TRANSFORMER FLEET MANAGEMENT THE CITY POWER EXPERIENCE

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INTRODUCTION

The catastrophic failure and poor performance of transformers is becoming a grim reality in the life of Maintenance Engineers and Asset Managers in South Africa. Most of whom are left powerless in this struggle due to financial constraints as a result of the huge capital investment that is required to replace a power transformer. A further compounding problem is the ever increasing delivery time for power transformers.

Therefore there is a need to detect and locate suspect units rather than wait for imminent failure. Furthermore, when faults do occur, there is a need to identify the type and location of the fault quickly enough to aid with the execution of the appropriate maintenance thus reducing downtime. Hence, great importance is placed on diagnostic testing and the interpretation of the results. There is therefore a need for appropriate (i.e. efficient yet cost effective) non-invasive condition monitoring tools and techniques to allow for early detection of defects and also for the analysis of faults.

BACKGROUND

City Power is responsible for the performance and life management of about 250 transformers and almost 100 substations operating from 33 kV to 275 kV. Due to the aging fleet, City Power is currently on a drive to perform condition assessment on all transformers. The expectations of this condition assessment process are as follows:

- Indentify high risk transformers in terms of the operating condition
- Indentify high risk transformers in terms of the environment, staff and third parties

The fundamental principle behind the condition assessment program was to establish a ranking system that can provide a realistic risk of failure for power transformers.

TRANSFORMER CONDITION ASSESSMENT

What we know about transformers is that their life expectancy can vary from a few cycles (ms) to more than fifty years.

What we need to know is the life expectancy of a particular transformer in a given network. This fact is interesting and very useful. This is the essences of condition assessment.

Effective condition assessment is not just testing a transformer and reproducing the test results nor is it diagnosing the cause of a failure after the transformer has failed. CIGRE Working Group on Life Management Techniques for Power Transformers has defined condition assessment as *“A comprehensive assessment of the condition of a transformer taking into account all relevant information eg. Design information, service history, operational problems, and results of condition monitoring and other chemical and electrical tests”*. This is an excellent definition that encompasses all aspects of the transformer’s life. This model has been successfully implemented in a number of utilities worldwide. However, can effective condition assessment be implemented in utilities with little to no information?

By using Doble’s two phase approach for condition assessment utilities with little documented information can enjoy the benefits of a comprehensive condition assessment on all types of transformers on the network.

DOBLE CONDITION ASSESSMENT PROCESS

The condition assessment techniques followed is a two phase approach. The first phase was performed on all transformers. The second phase was performed on a small sample group when compared to the first phase. Both phases include proprietary risk scoring system and combine analysis of individual units of similar designs with similar operating conditions and age.

Phase One

The first phase is online approaches where the transformer is not removed from service for additional testing. Phase one of assessment is a “scanning” approach and is more appropriate as a low cost assessment and step to provide “initial” risk assessment and ranking of transformers in a network. The first phase is essentially a review of available information. These include as much as possible of the following:

Step 1: Basic nameplate information from transformer and tapchanger.
All information related to the transformer's manufacturer, vintage, serial number design, ratings, BIL, fault level, impedance, cooling system etc must be captured. From this information design related issues with transformers, service advisories from manufacturers, reports of failure on similar designs, pattern of failure on similar designs can be identified.

Step 2: External visual inspection.
A visual inspection is conducted on the following:

- Plinth – check for cracks or deterioration, anchor bolts missing or rusty, evidence of oil leaks, ground leads or connectors oxidized/tight etc.
- Tank - Paint peeling and rust, signs of internal deformation or overheating, oil leaks, loose or missing nuts, bolts, or washers, record liquid level in main tank or any conservator tank, inspect liquid level gauges and wiring, inspect pressure relay and pressure relief device and wiring etc
- Cooling system - Paint peeling and rust, oil leaks, inspect pumps and wiring, inspect fans and wiring, inspect radiators for cleanliness, etc
- Temperature reading - Record temperatures, record position of maximum pointers, inspect temperature sensors and wiring, etc
- Marshalling kiosk - Inspect external for paint peeling and rust, inspect interior for water ingress and rust, heater operating, inspect breakers, contactors, terminals, wiring, etc
- Tapchanger - Paint peeling and rust, signs of internal deformation or overheating, oil leaks, loose or missing nuts, bolts, or washers, record liquid level inspect pressure relay and pressure relief device and wiring, record number of operations, inspect tap changer mechanism, etc
- Bushing - Chipped or broken sheds, oil leaks, oil levels, Inspect connections, etc
- Surge Arrester - Chipped or broken sheds, inspect connections, etc

