January 2026

Powerlink 2027-32 Revenue Proposal

Project Pack

CP.03005 T142 Tennyson T3 Replacement

Project Status: Unapproved

Network Requirement

Tennyson Substation, established in 2001, is located 6.3km south of the Brisbane CBD. It is a 110kV substation fed by three 110kV underground feeders from Rocklea, two of which comprise teed supplies to QR Corinda. In turn Tennyson supplies the Energy Queensland local distribution network via three 110/33/11kV 80MVA transformers.

Transformer 3, manufactured in 1999, has experienced significant condition issues including ongoing OLTC problems, oil leaks and corrosion. In addition, the winding insulation and bushings are at end of life [1].

Retaining Tennyson as a three 110/33kV transformer substation will allow Powerlink to continue to meet its required reliability obligations (N-1-50MW/600MWh). It will also allow Energy Queensland to meet its reliability standard [2].

Powerlink is currently unaware of any feasible alternative options to minimise or eliminate the load at risk at Tennyson 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.

Recommended Option

As this project is currently 'Not Approved', project need and options will be subjected to the public RIT-T consultation process to identify the preferred option closer to the time of investment.

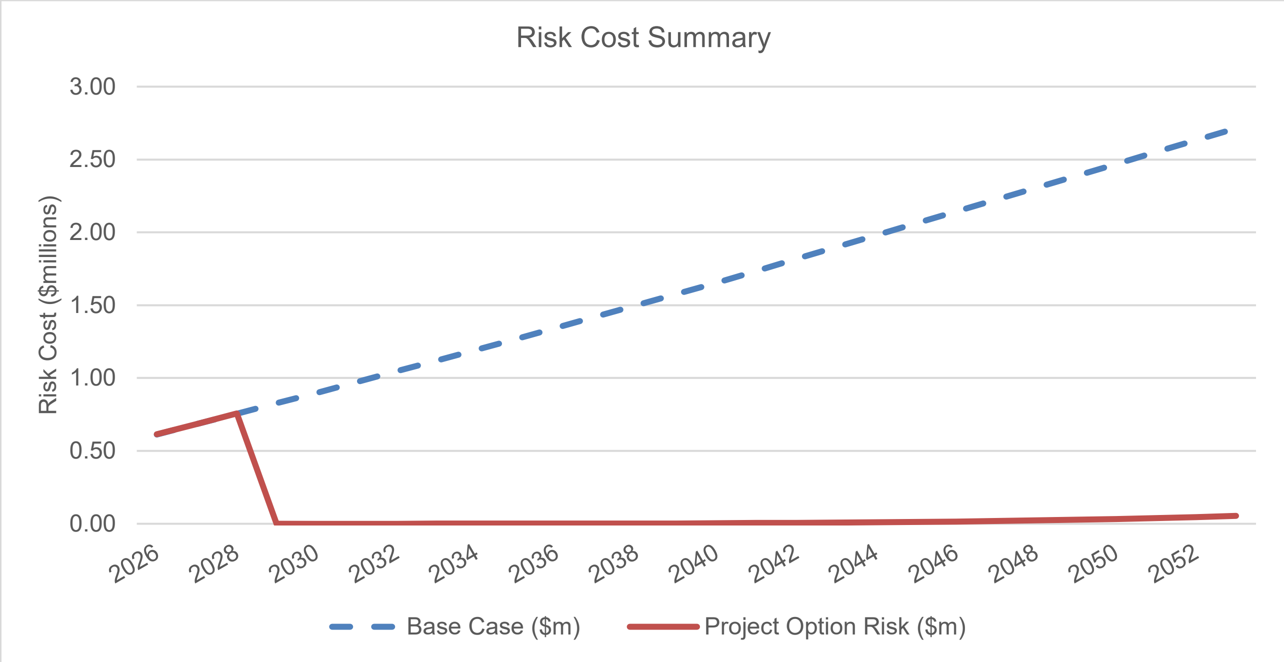
The current recommended option given the poor condition of the winding insulation is to replace Transformer 3 at Tennyson Substation by 2027 [3].

Options considered but not proposed include:

- Do Nothing – rejected due to non-compliance with reliability standards and safety obligations;
- Decommission Transformer 3 – rejected due to non-compliance with reliability standards under the credible contingency of loss of one of the remaining transformers;
- Transfer load off Tennyson to neighbouring substations – rejected due to the significantly higher cost of additional 33kV network capacity to transfer the required amount of load and limited transformer capacity headroom at neighbouring substations; and
- Non-network option – no viable non-network options have been identified at this time.

Figure 1 shows the current recommended option reduces the forecast risk monetisation profile of the Tennyson Substation T3 transformer from around $0.76 million per annum in 2028 to less than $0.01 million from 2029 [5].

Figure 1



Cost and Timing

The estimated cost to replace T3 at T142 Tennyson substation is $9.7m ($2025/26) [4].

Target Commissioning Date: October 2027

Documents in CP.03005 Project Pack

Public Documents

1. T142 Tennyson Substation T03 – Condition Assessment Report
2. CP.03005 Tennyson Transformer 3 Replacement – Planning Statement
3. CP.03005 Tennyson Transformer 3 Replacement - Project Scope Report
4. CP.03005 Tennyson Transformer 3 Replacement – Project Management Plan
5. CP.03005 Tennyson Transformer 3 Replacement – Risk Cost Summary Report

Transformer Condition Assessment T142 Tennyson Substation

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1. SUMMARY

A thorough onsite inspection was performed on an 80MVA 110/33/(11)kV transformer T03 at T142 Tennyson substation on the 10 December 2020 to gather relevant information concerning the transformer's physical condition. In addition to this, information was also added in September 2024 from online data available. This information was used in conjunction with a scientific analysis of its internal HV insulation system and structure for determining its residual service life and to raise any immediate issues that may need to be considered. No main tank internal inspection of the core and windings was performed.

This report does not attempt to cover any detailed economic analysis of the viability of rectifying the highlighted issues associated with the transformer.

This transformer has a range of issues that are discussed in detail in this report but in short, from a condition assessment of the "key" transformer parameters,

(a) This transformer's internal HV winding hot spot cellulose insulation system has reached statistical end of life with a degree of polymerisation (DPv) value of possibly less than 200. The bulk insulation DPv is estimated to be between 415 to 280 depending on the calculation method used. The reason for this accelerated insulation age is not proven, however there are a few reasons this may have occurred:
   a. It is possible that if the PLC is programmed to turn the fans on prior to the oil pump, a high winding hot spot gradient could occur due to high winding hot spot gradients on this mode which could accelerate the insulation ageing.
   b. Incorrect programming of the PLC, which may be relying on the WTI CT may also explain the accelerated ageing due to factory rise tests proving that the HV winding had higher winding hot spot gradients.
   c. This Power Transformer was purchased with another utilities specifications which may differ in quality from the specifications provided by Powerlink Queensland at the time.
   d. Manufacturing defect that was not found during factory acceptance testing, however all factory acceptance tests were acceptable.

(b) The mechanical stability of the coils is considered to be in poor condition.

(c) The external physical condition of the transformer found during the site inspection in 2020 is reasonable with only minor oil leaks at present. Prior localised corrosion has been addressed but will reappear given time. Both the existing oil leaks and future corrosion can be addressed under normal routine maintenance. Only one slight oil leak has been noticed since site inspection with rectification still yet to be completed.

The listed recommendations below do not consider the need for transformer functionality in this location in the network. This aspect needs to be confirmed prior to finalising any decisions in relation to extending the life of this transformer via the recommendations in clause 1.1.

The Health Index (HI) for the transformer's **internal** components would be a (9) due to the cellulose insulation on the windings reaching statistical end of reliable service life and this impacts all internal major components such as the dielectric and cooling oil, the core, the coils and the mechanical clamping structure / stability of the windings under short-circuit. Even though the HI for the **external** physical condition alone would be a (5), due to not wanting to understate the importance of the condition of the internal winding insulation, the overall transformer HI has to be a (9). This rating is reflected in the detailed findings outlined in this assessment report. With the consideration of the transformers internal components it is estimated that the transformer has 2-4 years of service life remaining assuming there is no change in loading conditions or through faults that occur during this period. To ensure no in service failure occurs, the transformer should be replaced before this period.

1.1 Reinvestment Needs:

The following recommendations are based on the findings from this investigation into the physical, chemical and electrical condition of the 80MVA 110/33/(11)kV transformer at T142 Tennyson substation.
It should be possible to continue to operate this transformer for 2-4 years even with the poor condition of the winding hot spot insulation until the transformer is either scrapped or replaced provided the transformer does not experience a severe through fault or change in loading conditions. This mechanical weakness of the winding insulation influences the following recommendations.

(a) Because this transformer's internal winding hot spot insulation system has reached statistical end of reliable service life, if the functionality of this transformer is required into the future at Tennyson substation, the transformer replacement is required as soon as possible. Its external physical condition is reasonable for its age

(b) Due to (a) above, there is little long-term benefit in doing anything other than ongoing normal scheduled routine maintenance sufficient to keep the transformer serviceable until a replacement can be arranged or the transformer is scrapped. This will address existing oil leaks and localised corrosion that may develop in the future. No extensive repaint of the transformer should be considered.

(c) If this transformer is to be replaced or scrapped within the next few years, there is no advantage in performing an oil change to lessen the effects of the high oil acidity on the core and winding insulation.

(d) The original HV and LV bushings do not need to be replaced.

(e) The lightning surge counters installed on the 110kV surge arresters should be bypassed during the next scheduled routine maintenance.

(f) The condition of the UV damaged multicore cables needs to be periodically monitored in case they need to be replaced prior to the transformer being scrapped or replaced.

2.0 INVESTIGATION:

A comprehensive on-site inspection of this transformer was performed in September 2020 and any major findings that may impact the transformer's serviceability are discussed in this report.

This 80MVA 110/33kV transformer T03 was manufactured in 1998/99 and was later commissioned at T142 Tennyson substation in February 1999 which makes it 25 years of age.

2.1 T142 Tennyson Transformer T03 Condition Observations:

2.1.1. Identification Details:

The transformer details are shown below;

- YOM = 1999.
- Commissioned February 1999 (25 years of age)
- 48/60/80 MVA ONAN / ODAN / ODAF.
- 110/33/(11) kV with a Vector Group = YNyn0(d11).
- Tap Changer YOM 1998, positioned in the neutral end of the HV windings.

As observed from figure 1, Tennyson substation has three 80MVA 110/33kV transformers supplying Energy Queensland. Transformers T01 and T02 were commissioned in 2001 while T03 was commissioned in 1999.

Transformer 3 was purchased from a different utility following the failure of the previous transformer shortly after being commissioned in 1999. The design of the existing T03 transformer is therefore not based on a Powerlink transformer Technical Specification.

The loading on all three of these transformers (see graphs below) has been almost identical as they were on a common 33kV Bus and also well within their ONAN rating of 45-48MVA for the majority of their lifetime, however, transformer T03 has aged about 2.5 times faster than T01 and T02 as will be discussed later in clause 2.1.5.

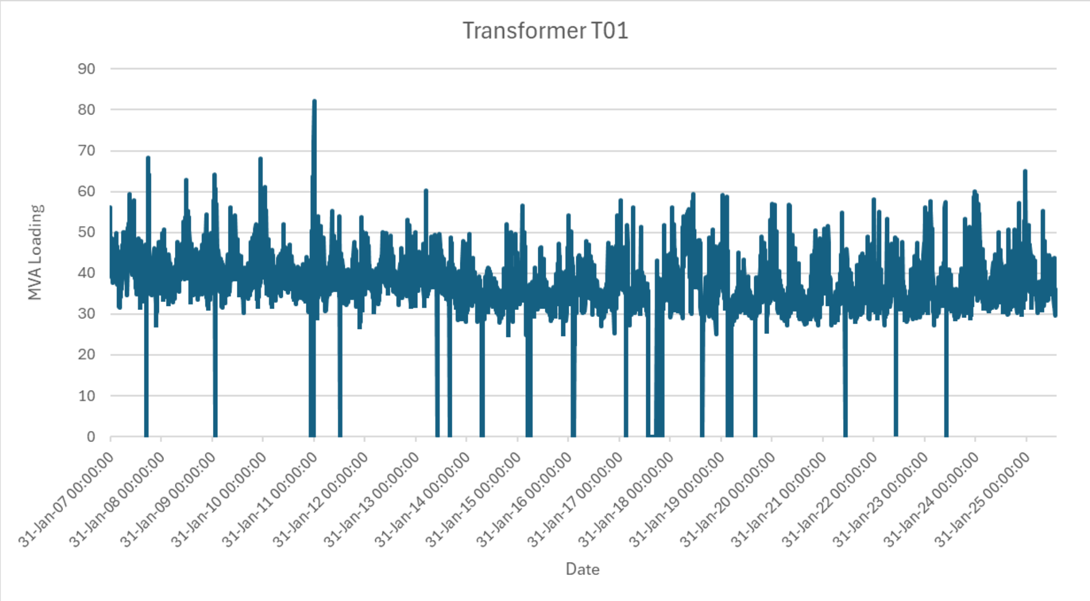


Figure 3: T142 Tennyson transformer **T01** loading in MVA.

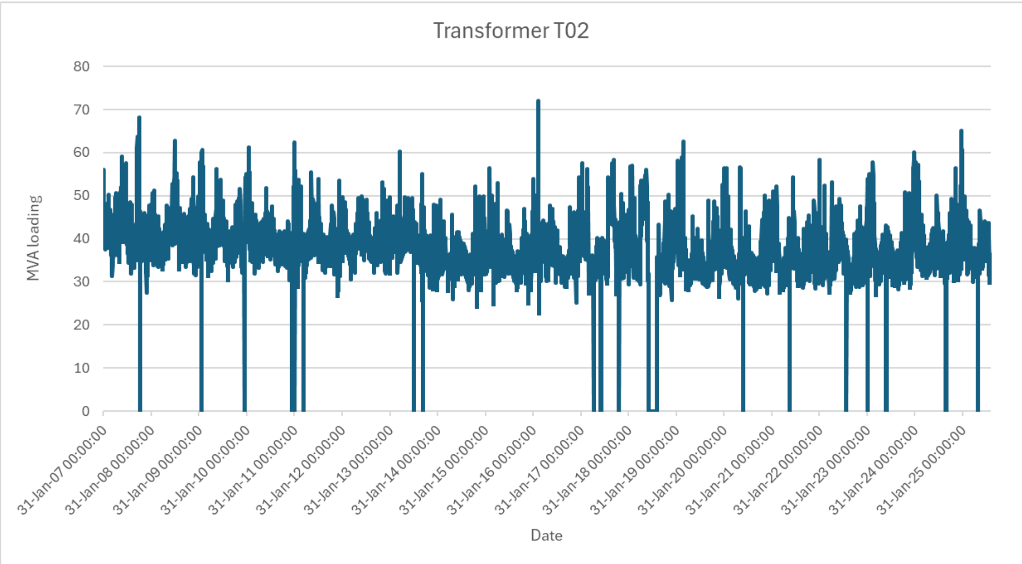


Figure 4: T142 Tennyson transformer **T02** loading in MVA.

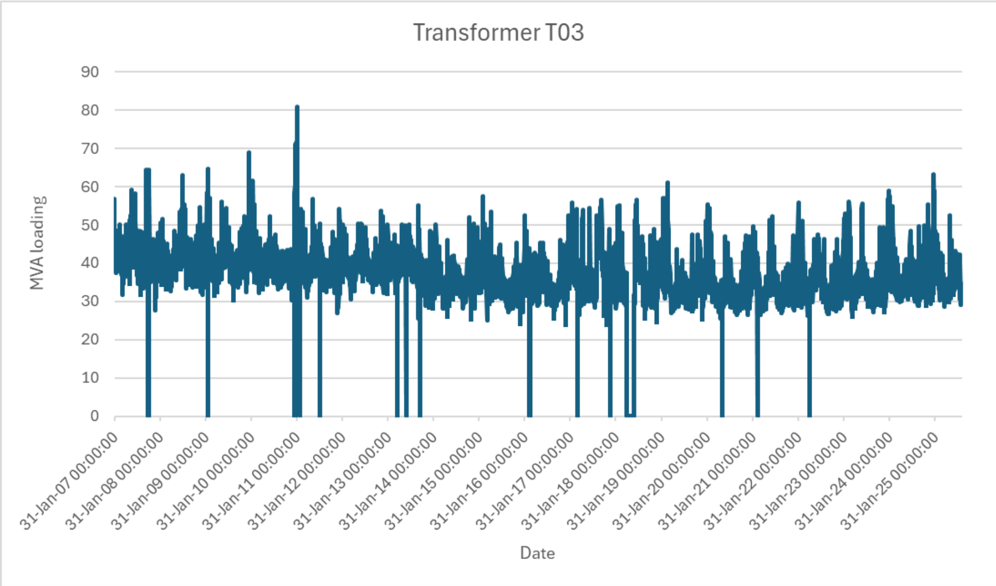


Figure 5: T142 Tennyson transformer **T03** loading in MVA.

Figure 6: T142 Tennyson transformer T03 installed inside a sound wall enclosure. Note the NEX installed on a steel post near the OLTC oil conservator.

Figure 7: T142 Tennyson transformer T03 installed inside a sound wall enclosure.

2.1.2 External Physical Condition:

2.1.2.1 Main Tank:

The main issues identified on this transformer main tank at present are the failed paint system and some minor oil leaks. There are signs where the paint coating has been touched up in local areas where necessary after removing corrosion. Overall though, the main tank is in fairly good condition only requiring routine maintenance to address the issues identified and to keep localised corrosion under control as it develops.

Figure 8: (LHS) Tennyson T03 HV side. (RHS) A view of the LV side. Note the paint touch-ups.

Figure 9: (LHS) Cooler bank end of T03. (RHS) Tap changer end of T03.

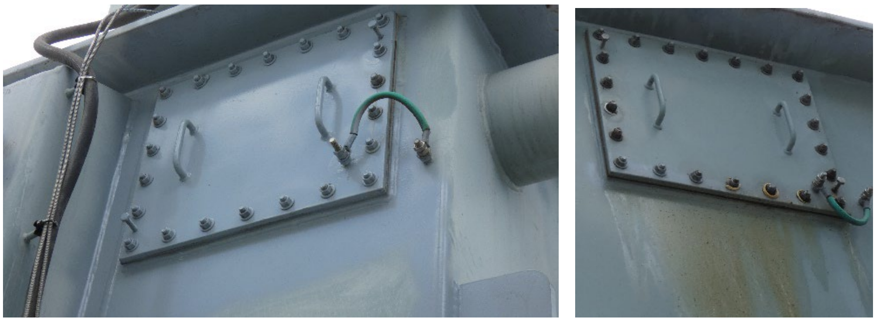


Figure 10: Corrosion repairs and paint touch-up on side access hatch as well as oil leaks on another hatch.

