, September 2017.

Since this investment is driven by an obligation in the Rules, it is a 'reliability corrective action' under the RIT-T.

2. Identified need

This section provides an overview of the existing arrangements at Bouldercombe Substation and describes the increasing risk to reliability of supply in the Rockhampton area and more broadly into northern and central Queensland, due to the assessed deteriorated condition of selected primary plant assets at the substation.

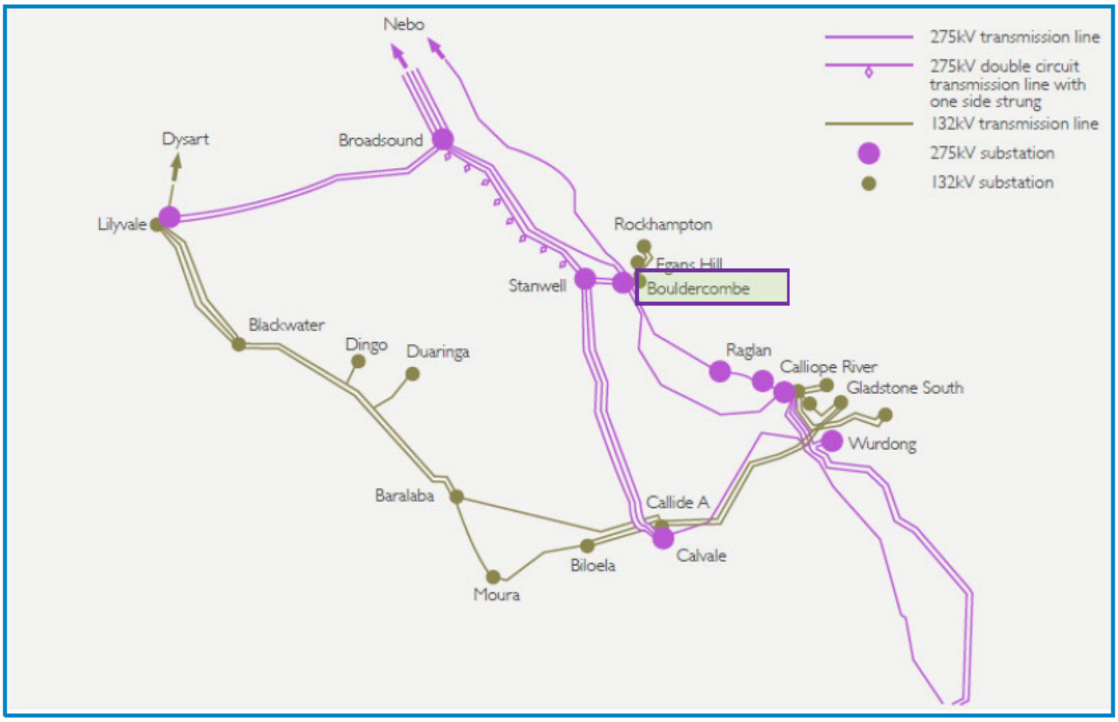
2.1 Geographical and network overview

Located approximately 19 kilometres south-west of Rockhampton and established in 1975, Bouldercombe Substation is a major transmission node for Central Queensland, marshalling a number of 275kV circuits from Nebo and Broadsound to the north, Stanwell to the west and Raglan and Calliope River to the south.

In addition, it provides the sole 132kV injection source for the Ergon Energy network in Rockhampton and surrounding areas, via Powerlink substations at Rockhampton, Egans Hill and Pandoin, while also providing the auxiliary supply to Stanwell Power Station and supply to customers directly connected to Powerlink's network.

Its location in the Central West and Gladstone Transmission Zone is shown in Figure 2.1.

Figure 2.1: Central West and Gladstone Transmission Zone[3]



2.2 Description of identified need

With peak demand in the Rockhampton area forecast to remain at or slightly above current levels[4], it is vital that Bouldercombe Substation has the ongoing capacity to satisfy these demands.