Step 3: Review of all available documentation

- Factory test report - Used to compare with current test results and operating ability
- Purchasing specification - Used to compare to current manufacturing standards
- Tests results (electrical and oil) - Current data can be compared to Doble database for industry norms
- Failure reports - Indicates the rate of aging, availability and performance
- Maintenance practices - What are you doing?
- Major modifications or rebuild - Indicates the rate of aging generally expected
- Substation fault level - Changes in fault rating
- Loading - Used to calculate loss of life

Step 4: Additional non invasive tests
(i) Oil tests (main tank)
A sample would be taken and analyzed with the standard methods. The table below gives a few standard oil tests.

Dissolved Gas (DGA)	Detection of incepted faults – IEEE, IEC etc
Furfuraldehyde (FFA)	Paper insulation degradation – Chendong relation to DP
Moisture in oil	Insulation dryness
Breakdown Voltage	Dielectric integrity
Acidity	Ageing and sludge
Interfacial Tension	Ageing, sludge and contamination

(ii) Doble DGA Scoring System
Doble has developed an algorithm to mimic the key gas response and gives a single number to track the change in pattern. This method uses the key gas method to present DGA used by IEEE method. The relative proportions of the combustible gases CO, H2, CH4, C2H4, C2H6 and C2H2 are displayed as a bar chart to illustrate the gas signature. The novel aspect of the approach proposed here is that this method is used to investigate and illustrate the clear difference that exists between 'normal' and 'abnormal' results. By contrast, in the IEEE Guide four examples of faults are given, but there is no guidance on what a normal result would look like. The DGA score reflects the seriousness of the signature. DGA results for normal transformers would be expected to return a score of no more than about 30, whereas a core circulating current would rate about 60 and more serious problems would score around 100.

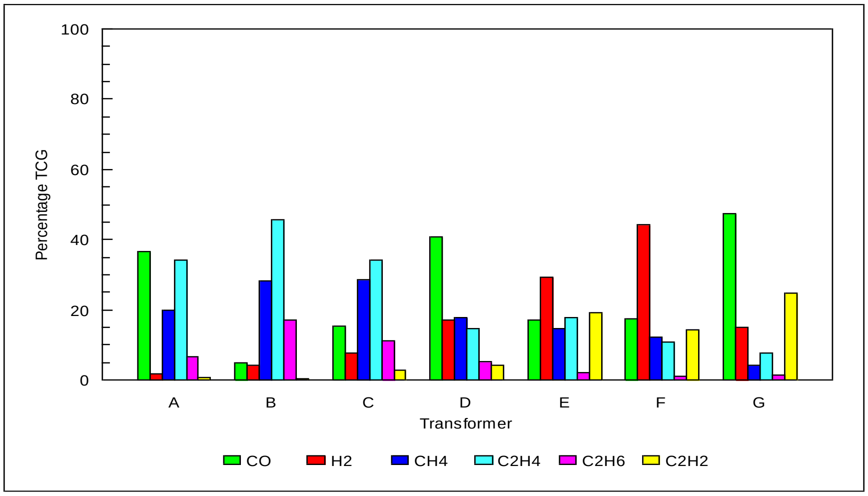


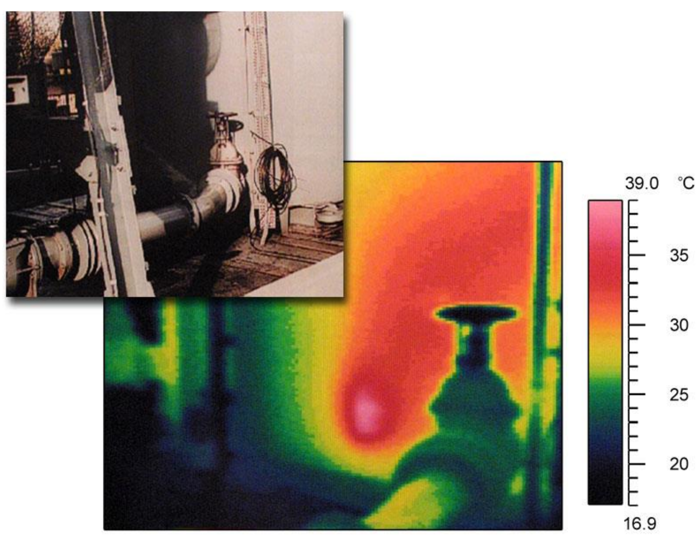
Figure 1: DGA signatures for faulty transformers

A – Core bolt fault
B – Core and frame to earth circulating currents
C – Winding inter-stand fault
D – Winding shorted turns
E – Winding phase to earth fault
F – Winding tracking fault
G – Winding clamping bolt sparking fault

(iii) Infra Red Scan

Infra-red will indicate external joint issues, bushing tap problems, oil levels in bushings and radiators, blockages in radiators, fan function- it can also indicate tank heating from stray flux, or frame tank circulating current. The figure below illustrates an internal tank hot spot.