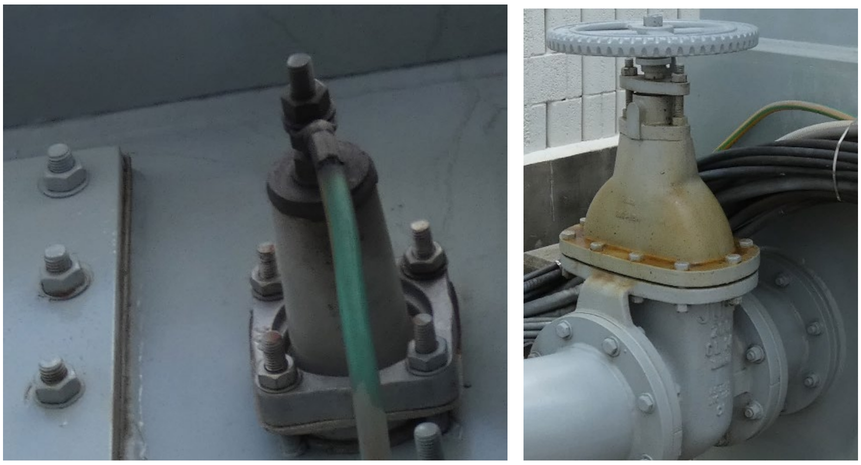


Figure 11: (LHS) Oil leak from the top seal on the bushing used to externally earth the internal magnetic core. (RHS) Oil leak from main gate valve spindle shaft seal.

It is interesting to note in the figure below the damage caused to the final tank paint by large ‘G’-clamps used in the factory to hold the main tank and lid flanges together while the transformer is going through test. If the transformer passes all tests, then the lid is welded to the main tank. This paint damage is not repaired correctly and just the application of a colour coat allows corrosion to start in these locations.

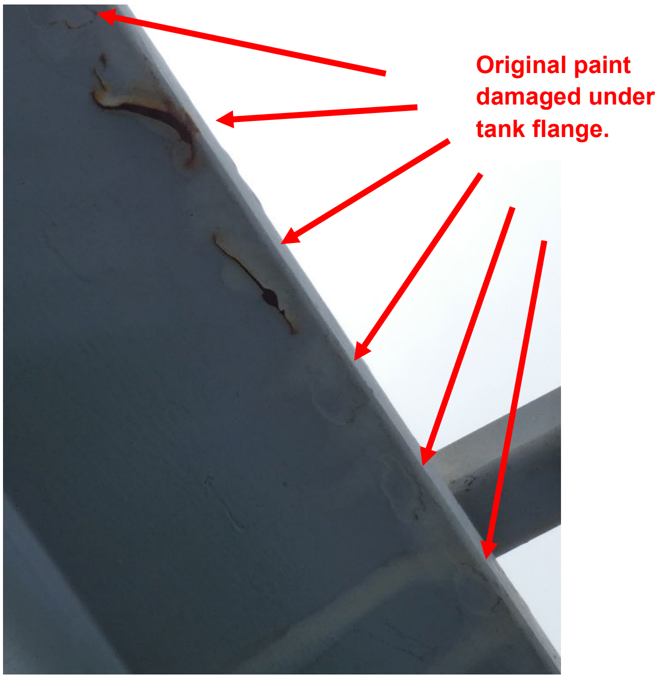


Figure 12: The final paint coating under the main tank flange has been chipped in the factory by the application of large 'G'- clamps.

Figure 13: A close-up of the paint damage under the main tank flange is visible. Damaged area has just a colour coating applied over it.

The Routine Maintenance History records in the previous Engarde system are not visible in the latest SAP system. The SAP routine maintenance history records commence from January 2002 so there is no maintenance information available for the first 3 years of the transformer's life. That is not considered an issue since there should be no significant issues arising in the first few years for a new transformer.

This transformer has the lid / main tank flanges directly welded together rather than a conventional bolted flange/gasket/flange type seal so it is important to prevent serious corrosion in this area. The irregular surface profile of the weld filler can encourage localised corrosion and oil leaks. No corrosion was visible in this region, however, in March 2017, the Routine

Maintenance Records indicate that oil was observed coming from a seal on the lid of the transformer but the source could not be confirmed.

In 2020, the tap changer was serviced and necessary parts were replaced so the reliability of the tap changer should be good for at least the next 6 years until inspected again on site.

The concrete apron surrounding the transformer main tank appears to be clean apart from a couple of oil stains under the main isolating gate valve (refer to figures 8 and 9).

2.1.2.2 Cooler bank:

The cooler bank radiator panels are hot dipped galvanised steel and are of as shown in the figure below. The supporting 'A'-Frames, top and bottom main oil headers and the main oil conservator and its supporting brackets are all painted. Even though the paint on these items is oxidised like the rest of the transformer, there is no visible corrosion at present due to regular routine maintenance and paint touch-ups. Since site inspection, one notification has been raised indicating that the main tank conservator drain bottom valve/flange plate has a slight oil leak that is yet to be rectified.

Figure 14: View of the Cooler Bank with galvanised radiator panels and painted support structures.

Figure 15: (LHS) View of the outer Cooler Bank ‘A’-frame support structure.

There were no signs of oil leaks pooling on the concrete below the cooler bank. There was a small oil leak coming from the Buchholz Relay.

Figure 16: View under and around the Cooler Bank. No oil residue or pooling.

Figure 17: View under and around the Cooler Bank. No oil residue or pooling

A minor oil leak was visible from the Buchholz Relay. The likely sources of the leak are the seal on the sight glass, the manual plunger for testing the electrical alarm and trip contacts, or the lid seal or plumbing fittings.

Figure 18: Minor oil leak from the top of the Buchholz Relay.

The galvanising on the radiator panels was still in good condition which is expected after only 25 years of service. The cooling fans and their protective cowls showed no signs of corrosion, however, a couple of fan motors have experienced motor bearing failure in 2006 causing their MCB to trip due to excessive motor armature drag.

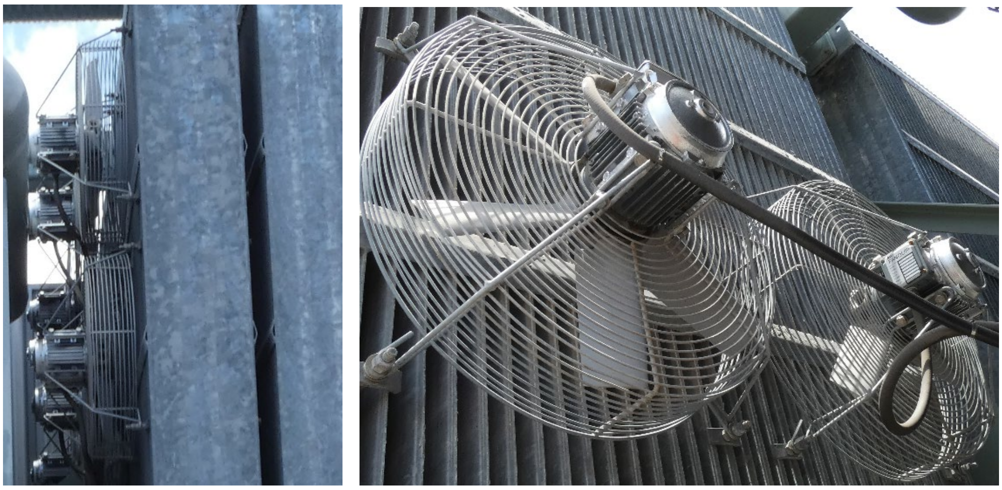


Figure 19: Galvanised radiator panels and cooling fans are in good condition.

The cooler bank has butterfly valves for isolating each of the radiator panels from the top and bottom main oil headers as can be seen in the figure below. They are not leaking oil and due to some maintenance, they do not show local corrosion.

Figure 20: Butterfly valves are installed for isolating each of the radiator panels from the top and bottom main oil headers.

The transformer is free breathing via a desiccant breather connected to its main oil conservator. The silica gel was recently replaced during RSM in 2023.

Figure 21: The main oil conservator showing oxidised paint and some local paint touch-ups.

2.1.2.3 Structural:

The main 'A'-frame support structures for the cooler bank are in good physical condition but the surface paint is oxidised. The surfaces of these structures show signs of paint touch-ups.

Figure 22: There is no sign of corrosion where the main oil conservator support structure is welded to the top main oil header.

The cooler bank is supported on 'A'-frames connected to a steel floor mounted beam as shown in the figure below. There are no external visible signs of corrosion growing out from under the steel footplates of the beam.

Figure 23: Typical condition of the cooler bank support structure feet showing no visible signs corrosion.

The grouting under the steel footplates is non-compliant with present design standards because it is problematic due to water retention in the grout material. This can result in necking of the hold down bolts and corrosion of the underside of the steel footplate.

Whilst this potential corrosion issue needs to be monitored in the future, at this stage, there does not seem to be any obvious signs that would require the hold down bolts and steel footplates on the support structures to be acoustically tested to confirm the degree of necking of the bolt shanks.

If the hold down bolts are tested in the future, the remaining thickness of all the steel foot plates should also be tested acoustically if possible because the integrity of the steel plates is necessary for transferring the load on the structure to the jacking nuts.

There is no visible evidence of physical deterioration of the original ‘support structures or main oil conservator support frame. The cooler bank should be able to provide a further 15 to 20 years of service with appropriate routine maintenance.

2.1.3 Secondary Systems:

The external black PVC/PVC multi-core cables have not been painted in the past and due to the replacement of the substation secondary system in 2018, there are some relatively new multicore cables now installed on the transformer. This is evident in the figure shown below.

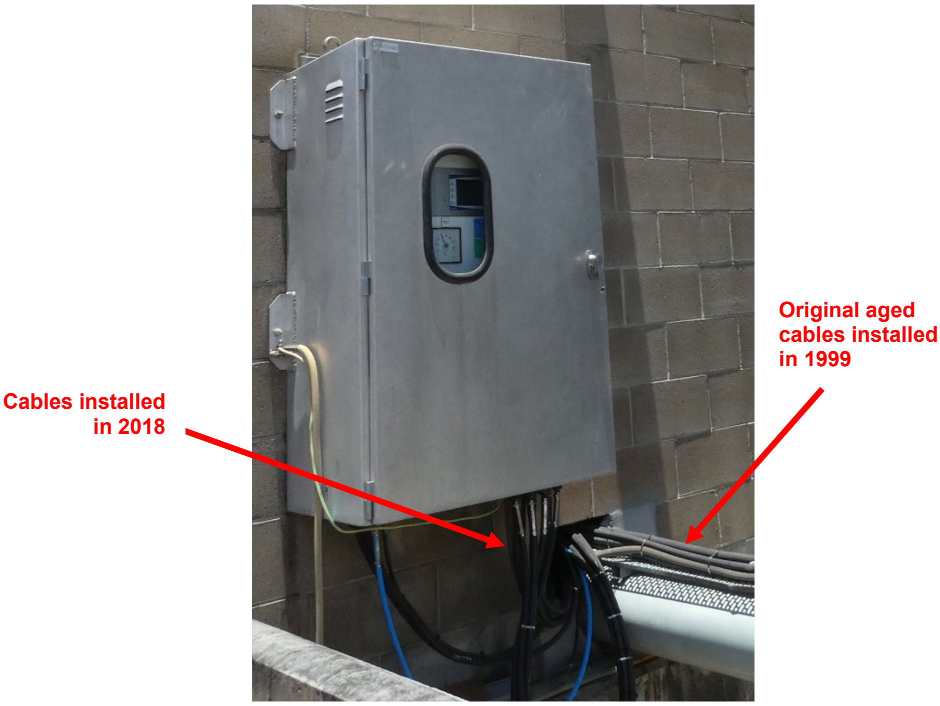


Figure 24: The old and new black PVC/PVC external multicore cabling. Note the aged original cables.

After 25 years, the original internal insulation of the cables should still be in reasonable condition and have retained some degree of flexibility, however, the external PVC on the original cables has aged excessively as shown in the figure below.

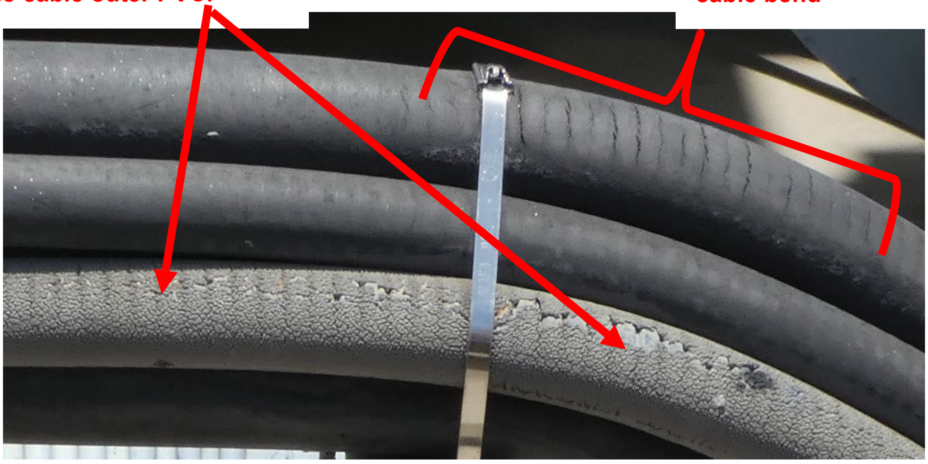


Figure 25: The original black PVC/PVC external multicore cabling showing the UV damage.

The multicore cables will not last for too many more years once the UV radiation starts to deteriorate the inner PVC insulation. Ignoring any other issues identified in this transformer, if a 40 plus year life is expected, these original multicore cables will have to be replaced. This would have to include the testing and recommissioning of the rewired transformer secondary system.

This transformer is designed with one winding hot spot temperature (WTI) instrument for the LV winding and one top oil temperature (OTI) monitoring instrument as shown in the figure below. In addition to this, the transformer also has a programmable logic controller that controls the on board cooling system and telemetry of transformer operating variables, alarms and trip signals. As such, the WTI instrument is not normally required for indicating the transformer winding hot spot temperatures since the PLC calculates this based on the transformer top oil temperature. Hence, no replacement of these instruments is necessary.

Figure 26: One WTI and one OTI are installed.

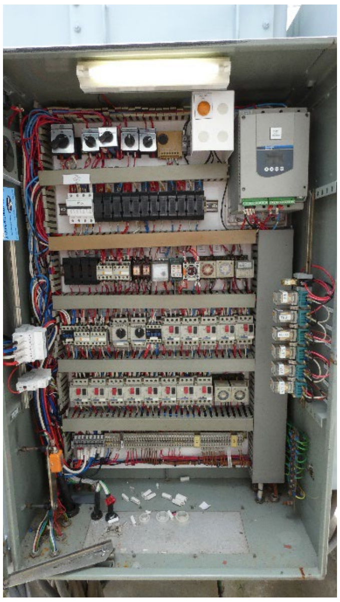
The clarity of the viewing window on the WTI and OTI is still serviceable at present. This permits the reading of internal instrument real time operating temperatures and alarm and trip temperature set point settings.

There have been a significant number of notifications in relation to the transformer secondary system throughout the recorded maintenance history from 2004, including PLC technical issues. Other secondary system issues have been caused by natural ageing, high resistance joints / terminal connections and others due to wiring being under rated. Others due to the age of componentry such as timers and MCBs.

Safety barriers are installed over terminal strips where there are live terminals that could pose a safety risk if the outer cubicle door is opened. These barriers are shown in the figure below.

Figure 27: Main Control Cubicle view with the outer door open. Note dual OLTC TPI cards, one for PLQ and one for Energy Queensland.

Due to being a shared substation with Energy Queensland, the transformer has dual tap changer tap position indication, one signal for Powerlink and the other for Energy Queensland.



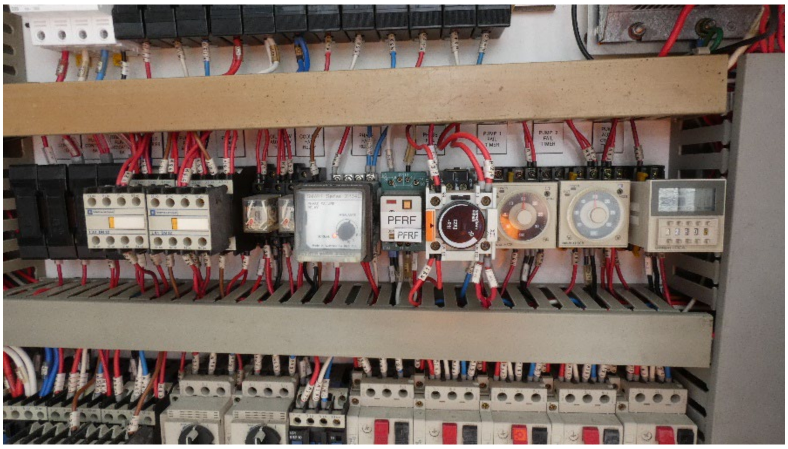


Figure 28: Main Control Cubicle view with the inner door open.

There is no oil film on the cable gland plate of the Main Control Cubicle. This indicates oil seals on CT secondary circuit bushings in the bushing turrets / junction boxes up high on the transformer main tank are not leaking down inside the PVC sheath of the multicore cables at this stage.

Judging by the prior issues that have occurred on this transformer secondary system to date, its reliability is reasonable but there will be ongoing component failures and other issues due to its age. These will be addressed via normal maintenance activities.

The transformer has an on-load tap changer (OLTC) of YOM 1998 positioned in the neutral end of the HV windings.

Figure 29: On-load tap changer (OLTC) Nameplate.

Figure 30: OLTC Control Cubicle.

The tap changer was last serviced in August 2022 and has 77,677 operations on the counter. There were significant issues reported with the OLTC and multiple trips occurred due to the OLTC motor in 2022. As such the motor was replaced in the same year, with these works being considered successful as no further defects have been noticed operationally.

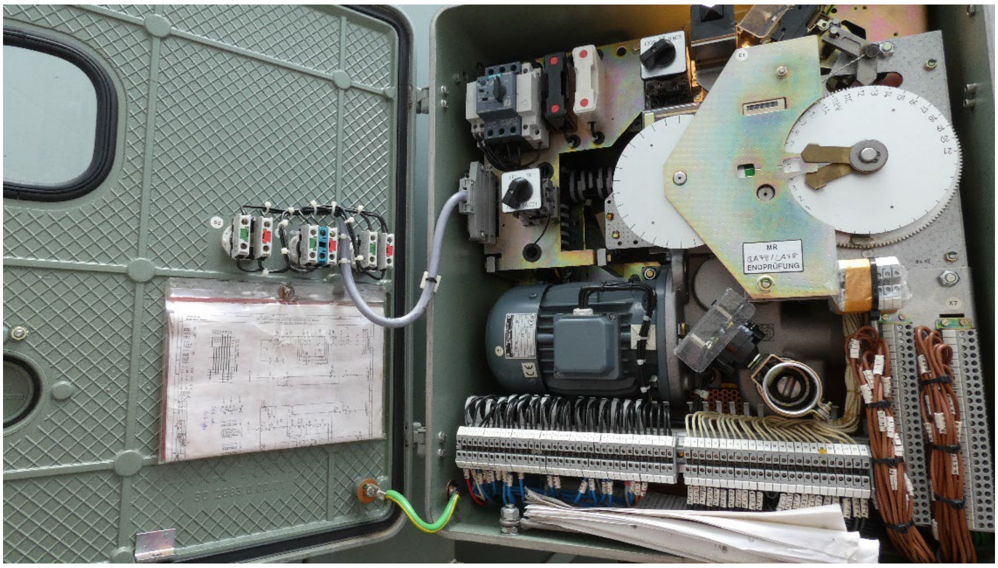


Figure 31: Inside the Tap Changer Control Cubicle.