Powerlink's condition assessment of the ageing transformers and primary plant assets at Bouldercombe has highlighted that they are nearing the end of their technical service life, with

[3] This relates to the standard geographic definitions (zones) identified within the *Powerlink's Transmission Annual Planning Report*, which is published annually by 30 June.
[4] *Powerlink's Transmission Annual Planning Report* (TAPR)

an increasing likelihood of failure and in many cases limited or no spares and manufacturer support for repairs.

2.3 Assumptions underpinning the identified need

The need to invest is driven by Powerlink's obligations to address the increasing risks to supply arising from ageing and obsolete assets remaining in service at Bouldercombe Substation. If not addressed, these risks will ultimately result in plant failure and extend the time taken to recover from faults, due to a lack of support from manufacturers and a lack of spare parts.

Powerlink's obligations as a TNSP[5] require it to maintain (including repair and replace if necessary) its transmission grid 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. For Bouldercombe, this includes ensuring the ongoing availability of its primary switchgear and power transformers in order to maintain a reliable supply of electricity to consumers.

It follows that the increasing likelihood of faults arising from the deteriorated condition of the ageing assets and the subsequent increased return to service times due to obsolescence, compels Powerlink to undertake reliability corrective actions at Bouldercombe Substation if it is to continue meeting the standards for reliability of supply and public safety set out in the Rules and its jurisdictional responsibilities.

2.4 Description of asset condition and risks

Bouldercombe Substation's high voltage plant consists of 132kV and 275kV primary plant and three 275/132kV power transformers; Transformer 1 and Transformer 2 have a rating of 200MVA and were installed in 1977, while Transformer 3 has a 375MVA rating and was installed in 2012. Much of the primary plant, Transformer 1 and Transformer 2 are reaching the end of their technical service lives with details of their condition and the associated network and safety risks discussed below.

2.4.1 Transformers

Both Transformer 1 and Transformer 2 are over 40 years of age and are reaching the end of their technical service lives based on Powerlink's condition assessment. Protective galvanised coatings have begun to break down on several components including radiators, connecting pipework, control system cabinets, bushing mountings and flanges, resulting in significant corrosion. The sealing integrity of numerous joints and valves has also been compromised, resulting in an increased observation of oil leaks around the radiator cores, bushings and conservator tanks.

Transformer 2 has recently been electrically disconnected due to safety concerns resulting from the degradation of its insulation and bushings along with a lack of spares to affect a timely repair.

Transformer 1 has had minor refurbishment work to allow it to remain in service until 2021.

The in-service failure of a transformer would result in an extensive replacement timeframe, increasing the risk of loss of supply to the local area, and in extreme cases, can present a risk to the safety of personnel and members of the public. Transformers 1 and 2 require remedial action to be taken.

The 375MVA transformer, Transformer 3, is six years old and is in good condition.

2.4.2 Primary Plant

The majority of primary plant including circuit breakers, earth switches, disconnectors and surge arrestors date back to the late 1970s and mid-1980s and present an increasing risk of failure with very few or no spares available and no manufacturers' support for repairs.

Installed in the mid-1970s, the circuit breakers are experiencing an increasing number of age related deterioration issues including oil and gas leaks, corrosion and wear of components. This has resulted in performance degradation including false trip alarms and failure of the circuit breaker to operate, increasing the risk to plant and staff safety. With few or no spares available

[5] Schedule 5.1a System Standards and 5.1.2 Network Reliability of the Rules, Electricity Act 1994 and Queensland Transmission Authority T01/98

from the respective manufacturers, it is also becoming increasingly difficult for Powerlink to service this ageing and deteriorating population of breakers across the network.

An increasing frequency of oil leaks and the onset of corrosion to bushings, terminals, gauges and switches have been observed in the substation's ageing voltage and current transformers, along with the presence of PCBs in the oil samples taken from the voltage transformers. Ageing porcelain housings on many of the voltage transformers also present an increasing risk to staff safety in the case of failure. The majority of the equipment is now obsolete, with insufficient spares to support ongoing operation.

Those disconnectors and earth switches installed in the late 1970s and early 1980s are also nearing 40 years of age and showing signs of advanced corrosion to supporting structures, spacer plates, joint palms, nuts and bolts. This equipment is facing obsolescence issues with few spares available and no manufacturer support for repairs.

