TRANSFORMER MID-LIFE REFURBISHMENT
- PREVENTION OR CURE?

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Abstract
The purpose of this paper is to present a more proactive view for the life-time management of power transformers. The minimalist and reactive model will be assessed against a proactive approach, with costs and benefits compared. It will be seen that by considering life-costs and maintenance issues at time of specification and purchase, in combination with an active condition monitoring policy that the condition of the transformer can be known and used for system planning and reduced cost of life.

Part 1: Transformer Management - The Old Way

Traditionally, transformer maintenance is considered by many to be either "all or nothing", but for the purposes of discussion, can be categorized into two areas:

- Routine maintenance
- Reactive maintenance

1.1 Routine Maintenance

Many asset owners undertake minimal routine maintenance of transformers, with the emphasis being on the moving parts, such as an on-load tap changer (OLTC) and associated motor drive etc, visual checks, and if the owner is particularly diligent, some monitoring of the general condition by use of annual oil tests.

OLTC. For the OLTC, most owners would consider following the manufacturers recommendations as the maximum requirement. However, unless there is a firm policy in place, attention to the manufacturers maintenance manual can lapse, or it can be lost altogether.

Visual Checks. Most utilities in Australia would at some time have had a policy of regular visual checks. This would consist of a monthly substation visit, when the technician would walk around the substation yard and fill out various log books recording details such as
- OLTC cyclometer readings - cumulative number of operations
- Maximum and minimum taps reached - idle arms then re-set
- WTI and OTI readings - maximums noted and idle arms re-set.
- In some cases a field in the log book would also leave room for comments., eg leaking bushing HV "A" phase, silica gel breather pink etc, which were diligently recorded month after month, often with no responsive action.

Figure 1
A transformer left in poor condition

In larger substations, information for the transformer such as present loading, maximum current, active and re-active power, were displayed on a control panel inside a substation building. This information was (or is) diligently recorded in a log book located near the panel. Often, however, such information was retained at the substation with the device, and not returned to any central point for collation or co-relation.

Oil Tests. For many years the standard tests for determining oil condition were limited to dielectric breakdown voltage and the "crackle" test. Most utilities had their own test sets; a sample of oil was taken and duly tested and the reading noted. These sets were rarely calibrated after purchase and were often modified when parts broke or wore out.

Figure 2
Old model dielectric breakdown test set

The now infamous crackle test involved heating a rod of perspex or glass and inserting into the oil. If "crackles" and "pops" were heard, then the presence of free water was indicated. One unanswered question here is the issue of varying degrees of water, i.e. How can you hear half a crackle?

For many transformer owners, the above constituted their total transformer maintenance policy. Many have argued that during this time they had virtually zero failures, however, particularly with utilities, the issue that had most impact was not the absence of failures but the fact that the majority of substations had at least two transformers connected in parallel supplying a load of about 40% of the total nameplate capacity. The only time a transformer saw anything close to nameplate load was when one was removed for maintenance.

In recent times we have seen loads dramatically increase, largely due to an increase in the use of reverse cycle (heat pump) air conditioning units as well as refrigeration load. These same transformers that have survived forty years or more with little or no trouble, are now developing problems *en-masse* due to load levels not experienced before. Common faults are:

- Leaks - main gaskets, bushings
- Increased water content
- Heating problems due to accumulated sludge deposits on windings and in cooling ducts.
- Hot connections
- Pump or fan failure including bearings
- OLTC failure
- Off load tap changer failure - hot connections due to loss of contact pressure
- Bushing failure
- Winding failure

The problem faced by many asset owners is that the majority of their assets are reaching this condition at the same time, stretching both maintenance and capital (replacement, augmentation) budgets.

This leads to the next phase:

1.2 Reactive Maintenance.

Reactive maintenance is often not planned well, and can be undertaken at a price premium. This premium can include:

- Cost of urgent procurement of parts
  - Reverse engineering and re-manufacture of obsolete parts
  - Air freight
- The cost of labour - overtime

- The cost of lost supply
  - Penalties by regulator for unplanned outage
  - Switching to re-configure network.
  - Finding and installing a replacement transformer or monitoring and managing overload on other transformer(s)
  - Load shedding
- Cost of urgent factory space for testing, inspection and repair.