Figure 2: IR scan of a hot spot



(iv) PD Scan

RFI signals from discharge activity are considered to be broadband and impulsive in nature with low repetition rates. Spectrum analyzers and EMI scanning receivers are widely available and used in detection and measurement of RFI signals. However, their use for measuring low repetition rate broadband signals presents particular challenges for reliable and repeatable detection and measurement. The measurement process requires specific understanding of signal and instrument characteristics to ensure the RFI signals are accurately represented. Surveillance of RFI emissions from PD phenomena involves the measurement of complex waveforms varying considerably and often erratically in amplitude and time. Research and practical measurement carried out on PD activity within oil-insulated HV equipment demonstrates that discharges produce current pulses with rise times less than 1 ns and therefore capable of exciting broadband signals in the VHF (30 to 300 MHz) and UHF (300 MHz to 3 GHz) bands. Other investigations in open-air insulation substations show that signals from PD and flashover occupy a frequency range up to 300 MHz.

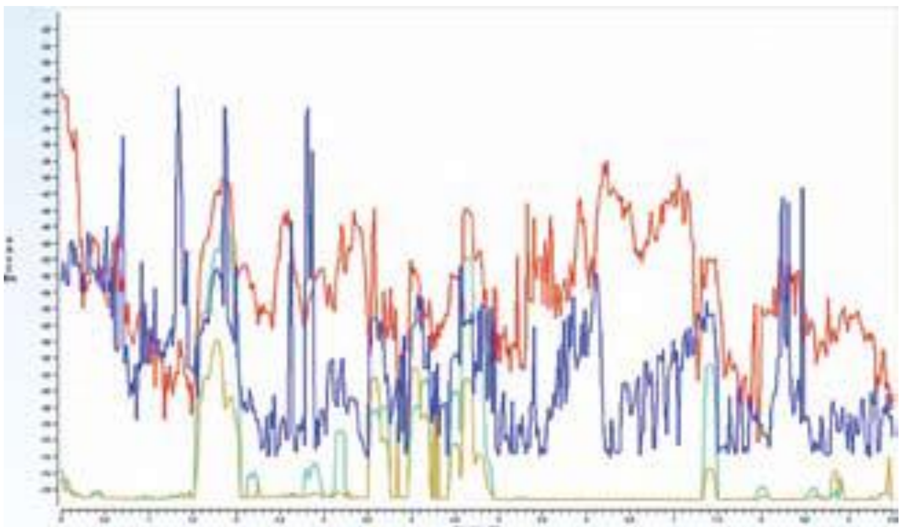


Figure 3: PD scan

Step 5: Consultation with staff

Consultation with all staff involved in the life management of transformers forms an integral part of this process in that this is a great source of information that has not been documented.

Step 6: Assessment of Technical Condition

Once all the information has been gathered and the additional non invasive tests performed the transformers can then be scored based on its condition. The Doble scoring system is given below.

Condition	Definition	Score
New	No damage	1
Normal ageing	Reasonable for age	3
Aged	Some ageing – in need of some monitoring	10
Suspect	Identified ageing, significant risk for failure	30
Unacceptable	Unacceptable ageing	100

Transformers condition is further divided in design, dielectric and thermal and scored to a Doble scoring system. A typical assessment of the technical condition is given below.