Electrical safety barriers are not installed over live terminals in the tap changer Control Cubicle but PQ have been advised that such barriers are available if specified when the tap changer is purchased. Retrofitting of the barriers may also be possible during routine tap changer maintenance.

There were no other signs of immediate issues within the Tap Changer (OLTC) Control Cubicle. The tap changer drive motor gearbox was not leaking oil onto the cubicle cable gland plate.

2.1.4 High Voltage (HV) and Low Voltage (LV) Bushings:

All three HV bushings are oil impregnated paper (OIP) inner insulation system with an outer porcelain shell / insulator design. This design is shown in the figure below. The bushings have an internal gas expansion space (gas cushion) at the top above the oil to prevent hydraulicing the seals as the oil temperature increases.

The LV bushings on the 33kV side are rated at 44kV 3150 amps. The HV neutral bushing is rated at 33kV 850 amps and the LV neutral bushing is rated to 33kV 1800 amps.

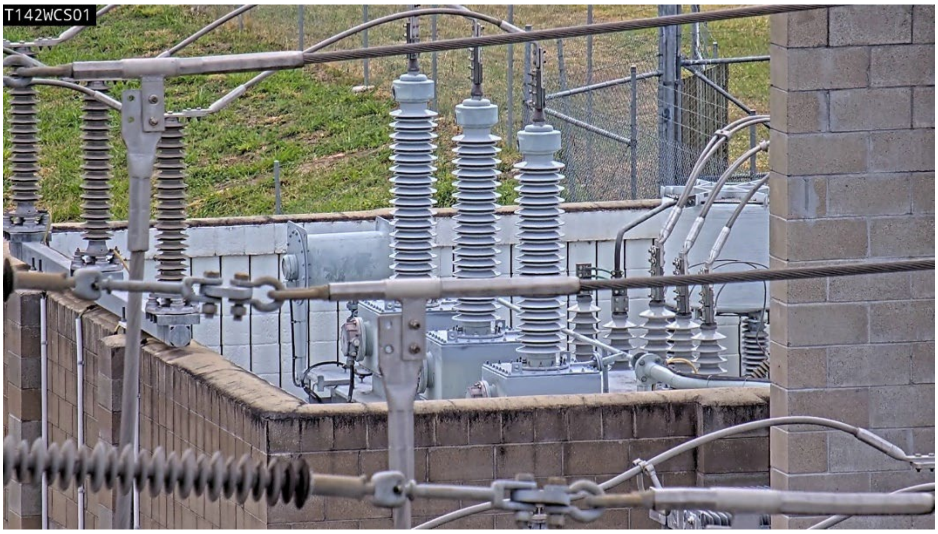


Figure 32: 110kV OIP HV bushings and 33kV LV bushings are shown.

Figure 33: 110kV OIP HV bushings are shown.

The oil level could not be verified in all of the HV bushings. There did not appear to be any external oil leaks coming from the HV bushing themselves.

Ordinarily, following the first 12 years of service from new, the bushings are electrically tested in situ and then the electrical testing is repeated every subsequent 6 years. They are approximately 2 years away from being electrically tested. These bushings appeared to be in a serviceable condition when last tested and are at the end of their 25 year reliable service period.

These HV and LV bushings are non-compliant with Powerlink's bushing policy in as much as if the bushing were to fail catastrophically, two outcomes are more likely to occur due to their design, namely;

(a) The OIP inner HV insulation can result in the entire transformer burning to the ground rather than just losing a bushing.

(b) When the bushing explodes, sizable irregular pieces of sharp and weighty porcelain can be ejected outwards for up to 50 metres creating a recognised potential safety hazard for field staff within the substation as well as collateral damage to other HV plant.

As for the LV 44kV porcelain bushings non-compliance is concerned, even though alternative bushings with Resin Impregnated Paper (RIP) inner insulation could be sourced, they are likely to still have a porcelain outer insulator shell no different to the existing LV bushing design. The existing transformer bushings are low cost, hollow porcelain bushings that are not prone to disruptive failure so unless oil leaks develop in the years to come, their life expectancy is high. Therefore, there is no real advantage in replacing these LV bushings with more expensive designs that have a higher risk of failure.

The reliability of the HV bushings at present is considered reasonable at only 25 years of service. Based on historical data for bushings of this manufacturer and design, it should be possible to achieve a further 6 years of service for the HV bushings but if they are tested as scheduled for 2026, the test results can be used to confirm this suggestion.

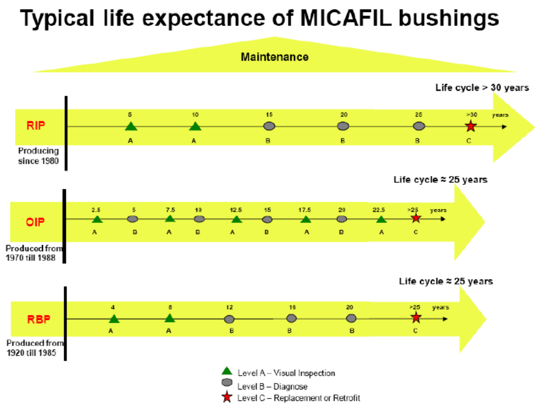


Figure 34: Bushing life expectancy provided by the bushing manufacturer.

2.1.5 Oil and Insulation Assessment:

A desktop scientific assessment was also performed on the transformer oil test data supplied by Powerlink's Oil and Insulation Testing Laboratory to derive a more in depth understanding of the transformer's internal high voltage insulation system condition.

The graph in the previous figure 5 shows the average transformer T03 MVA loading over the past 5 years was around 26MVA, well below its 48MVA ONAN nameplate rating (48/60/80MVA ONAN/ODAN/ODAF). Under normal circumstances, this relatively light loading should allow for slow internal HV cellulose insulation ageing, especially if this loading characteristic is representative of the 25 years of service.

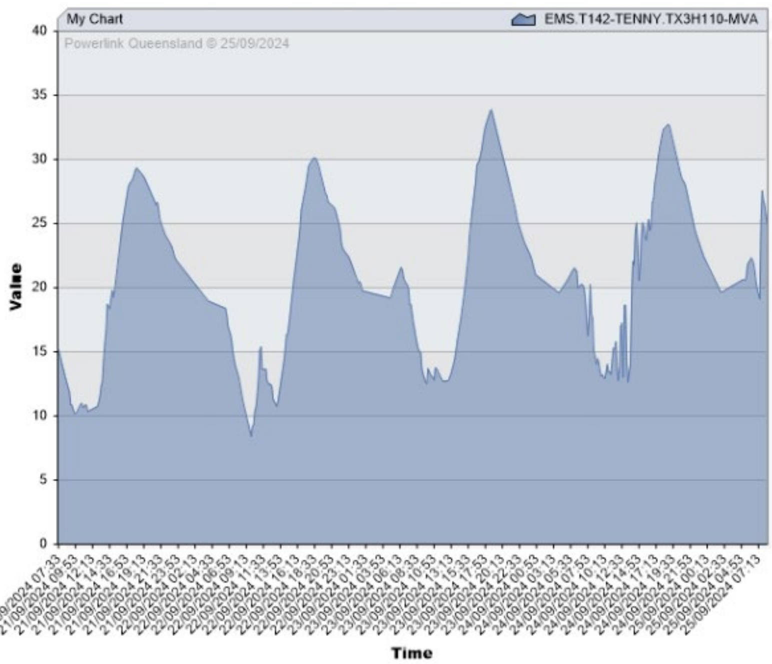


Figure 35: Transformer T03 loading over 4 days in September 2024.

The above figure shows typical repetitive load cycling over 4 days with adequate cooling intervals in between each loading. Over the years of service, this load fluctuation even though small can impact the windings and clamping due to thermal / mechanical working of internal load carrying conductors / joints. There is a phenomena called “***Thermal Softening***” and “***Hydroscopic Softening***” of the cellulose insulation which load cycling contributes to and which will negatively impact the mechanical clamping of the windings over time.

It is also worth a brief mention of the CIGRE Working Group A2:37 Transformer Reliability Survey results shown below. Note that almost a **25 percent of the failures were contributable to <u>mechanical</u> issues** and about 40 percent to windings and insulation <u>dielectric issues</u>.

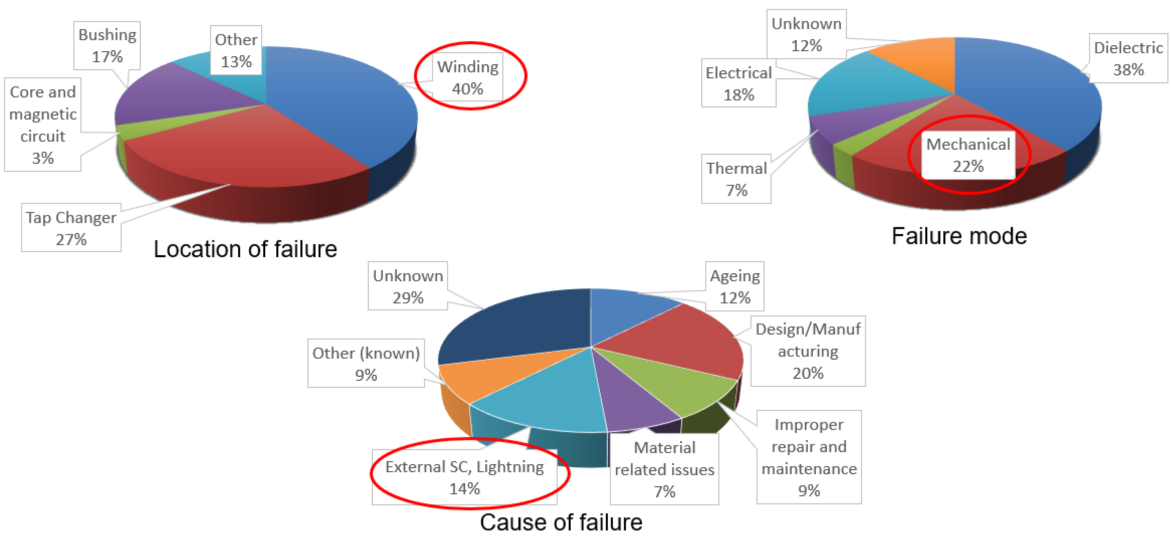


Figure 36: CIGRE Working Group A2:37 Transformer Reliability Survey results.

Regardless of the light transformer loading, the various oil quality "key" indicators show the oil and cellulose insulation to be in very poor condition chemically after only 25 years of service, contrary to what was expected due to the light transformer loading from 2019 to 2024. In June 2010, the transformer tripped on over temperature. This suggests that the loading on this transformer in past years must have been much higher than what is visible for the past 5 years. In May 2017, there was a need to rectify transformer temperature and trip circuits due to PLC abnormal issues.

The thermal performance of the windings shown in the temperature rise test report for the Tennyson T03 transformer is acceptable.

This transformer has a PLC integrated into its control system to manage cooling and to provide the required operational signals back to Powerlink's and Energy Queensland's network Control Room.

An interesting aspect for the transformer design and operation is that it only has a WTI CT installed on the LV winding. Even though this WTI should not be needed due to the PLC, factory temperature rise testing proved that the HV windings had higher winding hot spot temperature gradients as shown below in Table 1 and this could explain one reason why the cellulose insulation is showing accelerated ageing. Whoever programmed the PLC may have selected the LV winding gradients to align with where the transformer manufacturer positioned the WTI CT even though the PLC algorithm is based on the top oil temperature and does not use the WTI input.

Table 1: HV and LV Winding Temperature Gradients

Cooling Mode	HV WINDINGS – No WTI CT		LV WINDINGS - with WTI CT	
	Average Winding Gradient	Winding Hot-Spot Gradient	Average Winding Gradient	Winding Hot-Spot Gradient
ONAN	11.5^0 C	15^0 C	9.5^0 C	12.3^0 C
ODAN	7.6^0 C	9.8^0 C	3.5^0 C	4.5^0 C
ODAF	14^0 C	18.2^0 C	7^0 C	9^0 C

It should also be noted that the transformer nameplate shows a 64MVA ONAF rating but only a 60MVA ODAN rating. The average winding temperature gradients for ONAF rating are **double** what they are for the ODAN rating. This arrangement of fans coming in prior to the main oil pump will lead to accelerated cellulose insulation ageing.

Because of the accelerated ageing of the internal HV cellulose insulation, the following checks should be performed on site based on the findings of this investigation.

- Are the fans set to turn on before the duty oil pump and if so, this is bad practice and should be corrected because the winding temperatures increase too high in ONAF operation. The cooling modes should be ONAN/ODAN/ODAF only.

- That the highest winding hot spot temperature gradients as shown below were used for the PLC input data;
  ONAN - 15 Degrees C
  ODAN - 9.8 Degrees C
  ODAF - 18.2 Degrees C

2.1.5.1 Oil Quality:

The original insulating oil would more than likely have been Nynas '*Nitro 10GBN'* that was eventually recognised globally as being "corrosive" per IEC Standard test method and this was confirmed by Powerlink's Oil and Insulation Testing Laboratory in 2007. The appropriate concentration of metal passivator ("*Irgamet 39*") was added to the insulating oil.

When an oil sample was tested in November 2015, there was no detectable PCB in the oil. The oil is therefore classified as "Non-Contaminated" for being less than 2 ppm.

Acidity:

High oil acidity within the range of 0.1 to 0.3mgKOH/gm of oil for neutralisation exponentially accelerates the aging of the internal steel, copper, solid and paper cellulose HV insulation resulting in a corresponding progressive reduction in winding clamping pressure as well. Because of this, if the oil acidity is approaching 0.1mgKOH/gm of oil, concern is normally raised to investigate if an oil change should be considered within the next few years if the transformer is still needed to remain in service for another several years. Therefore the 0.1mgKOH/gm of oil acidity level can be considered an "*alarm*" level just to bring attention to possible future maintenance requirements.

The Tennyson T03 transformer's oil acidity level rose steadily from new up to 0.16mgKOH/gm of oil over the 25 years of service and is now in the "***alarm***" region. This occurred relatively quickly and is due to localised regions of the internal winding insulation system operating for too long at higher than acceptable temperatures.

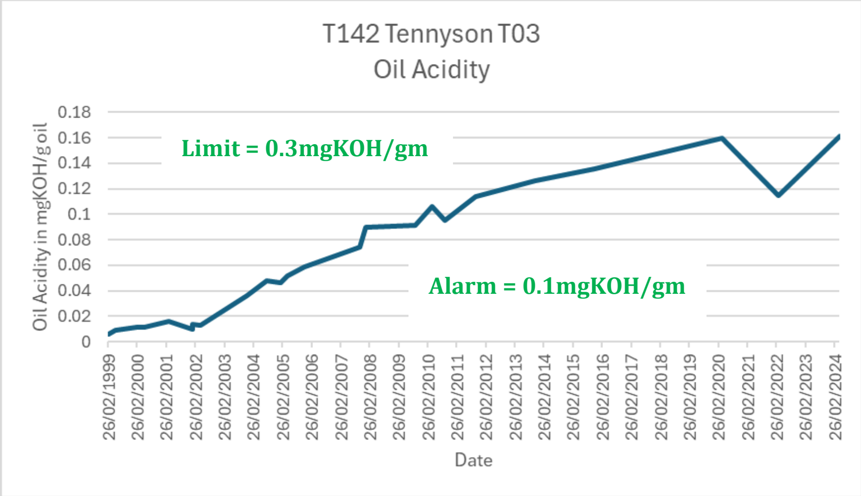


Figure 37: T142 Tennyson T03 oil acidity characteristics over its service life.

Resistivity:

The resistivity of a liquid is a measure of its electrical insulating properties. High resistivity reflects low content of free ions and ion-forming particles and normally indicates a low concentration of conductive soluble contaminants and aging by-products in the oil.

Transformer oil resistivity (Gohm.m) value normally decreases fairly quickly in service. The scaling of the resistivity axis in the figure below creates an illusion that the oil resistivity is very poor. Based on the resistivity characteristic shown in the figure below for this transformer oil and using assessment categories of “Good”, “Fair” and “Poor”, this oil’s resistivity of 4Gohm.m (at 90C) would fall into the category of “Poor” for its age from a conductivity point of view. No action is required due to oil resistivity alone.

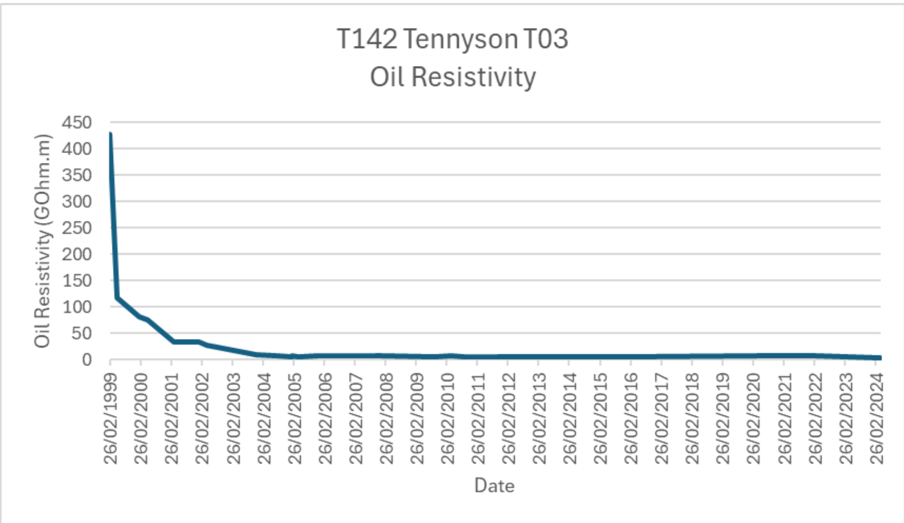


Figure 38: Transformer T03 oil Resistivity characteristics over its service life.

Dielectric Dissipation Factor (DDF):

A rising oil dissipation factor is an indication of oil ageing or oil contamination. The dissipation factor is strongly influenced by polar components as shown in the figure below and is therefore a very sensitive parameter.