Corrosion is becoming an issue on the support insulators of the surge arrestors with a number of arrestors also having become deformed.

Poor asset condition increases the risk of faults, while obsolescence increases the time needed for Powerlink to remedy them, potentially up to several weeks. The inability to repair, replace, or otherwise resolve primary plant faults in a timely manner can have operational consequences, as this reduces the overall resilience of the transmission network to subsequent forced outages, resulting in loss of supply to consumers.

Taking into consideration the most recent analysis and understanding of the risks arising from the primary plant at Bouldercombe Substation, the proposed credible network solutions have been brought forward by 12 months from the possible commissioning date of December 2022 as advised in the 2018 TAPR to December 2021.

3. Submissions received

Powerlink published a PSCR in October 2018 calling for submissions from Registered Participants, AEMO and interested parties on the credible options presented, including alternative credible non-network options that could address the risks arising from the ageing primary plant at Bouldercombe Substation. Members of Powerlink's Non-network Engagement Stakeholder Register were also advised of the PSCR publication.

There were no submissions received in response to the PSCR that was open for consultation until 25 January 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.

4. Credible options assessed in this RIT-T

Powerlink has considered six credible network options as part of this RIT-T.

The Base Option involves the replacement of the two aged 200MVA transformers with a single 250MVA transformer, along with minimal primary plant replacement coupled with life extension work in 2021 to defer replacement of aged 132kV and 275kV primary plant by 10 years until 2031. In 2031, the remaining aged primary plant is replaced.

Option 1 combines the replacement of the two aged 200MVA transformers with a single 250MVA transformer, with a more comprehensive primary plant replacement and life extension strategy to achieve a 20 year life extension. In 2041, the remaining aged primary plant is replaced.

Option 2 combines the replacement of the two aged 200MVA transformers with a single 250MVA transformer, with the complete replacement of all primary plant in the affected bays by December 2021.

Options 3 to 5 are based upon replacement of the two aged and degraded 200MVA transformers with a 375MVA transformer in combination with the same range of primary plant strategies as employed in the Base Option, Option 1 and Option 2 respectively.

Details and costings of the options are summarised in Table 4.1.

Table 4.1: Credible Options

Option	Description	Indicative capital cost ($million, 2018/19)	Indicative annual O&M costs ($million, 2018/19)
Base Option Standard 250MVA transformer with staged replacement of primary plant by December 2031	Install a new 250MVA transformer Decommission Transformers 1 & 2 Life extend or replace selected primary plant by December 2021*	26.77*	0.14
	Replace balance of ageing plant by December 2031†	16.96†	
Option 1 Standard 250MVA transformer with staged replacement of primary plant by December 2041	Install a new 250MVA transformer, decommission transformers 1 & 2, life extend or replace selected primary plant by December 2021*	26.98*	0.14
	Replace balance of ageing plant by December 2041†	15.95†	
Option 2 Install standard 250MVA transformer with upfront replacement of all primary plant in selected bays by December 2021	Install a new 250MVA transformer, decommission transformers 1 & 2 and single stage replacement of all plant in selected bays by December 2021*	30.60*	0.12
Option 3 Standard 375MVA transformer with staged replacement of primary plant by December 2031	Install a new 375MVA transformer, decommission transformers 1 & 2 and life extend or replace selected primary plant by December 2021*	27.28*	0.14
	Replace balance of ageing plant by December 2031†	16.96†	
Option 4 Standard 375MVA transformer with staged replacement of primary plant by December 2041	Install a new 375MVA transformer, decommission transformers 1 & 2 and life extend or replace selected primary plant by December 2021*	27.49*	0.14
	Replace balance of ageing plant by December 2041†	15.95†	
Option 5 Standard 375MVA transformer with upfront replacement of all primary plant in selected bays by December 2021	Install a new 375MVA transformer, decommission transformers 1 & 2 and single stage replacement of all primary plant in selected bays by December 2021*	31.12*	0.12

*Proposed RIT-T Project
†Model Project

All credible options address the risks arising from the deteriorated condition of ageing transformers and primary plant at Bouldercombe Substation. Any recovered primary plant with a remaining technical service life will be retained as spares for the network.