Station	Circuit	Serial No	Manufacturer	Year of Manufacture	Years in Service	Ratio	Rating (MVA)	Condition	Recommendations	Overall	Thermal	Dielectric	Comments
Alexandra	T3	29940	ABB	not given		88/11kV	45	Normal Ageing	Verify Oil Type. Furan Sample required.Repair oil leaks and temperature gauges	6	3	3	The DGA shows higher than normal levels of hydrogen and eth
Alexandra	T4	29555	ABB	1994	15	88/11kV	45	Normal Ageing	Furan Sample required. Repair oil leaks	6	3	3	Normal
Baragwanath	T2	128846	Ferranti	not given		20.5/6.6kV	11	Suspect	Monitor Furans. Electrical Testing. Repair oil leaks	43	3	40	High furans (DP=338). Sample for Furans every 6 months.
Bellevue	T3	21563	ASEA	1967	42	88/11kV	45	Suspect	Monitor Furans. Electrical Testing. Repair oil leaks	73	3	70	High Furans (DP=305). Sample for Furans every 6 months
Bellevue	T4	21564	ASEA	1967	42	88/11kV	45	Normal Ageing	Furan sample required. Repair oil leaks	6	3	3	Sister unit shows signs of advanced paper aging
Bond Street	T1	29730	ABB	1996	13	88/11kV	30	Normal Ageing	Verify Oil Type.Furan sample required	6	3	3	The DGA shows higher than normal levels of hydrogen and eth
Bond Street	T2	29729	ABB	1996	13	88/11kV	30	Normal Ageing	Furan sample required	6	3	3	Normal
Braamfontein	T1	26221	ASEA	not given		88/11kV	45	Normal Ageing	PD and IR scan required	6	3	3	Normal. Could not enter substation.
Braamfontein	T2	26222	ASEA	not given		88/11kV	45	Normal Ageing	PD and IR scan required	6	3	3	Normal. Could not enter substation.
Fort	T1A	3716057	ASEA	1960	49	88/11kV	30	Suspect	Electrical testing required. Repair oil leaks.	43	3	40	Developing dielectric fault. Sample every 3 months
Bree Street	T2	26225	ASEA	1971	38	88/11kV	45	Normal Ageing	Furan Sample required. Repair oil leaks	6	3	3	Normal
Bree Street	T3	29252	BBT	1991	18	88/11kV	45	Suspect	Monitor Furans. Electrical testing required. Repair oil leaks.	83	3	80	High Furans (DP=295). Increasing trend in Furans. Sample for F

Figure 4: Phase One Assessment

All units have been assessed in terms of design groups with problems, overall condition, thermal and dielectric condition. Each aspect has its own score - a number between 1 and 100. Even with summation any aspect with a 100 score will be carried through and easily recognized. The results are assessed using this sum of the numerical scoring system and it is this sum that determines the position in the "league table" and summarized using a red- green colour traffic light code. It should be emphasized that the score is not permanent it's a "live" document, reviewed each month as new evidence is presented.

Phase Two

This phase is applied only to units that have been identified as high risk from Phase One. This phase is a comprehensive analysis of the transformer and requires off line testing. The standard off line tests are as follows:

- Tan δ and Capacitance - windings and bushings
- Sweep Frequency Response Analysis
- Leakage reactance
- Insulation Resistance
- Winding resistance
- Exciting current
- Ratio test

Rescoring the Technical Condition

Once all the off line tests are performed the technical condition of each transformer can be rescored with greater detail. The rescoring now includes the mechanical condition of the transformer. With the final scoring for the condition of the transformer now in place a weighting for each unit level can be assigned. From this a risk of each unit level can be determined. A total risk of each transformer can then be calculated.

Outcomes of Phase Two

Once the rescoring has been completed the following is made evident:

- High risk transformers in terms of the dielectric, thermal and mechanical condition.
- More accurate overall condition as a result of the off line tests
- An action plan in terms of units that require replacement, repair and monitor
- The transformers risk

The results of phase two are merely added to the existing assessment. A typical layout is shown below.

THE CITY POWER STUDY

Doble's phase one approach was performed on all power transformers within City Power. Each of the assessed transformers were scored and ranked in terms of risk of failure. In addition to the risk of failure recommendations were also formulated either to perform further tests to ascertain the extent of the fault or what immediate action is required to reduce to risk of failure.

An extract of the summary of the assessment is given below. The transformers condition is assessed in terms of their thermal and dielectric condition. The results are assessed using this sum of the numerical scoring system and it is this sum that determines the position in the "league table" and summarized using a red- green colour traffic light code. It should be emphasized that the score is not permanent it's a "live" document, reviewed each month as new evidence is presented.

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Figure 5: Phase One Assessment

Analysis of Data

Transformer Vintage

The treatment of transformers by age is a matter of owner's internal policy. The age of a transformer can have a number of factors including the effect on the mechanical strength of the transformer's insulation and hence its ability to withstand common short circuit forces that are inherent in a transmission system. A further consideration is the relationship between advanced paper aging and transformer age. The relationship between the age of the transformer and its performance is a subject of great uncertainty. However, coupled with the other factors listed here the transformer's age can play an importance role in risk decision. It is common knowledge that transformers built and designed in the past have proven to be highly reliable with a low failure rate for many decades. The introduction of advanced computer programming for design purposes have resulted in modern transformers having a low loading capability. However, it is noticed that older transformers may lack adequate provision for leakage flux and have a higher probability of localized thermal problems. Further, industry standards (IEC and IEEE) were revised to ensure greater short circuit duty for modern transformers.