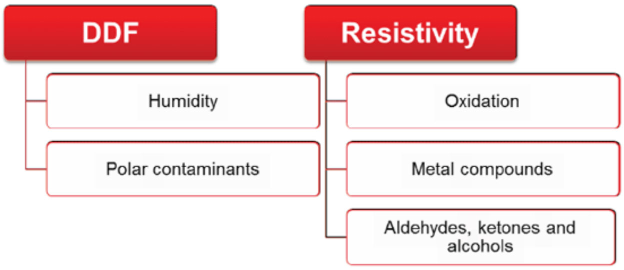


Figure 39: Transformer oil DDF & Resistivity influencing factors.

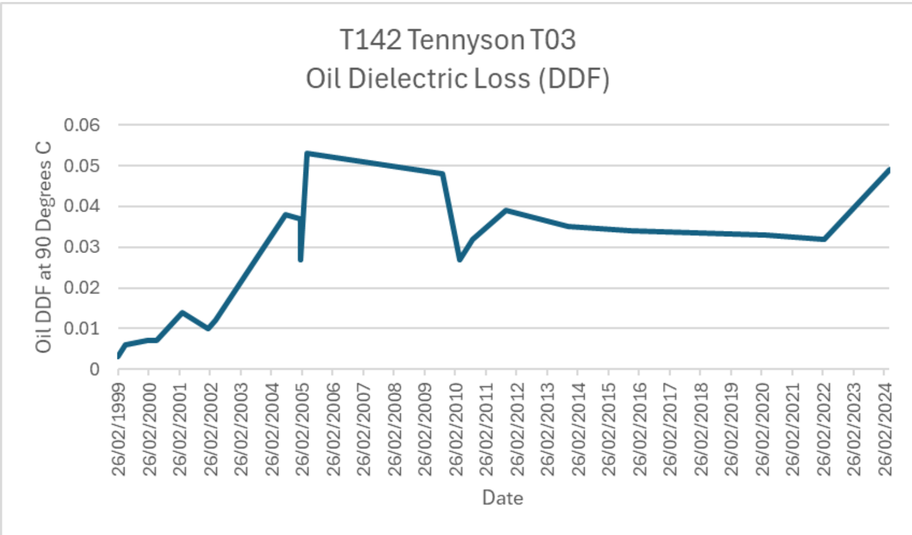


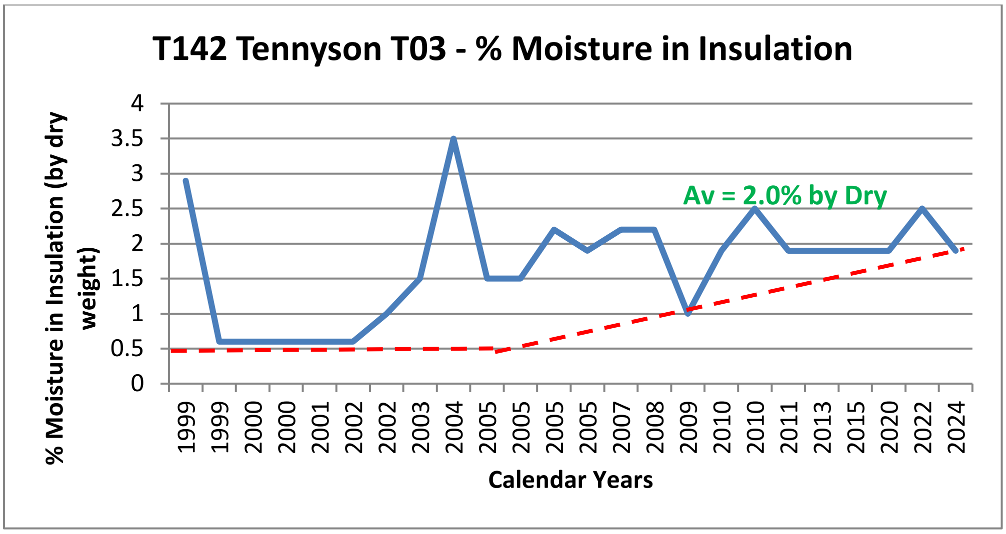
Figure 40: Transformer oil Dielectric Dissipation Factor (DDF) characteristics over its service life.

The Tennyson T03 transformer oil DDF rose steadily up to 0.05mgKOH/gm (mgKOH/gm is an “acidity” unit. The DDF rose steadily up to approximately 0.035 and peaked in 2024 at 0.049 where the limit for DDF = 0.10). This is well below the alarm level.

The oil DC losses characterised in the above figure are relatively low and will not by itself limit the oil’s serviceability over the next 10 years. The oil requires no action due to its DDF.

2.1.5.2 Moisture in Insulation:

Analysis of Powerlink’s Oil and Insulation Testing Laboratory test data by using internally developed diagnostic software suggested an average moisture in the cellulose insulation figure of about 2.0% by dry weight.



With a gradual increase up to 2.0% by dry weight moisture in the cellulose insulation combined with daily load cycling, it would be reasonable to expect some cyclic physical growth in the winding clamping structure, all be it small. The load cycling on the transformer and changing direction of moisture migration in response to the changing temperature gradients across the paper / oil interface would also induce some loss in mechanical clamping pressure on the windings. This is in addition to the previously mentioned thermal and hydroscopic softening of the cellulose insulation.

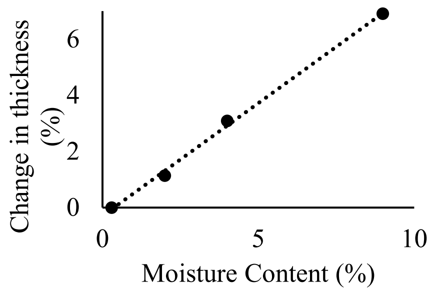


Figure 41: Change in thickness for cellulose insulation due to its percent moisture content.

Based on this present 2.0% moisture in the cellulose insulation level, the moisture alone will NOT be a limiting consideration for the life extension of this transformer.

2.1.5.3 Dissolved Gas Analysis:

A review of Powerlink's Oil and Insulation Testing Laboratory DGA (dissolved gas in oil analysis) test data for this transformer revealed periodic signs of localised hot spot(s). This heating occurred over an extended period from around 2005 through to 2010 and then again from 2020 to 2022 before stabilising in 2024. The individual peaks shown in the dissolved gas-in-oil trends in the figure below have occurred due to changes in transformer loading for those periods of time.

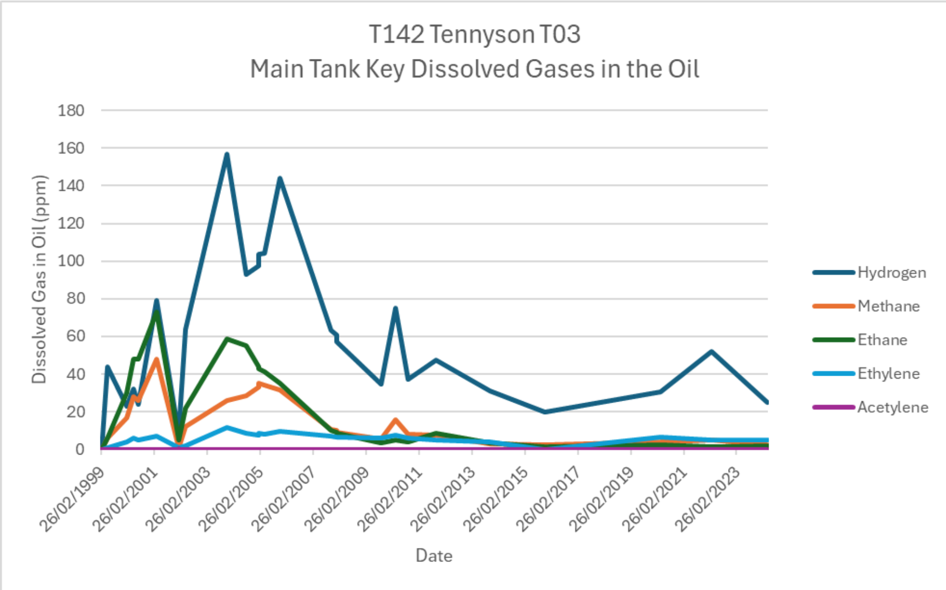


Figure 42: "Key" dissolved gases in oil over the transformer's service life.

The dissolved carbon oxide gases shown in the figure below also confirm the localised heating discussed above for the key dissolved thermal gases for 2005 through to 2010 and then again in 2020 to 2022.

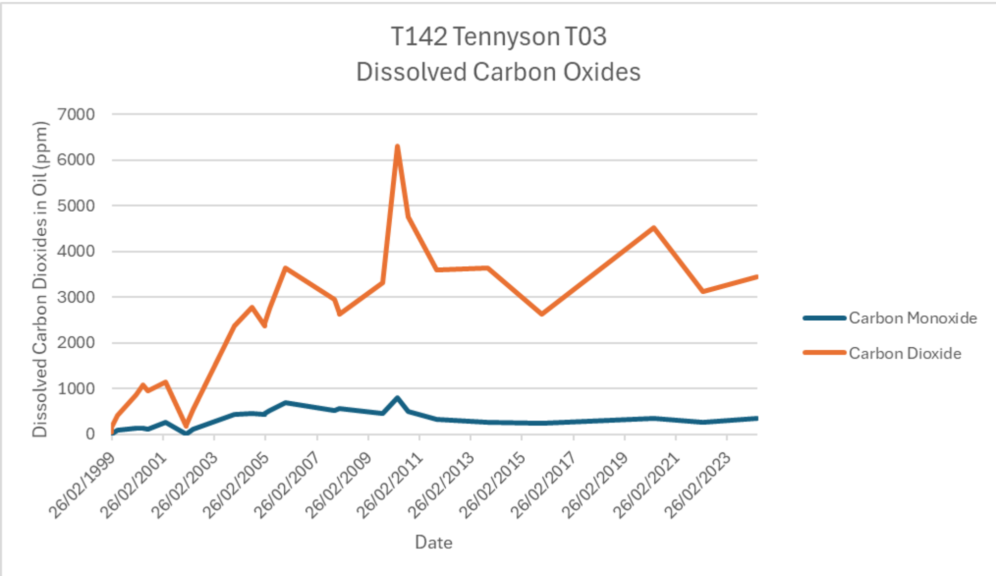


Figure 43: Carbon Monoxide and Carbon Dioxide dissolved gasses over the transformer's service life.

It is interesting to examine the dissolved oxygen levels over the transformer's life to check for correlation with plant loading impacts or other internal chemical reactions which may be occuring. This is because oxygen consumption occurs for the chemical oxidation-reduction reactions during the period of higher operating temperatures for the cellulose insulation. For a "*healthy*" transformer free breathing via a descicant breather, the dissolved oxygen level is typically expected to be in the range of 20,000 ppm to 30,000ppm.

We are expecting more dissolved oxygen consumption for the above mentioned periods of time when other oil parameters indicated that the transformer had localised hot spots for several years and this is what has been displayed in the figure below for the dissolved oxygen in oil.

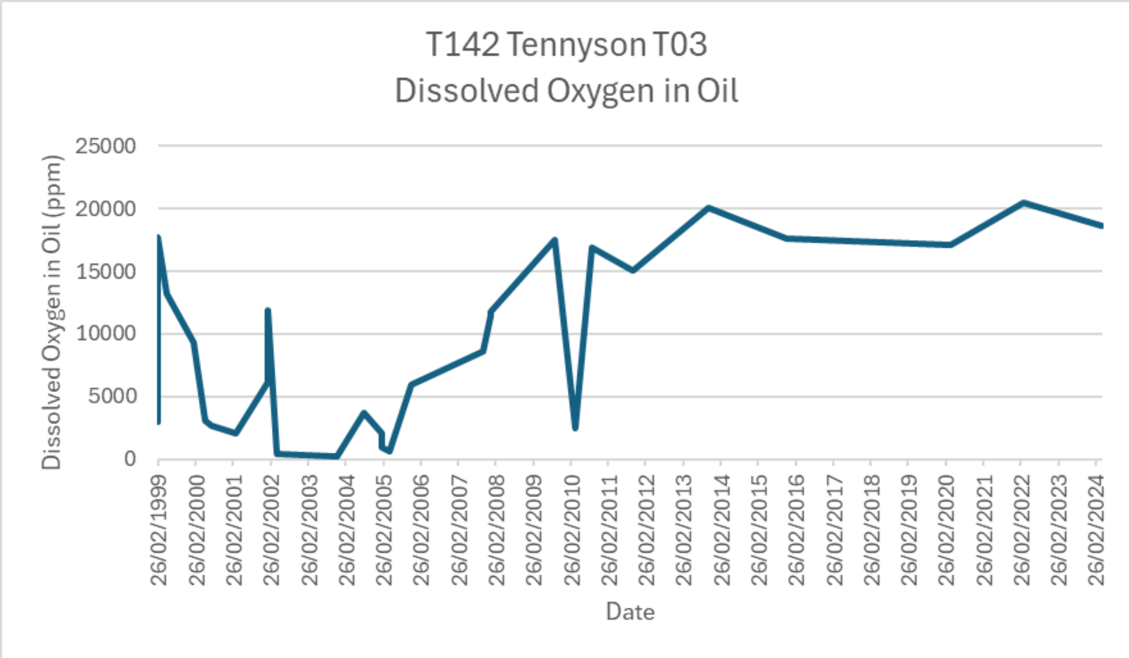


Figure 44: Dissolved oxygen in oil activity over the transformer's life.

2.1.5.4 Winding Paper:

Provided the insulating oil inside a transformer has been well maintained and there is no serious defect, the life of a transformer often depends upon the state of the paper insulation on the windings and the residual clamping pressure on the windings.

It is widely known that as the cellulose solid insulation and winding paper degrades and becomes weaker, "*2 furfuraldehyde*" is one of the many degradation products. It is also widely known that a linear relationship exists between the logarithm of the mass of furfuraldehyde (furan) produced and the resulting reduction in the degree of polymerisation (DP) or strength of the paper. When the DP falls, cellulose paper insulation becomes more brittle and ultimately will fall away from the energised windings reducing the insulation level between adjacent turns. This is especially relevant during through fault conditions when the adjacent turns of a winding will try and move closer together and even touch (beam bending) if the winding structure is weak.

By using the dissolved Furan (2FurFur) in oil test data from Powerlink's Oil & Insulation Scientific Testing Laboratory, the average trend in dissolved

Furan level gives an average value at present of 1.1 ppm (parts per million) in oil. Because of the more localised nature of the winding hot spots, when the dissolved Furan generation from these higher temperature locations is averaged out in the total transformer oil volume, the hot spot contribution of Furans is not easily distinguishable from that generated by the bulk insulation mass. The dissolved Furan in oil characteristic in the figure below certainly adds further confirmation of the more severe cellulose insulation heating from around the 2005 through to 2024.

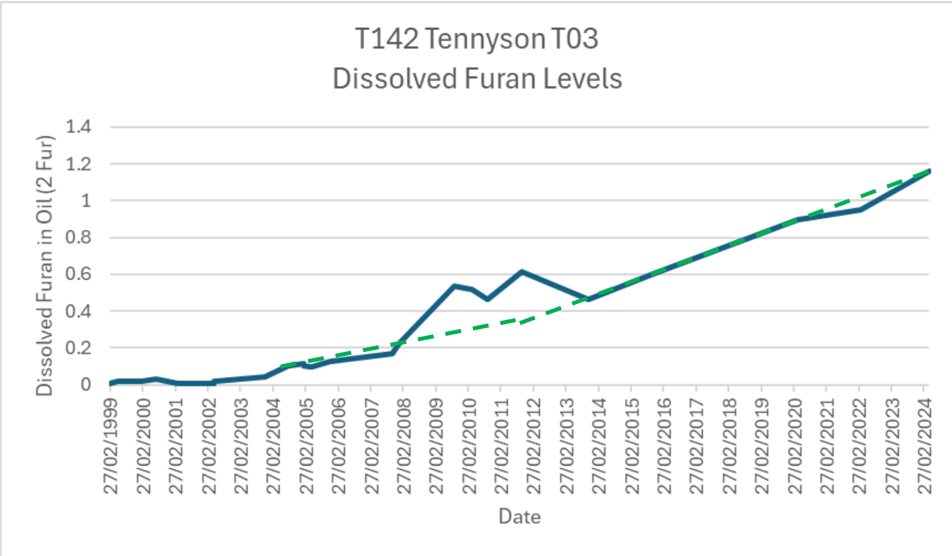


Figure 45: Dissolved Furan (2 Furfur) in oil over the transformer's life.

The <u>average</u> cellulose insulation *Degree of Polymerisation* (DPv) can be calculated to provide a more tangible feel of the residual mechanical strength of the winding paper insulation wraps.

To help understand the significance of DPv, the figure below provides a microscopic view of the cellulose fibres in cellulose insulation. The fibres when new act as strong reinforcing in the cellulose paper insulation but as the paper ages due to chemical, thermal or electrical reasons, the fibres breakdown (lower DPv) and the paper loses its mechanical strength.

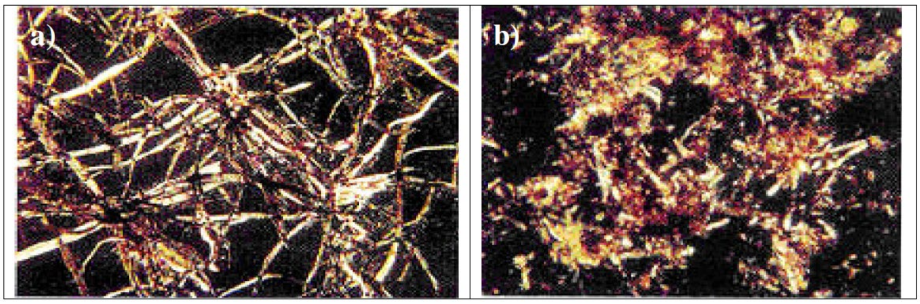


Figure 46: (LHS) Microscopic view of cellulose paper with a high DPv.
(RHS) Microscopic view of cellulose paper with a low DPv.

The **average** *Degree of Polymerisation* (DPv) of the bulk cellulose insulation system within the transformer is calculated to be between **415 to 280,** as shown in the figure below.