Scenario:

1. Transformer 40 MVA 66/11 kV
2. Buchholz gas alarm
3. Transformer is visually checked, perhaps some basic tests.
4. Transformer placed back in service and trips again. The substation has another transformer that can handle the additional load.
5. Owner reacts and returns transformer to factory.
6. Transformer is tested, de-tanked and inspected. A hot connection with some arcing is found on the bottom of a bushing. This could have been repaired at site.
7. Whilst the transformer is in a factory the owner needs to consider:
   - Minimal repair only?
   - Take advantage of opportunity and rewind?
   - If rewinding, should I consider upgrading to a higher nameplate rating?
   - Consider life costs - eg has the transformer a high loss core?
   - How does this compare to the cost of a new transformer?

This needs to be considered due to the high cost of returning the above transformer to a factory, as follows :

Strip transformer for transport	$ 20,000
100 tonne crane at site	$ 9,000
Transport (say 50 km)	$ 10,000
Total:	**$ 39,000**

These costs have to be repeated for the return trip, so that **$80,000** or more is spent before any corrective action is taken. These costs can be much more if the transformer is located at a site remote from a suitable repair facility and where adequate craneage is difficult or expensive to procure, as well as the extra cost of additional mileage.

The cost of thorough testing and inspection at site and repair of the fault as above would be about 50% of the total above cost, i.e. approximately $40,000. This includes:

- Testing: DGA, DLA, IR, DC resistance through taps, ratio and phase angle through taps.
- "Ductor" (micro-ohm) test of connections and contacts - bushings and OLTC. This would involve lowering of oil to access bushing connections via inspection plates.
- Repair

- De-gas oil and vacuum fill.

Of course, the time and money spent at site may be inconclusive, or a major fault may be indicated, such as a winding failure. However if thorough site assessment is made, the asset owner is then in a better position to answer some of the questions raised above before incurring the major expense of returning the transformer to a repair facility.

Bushing Failure. Bushing failures are often catastrophic and can result in the total loss of the transformer, and sometimes surrounding equipment.

Figure 3 - Bushing Fire

Replacement of bushings needs to be planned as they are often subject to lead times of 12 weeks or more plus shipping time. In the case of obsolete designs, adapters have to be made which may introduce other problems, such as winding lead length. If the design information for the original bushing is no longer available, then the transformer will need to be accessed to measure flange dimensions, oil lowered and covers taken off to determine the dimensions of the current transformer extension, lead connection type and length.

Generally bushings can be replaced in the field by experienced technicians.

On Load Tap Changer Failure. Like bushing failures, OLTC failures can often be catastrophic. Even when not, most OLTC failures occur in obsolete models, so that extensive modifications are required to fit a new type or make. These would include:

- Tank modifications

- Winding lead modifications

As this can require the winding to be removed from the tank for some days, the replacement of an OLTC is generally a factory job.

Part 2: Consideration of a Pro-Active Approach to Life-time Management of Transformer Assets.

The following is an outline of what could constitute a proactive approach to the life-time management of transformer assets.

2.1 Specification, Design and Manufacture

There is no better opportunity to set the scene for life-management of transformers than at the conception and manufacturing stages. Whilst there are relevant standards to guide the specification, design and testing, there are other factors to consider as the following quotation shows: " *Almost all specifications are clear concerning the power ratings, voltage requirements, tapping ratios and impedance variations across the tapping range, but there can be ambiguity concerning the requirements for high ambient temperatures, environmental aspects such as humidity, lightning activity, earthquake activity, the incidence or solar-induced currents, harmonic current loading, the number and magnitude of through-fault short-circuit currents, and transportation difficulties. It is essential that both purchaser and manufacturer fully understand the importance of preparing and agreeing a strong purchasing specification for the transformer in order to meet actual service conditions*."[i]
This process can be greatly assisted by the potential owner of the transformer by:

- Being actively involved with the transformer manufacturer during specification and subsequent design reviews.
- Entering into an alliance partnership with the manufacturer to make the process more pro-active.
- Using an independent advisor to assist with specification and design review. This can be of particular benefit as many owners are losing the specialized expertise of engineers with specific transformer knowledge.