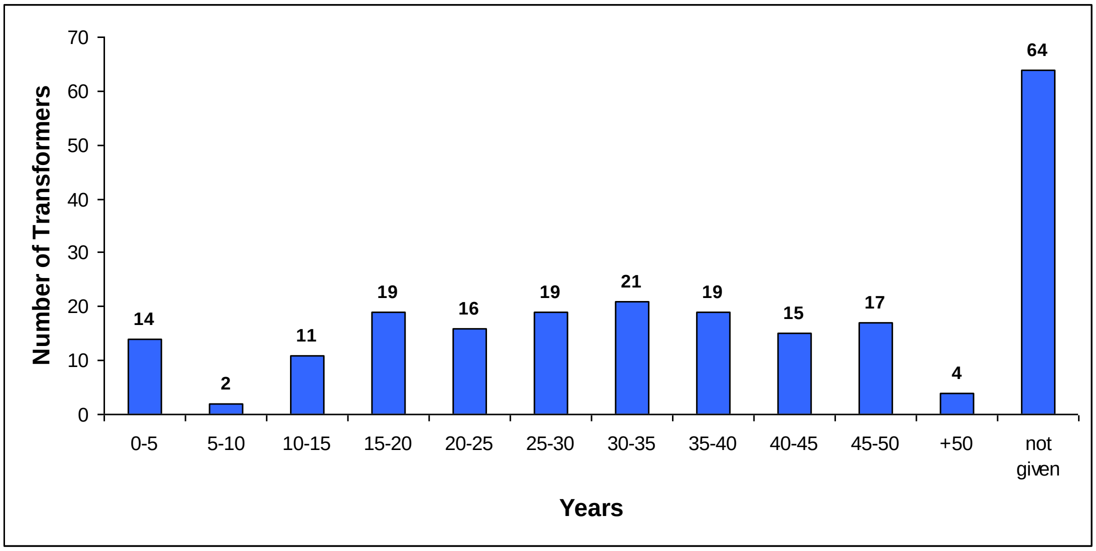

Figure 6: Transformer Age Distribution

Notes:
The date of manufacture was obtained from the transformer nameplate during the visual inspection phase.

The age distribution for the transformer are typical of what is seen in other utilizes in South Africa of similar size to that of City Power. There is large installed base of transformers that are between 20 and 40 years old with a further significant population over 40 years old. This is a clear indication of an aging asset base. Further there is an increase in transformers between 0 to 5 years due to the replacement program possibly the result of failures of older transformers. This is a good indicator of transformer failures or an increase in demand of electricity. It must be noted that a total of 22 transformers have been removed from site with a further 16 transformers that are out of service (data as of the 31-06-2009).

The City Power fleet has an average life of 29 years. This average life is in line with industrial norms (utilizes of the similar size in South Africa). However, it must be noted that there was a significant number of transformers (64) that have no indication of the year of manufacture on the nameplate.

There is significant number (64) of transformers that have no indication of the year of manufacture on the nameplate. Typically very old transformers did not include the date of manufacture however; it was very surprising that even the newly installed transformers like Crompt Greeves and Alsthom have neglected to include the date of manufacture on the nameplate. The lack of inclusion of this date has a server effect on the age distribution and also the average transformer life.

Transformer Manufacturer

The place of manufacture and the manufacturer is a key indicator of quality related issues. The identification of dominating deterioration and failure modes for each design group/manufacturer can be used to identify the optimum diagnostic strategy to reveal the onset of failure modes.