None of these options has been discussed by the Australian Energy Market Operator (AEMO) in its most recent National Transmission Network Development Plan (NTNDP).[6]

Additional options that have been considered but not progressed, due to not being either economically or technically feasible, are listed in Appendix 1 of the PSCR.

The primary plant to be installed or life extended under the proposed RIT-T projects for each option is summarised in Table 4.2.

Table 4.2: Primary plant to be replaced (R) or life extended (LE) under each network option by 2021

Options	Circuit Breakers		Current Transformers		Voltage Transformers		Surge Arrestors		Isolators		Earth Switches	
	R	LE	R	LE	R	LE	R	LE	R	LE	R	LE
Base Option & Option 3*	16	-	-	-	40	-	3	6	-	46	-	51
Option 1 & Option 4♦	16	-	3	-	40	-	3	6	29	17	37	14
Option 2 & Option 5	16	-	15	-	50	-	30	-	46	-	51	-

*All life extended items under the Base Option and Option 3 will be replaced in 2031

♦All life extended items under Options 1 and 4 will be replaced in 2041

[6] 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 2016 NTNDP is currently the most recent NTNDP.

4.1 Base Option: Standard 250MVA transformer with staged replacement by December 2031

Powerlink is the proponent of this option.

The two existing 200MVA transformers are replaced with a single 250MVA transformer, along with selected primary plant by December 2021. The balance of at risk primary plant is life extended to obtain a 10 year deferral of its replacement until December 2031.

Table 4.3: Main project components for the Base Option

Components	Cost ($k, real 2018/19)	Construction timetable and commissioning date
Life extend and replace selected items of primary plant	14,249	Completion: December 2021*
Replace transformers with single 250MVA unit	6,561	
Replace selected secondary systems and communications equipment	3,306	
Other *- this includes project management, commissioning coordination, network operations, compliance management and statutory costs (Qleave)*	2,654	
Sub Total	**26,770***	
Replace balance of primary plant	12,081	Completion: December 2031†
Replace balance of secondary systems and communications equipment	2,969	
Other *- this includes project management, commissioning coordination, network operations, compliance management and statutory costs (Qleave)*	1,910	
Sub Total	**16,962†**	
Total	**43,732**	

*Proposed RIT-T Project
†Modelled Project

4.2 Option 1: Standard 250MVA transformer with staged replacement by December 2041

Powerlink is the proponent of this option.

The two existing 200MVA transformers are replaced with a single 250MVA transformer, along with selected primary plant by December 2021. The balance of at risk primary plant is life extended to obtain a 20 year deferral of its replacement until December 2041.

Table 4.4: Main project components for Option 1

Components	Cost ($k, real 2018/19)	Construction timetable and commissioning date
Replace or life extend selected items of primary plant	14,398	Completion: December 2021*
Replace transformers with single 250MVA unit	6,561	
Replace selected secondary systems and communications equipment	3,361	
Other *- this includes project management, commissioning coordination, network operations, compliance management and statutory costs (Qleave)*	2,656	
Sub Total	**26,976***	
Replace balance of primary plant	11,066	Completion: December 2041†
Replace balance of secondary systems and communications equipment	2,969	
Other *- this includes project management, commissioning coordination, network operations, compliance management and statutory costs (Qleave)*	1,910	
Sub Total	**15,945†**	
Total	**42,922**	

*Proposed RIT-T Project
†Modelled Project

4.3 Option 2: Standard 250MVA transformer with upfront replacement by December 2021

Powerlink is the proponent of this option.

The two existing 200MVA transformers are replaced with a single 250MVA transformer, along with all primary plant in selected bays by December 2021.

Table 4.5: Main project components for Option 2

Components	Cost ($k, real 2018/19)	Construction timetable and commissioning date
Replace primary plant	17,829	Completion: December 2021
Replace transformers with single 250MVA unit	6,561	
Secondary systems and telecommunications work	3,463	
Other *- this includes project management, commissioning coordination, network operations, compliance management and statutory costs (Qleave)*	2,750	
Total	**30,604**	

4.4 Option 3: Standard 375MVA transformer with staged replacement by December 2031

Powerlink is the proponent of this option

The two existing 200MVA transformers are replaced with a single 375MVA transformer, along with selected primary plant by December 2021. The balance of at risk primary plant is life extended to obtain a 10 year deferral of its replacement until December 2031.