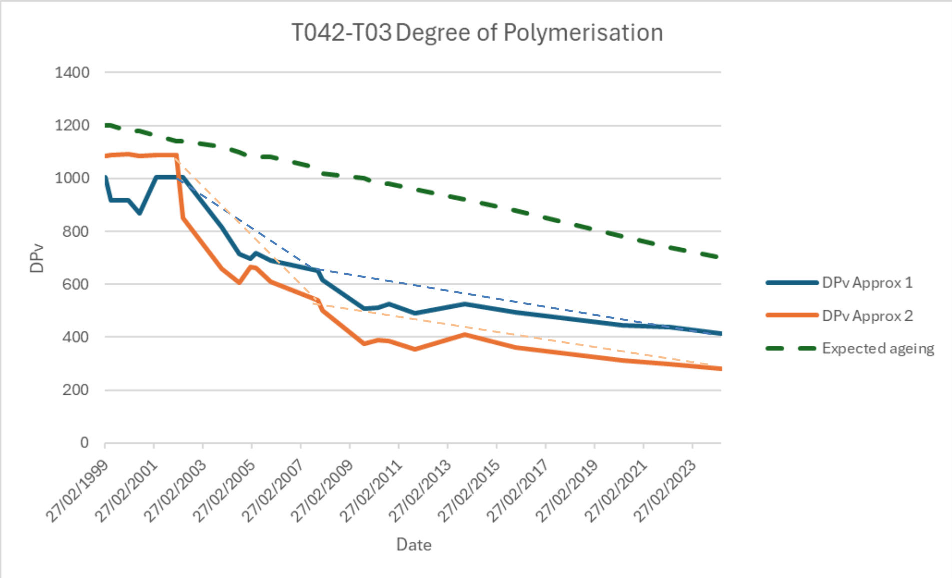


Figure 47: Calculated bulk insulation Degree of Polymerisation (DPv) over the transformer's life.

Now that the average cellulose insulation *Degree of Polymerisation* (DPv) has been calculated to be between a DPv of between 415 to 280, the **average insulation chemical age** is calculated to be between **31 years to 33 years** as shown in the figure below. This is poor for a 25 year old transformer, representing accelerated insulation ageing of about 1.32 times. The reason for this accelerated ageing cannot be known for fact, however aside from the possible PLC issues indicated in this section, it should be noted that the Power Transformer was purchased from another utilities specification and as such may be of different quality to that expected by Powerlink Queensland specifications. Poor manufacturing quality of this specific transformer may be to blame for the accelerated ageing, however it is worth stating that the factory tests all tested acceptably.

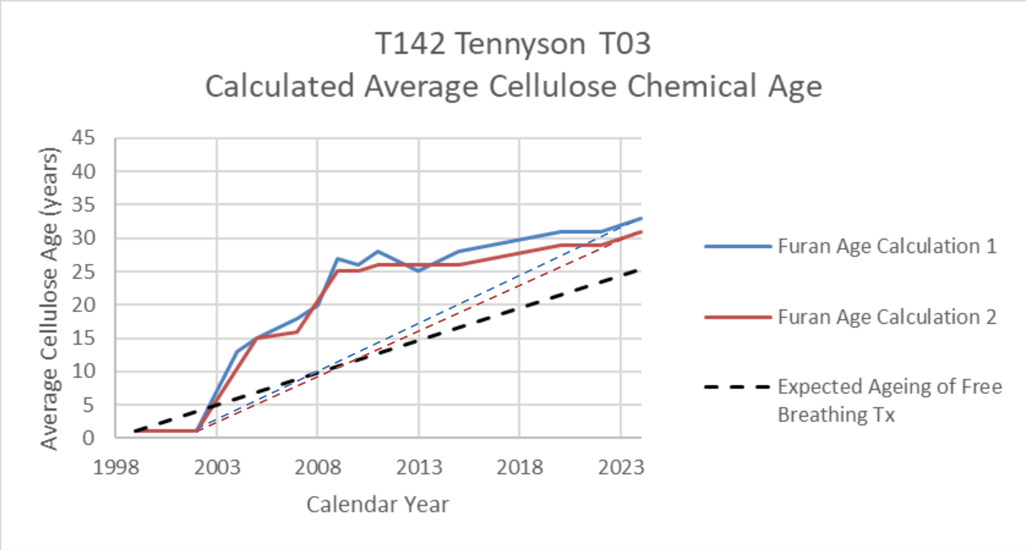


Figure 48: Calculated bulk insulation chemical age over the transformer's life.

There will obviously be a lower DPv in more critical, localised areas of the **winding hot spots** and this value is estimated to be below 200. This calculated DPv for the localised winding hot spot insulation represents a calculated **winding hot spot insulation chemical age of 40 years** which is well above unity insulation ageing for a 25 year old transformer.

Due to the rate of generation of dissolved Furan in the oil can change fairly quickly depending on how the transformer is being loaded over a period of time, the calculated DPv based on the dissolved Furan level can appear to vary erratically at times but this is not a "real" reflection of the winding paper physical state. As the internal winding cellulose insulation ages and loses insulation mass (eg; lowering of DPv), the physical degradation on the cellulose paper fibres can't be reversed. The calculation of the "real" DPv of the cellulose paper insulation needs to consider this.

To estimate (extrapolate) the residual life of the cellulose insulation based on the DPv characteristics shown previously in this report would be fairly reliable, however, there is a less scientific approach that can be used for the residual insulation life calculation but it represents the worst case for insulation ageing. This simplified approach, which is based on the original DPv when new and the calculated DPv now, is shown in the figure below.

A statistical figure adopted globally for the cellulose end of life is a DPv = 200 by which time the winding paper insulation has become very mechanically weak and brittle. By referring to the figure below, it is obvious that the internal winding hot spot cellulose insulation has reached the statistical end of reliable service life and is a limiting factor for this transformer to future life. It is expected that there will only be a maximum of 2-4 years of service life remaining given no change in loading conditions or severe fault conditions.

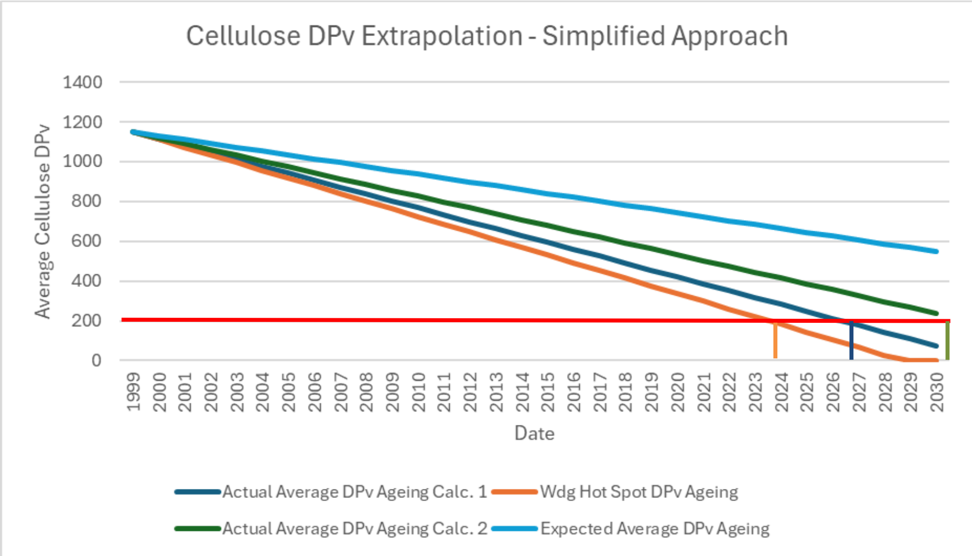


Figure 49: The simplified prediction of residual cellulose insulation life based on initial and present DPv calculations for Tennyson T03.

2.1.6 Winding Dynamic Mechanical Stability

No internal inspection was performed on this transformer to review the condition of the core and coils for displacement, twisting or tilting, blocking stability and residual clamping pressure. This would only be possible with the complete removal of the main tank lid in the field or factory.

What can be stated about the mechanical stability of the windings is as follows;

(a) The top winding clamping structure for this transformer factory design was not inspected by Powerlink SMEs. The transformer manufacturer that built transformers for Powerlink around that time were known to have excessive flex in the top clamping board for the windings and this was raised with the designers who then increased the thickness of this board. Excessive flex in the top clamping board can allow an uneven relaxation in clamping pressure across the concentric windings.

(b) Based on recent research into the loss of winding clamping by the University of Queensland, it was shown that for the **winding radial spacers alone**, where the biggest axial thicknesses exists within the winding, a change of 1.5% moisture produces a change in clamping pressure of about 1%. The Tennyson transformer would have experienced approximately 1.5% cyclic increase in moisture in cellulose insulation over its life so about 1% change in clamping pressure would apply per this research model. Whilst still not considered high, there would be moisture dynamic movement in and out of the winding insulation occurring that adds to the collective impact of a number of other variables.

(c) There is also the phenomena of "*Hydroscopic Softening*" of the cellulose insulation to consider and even though the moisture in the cellulose insulation is calculated to be relatively low, this would still be having a direct impact on the paper wraps on the winding turns, the radial spacers and solid blocking.

(d) "*Thermal Softening*" of the cellulose insulation is an additional phenomena which will also compound with the effects from moisture absorption / desorption and *Hydroscopic Softening* on the clamping structure of the windings. The fact that the transformer has experienced localised hot spots for several years as discussed earlier in this report, this will increase the overall impact of "*Thermal Softening*" on winding clamping pressure.

(e) Exposure to through-faults would have a contribution effect to progressive loss of winding clamping pressure. The through fault history for this bulk supply transformer is not available for analysis.

(f) Cyclic loading will also mechanically work the winding clamping structure. It is realised that the load (temperature) changes are not normally as sharp as shown in the diagram below but the diagram demonstrates the result of cyclic compressive forces on the clamping structure of the windings.

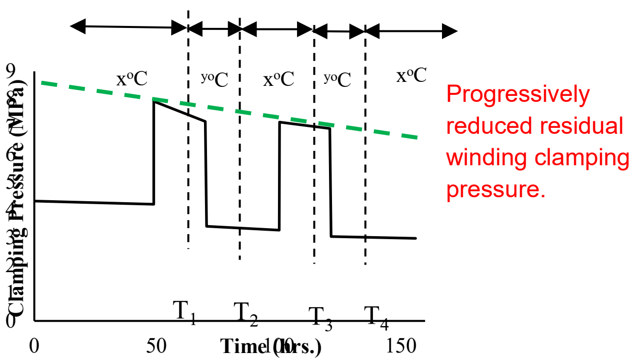


Figure 50: Example of the effect of cyclic compression on a clamped insulation structure.

(g) Softening due to cellulose ageing (loss of cellulose mass) indicated by the decrease from DPv = 1150 when new to a lowest average now of DPv = 282 will lower the winding residual clamping pressure significantly but as to exactly how much would require transformer internal access.

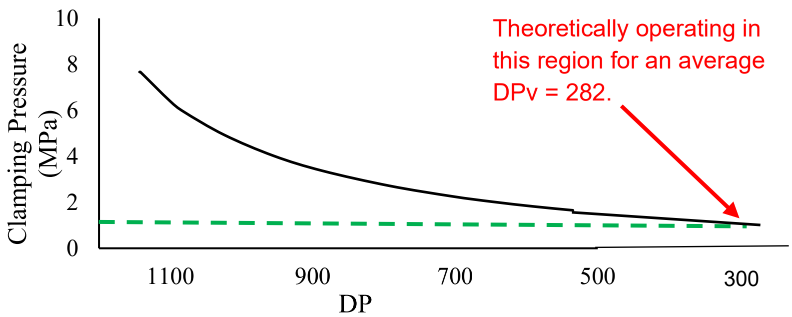


Figure 51: Example of the effect of loss of DPv on Clamping Pressure.

Considering all of the above aspects, the mechanical stability and through fault withstand capability of the winding structure is considered to be in a weakened state. Provided no significant through faults occur, the transformer should be able to continue to operate under normal service conditions until it is either replaced or scrapped within 2-4 years.

2.1.7 General Interest Comments:

This transformer has surge arrester surge counters installed on each of the surge arresters connected to the 110kV bushings. During the next scheduled routine transformer maintenance, these surge counters should be short circuited.

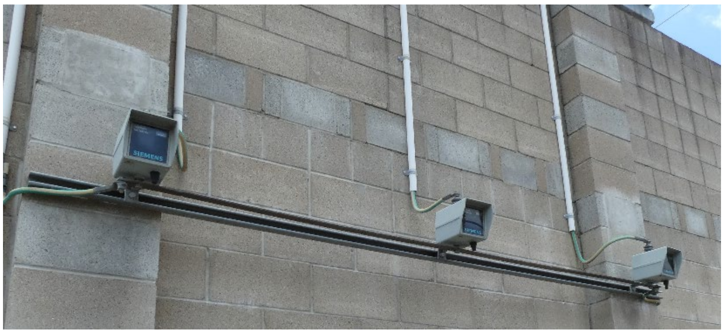


Figure 52: Lightning surge counters installed on the 110kV bushings.

Figure 53: Readings on the lightning surge counters installed on the 110kV bushings from left to right are 26, 07 and 07.

3.0 RECOMMENDATIONS:

The following recommendations are based on the findings from this investigation into the physical, chemical and electrical condition of the 80MVA 110/33/(11)kV transformer at T142 Tennyson substation.

This transformer's internal HV insulation system is in poor condition, reaching statistical end of reliable service life. If the functionality of this transformer is required into the future at Tennyson substation, the transformer will need to be replaced within 2-4 years. Its external physical condition is acceptable for its age.

It could be possible to continue to operate this transformer for the next few years even with the poor condition of the winding hot spot insulation until the transformer is either scrapped or replaced provided the transformer does not experience a severe through fault. This insulation mechanical weakness influences the following recommendations.

3.1 Reinvestment Needs:

(a) Because this transformer's internal winding hot spot insulation system has reached statistical end of reliable service life, if the functionality of this transformer is required into the future at Tennyson substation, the transformer replacement is required as soon as possible. Its external physical condition is reasonable for its age

(b) Due to (a) above, there is little long term benefit in doing anything other than ongoing normal scheduled routine maintenance sufficient to keep the transformer serviceable until a replacement can be arranged or the transformer is scrapped. This will address existing oil leaks and localised corrosion that may develop in the future. No extensive repaint of the transformer should be considered.

(c) If this transformer is to be replaced or scrapped within the next few years, there is no advantage in performing an oil change to lessen the effects of the high oil acidity on the core and winding insulation.

(d) The original HV and LV bushings do not need to be replaced.

(e) The lightning surge counters installed on the 110kV surge arresters should be bypassed during the next scheduled routine maintenance.

(f) The condition of the UV damaged multicore cables needs to be periodically monitored in case they need to be replaced prior to the transformer being scrapped or replaced.

(g) Due to the deteriorated condition of the transformers insulation, it is considered prudent to organise a contingency plan in the case that the unit fails prior to being replaced.

(h) Due to the degraded insulation condition of the transformer increasing the probability of failure it is recommended that the porcelain bushings are put on increased testing frequency to ensure that their condition does not also degrade and pose a safety risk due to catastrophic failure.

(i) When the transformer is replaced, the control unit PLC should be replaced with a conventional unit as this is the secondary systems strategy for these units.

Planning Report		3/07/2025
Title	CP.03005 - Tennyson 3T 110/33kV Transformer Replacement	
Zone	Moreton	
Need Driver	Emerging operational and safety risks arising from the condition of T3 110/33/11kV transformer.	
Network Limitation	Tennyson T3 110/33kV Transformer is necessary to meet Powerlink Queensland's N-1-50MW/600MWh Transmission Authority reliability standard.	
Pre-requisites	None	

Executive Summary

The peak delivered demand at Tennyson substation already exceeds the N-1 capacity of the 3 transformers. This is operational managed at present using short term ratings and Energy Queensland load transfers.

The Tennyson 3T 110/33kV transformer was manufactured in 1999. The condition assessment has shown that the transformer is ageing prematurely and is uneconomical to repair. The transformer has reached its statistical end of reliable service life.

The Central scenario load forecast confirms there is an enduring need to maintain electricity supply into Tennyson. Removal of the transformer to address emerging condition and safety risks would violate Powerlink's N-1-50MW/600MWh Transmission Authority reliability standard.

The preferred network solution for Powerlink to continue to meet its statutory obligations is the replacement of the at-risk transformer with a new 100MVA transformer by 2027, and a Transformer Overload Scheme implemented by 2033.

Table of Contents

1. Introduction

Tennyson Substation, established in 2001, is located 6.3km south of the Brisbane CBD. It is a 110kV substation fed by three 110kV underground feeders from Rocklea, two of which comprise teed supplies to QR Corinda. In turn, Tennyson supplies the Energy Queensland local distribution network via three 110/33/11kV 80MVA transformers.

The peak delivered demand at Tennyson Substation already exceeds the N-1 capacity of the 3 transformers. This is operational managed using short term ratings and EQL load transfers.

Tennyson's location is shown in Figure 1.

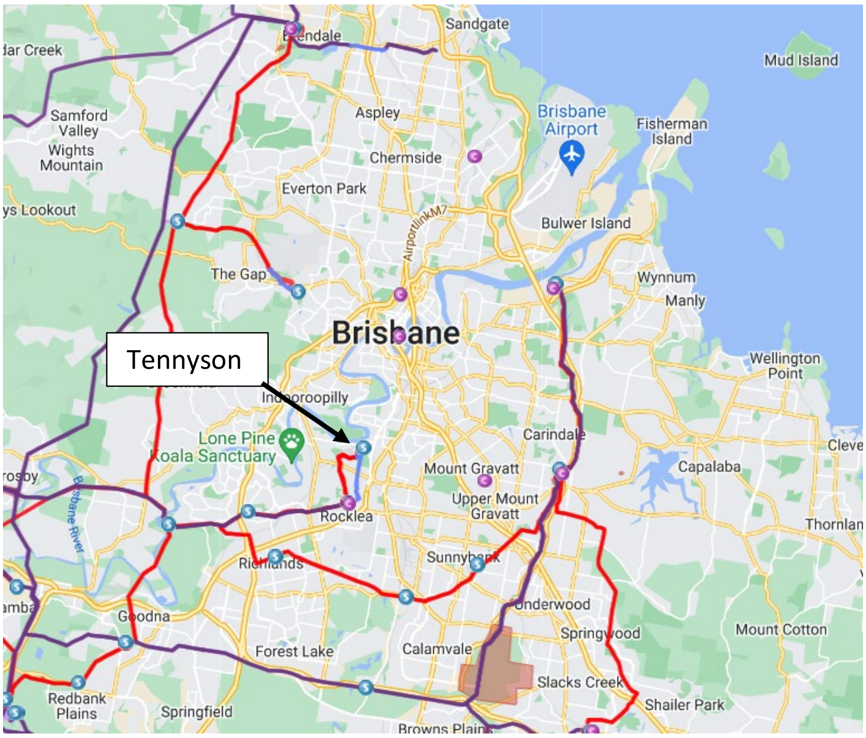


Figure 1. T142 Tennyson Substation – Southeast Queensland

This report assesses the impact that removal of the at-risk transformer would have on the performance of the network and Powerlink's statutory obligations. It also establishes the indicative requirements of any potential alternative solutions to the current services provided by the transformer.

2. T142 Tennyson Substation configuration

The operational configuration of the Tennyson Substation is shown in Figure 2.