Some life management issues that relate directly to loss of life and maintenance cost are shown below:

Table 1
Actions at Time of Manufacture that have Life-Management Benefits

Action	Reason/Effect
Insertion of fibre-optic temperature probes in winding	Accurate measurement of hot spot temperatures in multiple locations.
Heat run tests	Data for dynamic rating.
Conservator oil preservation system	Isolation of oil from oxygen, impeding oxidation of oil and build up of degradation products. Extended insulation life.
Moisture management system	Maintaining moisture in insulation at 1.0% and in oil at < 10 PPM.
Transformer monitoring and control system - dynamic rating	On-line control and condition monitoring in real time, especially for consideration of cellulose insulation life. Dynamic rating typically allows safe loading 10% to 20% higher than conventional "static" thermal rating.
Paint system to match environmental conditions	Preservation of surfaces and reduced frequency of repainting

Given a solid design basis and that the network a transformer supplies is adequately protected, the three agents that affect transformer aging are:

- Oxygen
- Water
- Temperature

All of these can be managed and controlled from the first day of a transformer's life. Transformer consultant, Dr Harold Moore, has stated ." *..there has been very little emphasis on the impact of water and oxygen on the life of paper insulation although studies have shown that the oxygen content of the insulation system has a major impact on paper insulation life. Water does not have the dramatic impact on aging as oxygen, but the aging is certainly accelerated as the water content increases. It is obvious that control of the oxygen and water content is important in the life extension process*."[ii]

Oxygen Control The fitting of conservators oil preservation systems (COPS) will only be effective if the transformer is filled with degassed (in particular deoxygenated) oil. Specifications for filling after erection should include a requirement for a total gas content of the oil of less than 1% **after** filling. This is usually readily accommodated on site by the use of a vacuum degassing plant with oil entering an evacuated transformer. However, unless care is taken, the benefits of the COPS will be lost. The COPS itself is not 100% impervious to oxygen, but it will take 15 or 20 years for the oxygen level in the oil to reach atmospheric ratios if the transformer is adequately maintained (e.g. leaks). The oxygen levels can be traced through annual DGA's. When oxygen levels start to increase to 5,000 PPM and above, then a degassing plant can be connected and the oil degassed to 1% for a cost of only a few cents per litre.

Moisture Control As well as being introduced by leaking gaskets or poor oil handling techniques, moisture is the natural product of the aging of cellulose insulation. As paper degrades it gives off CO_2 and H_2O. So even if all other sources of moisture are controlled, water will be generated as the transformer ages. The destructive effects of water include:

- Expansion of cellulose insulation, altering the mechanical pressure of the transformer clamping system. If water is later removed (as it must be to retain insulation integrity) then the windings will be loose and subject to movement and subsequent damage especially during system faults. After a dry-out, it is essential to assess the winding clamping pressure and re-clamp if necessary.
- Loss of insulation integrity.
- Flashover failure on the insulation surfaces or to earth[iii]

The use of molecular sieve systems permanently connected in parallel with the oil circulating system are very effective in controlling moisture levels. Those systems which also offer reclamation and re-use of the molecular sieve materials not only reduce life-time cost, but also satisfy environmental requirements for recycling and negate the issue of disposal of waste. The cost of such systems is easily off-set by the cost of subsequent dry-out and re-clamping, not to mention the risk of insulation failure and the associated costs.

It is an interesting exercise to evaluate the amounts of water present in the paper system of a transformer compared to the oil system.

Example: 20 MVA 66/11 kV transformer, containing 13,000 litres of oil and 4% water in insulation.

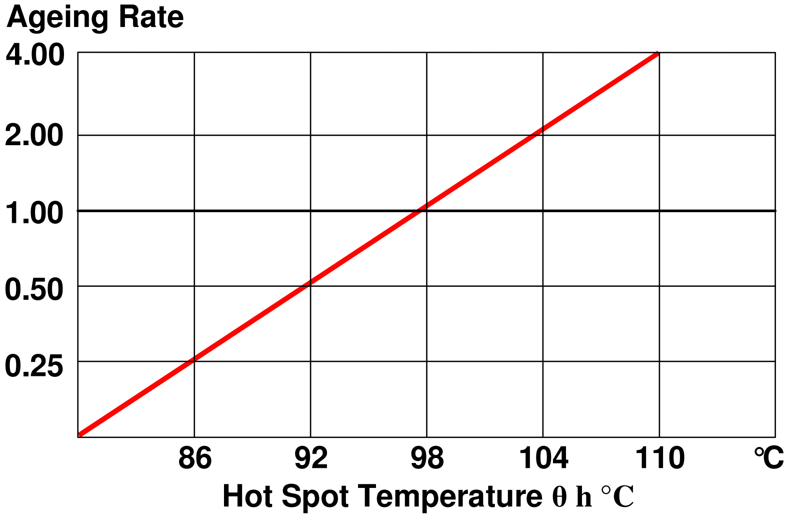
- Total Oil Volume 13,000 litres
- Core and Coil Weight 20 tonnes
- Insulation weight 1,600 kg (i.e. approx. 8% of coil & core weight)
- Moisture in insulation: 4%
- Total water volume 64 litres