Table 4.6: Main project components for Option 3

Components	Cost ($k, real 2018/19)	Construction timetable and commissioning date
Replace or life extend selected items of primary plant	14,249	
Replace transformer with single 375MVA unit	7,061	
Replace selected secondary systems and communications equipment	3,306	Completion: December 2021*
Other *- this includes project management, commissioning coordination, network operations, compliance management and statutory costs (Qleave)*	2,667	
Sub Total	**27,284***	
Replace balance of primary plant	12,081	
Replace balance of secondary systems and communications equipment	2,969	
Other *- this includes project management, commissioning coordination, network operations, compliance management and statutory costs (Qleave)*	1,910	Completion: December 2031†
Sub Total	**16,962†**	
Total	**44,245**	

*Proposed RIT-T Project
†Modelled Project

4.5 Option 4: Standard 375MVA transformer with staged replacement by December 2041

Powerlink is the proponent of this option

The two existing 200MVA transformers are replaced with a single 375MVA transformer, along with selected primary plant by December 2021. The balance of at risk primary plant is life extended to obtain a 20 year deferral of its replacement in December 2041.

Table 4.7 Main project components for Option 4

Components	Cost ($k, real 2018/19)	Construction timetable and commissioning date
Replace or life extend selected items of primary plant	14,398	
Replace transformers with single 375MVA unit	7,061	
Replace selected secondary systems and communications equipment	3,362	Completion: December 2021*
Other *- this includes project management, commissioning coordination, network operations, compliance management and statutory costs (Qleave)*	2,669	
Sub Total	**27,489***	
Replace balance of primary plant	11,066	
Replace balance of secondary systems and communications equipment	2,969	Completion: December 2041†
Other *- this includes project management, commissioning coordination, network operations, compliance management and statutory costs (Qleave)*	1,910	
Sub Total	**15,945†**	
Total	**43,435**	

*Proposed RIT-T Project
†Modelled Project

4.6 Option 5: Standard 375MVA transformer with upfront replacement by December 2021

Powerlink is the proponent of this option

The two existing 200MVA transformers are replaced with a single 375MVA transformer, along with all primary plant in selected bays by December 2021.

Table 4.8 Main project components for Option 5

Components	Cost ($k, real 2018/19)	Construction timetable and commissioning date
Replace primary plant	17,829	Completion: December 2021
Replace transformers with single 350MVA unit	7,061	
Secondary systems and telecommunications work	3,463	
Other *- this includes project management, commissioning coordination, network operations, compliance management and statutory costs (Qleave)*	2,763	
Total	**31,117**	

4.7 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.[7]

5. Materiality of Market Benefits

Powerlink does not consider that proposed works at Bouldercombe Substation will provide any market benefits, due to the nature of the project.

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

None of the replacement options will have an impact on wholesale market outcomes. The Australian Energy Regulator (AER) has recognised that if the proposed investment will not have an impact on the wholesale market, then a number of classes of market benefits will not be material in the RIT-T assessment[8]. Consequently, no market benefits have been estimated as part of this RIT-T.

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

[7] 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.

[8] AER, *Final Regulatory Investment Test for Transmission Application Guidelines,* September 2017, version 2, page 13.

6. General modelling approach adopted to assess net benefits

6.1 Analysis period

The RIT-T analysis has been undertaken over a 35-year period, from 2019 to 2053. A 35-year period takes into account the size and complexity of the primary plant and transformer replacements.

As the replacement plant will have differing residual values by 2053 under each option, terminal values have been calculated to offset these variations.

6.2 Discount rate

Under the RIT-T, a commercial discount rate is applied to calculate the net present value (NPV) of costs and benefits of credible options. Powerlink has adopted a real, pre-tax commercial discount rate of 7.04%[9] 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%[10] and an upper bound discount rate of 10.61% (i.e. a symmetrical upwards adjustment).

6.3 Description of reasonable scenarios

The RIT-T analysis is required to incorporate different reasonable scenarios to estimate market benefits. The scenarios must be appropriate to the credible options under consideration.