[redacted]

Figure 2. T142 Tennyson Substation – Southeast Queensland

3. T142 Tennyson Demand Forecast

The Tennyson Substation forms part of the 110kV network supplying Brisbane. Three radial feeders between Rocklea and Tennyson are the only feeds into the substation. Three 80MVA transformers supply Energex with 33kV into their sectionalized flat bus substation.

The historical peak demand and forecast maximum demand are plotted in Figure 3.

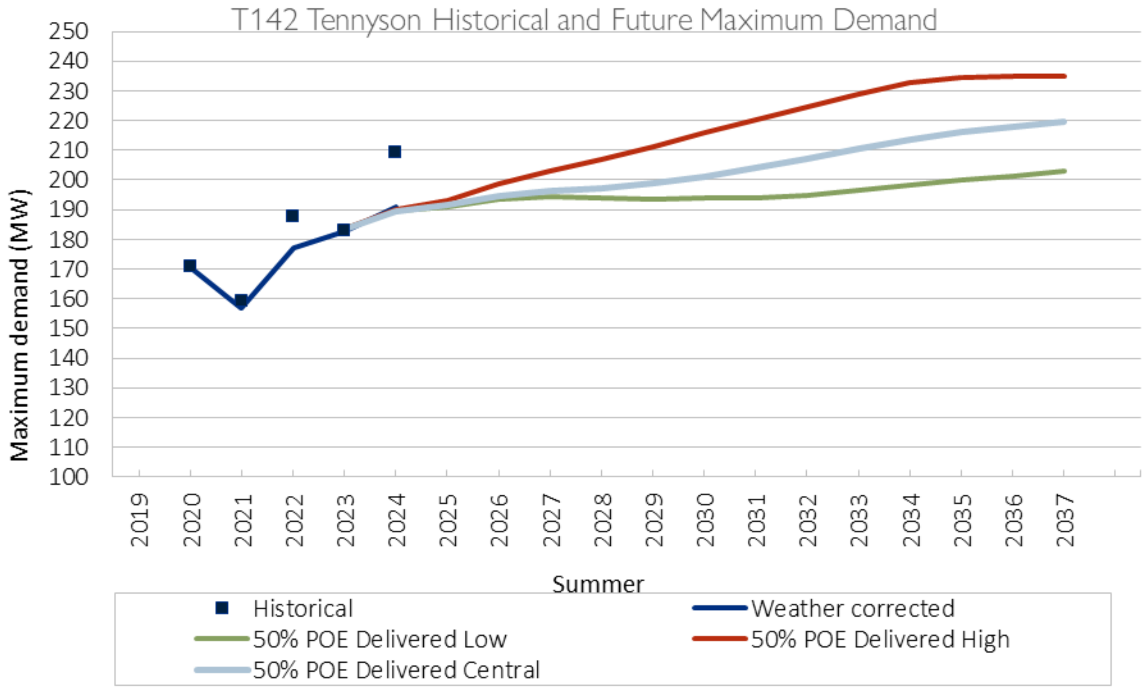


Figure 3. T142 Tennyson Substation Historical and Future Load Forecast

The historical load duration data between 2019 and 2025 is shown in Figure 4.

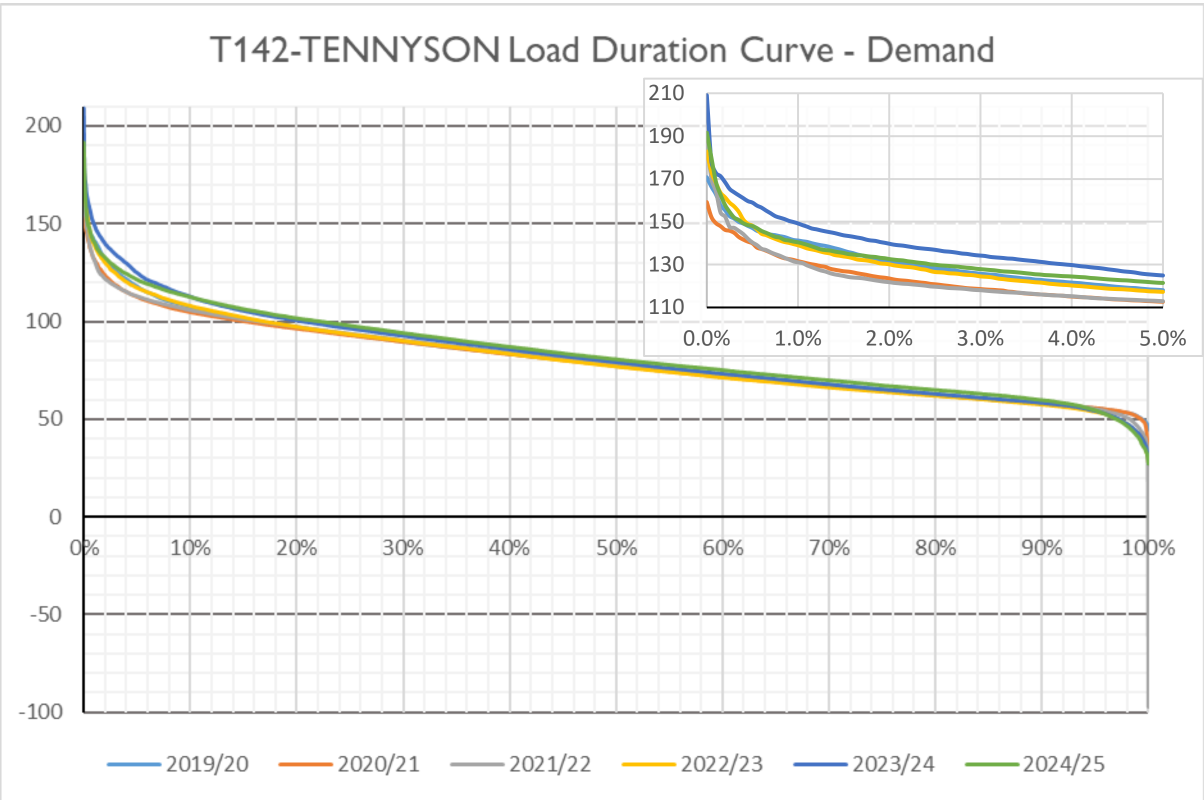


Figure 4. T142 Tennyson Substation Load Duration Curve

The historical and forecast load (refer to Figure 3) and the load duration curve (refer to figure 4) are net of the impact of installed rooftop PV. With consideration of rooftop PV within the Energex network supplied from Tennyson, the maximum customer load is actually significantly higher. Figure 5, shows that the rooftop PV meets up to 80MW of underlying demand.

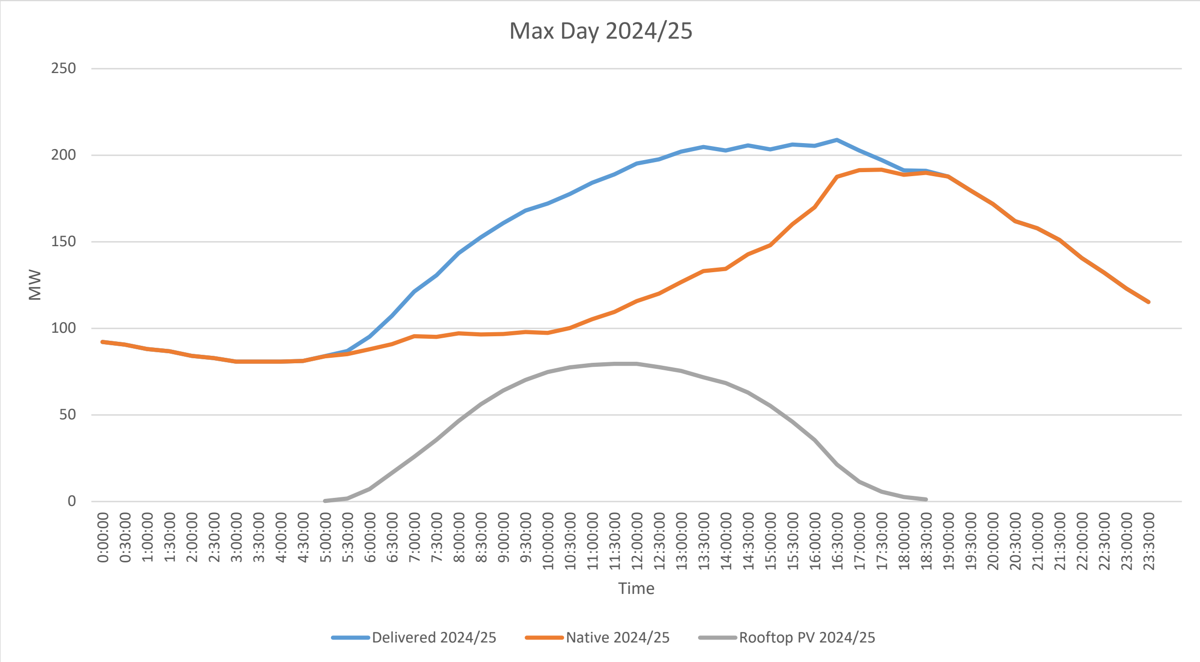


Figure 5. Rooftop PV on Peak Demand (Native) Day 2024/25

4. Statement of Investment Need

Tennyson Transformers 1T, 2T and 3T supply Energex loads at 33kV. If no reinvestment for T3 is undertaken, the retirement of T3 will result in Tennyson being supplied from two 80MVA transformers.

Replacement of T3 is necessary to maintain Powerlink's N-1-50MW/600MWh Transmission Authority reliability standard.

5. Network Risk

Table 1 summarises results of analysis to determine the load and energy at risk at Tennyson for the scenario where T3 is removed from service. The estimation takes into account the expected level of rooftop PV connected to the Energex network supplied from Tennyson. This level of rooftop PV needs to be discounted so as to capture the total level of customer load that is at risk of not being supplied.

Appendix B describes the methodology and assessment against the reliability standard.

Table 1. Load at Risk

At Risk	Contingency	Measure	2025	2034
		Max Native Load (MW)	191.6	214.4
		Average Native Load (MW)	100	120.6
Tennyson 33kV Loads	Loss of Tennyson T1 or T2 + associated PV	Max (MW) > capacity limit	111.7	189.1
		Annual Average (MW) > capacity limit	6.2	16.2
		24hr Energy Constrained Max (MWh)	344.4	2061.6
		24hr Energy Constrained Average (MWh)	147.8	387.2
Tennyson 33kV Loads	Loss of Tennyson T1 or T2 (excl. PV)	Max (MW) > capacity limit	99	124
		Annual Average (MW) > capacity limit	5	14
		24hr Energy Constrained Max (MWh)	854	1399
		24hr Energy Constrained Average (MWh)	121	345

6. Non Network Options

Potential non-network solutions would need to provide supply to the 33kV network at Tennyson as per Table 1. That is, up to 125MW and 1400MWh per day. The non-network solution would be required to operate pre-contingent at a level such that the remaining transformer would fall to its 10-minute rating following the contingency.

Additional non-network would then need to be available to return the transformer to within its emergency cyclic rating until normal supply is restored.

Powerlink is not aware of any Demand Side Solutions (DSM) in the area supplied by Tennyson. However, Powerlink will consider any proposed solution that can contribute significantly to the requirements of ensuring that Powerlink continues to meet its required reliability of supply obligations as part of the RIT-T consultation process ahead of the actual investment decision.

7. Network Options

7.1 Proposed Option to address the identified need

To address the end of life of 3T Transformer at Tennyson, it is recommended to replace the transformer by 2027.

Considering the forecasted load, Powerlink's standard specification transformer of 100MVA is recommended, with 1T and 2T also upgraded to 100MVA when they are replaced in the future.

Until 1T and 2T are replaced there is an emerging limitation from summer 2033/34 as described in Appendix B. Based on the Central scenario load forecast the loading on T1 and T2 is forecast to exceed the aggregate 10-minute rating of these transformers. To address this a special protection scheme is proposed to be installed at Tennyson to trip load before transformer overload protection would operate.

Powerlink considers the proposed network solution will not have any material inter-network impact, and as such does not need to formally consult with other Market Participants.

7.2 Option Considered but Not Proposed

This section discusses alternative options that Powerlink has investigated but does not consider technically and/or economically feasible to address the above identified issues and thus are not considered credible options.

6.2.1 Do Nothing

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

6.2.2 Decommission Transformer 3 and implement a post-contingent load shedding scheme

Under this option, 3T Transformer is permanently decommissioned, with the Tennyson load being supplied by only 2 transformers. Both 1T and 2T have emergency cyclic ratings of 94MVA, so peak load periods already exceed the combined 188MVA capacity. Additionally, if either transformer were to trip, or fail, the load would be curtailed immediately to the rating of the remaining transformer. The mean time to repair or put a spare transformer in place is 10 to 12 weeks.

This option would not meet Powerlink's Transmission Authority reliability standard (N-1-50MW/600MWh) or Energy Queensland's reliability obligations (see Appendix 1).

6.2.3 Transfer load off Tennyson to neighbouring substations

Energex has limited power transfer capacity between Tennyson and Ashgrove West and between Tennyson and Abermain. The amount of load that would need to be permanently transferred is equivalent to the quantities defined under the non-network option (i.e. up to 189MW at peak and 2062MWh per day). Notwithstanding that additional 33kV network would need to be built to support these transfers, the approximate headroom currently available (based on existing maximum demands) on the firm (N-1) transformation capacity at Ashgrove West and Abermain is 5MW and 70MW respectively. This is significantly less than that required and would drive the need for not only investment in 33kV network but also transformer upgrades and these locations.

This option has not been considered further.

8. Recommendations

Powerlink has reviewed the condition of the 3T 110/33kV Transformer at Tennyson Substation and concludes it will soon reach the end of its technical service life.

It is recommended that the 110/33kV transformer 3T at Tennyson Substation be replaced. It also suggests that a Transformer Overload Scheme will be required by 2033.

Retaining Tennyson as a three 110/33kV transformer substation will allow Powerlink to continue to meet its required reliability obligations (N-1-50MW/600MWh). It will also allow Energy Queensland to meet its reliability standard (See Appendix 1).

Powerlink is currently unaware of any feasible alternative options to minimise or eliminate the load at risk at Tennyson 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.

9. References

1. CP.03005 Tennyson Transformer 3 Replacement – Project Scope Report

2. T142 Tennyson T03 Transformer – Condition Assessment Report

3. 2025 Transmission Annual Planning Report

4. Asset Planning Criteria - Framework

5. Powerlink Queensland's Transmission Authority T01/98

10. Appendix A: – EQ Planning Standards

Area	Targets for restoration of supply following an N-1 Event
Regional Centre[13]	Following an N-1 Event, load not supplied must be: • Less than 20MVA (8000 customers) after 1 hour • Less than 15MVA (6000 customers) after 6 hours • Less than 5MVA (2000 customers) after 12 hours • Fully restored within 24 hours.
Rural Areas	Following an N-1 Event, load not supplied must be: • Less than 20MVA (8000 customers) after 1 hour • Less 15MVA (6000 customers) after 8 hours • Less 5MVA (2000 customers) after 18 hours • Fully restored within 48 hours.

11. Appendix B – Network Risk methodology

11.1 The replacement of 3T

Transformers T1 and T2 each have an emergency cyclic loading capacity of 94 MVA (~90MW @ 0.96PF).

With T3 out of service, and a contingency on T2, a capacity of 90MW from T1 is available.

With consideration of the embedded rooftop PV (scaled depending on how much load is lost), this leaves Tennyson with 111.7MW of load over in excess of the available firm 110/33kV transformation capacity in 2025.

This exceeds the 50MW that can be shed as per Powerlink's Transmission Authority reliability standard. Given that the mean time to repair or replace a transformer is 10 to 12 weeks, the 600MWh limit will also materially be exceeded.

11.2 Post-contingent load shed/transfer scheme

Transformers T1 and T2 each have a 10-minute rating of 120 MVA (~115MW @ 0.96PF).

For the network to be in a "secure" state, then a contingency of T3, must not overload the remaining T1 and T2 i.e. combined capacity = 2 x ~115MW =~230MW. Alternatively, an automated scheme is required. Based on the 10PoE load forecast of Figure 3, a scheme is required for the 2033/34 summer period.

Project Scope Report

CP.03005

Tennyson Transformer 3 Replacement

Proposal – Version 1

Document Purpose

The purpose of this Project Scope Report is to define the business (functional) requirements that the project is intended to deliver. These functional requirements are subject to Powerlink's design and construction standards and prevailing asset strategies, which will be detailed in documentation produced during the detailed scoping and estimating undertaken by DTS (or OSD), i.e. it is not intended for this document to provide a detailed scope of works that is directly suitable for estimating.

Project Details

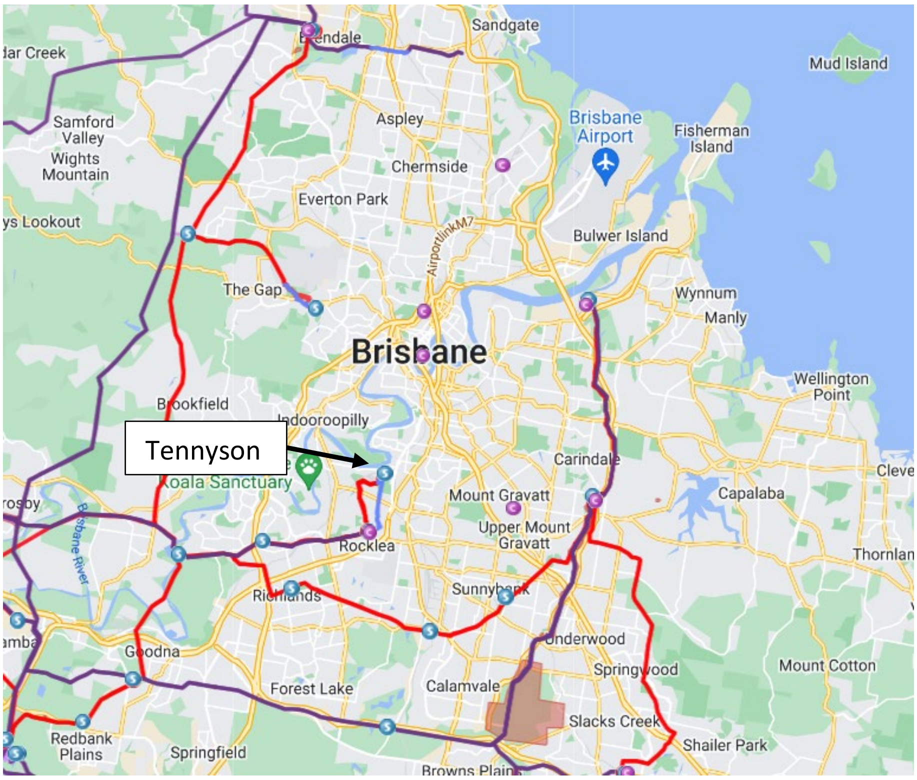
1. Project Need & Objective

Tennyson Substation, established in 2001, is located 6.3km south of the Brisbane CBD. It is a 110kV substation fed by three 110kV underground feeders from Rocklea, two of which comprise teed supplies to QR Corinda. In turn Tennyson supplies the Energy Queensland local distribution network via three 110/33/11kV 80MVA transformers.