If the oil is testing say at 30 PPM, then the amount of water in the oil is less than half a litre, constituting less than 0.8% of the total water content of the transformer. To reduce the water in insulation to 1 % or less means that 48 litres of water must be removed. It is far more cost effective to control the moisture content from the outset.

It is also worth noting that the installation of a COPS will decrease the rate of moisture generation in a transformer. Research has shown that average rate of water contamination in transformers with open-breathing conservators is in the order of 0.2 % per year, whereas for transformers fitted with membrane sealed conservator preservation systems the rate is about 0.03% to 0.06% per year.[iv]

Temperature Control Similarly temperature is best managed by a dynamic, on-line, computerized system. [v] The IEC 60354 " Loading Guide" states: " *Cumulative thermal deterioration of the mechanical properties of the conductor insulation will accelerate at higher temperatures. If this deterioration proceeds far enough, it may reduce the effective life of a transformer, particularly if the latter is subject to short circuit.*" The same guide also states that for every 6 degree temperature rise, the life of the cellulose paper is halved. It is therefore important that temperature is managed so as to maximize the life of the paper.

Figure 4 Relative Ageing Rate vs Hot Spot Temp.



The insertion of fibre optic temperature probes greatly enhances the accuracy of temperature monitoring and, when combined with other relevant data, can allow the asset owner to maximize the rating of the transformer and increase return on assets, as well as providing controlled conditions for emergency overloading and subsequent informed decision making.

2.2 Routine Inspection & Maintenance Activities

Apart from manufacturers recommendations for devices such as OLTC's, asset owners need to develop inspection and maintenance policies that are consistent with their systems needs, budgets and reliability targets.

A sample part of a typical policy is given below. Note that in some cases the periods between checks and inspections may need to be reduced as the transformer ages. For example, the frequency of diagnostic tests on oil and bushings.

Table 2
Sample Oil-Filled Transformer Maintenance Summary[vi]

Task	Monthly or two monthly	Annually	5 to 10 years
Before energizing, inspect and test all controls, wiring, fans, alarms and gauges. Test for DGA, furan, particle count and other oil quality & electrical tests. Repeat DGA after one week in service.			
In-depth inspection of transformer and cooling system, check for leaks and proper operation.	Yes * Also after first month in service only :Oil pumps load current, oil flow indicators, fans etc. Thermometer Heat exchangers Transformer Tank Oil level gauges Pressure relief device	Yes - also oil pumps load current, oil flow indicators, fans etc. Thermometers, comparing with load current. Heat exchangers Transformer Tank Oil level gauges Pressure relief device	
OLTC cyclometer	Yes	Yes	
Breather desiccant - inspect & change if required	Yes	Yes	
DGA and other oil tests	* After first month in Service only, then at three and six months	Yes. Consider six monthly for critical transformers	
IR Scan of transformer, cooling system, bushings and all wiring.	* After first month in service only	Yes	
Test all controls, relays, gauges; test alarm & annunciator points	Yes	Yes Inspect pressure relief for leaks and indication of operation	Thermometers Oil level gauges Pressure relief Sudden pressure relay Buchholz relay Test alarms, fan and pump controls etc
Inspect transformer bushings	Check with binoculars for cracks & chips; look for oil leaks and check	Check with binoculars for cracks & chips; look for oil leaks and check	

	oil levels * IR scan after first month in service only	oil levels IR scan	
In-depth inspection of bushings including testing			Close physical inspection, cleaning, capacitance, DLA tests, IR, option of PD if a problem suspected, DGA if possible
DLA test of transformer and bushings			Yes
OLTC	DGA plus other oil tests after first month in service and again at 3 & 6 months	DGA plus other oil tests. Observe diagnostic tests and servicing to manufacturers recommendations.	Servicing according to diagnostic tests and manufacturers recommendations. Check contact pressure, continuity, timing, motor load current, limit switch operation and continuity.
Other Tests			RVM, FRA, DLA, IR, ductor tests, winding resistances.