The choice of reasonable scenarios must reflect any variables or parameters that are likely to affect the ranking of the credible options, where the identified need is reliability corrective action[11].

Powerlink has considered capital costs and discount rate sensitivities individually and in combination and found that only the discount rate affects option rankings. Powerlink has therefore adopted three scenarios based on high, low and central estimates of the discount rate.

As all cashflows being discounted relate to regulated network costs and there are no material market benefits identified, Powerlink has applied weightings to the final NPV ranking that reflect that the low discount rate scenario is the most appropriate for the discounting of costs. Notwithstanding this, any credible non-network options identified during the PSCR consultation process will be modelled accordingly and weightings amended as necessary.

Table 6.1: Reasonable scenarios adopted

Key variable/parameter	Low discount rate scenario	Central discount rate scenario	High discount rate scenario
Discount rate	3.47%	7.04%	10.61%
NPV Weighting	0.6	0.3	0.1

9 The indicative commercial discount rate is calculated on the assumption that a private investment in the electricity sector would hold an investment grade credit rating, a return on equity and a debt gearing ratio equal to an average firm on the Australian stock exchange.

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

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

7. Cost-benefit analysis and identification of the preferred option

7.1 Net present values

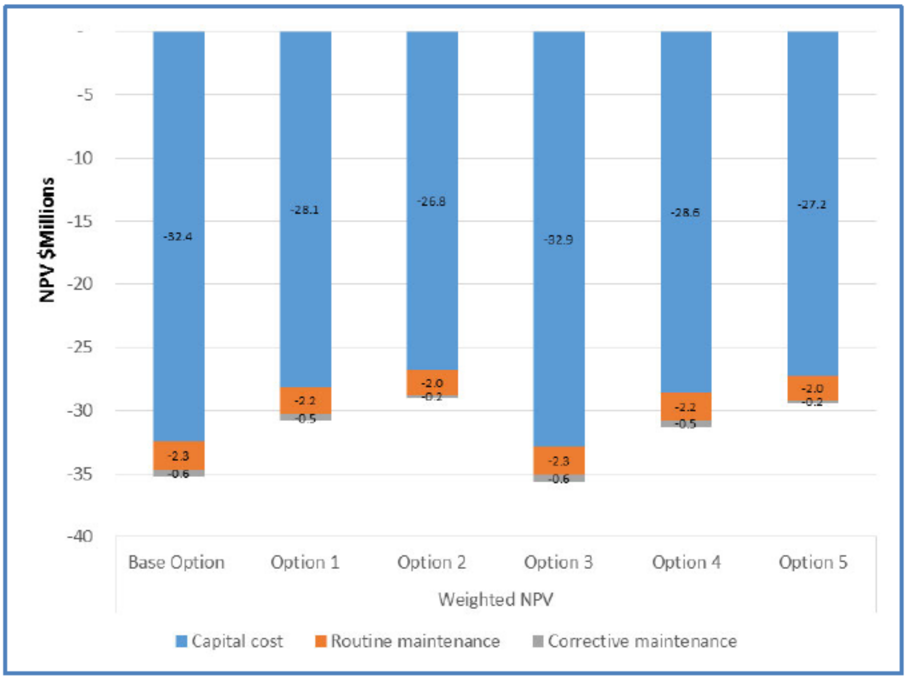
Table 7.1 outlines the NPV for each credible option. The table also shows the corresponding ranking of each option, illustrating that the NPV of Option 2 is the lowest cost preferred option.

Table 7.1: Weighted NPV for each credible option ($m, 2018/19)

Option	Description	Weighted NPV ($m)	Ranking
Base Option	Install a standard 250MVA transformer Staged replacement of aged primary plant by December 2031	-35.2	**5**
Option 1	Install a standard 250MVA transformer Staged replacement of aged primary plant by December 2041	-30.8	**3**
Option 2	Install a standard 250MVA transformer Replace all primary plant in selected bays by December 2021	-29.0	**1**
Option 3	Install a standard 375MVA transformer Staged replacement of aged primary plant by December 2031	-35.7	**6**
Option 4	Install a standard 375MVA transformer Staged replacement of aged primary plant by December 2041	-31.3	**4**
Option 5	Install a standard 375MVA transformer Replace all primary plant in selected bays by December 2021	-29.4	**2**

Option 2 is ranked as the lowest cost option in NPV terms. Figure 7.1 provides a breakdown of capital and maintenance costs for each scenario.