Transformer 3, manufactured in 1999, has experienced significant condition issues including to ongoing OLTC problems, oil leaks and corrosion. In addition, the winding insulation and bushings are considered to be at end of life. Given the bushings are porcelain type, they pose a safety risk due to their explosive failure mode.

The objective of this project is to replace 3 Transformer by June 2027.

2. Project Drawing

3. 

4. Deliverables

The following deliverables are to be provided in response to this Project Scope Report. The requirement dates for these deliverables will be communicated separately.

This project will follow the two stage approval process. The following deliverables are required for RIT-T purposes and Stage 1 approval for the single proposed solution:

1. A report (e.g. Project Proposal) detailing the works to be delivered, proposed staging of delivery, resource requirements and confirmation of availability, and outage requirements

2. A class 3 estimate (minimum), based upon published design advices detailing key design elements

3. A basis of estimate document and risk table, detailing the key estimating assumptions and delivery risks

4. A detailed project staging and outage plan that includes primary plant, secondary systems and telecoms outages

5. As this project will follow the two (2) stage approval process, provide a separate estimate for stage 2 development phase costs which include project planning, design and preliminary works. Also provide the schedule and time information to align with 2-stage approval

The following deliverables are subsequently required, upon conclusion of the RIT-T, to facilitate full project approval:

1. A report (e.g. Project Proposal) detailing the works to be delivered, proposed staging of delivery, resource requirements and confirmation of availability, and outage requirements

2. A class 2 estimate including contractor pricing and MSP RFQ, based on detailed design sufficient to inform delivery costs to this minimum accuracy level

3. A basis of estimate document and risk table, detailing the key estimating assumptions and delivery risks

4. A detailed project staging and outage plan that includes primary plant, secondary systems and telecoms outages

5. Project Scope

5.1. 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 6 Special Considerations*.

Briefly, the project consists of the replacement of 3 Transformer.

5.1.1. T142 Tennyson Substation Works

Design, procure, construct, test and commission replacement of 3 Transformer. Within the scope of work:

- Procure a new 100MVA 110/33/11kV transformer;
- Decommission and dispose of the existing 3 transformer;
- Install the new transformer into the existing bay at Tennyson, including:
  - review and replacement of the transformer foundation as required;
  - review the condition and capacity of existing oil separation tank and modify as required to ensure compliance with relevant environmental legislation;
  - undertake all necessary civil works;
  - review the transformer primary connections and modify as required;
  - modify secondary systems as necessary to accommodate the new transformer; and
- update drawing records, SAP, config files etc accordingly.

5.1.2. Telecoms Works

Not applicable

5.1.3. Easement/Land Acquisition & Permits Works

Not applicable

5.2. Key Scope Assumptions

The following assumptions should be included in the estimating of this scope:

- The replacement will be on a like for like basis
- The transformer will be located in the existing 3 transformer bay

5.3. Variations to Scope (post project approval)

Not applicable

6. Key Asset Risks

Asset risk management shall be in accordance with the Asset Risk Management Process Guideline

7. Project Timing

7.1. Stage 1 Approval Date

The anticipated date by which the project will be approved is 30 November 2024.

7.2. Site Access Date

T142 Tennyson Substation is an existing Powerlink site and access is available immediately.

7.3. Commissioning Date

The latest date for the commissioning of the new assets included in this scope <u>and</u> the decommissioning and removal of redundant assets, where applicable, is 30 June 2027.

8. Special Considerations

Not applicable

9. 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 Network and Business Development including Asset Strategies & Planning.

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

10. Asset Ownership

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

The asset boundary with Energy Queensland will be the 33kV terminals of the 110/33/11kV transformer.

11. 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.

12. Options

Not applicable

13. Division of Responsibilities

Not applicable

14. Related Projects

Project No.	Project Description	Planned Comm Date	Comment
Pre-requisite Projects			
Co-requisite Projects			
Other Related Projects			
Or.02412	Tennyson F768 and F769 Protection Upgrade	Feb 2025	

CP.03005 T142 Tennyson Transformer 3 Replacement

Project Management Plan

Revenue Reset 2027-2032

Version History

Version	Date	Section(s)	Summary of amendment
1.0	12/08/2025	1-5	Revenue Reset 2027-2032

Table of Contents

1. Executive Summary

Tennyson Substation, established in 2001, is located 6.3km of the Brisbane CBD. It is a 110kV substation fed by three 110kV underground feeders from Rocklea, two of which comprise teed supplied to QR Corinda. In turn Tennyson supplies the Energy Queensland local distribution network via three 110/33/11kV 80MVA transformers.

3 Transformer, manufactured in 1999, has experienced significant condition issues including ongoing OLTC problems, oil leads and corrosion. In addition, the winding insulation and bushings are at end of life. Given the bushing are porcelain type, the pose a safety risk to their explosive failure mode. The objective of this project is to replace in-situ the existing 80MVA 3T Transformer with a new 100MVA unit.

The assessment behind this proposal has established that the project can only be delivered by October 2027.

This project will follow the two (2) stage approval process.

Deliverable	Date
Project Scope Report (version 1) – date received	12 September 2024
Project Proposal and Class 3 Estimate	8 August 2025
Stage 1 Approval	31 October 2025
Class 2 Estimate Submission	31 May 2026
Full Project Approval Advice (PAA)	31 July 2026
Transformer Procurement	15 July 2027
Project Commissioned	31 October 2027

Overview of Estimated Costs

The following table summarises the breakdown of the project estimate.

Estimate Components		Base Cost $	Escalated $
Base Estimate (A)		**9,693,938**	**10,178,930**
Contingency (Unknown Risk) (B)	[redacted]	[redacted]	[redacted]
Mitigated Risk (Known Risk) (C)	[redacted]	[redacted]	[redacted]
Total Proposed (B+C)	[redacted]	[redacted]	[redacted]
Total Proposed Approval (A+B+C)		[redacted]	[redacted]

2. Project Definition

2.1 Project Scope

Design, procure, construct, test and commission replacement of T142 Tennyson 3T Transformer.

Within the scope of work:

- Extension of the existing 2T Transformer Fire wall to widen the coverage of the larger Transformer.
- Procure a new 3T Transformer 100MVA 110/33/11kV transformer, with on-load tap changer and cooling facilities.
- Decommission and dispose of the existing 3T Transformer.
- Demolition of the existing 3T Transformer noise wall and foundations.
- Construction of a new 3T Transformer foundation to accommodate the new transformer size.
- Installation of new structures for all plant and equipment required for the new 3T Transformer.
- Installation of a new 3T Transformer into the existing bay at T142 Tennyson.
- Replacement of 110kV and 33kV surge arrestors.
- Establish HV and LV connections to transformer bay infrastructure.
- Installation of a second stage SPEL tank.
- Modification to the existing oil drainage system to suit the new transformer and upgrade to the current Powerlink standards.
- Modifications to existing protection and automation systems to accommodate the new transformer.
    - Existing Transformer 3 protection panel (+4A6) modifications.
    - New cables run from the new transformer marshalling cubicle(s) to the control building termination rack.
    - 3 Transformer PLC connections will be removed, and status indications will be rewired.

    - New Control Build installed to include new and changed alarms and indications for the new transformer.

- Replacement of AC supply cables from main change-over board to the new transformer.
- New cable trenches and conduits to suit the new transformer.
- Replacement of Current Transformer (CT) link terminals in the panel and termination rack, as per Standards Update, SU0049.
- Removal of redundant equipment and cabling.
- Update drawing records, SAP records, config files, etc., accordingly.

2.2 Exclusions

The following items are excluded from the Project Estimate.

- No allowance for any EQL projects that may impact Powerlink works.
- EQL's transformer connection 33/11kV works.
- Upgrade or uprating of EQL's assets due to the implementation of this project.
- Firewall for the new 3T Transformer.
- No major modification to the earth grid.
- No costs for repairing or modification to the primary plants not listed to be replaced under the scope.
- No allowance to repair or upgrade existing access tracks to the substation and existing roads within the substation.
- No allowance for management of unsuitable ground conditions during foundation works. This would be regarded as a latent condition.
- Rock or unsuitable material (asbestos and other contamination) including removal, treatment and disposal
- No offsetting of costs has been included for value of scrapped or recovered plant items.
- No allowance for extreme weather events.

2.3 Assumptions

The following key assumptions have been made in compiling this Project Estimate.

- Access to network for outages is available.
- All existing equipment to be reused in the project is in good condition and working order.
- All resources will be available, including necessary operational resources to complete necessary construction, testing and commissioning activities.
- Site access is available for project works as required.
- Existing ground conditions are suitable for the construction of standard foundations.
- Powerlink resources are available as required.

- No Restricted Access Zones will be deployed on this site during construction.
- Procurement of long lead items aligns with project delivery requirements.
- Energy Queensland design and construction resources will be available when required for remote end works.
- Timely agreement of Division of Responsibility (DOR) between Energy Queensland and Powerlink for all the works involved.
- Outages will be available.

2.4 Project Interaction

There are no known interactions with other projects and Engineering Task Requests (ETRs).

2.5 Project Risk

Project risks identified during Project Proposal phase are as follows:

No	Category	Risk Description	Consequence (L/M/H)	Likelihood (%)	Cost ($)
1	Contract	Contractor Validity expiring due to delay to full approval and subsequent Contract Award. 5% of subcontractor costs.	Minor	Possible	[redacted]
2	Variations (EOT etc)	Variation to fixed price contracts. 10% of total contract values.	Minor	Possible	[redacted]
3	Supplier Risks	Procurement delays due to manufacturing delays. 10% of subcontractor costs.	Minor	Possible	[redacted]
4	Subcontractor Risks	Subcontractor resource capacity for completing projects. 5% of subcontractor cost.	Minor	Possible	[redacted]
5	Performance Warranty	Warranty on plant and equipment purchased by PLQ. 10% of procurement.	Minor	Possible	[redacted]
6	Weather Conditions	Rain events and the effects of these events are impacting the program above seasonal rainfall. Wind events grounding the use of EWPs and cranes for structure erection, resulting in an impact on the overall program, allow for a potential impact of $250K for wind events. Lightning events are causing damage to equipment and delays to the program. $150K for Lightning events, $100k for other events.	Minor	Possible	[redacted]
7	Interfacing with Client	Project work interface with Energy Queensland and Queensland Rail from both a technical and coordination perspective.	Minor	Possible	[redacted]
8	Interfacing with Contractors	Contractor interfaces causing variations and delay claims. $100k to cover interface management and delays.	Minor	Likely	[redacted]
9	Community Liaison Issues	Stakeholder expectations can lead to dissatisfaction and conflict, and may have impacts on the community, such as noise and disruption.	Minor	Likely	[redacted]
10	Maturity of Project Scope/Design	Ongoing design resource constraints could delay design delivery, delaying the project delivery timeline.	Minor	Possible	[redacted]
11	Staging/ Outages	Additional outage management/ops engineering input requires for contingency plan (outage management requirements).	Minor	Likely	[redacted]
12	Site Access	Alternate access to be upgraded for delivery of plant.	Moderate	Possible	[redacted]
13	Latent Conditions	Project Works involve earthworks on previously undisturbed land, and subsurface rock or similar may be encountered, resulting in increased cost.	Minor	Likely	[redacted]
14	Outage Cancellation	Outages may be cancelled due to unforeseen circumstances i.e.: Higher priority incidents, lack of approval or resources, conflicts with business operations.	Minor	Likely	[redacted]
15	Remobilisation	Principal delays or disruptions to work causes Contractors / OSD to remobilise.	Minor	Possible	[redacted]
16	Testing, Commissioning and Staging	Principal delays for commissioning. 15% of OSD costs.	Minor	Possible	[redacted]
17	Outage Availability	The transformer feeds both Queensland Rail and Energex; therefore, outage availability may be affected.	Minor	Likely	[redacted]
18	Availability of Resources	MSP resources for testing and switching may be constrained, resulting in longer-than-expected work execution timeframes. Allow 10% of OSD costs.	Minor	Likely	[redacted]
19	Material Delivery Delays	Hardware/material delivery late for a tight commissioning timeframe.	Minor	Unlikely	[redacted]
		TOTAL			[redacted]

2.6 Applicable Lessons Learned

Applicable lessons learned that have been identified during the Project Proposal phase are as follows:

No	Project Number & Name	Lesson Title	Expected Outcomes	Actual Outcome	Recommended Changes
1	Collinsville T1 Transformer Replacement H075T2FAIL – H075 Kumbarilla Park Failed Transformer Replacement	Manufacture Drawings	Improve Manufacturer Drawings, which are not being appropriately uploaded into SPF. This issue has been observed in multiple projects, leading to discrepancies between the installed components and the sign-off drawings.	The team acknowledged the challenge with manufacturing drawings but noted that they had managed to resolve the issue quickly. Once the complete information was received, updates were organised within a day, reflecting the actual state of the drawings.	Establish a straightforward process for uploading and signing off manufacture drawings in SPF, ensuring they reflect installed components accurately. Assign dedicated persons or checkpoints to track this process.
2	Collinsville T1 Transformer Replacement H075T2FAIL – H075 Kumbarilla Park Failed Transformer Replacement	Design and Project Delivery & Meetings and design intent document	Improve Division of responsibilities - The Project Team recognised improvements in coordination.	There were instances where there was confusion about who was responsible for ordering materials, leading to inefficiencies. Site Updates at the end of each roster and from the Construction advisors were brilliant.	Clear Division of Responsibilities.
3	Collinsville T1 Transformer Replacement H075T2FAIL – H075 Kumbarilla Park Failed Transformer Replacement	Project number allocation & Project Schedule	Improve project setup in SAP, Project Server, & Objectives. Leveraging project servers (e.g., used in the 2021 Kumbarilla Park and 2024 Collinsville projects) for centralised documentation could enhance efficiency.	Project setup and the establishment of standard templates for project schedules. This would streamline the process and provide a reference for future projects.	The Project Scheduler and Project Controller are to be assigned from the beginning of the project. Develop a standard template for project number allocation and ensure it is set up correctly at the start of each project. For example, if it's under emergency/insurance or a "Damage to Powerlink Property" project. Create a "Damage to Powerlink" workflow in consultation with the Finance team. Create a standard template for project schedules for replacements, including CAP banks, transformers, and other standard assets in these templates. As well as OSD rosters, i.e.: 8/6
4	Collinsville T1 Transformer Replacement H075T2FAIL – H075 Kumbarilla Park Failed Transformer Replacement	Streamline Checklist and ITPs' Management Process	Improve the management of Checklists and ITPs	The GE report was received, but GE never completed the ITP, which was issued. In the end, Powerlink Principal Engineer approved the report.	Create a standardised checklist and workflow for the installation and commissioning process. Regular reviews of ITPs during the project can ensure that the approval stage is completed on time.

3. Project Financials

3.1 Stage 1 Funding Approval

As part of the early work approvals: funds will be required for design development, procurement activities, preliminary geotechnical investigations for design, labour and management. A breakdown of these costs for early release is displayed below:

Description	Total ($)
Stage 1 (Early Works)	
PLQ Overheads (incl RIT-T, Project Management, Design, Commercial Support)	[redacted]
Transformer Procurement including supply chain services	[redacted]
Other Procurement (i.e., Surge arrestors)	[redacted]
TOTAL	**4,900,000**

3.1.1 Estimate Summary

Refer to Basis of Estimate (refer to section 5) for this project.

		Sub Total ($)	Total ($)
Estimate Class	3		
Estimate accuracy (+% / - %)	-20% / +30%		
Base Estimate		9,693,938	
Escalation		484,992	
Proposed Release Budget			10,178,930
Contingency (Unknown Risk)	[redacted]	[redacted]	
Mitigated Risk (Known Risk)	[redacted]	[redacted]	
Total Risk			[redacted]
TOTAL			[redacted]

3.1.2 Asset Write-Off Table

CP.03005 Asset Write-off. Values current at 30th June 2025

Functional Location	Description	Asset	Sub-number	Book val.	Write-off %	Write-off Value	Currency
T142-T03-3TRF	3 TRANSFORMER	104190	0	643,566.55	100%	$ 643,566.55	AUD
Asset Class 10001 Sub - Transformers				643,566.55		$ 643,566.55	AUD
					Total	$ 643,566.55	AUD

3.2 Approved Released Budget

The approved release budget to execute the project is as follows.

	Total ($)	Control Management
Project Estimate Approved Budget	[redacted]	Project Manager + Sponsor
Project Allowance (Risks + Contingencies)	[redacted]	Project Sponsor
Project Requested Released Budget	10,178,930	Project Manager

3.3 Planned Costs (Forecasted Cash Flow)

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

Overall Cashflow		
Financial Year	**Unescalated Cost ($)**	**Escalated Cost ($)**
To June 2026	1,325,974	1,325,974
To June 2027	1,662,782	1,717,654
To June 2028	6,673,186	7,100,203
To June 2029	31,996	35,099
TOTAL	**9,693,938**	**10,178,930**

4. Project Planning Strategy

4.1 Milestones

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

Major Project Milestones	High-Level Timing
Class 3 (Stage 1) Project Proposal Submission	August 2025
RIT-T (assumed 26 weeks)	April 2026
Stage 1 Approval (PAN1) includes funds for design, procurement & ITT preparation.	November 2025
Project Development Phase 1 & Phase 2	May 2026
ITT Submission (8 weeks)	April 2026
Evaluate Tender, Reconcile Estimate and Submit PMP for Stage 2 Approval	May 2026
Stage 2 Approval (PAN2), including execution of SPA contract	July 2026
Site Mobilisation	March 2027
Transformer Delivery	July 2027
Project Commissioning	October 2027

4.2 Project Staging

The high-level project staging are as follows:

<table>
<tr><th>Stage</th><th>Activity/Stage Description</th><th>High-Level Timing (Completion)</th></tr>
<tr><td>1</td><td>2T Firewall Extension</td><td>1 week</td></tr>
<tr><td>2</td><td>3T Decommissioning and disconnect</td><td>2 weeks</td></tr>
<tr><td>3a</td><td>3T Removal, including the noise wall</td><td>3 weeks</td></tr>
<tr><td>3b</td><td>3T Civil Works</td><td>8 to 10 weeks</td></tr>
<tr><td>3c</td><td>Install 3T</td><td rowspan="2">4 to 6 weeks</td></tr>
<tr><td>3d</td><td>SPA Construction (3T earthing, install and terminate secondary cabling from 3T to control building)</td></tr>
<tr><td>3e</td><td>SAT</td><td>4 weeks</td></tr>
<tr><td>4</td><td>HV Reconnection</td><td>1 week</td></tr>
</table>

4.3 Project Schedule

Project timing shall be managed using a Project Schedule.