2.3 Condition Assessment

2.3.1 Oil Tests and Diagnostics. The most cost effective method for determining transformer condition is by the use of regular oil sampling, testing and diagnostics. Whilst sampling itself is relatively simple, it is important that attention is paid to cleanliness and the handling of the sample and sampling equipment to prevent contamination and thence misdiagnosis.

Sampling Vessels. The traditional glass bottles were subject to breakage due to temperature change, and ingress of air. They are also immediately compromised once opened in the laboratory. A far more accurate vessel for DGA and moisture is the 50 ml syringe, which is fitted with a special three-way valve for sampling. Any air contamination can be easily seen and expelled. Also any contamination by foreign matter can be observed and another sample taken before leaving site. The oil for remaining tests can be collected in a clean 1 litre recyclable plastic bottle. The plastic allows the sides of the bottle to act like a bellows, preventing leakage and breakage.

Sampling Interval. Oil sampling is generally taken according to the following patterns:

- In factory after heat runs
- Upon installation
- After one week in service
- After one month in service
- After three months in service

- After six months in service
- Thereafter annual or six monthly, depending on criticality.
- The final period selected for regular testing should be determined by the criticality of the equipment and the subsequent diagnosis.

Diagnostics. An important part of testing is understanding what the tests are indicating. Sophisticated diagnostic programmes have been developed to aid asset managers and owners in prioritizing maintenance, preventing plant failure and unplanned outages and ensuring those items of equipment that need attention are targeted.[vii] Comments about some particular tests are given below (refer also to IEC 60422):

Moisture. The relationship between water in insulation and the moisture content of the oil is dynamic with water migration between the two systems dependant on temperature and time,[viii] so that measurement of oil moisture content alone is misleading if not correctly applied.

Dielectric Breakdown Voltage. According to IEEE C57.106-1991, " *The dielectric breakdown voltage of an insulating oil is a measure of its ability to withstand voltage stress without failure. It is the voltage at which breakdown occurs between two electrodes under prescribed test conditions. The test serves primarily to indicate the presence of electrically conductive contaminants in the oil, such as dissolved water, dirt or particulate matter.* ***A high dielectric breakdown voltage does not indicate the absence of all contaminants, however***."[ix] (emphasis added). Whilst a valuable test, the DBV test needs to be used in conjunction with other tests to give a true picture of oil, and indeed transformer, condition. Suggested tests that will assist in giving a more accurate assessment include particle count, DC Resistivity and DDF (Power Factor).

Dissolved Gas Analysis. The development of DGA testing and interpretation is one of the major advances for condition assessment of the last 30 years or so. Full credit must go the pioneers of this diagnostic tool which has now become standard industry practice. For all of their simple external appearance, transformers are quite complex, and the interaction of various internal and external forces, magnetic & electric fields and chemical reactions all have an effect on the resultant dissolved gas patterns. It is therefore important to keep historical records, note condition changes, such as "oil degassed", "inhibitor added", or "oil replaced", and co-relate DGA's with other information, such as loading. It is also important to inform the testing laboratory if the transformer shares oil or head space with the OLTC. Another aspect of vital importance is the accuracy and repeatability of DGA testing. Given the importance of the diagnosis, careful sampling and rigorous laboratory testing techniques are essential.

Furan and Relationship to Degree of Polymerization of Paper Insulation. Furans are organic compounds formed by the degradation of paper insulation (refer ASTM D-5837). One of the developing diagnostic tools is establishing the relationship between furan and DP of cellulose insulation. DP is an invasive and destructive test, whereas furan analysis can be done from an oil sample. Interestingly, furan signatures are not entirely lost by oil regeneration or even replacement and quickly return to the oil to continue to provide useful information on aging.