Figure 7.1: Weighted NPV component for each credible option (NPV $m, 2018/19)



A comparison of the weighted NPVs for each option relative to the Base Option is shown in Table 7.2.

Table 7.2: Weighted NPV for each credible option relative to the Base Option (NPV $m, 2018/19)

Option	Description	Weighted NPV relative to Base Option ($m)
Option 1	Install standard 250MVA transformer Staged replacement of aged primary plant by December 2041	4.4
Option 2	Install standard 250MVA transformer Replace all primary plant in selected bays by December 2021	6.3
Option 3	Install standard 375MVA transformer Staged replacement of aged primary plant by December 2031	-0.4
Option 4	Install standard 375MVA transformer Staged replacement of aged primary plant by December 2041	4.0
Option 5	Install standard 375MVA transformer Replace all primary plant in selected bays by December 2021	5.8

7.2 Sensitivity analysis

Powerlink has investigated the following sensitivities on key assumptions:

- a lower discount rate of 3.47% as well as a higher rate of 10.61%
- a 25% increase/decrease in capital costs.

Sensitivity analysis for the NPV relative to the Base Option shows that varying the discount rate impacts the ranking, whereas varying the capital cost has no impact on the preferred option.

For a discount rate of less than 7.7%, Option 2 is identified as the best ranked option. For discount rates greater than 7.7%, Option 1 is identified as the best ranked option. Overall, Option 2 maximises the present value of net economic benefit across the range of scenarios modelled under this RIT-T.

Figure 7.2: Sensitivity Analysis for Discount Rate

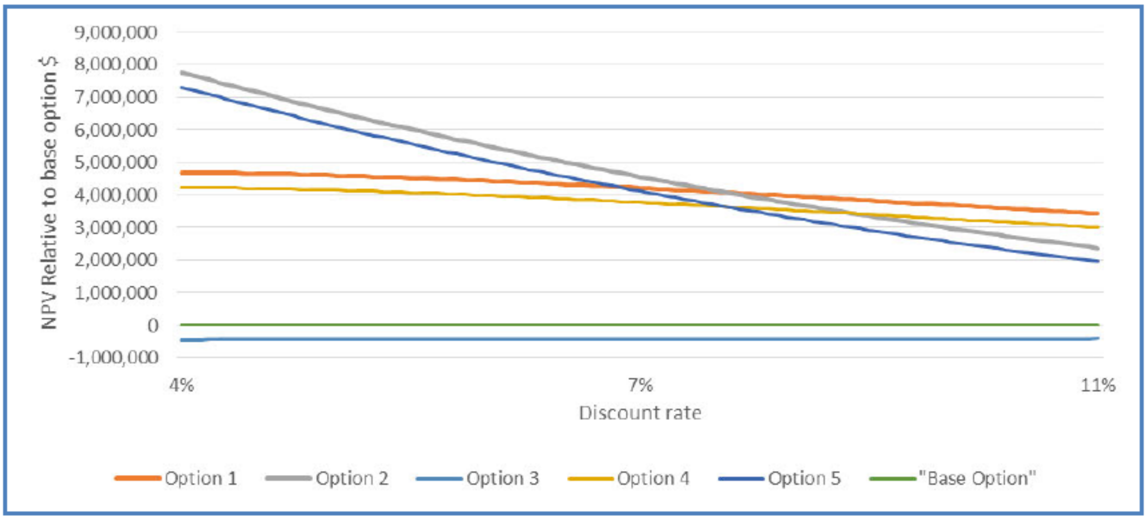
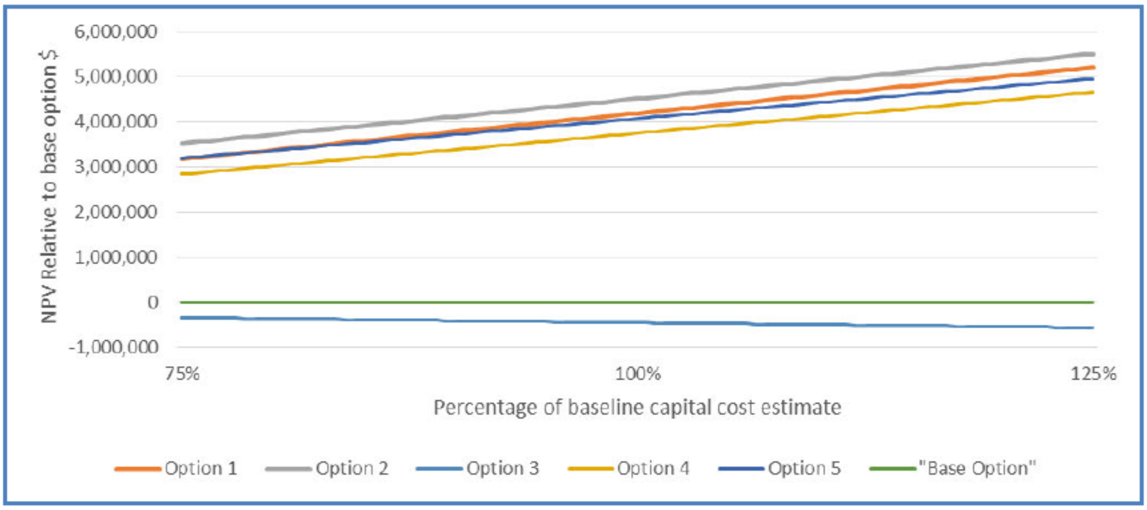