4.4 Network Impacts and Outage Planning

An outage plan will be submitted within the 14-month notification timeframe, therefore, outages are assumed to be available.

Discussions with Powerlink Outage Management, EQL and Queensland Rail will take place over the next planning phase of the project to confirm outage requirements.

4.5 Project Delivery Strategy

Strategy to deliver the project as follows:

Description	**Responsibility**			
	Main Site			
	Powerlink	**Contractor**	**MSP – O&SD**	**MSP - Ergon**
Primary Design Systems (PSD):				
Civil and Structural	☒	☐	☐	☐
Electrical	☒	☐	☐	☐
Secondary Systems Design (SSD):				
Protection	☒	☐	☐	☐
Automation (Circuitry and Systems Configurations)	☒	☐	☐	☐
Construction:				
Civil	☐	☒	☐	☐
Construction (support structures, plant and equipment installation and demolition Works)	☐	☒	☐	☐
Transformer Installation	☐	☒	☐	☐
Secondary Systems Installation (loose panel's installation, panel modification, IED replacement, etc.)	☐	☐	☒	☐
Testing and Commissioning:				
Factory Acceptance Test	☐	☐	☒	☐
Site Acceptance Test (partial)	☐	☐	☒	☐
System Cut Over and Commissioning	☐	☐	☒	☐

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 – Civil, Earthworks	ITT - Substation Panel Arrangement (SPA)
Optical Fibre System	Shortform ITT – Standing Offer arrangement with preferred/preapproved suppliers
MSP – OSD	RFQ
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
Secondary Systems Equipment:	
IEDs	Period Contract
Panels, Kiosks, Boards and building fit-out	Shortform ITT – Standing Offer arrangement with preferred/preapproved suppliers

5. References

The following documents are applicable to this Project Management Plan.

Document name and hyperlink	Version	Date
Project Scope Report	1.0	9/09/2024

Risk Cost Summary Report

CP. 03005

Tennyson Transformer 3 Replacement

Document Control

Change Record

Issue Date	Revision	Prepared by
18/12/2025	1.0	Asset Strategies

Related Documents

Issue Date	Responsible Person	Objective Document Name

Document Purpose

The purpose of this model is to quantify the base case and option risk cost profiles for the equipment at the Tennyson Substation which is proposed for replacement under CP.03005. These risk cost profiles are then included as part of an overall cost-benefit analysis (CBA) to understand the economic benefit of the proposed upgrades. This process provides a benchmarking and internal gate process to support Powerlink in effectively identifying prioritised infrastructure upgrades.

The CBA was designed to demonstrate and quantify the value to be gained through specific infrastructure investments. To evaluate the CBA, an NPV is derived based on the present values of costs and benefits. The flow chart in Figure 4 below designates the methodology used in designing the CBA process.

Key Assumptions

In calculating the risk cost arising from a failure of the ageing equipment at the Tennyson Substation, the following modelling assumptions have been made:

- The functionality of the equipment is assumed to decay according to decay curves calculated by Powerlink, and associated probability of failure (PoF).

- Where equipment in scope is replaced, its associated Health Index (HI) score is reverted to one.

- The likelihood of personnel within the substation in the event of explosive failure of equipment (used to calculate safety risk) is assumed to be 25% (based upon historic site entry averages), with the likelihood of resulting injury or death depending on the explosive radius of the equipment, its housing, and the total substation land area. The modelling also assumes that personnel are equally likely to be anywhere within the substation land area. No escalation to the likelihood has been made during construction as it is assumed appropriate risk assessments and risk mitigation measures are completed by the project team.

- For the purposes of the cost-benefit analysis, the total useful asset life of 40 years has been applied.

- A site-specific value of customer reliability (VCR) of $23,800 has been applied when calculating network risks.

Base Case Risk Analysis

Risk Categories

Four main categories of risk are assessed as part of this project as consistent with Powerlink's Asset Risk Management Framework:

- Financial Risk

- Safety Risk

- Network Risk (including market impact if applicable)

- Environmental

Table 1: Risk categories

Risk Category	Failure Types	Equipment in scope
Safety Risk	Explosive failure	All equipment with the potential to fail explosively
Financial Risk	Peaceful failure	All equipment
	Explosive failure	All equipment with the potential to fail explosively
Network Risk	Peaceful failure	All equipment related to network elements identified in the planning statement
Environmental Risk	Peaceful failure	None for this project

Base Case Risk Cost

The modelled and extrapolated total base case risk costs are shown in Figures 1 and 2 below.

Risk costs associated with the equipment in scope are expected to increase from $0.61 million in 2026 to $1.35 million in 2036 and $2.15 million by 2046. Key highlights of the analysis include:

- Financial risks forms approximately 96% of the base case risk. Of this, the majority is a result of peaceful failures modes.
- Network risk and safety risk accounts for approximately 2% and 2% of the total risk, and environmental risk is zero for this project.

Figure 1: Total risk cost

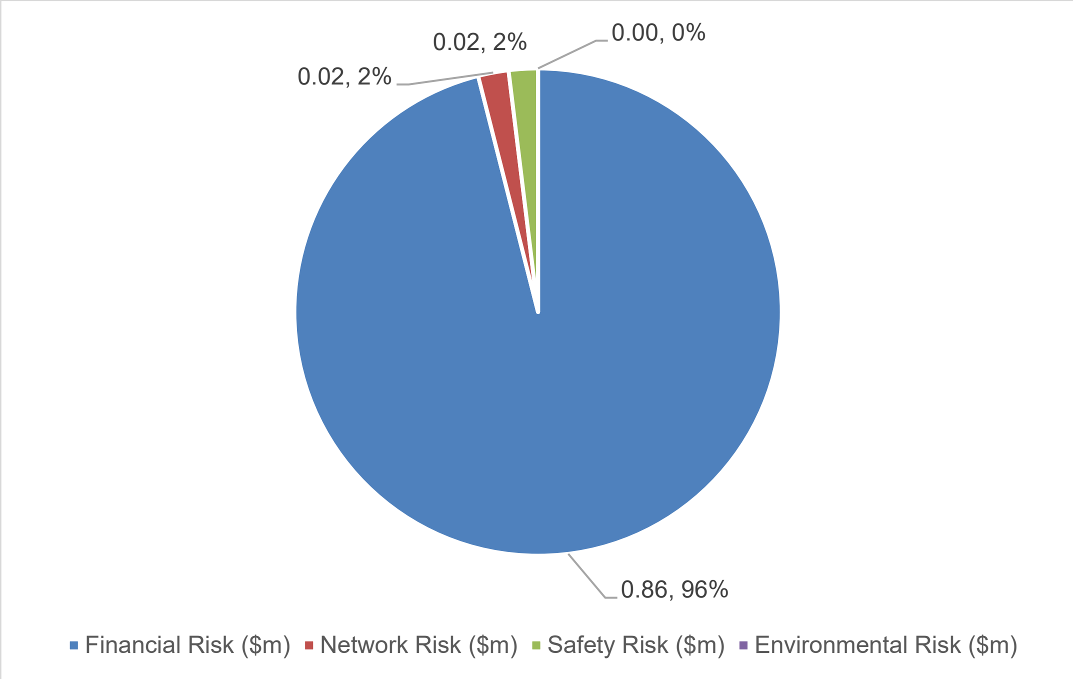


Figure 2: Base case risk cost by contributions (2030)

Option Risk Cost

For modelling purposes, effective HI scores have been reduced to one for equipment replaced under this project. Replacement of the equipment results in a lower probability of failure and therefore risk cost.

The figures below set out the total project case risk cost, and associated risk cost savings incremental to the base case.

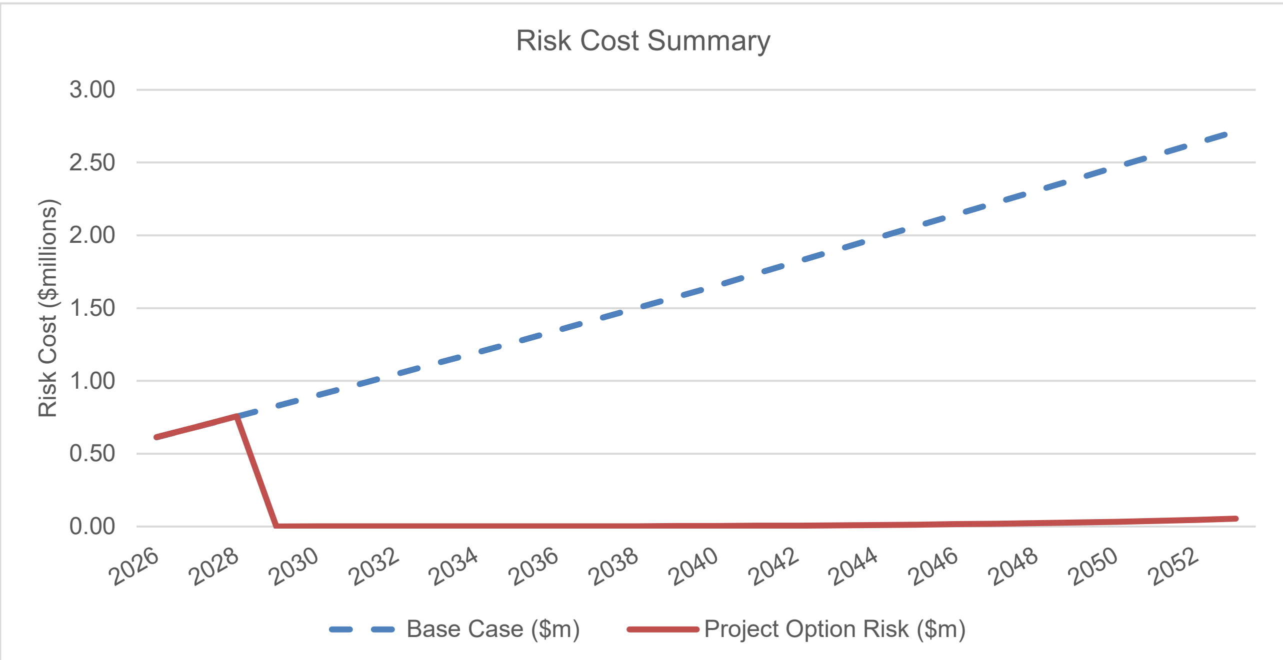


Figure 3: Project Option Risk Cost (compared to base case)

Following the year of investment (2028) the risk cost associated with the equipment in scope reduces close to $0. By 2041, the risk cost of the project option is approximately $.01 million, compared with the base case risk cost of $1.74 million.

Cost Benefit Analysis

The methodology designed for the cost benefit is set out as per Figure 4 below.

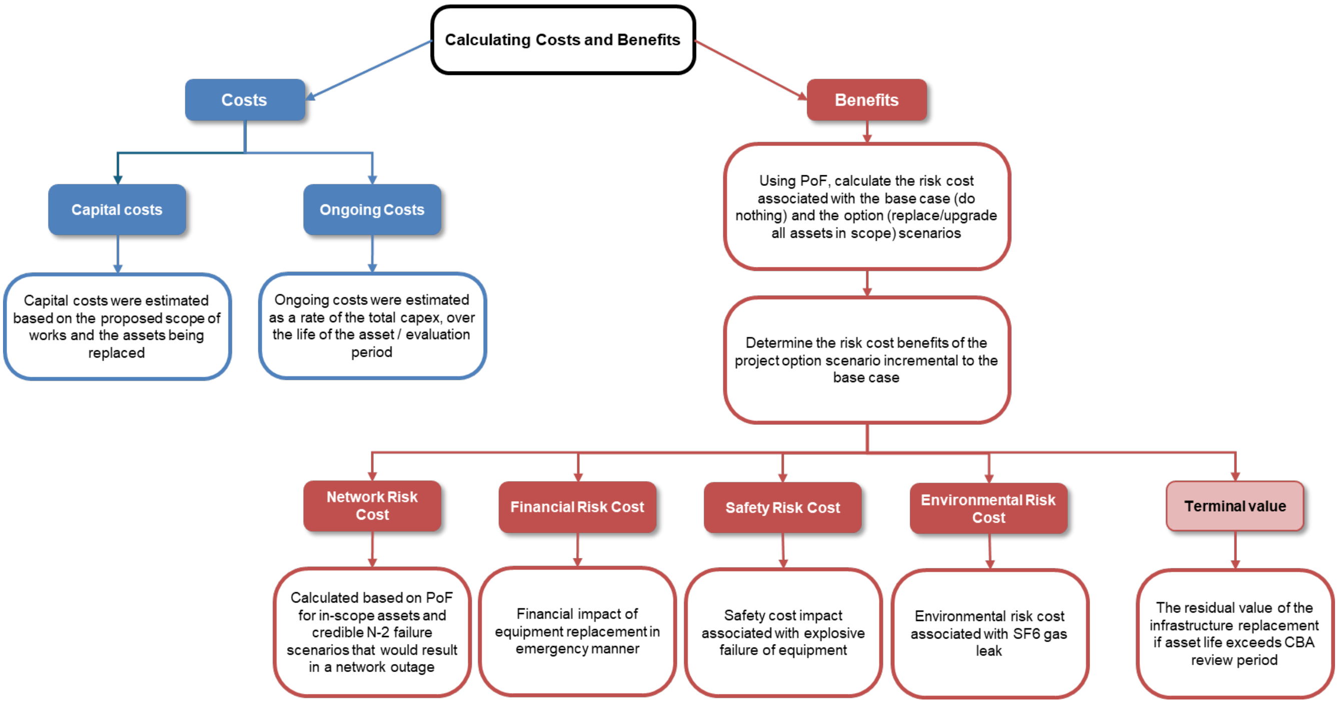


Figure 4: CBA methodology

The project is estimated to cost approximately $9.69 million. This represents a significant cost saving over the estimated financial risk cost of replacing assets individually in an emergency manner, due to the efficiencies associated with planned upgrades.

Based on a baseline discount factor of 7%, the project has a net present value (NPV) of $4.8 million over a 35-year period, and a benefit-cost ratio (BCR) of 2.11.

The project also has a positive NPV and BCR when a discount factor of 10% is applied.

Given this, the scope of work associated with the nominated assets within this project is considered appropriate.

Table 2: Net Present Value and Benefit-Cost Ratio

		Present Value Table ($m)		
Discount rate	%	**3%**	**7%**	**10%**
NPV of Net Gain/Loss	$m	$25.8	$8.8	$3.3
Benefit-Cost Ratio	ratio	3.91	2.11	1.45

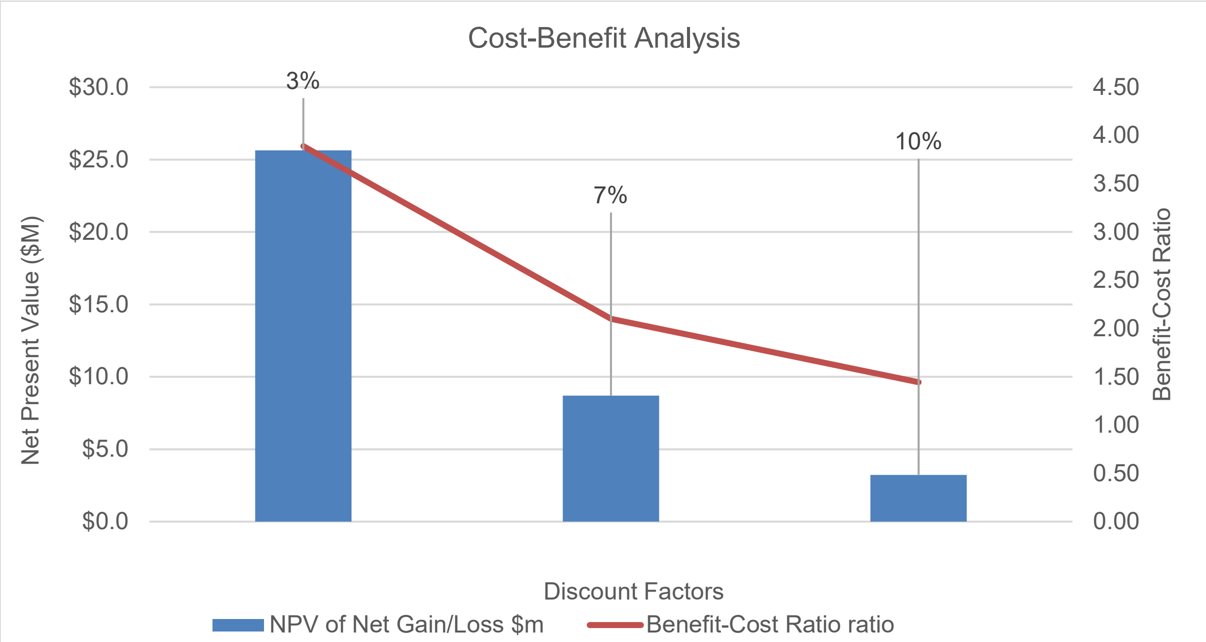


Figure 5: Cost benefit summary

Participation Factors

A sensitivity analysis was undertaken to determine the participation factors for key inputs to the risk cost models (i.e. to identify which inputs are most sensitive to overall risk cost). Applying a 50% reduction in key inputs still resulted in a cost benefit ratio equal to 1.94.

The participation factor is defined as the ratio of percentage change in output (i.e. risk cost) to a percentage change in input (e.g. VCR). The participation factors for key model inputs are shown in the table below.

Due to the non-linear nature of the risk cost model (especially network risk costs, which are a function of concurrent failures), the participation factor can change depending on the magnitude of input percentage change.

The model is most sensitive to:

- **changes in emergency premium (peaceful failure)** results in a decrease in risk cost of $0.07 million, or approximately 7.5% of the original base risk.

Table 3: Participation Factors

Input	Baseline value	Sensitivity value (-50%)	Change in risk cost at 2030 ($m)	CBA	Participation (%)
Safety					
Likelihood of personnel within substation	25%	12.5%	-0.01	2.07	-1.08%
Cost consequence of multiple fatality	$11,400,000	$5,700,000	0.00	2.10	-0.34%
Cost consequence of single fatality	$5,700,000	$2,850,000	-0.01	2.08	-0.75%

Cost consequence of multiple serious injury	$4,206,600	$2,103,300	0.00	2.10	-0.24%
Financial					
Emergency premium (peaceful failure)	20%	10%	-0.07	1.94	-7.51%
Emergency premium (explosive failure)	100% (Pwr TX) 30% (Bushings)	50% (Pwr TX) 15% (Bushings)	-0.01	2.07	-1.40%
Network					
VCR ($/MWh)	23,800	11,900	-0.01	2.08	-1.01%
Restoration Time (hrs)	168-720	84-360	0.00	2.10	-0.28%