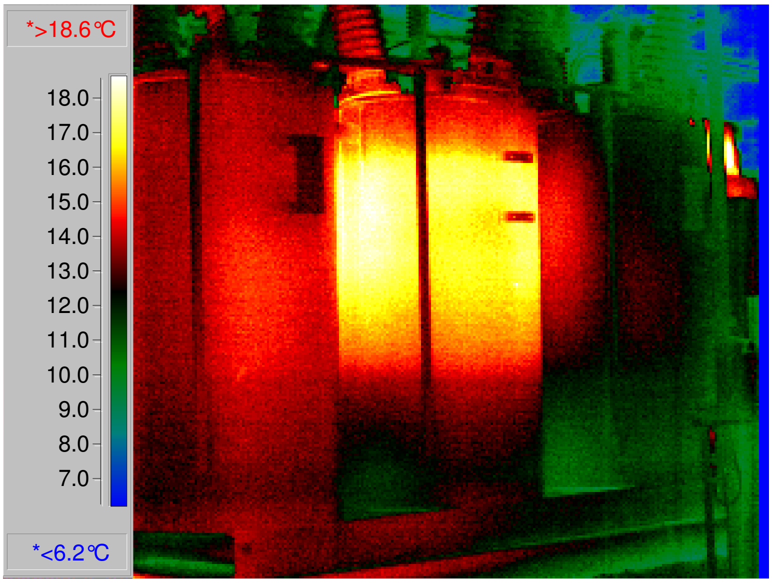
Dielectric Dissipation Factor (DDF) and DC Resistivity These tests are often maligned, yet provide very useful and accurate information for new as well as for aged oils. Both tests are sensitive to aging products and soluble polar contaminants, and for this reason it is essential that care is taken both in taking the sample (flushing of sampling valve, cleanliness of tubing and receptacle) and during the test for cleanliness as well. However, if good practices are observed, the test is highly repetitive and accurate. As IEC 422, 1989 states, these tests are so sensitive "*Changes may be so slight as to be undetectable by chemical methods*." Reference should be made to the standard for further information that has proven very effective in determining the condition of oil and suitability for service.

Diagnosis of OLTC Condition Using Oil Analysis. Since OLTC's by nature produce "fault" gases, it was thought for many years that DGA techniques could not be used to detect abnormal conditions. Extensive research involving forensic collaboration of gas patterns has led to the establishment of diagnostic protocols that have proven invaluable in determining the condition of OLTC's (and oil circuit breakers) and setting maintenance priorities.[x] When combined with other diagnostic tools, such as monitoring differential temperature to warn of developing thermal problems, the use of diagnostics based on oil tests is a powerful tool in reducing maintenance cost and increasing system reliability.

2.3.2 Infra Red Scanning.

IR scans are very cost effective in identifying thermally linked problems. Faults identified by IR include loose connections, hot joints, tank heating due to leakage flux, overheating due to shorts or circulating currents, winding & bushing faults, indeed any condition that is thermally related.

Figure 5
Infra Red Image of a circuit breaker



2.3.3 DLA Testing and Monitoring of Bushings

The condition of bushings can be monitored by visual inspections, oil sampling programs, intermittent on-line devices and continuous on line systems.[xi] Considering that bushing failure is a major contributor to transformer catastrophic failure, it is worth adopting a flexible programme of condition monitoring that is more frequent as the bushing ages.

2.4 Summary of Condition Assessment. Apart from external influences such as flood, lightning, line disturbance and external fire, at least 75% of faults that result in transformer failure can be detected by routine oil tests.[xii] When coupled with other non-invasive tests such as IR scanning, bushing DLA etc, then a diagnostic programme can drastically reduce the risk of unexpected failure. Other tests additional to those detailed above include acoustical analysis and vibration analysis.

2.5 Mid Life Refurbishment - An opportunity to reset the "age" clock.

A typical mid-life refurbishment can be done in-factory or on-site. The following table compares the two options:

Table 3
Advantages and Disadvantages of Location of Transformer Refurbishment

In-Factory Refurbishment	On-Site Refurbishment
In controlled environment	Affected by weather. This can be minimized by use of a pre-fabricated atmosphere-controlled room or tent to protect the winding if de-tanked.
Transport costs	No transport costs
"Free" crane use.	Mobile crane required. Needs to be well planned to control cost.
Transformer is away from site	Transformer is still on site and can be prepared for emergency service if required.
Access to vapour phase for cleaning and dry-out.	Other drying and cleaning methods need to be used. This can be by oil spray/vacuum, or pre-refurbishment dry-out using molecular sieve material followed by re-clamping at time of refurbishment.
Full test facilities are usually available	Limited test facilities, although mobile facilities that include applied and induced voltage can be provided at a cost.

Typical Works Programme for Major Mid-Life Refurbishment in the Field. A typical works programme for major on site works involving in-situ maintenance of a power transformer is given below.