Figure 7.3: Sensitivity Analysis for Capital Cost



7.3 Preferred Option

The result of the cost benefit analysis indicates that Option 2 (installation of standard 250MVA transformer and replacement of all primary plant in selected bays) is the highest net benefit solution (lowest cost in NPV terms) over the 35 year period of analysis.

Sensitivity testing shows the economic analysis is robust to variations in capital cost, however it is sensitive to discount rate assumptions, with the crossover point for the rankings being a discount rate above 7.7%. Overall Option 2 maximises the present value of net economic benefit over the range of scenarios modelled, and is therefore considered to satisfy the requirement of the RIT-T and is the proposed preferred option.

8. Conclusions

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

- Powerlink has identified condition risks arising from ageing primary plant at Bouldercombe Substation requiring action.
- 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 ageing primary plant compels Powerlink to undertake reliability corrective actions at Bouldercombe Substation if it is to continue meeting the reliability standards set out in the Rules.
- Studies were undertaken to evaluate six credible options. All six credible options were evaluated in accordance with the AER's RIT-T.
- Powerlink published a PSCR in October 2018 requesting submissions from Registered Participants, AEMO and interested parties on the credible options presented, including alternative credible non-network options which could address the primary plant condition risks at Bouldercombe 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 NER clause 5.16.4(z1) for investments of this nature.
- There were no submissions received in response to the PSCR which was open for consultation until 25 January 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 highest net benefit solution over the 35-year analysis period. Sensitivity testing shows the economic analysis is robust to variations in capital cost, however it is sensitive to discount rate assumptions, with the crossover point for the rankings being a discount rate above 7.7%. Overall Option 2 maximises the present value of net economic benefit over the range of scenarios modelled, and is therefore 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.

9. 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 condition risks arising from ageing primary plant at Bouldercombe Substation.

Option 2 involves the installation of a standard 250MVA transformer and the upfront replacement of all primary plant in selected bays by December 2021. The estimated capital cost of this option is $30.6 million in 2018/19 prices.

Powerlink is the proponent of the proposed network project.

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

Contact us

Registered office	33 Harold St Virginia Queensland 4014 Australia
Postal address:	GPO Box 1193 Virginia Queensland 4014 Australia
Contact:	Roger Smith Manager Network and Alternate Solutions
Telephone	(+617) 3860 2328 (during business hours)
Email	networkassessments@powerlink.com.au
Internet	www.powerlink.com.au