The extent of works includes the following:

- Site establishment: includes induction of staff, preparation of bunded areas for oil storage and processing equipment, establishment of adequate electricity supplies, isolation of equipment, issuing of permits etc.
- Preliminary transformer testing
- Draining & removal of transformer oil
- Refurbishment of oil - vacuum degassing and filtering. In some cases oil is regenerated using fullers earth or a desiccant with similar characteristics, or the oil is replaced with new.
- Transformer external and internal inspection including assessment of clamping pressures and removal of paper samples for DP testing.
- Removal and inspection of radiators
- Repair of all oil leaks
- Replacement of all gaskets and seals -including tank lid, HV and LV bushings
- Vacuum leak test.
- Refill transformer under vacuum.
- Pressure test for 24 hours.
- Refurbish pumps, motors and re-pack valves
- Replace damaged or aged wiring and conduits.
- Refurbish and calibrate instrumentation
- Refurbish buchholz relay
- Refurbish fans, fan cowls and motors including balancing and bearing replacement.
- Removal of HV bushings for testing or replacement.
- Refurbish LV bushings
- Supply and install new silica gel breather or replace desiccant. Ensure that breather capacity matches frequency of routine inspections.
- Transformer painting - clean and prepare surface, spot prime, apply two pack final coat.
- Make transformer ready for service and perform final tests
- Clean site and demobilize
- Submission of final report

Should a full dry-out be required, then the transformer active part will need to be de-tanked for re-clamping. The customer will also require various hold points during the refurbishment process for inspection and consultation.

Testing is often undertaken before and after the refurbishment as a guide to the effectiveness of the process and to establish the suitability of the transformer for the overhaul or for continued service.

"Before" Tests: FRA, RVM, IR, power factor and capacitance, winding resistance, ratio and phase angle, degree of polymerization, excitation current measurements, winding impedance, DGA and other oil tests.
"After" Tests: As above plus meter calibrations, (DP not repeated)

The cost for applying the above services to, for example, a 132 kV 50 MVA transformer, will be in the order of **$AUD150k,** including the dry-out. To this must be added the cost of switching, isolation etc and any costs such as the use of a temporary transformer during the refurbishment, plus the cost of oil replacement or reclamation if it is required. A total cost then of **$200k** is not unusual.

If however the refurbishment requirements have been reduced by pro-active life management, then the most expensive actions will not be necessary, ie the following actions will **not** be required:

- Dry-out
- Re-clamping
- Oil reclamation or replacement.

This will reduce the cost of mid-life refurbishment to well under $100k.

Special Equipment Required: Some of the special equipment required for field refurbishment includes:

- Multi stage vacuum pumps
- Oil Filtering/Degassing plant of at least 4,000 litres per hour capacity and adequate heating. Filters of one micron absolute are also recommended.
- Dry air generation equipment to deliver dry air @ dewpoint < -40 degrees C
- Hydraulic jacks for re-clamping
- Torque wrenches
- Bottled dry nitrogen of medical grade
- Oil storage tanks and pumps
- Oil spill response kits

Part 3. Comparison of Life-Time Costs

3.1 NPV Calculation.

Transformer: 132/11 kV 60 MVA OLTC 20,000 litres of oil

Assumptions:

- Discount Rate: 7.8% (NSW Treasury Rate)
- $PV=A/(1+d)^n$ where PV = Present Value expense
  A = expense in nth year
  d = discount rate
  n = number of years since original expense
- Only costs affected by initial purchase decisions have been included.

- Condition monitoring practices are the same in all cases, ie pro-active.
- That the transformer does not fail until end of life.
- **Option A:** Basic transformer with no life management features.
- **Option B:** Added to transformer: Dynamic rating and management system, COPS, moisture management system, OLTC with vacuum interrupters

Key to Maintenance Activities:

OLTC	=	OLTC maintenance
MS	=	Regenerate molecular sieve material
DG	=	De-gas oil to reduce oxygen content
Major MR	=	Major mid-life refurbishment including dry-out and re-clamp
Minor MR	=	Minor mid life refurbishment including OLTC maintenance

Table 4

PV Comparison of Cost of Life Options

	Option A			Option B		
	Action	**Nominal $**	**Discounted $**	**Action**	**Nominal $**	**Discounted $**
Rate			**7.8%**			**7.8%**
TOTAL			**1,111,403**			**1,087,355**
Year		Amount	Amount		Amount	Amount
0	Purchase	1,000,000	1,000,000	Purchase	1,050,000	1,050,000
5	OLTC, MS	8,000	5,495	MS	5,000	3,435
10	OLTC, MS	8,000	3,775	MS	5,000	2,359
15	OLTC, MS	8,000	2,593	MS	5,000	1,621
20	Major MR	200,000	44,530	Minor MR	60,000	13,359
25	OLTC, MS	8,000	1,224	MS	5,000	765
30	OLTC, MS	8,000	840	MS	5,000	525
35	OLTC, MS	8,000	577	MS	5,000	361
40	Replace	1,000,000	49,573	Minor MR	60,000	2,974
45	OLTC, MS	8,000	272	MS	5,000	170
50	OLTC, MS	8,000	187	MS	5,000	117
55	OLTC, MS	8,000	129	MS	5,000	80
60	Major MR	200,000	2,208	Replace	1,050,000	11,589

Outcome: **PV of Option A: $AUD1,111,403**
PV of Option B: $AUD1,087,355

When considering the above expenditures, it is also important to consider that future expense needs to be provided for at some stage, the issue being that the costs over the life of the asset needs to be minimized, not just the purchase cost, which is often the major focus of attention.

3.2 An Alternative - Leasing of Power Transformers.

An alternative to the traditional models of ownership is the issue of leasing. For example, a company, such as a transformer manufacturer, may lease a transformer to a utility and take full responsibility for maintenance and replacement. The lease would need to include clauses covering operating conditions such as load management and protection systems to ensure that the transformer's health is not compromised by mismanagement by the lessee. On line control and management systems can log operational information and can be accessed by the asset owner (ie, in this case, the manufacturer) to ensure the transformer is being well treated and to monitor alarms etc.. The owner would have insurance, the premium of which is affected by the condition monitoring and maintenance practices in place. A transformer manufacturer, or related company, would be in a good position to manage the asset (engineering expertise and latest design tools, assessment systems) and keep on hand emergency "spares" (generic replacements, windings, OLTC's etc.)

3.3 When is it "Too Late"?

It is only too late to take action on life-management after a transformer (and/or its major ancillary equipment) has failed, or insulation integrity has been lost to a point of imminent failure. It is certain that transformer insulation does not have a definite "life" (e.g. 60 years) at the end of which it will suddenly fail. Rather, the risk of failure of the insulation due to stresses caused by system short circuits increases with insulation aging. The transformer should be rewound or replaced when the risk becomes unacceptable. I have successfully refurbished (dry-out, re-clamp, new HV bushings etc) transformers with a degree of polymerization of 300 and water content in insulation of 6% and more. Such action will no doubt offer the transformer its' best chance of survival, and will defer capital expenditure for the owner, however it is a far better strategy to:

- Prevent, or at least minimize, the loss of life and increase in moisture content in the first place
- Undertake a refurbishment at mid-life rather than end of life.

This statement is justified on the basis that:

- A transformer in good condition (electrically and mechanically sound) can better withstand service conditions (system surges, impulses, overload, voltage spikes)
- Loss of insulation life is irrecoverable.
- It cannot assumed that the relevant expertise for specialized maintenance will be available when required. If such requirements are minimized, the potential cost and risk is also minimized.

Conclusion

The paper has laid out options for life management of transformers and compared costs. The same principles can be applied to any asset, namely:

- Time and effort spent at time of specification are a wise investment
- Being pro-active rather than reactive saves dollars. Prevention is better than cure.
- Non-invasive condition based maintenance predicts faults and prevents unnecessary expense.
- Mid-life refurbishment can extend asset life.

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Biography

Ken Budin is the Services Manager, Wilson Transformer Co. Pty Ltd, and is Director, Sales & Marketing, TJ|H2b Analytical Services Pty Ltd., both Australian companies being based in Melbourne. Prior to commencing with Wilson in January 1998, Ken was employed with Great Southern Energy, NSW (now incorporated into Country Energy) and it's predecessors for 21 years in field, technical and management positions. Ken has extensive experience in many aspects of electricity networks including metering, protection, asset management and the servicing and maintenance of power transformers.

Ken has conducted seminars in Australia and overseas, and is the organizer and co-Chair of the Techcon series of conferences held annually in Melbourne. He was awarded the Conway Prize at the Electric Energy Society of Australia annual conference, Canberra, August 2000.

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