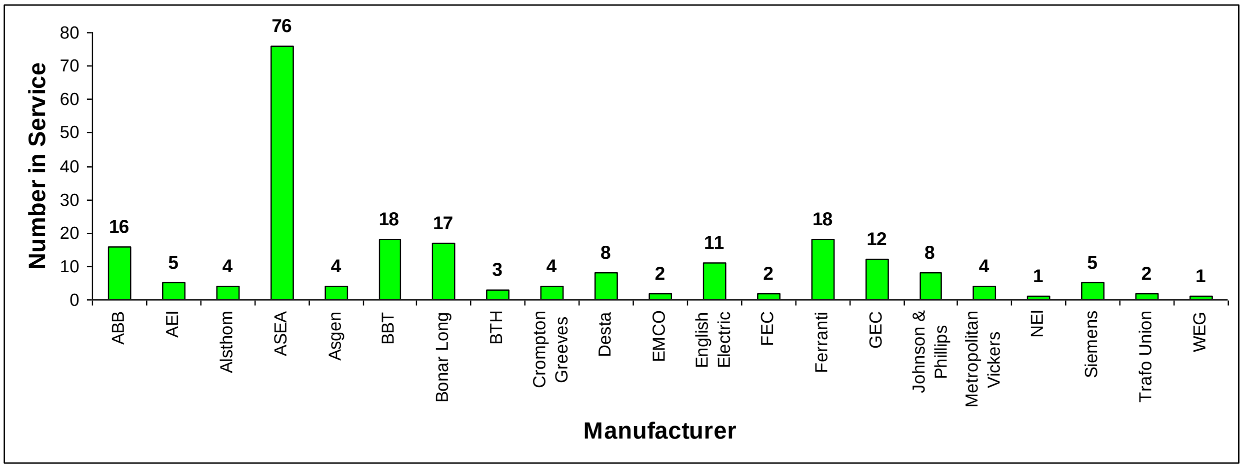

Figure 7: Transformer Manufacturers

Transformers of the same manufacturer and of same design (based on the serial numbers) have shown to have common fault characteristics. They are as follows.

a) The ASEA transformers at T1(26051) and T2(26050) at Florida Glen have high levels of acetylene which can be attributed to a possible floating potential.

b) The ASEA transformers at Mayfair T2A(26219) and Eikenhof T2A(26220) show discharge activity.

c) The ASGEN transformers at Cleveland T4 (14449), Robertsham T1B(14454) and Eldorado Standby T3 (14452) have high furan levels.

d) The Bonar Long transformers at PPC Cement T2A(69-320)and PPC Cement T1B(69-321) show signs of a thermal fault.

e) The Ferranti transformers at Riviera T1(109846), T2(1098467) and Johannesburg Central T1(109845) show signs of a discharge type fault.

f) The Johnson & Phillips transformers at Nursery T1(3651), T2(3653), Roodepoort T3(3656), T2(3655) show signs of a discharge type of fault.

Once electrical tests are performed in Phase Two the different transformer design will be scored.

Transformer Faults

General
Figure 3 below illustrated the difference faults that are considered to increase the risk of a transformer failure.

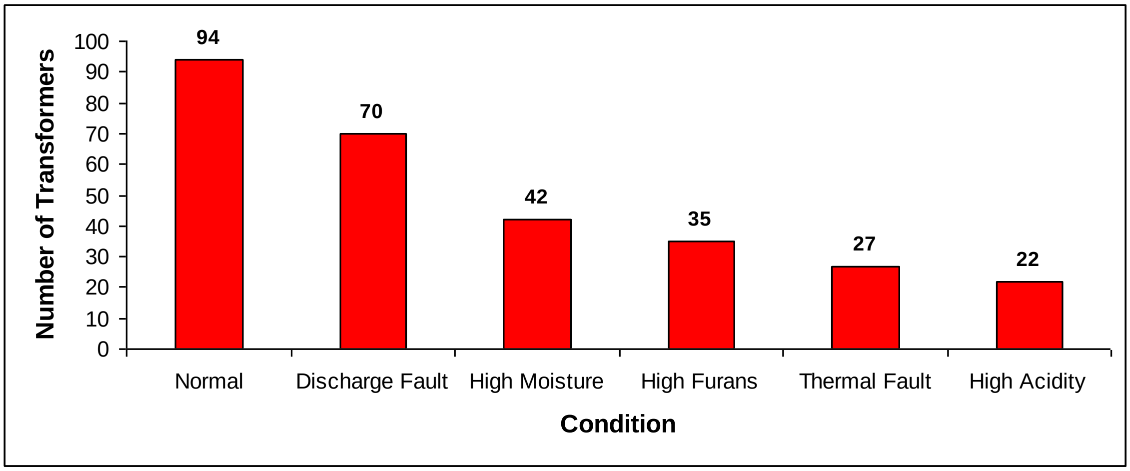

Figure 8: Transformer Condition Classification

All transformers were placed into the following condition classifications

a) Normal
Transformer that are considered to have normal operation

b) Discharge Fault
Transformers that are considered to have some form of partial discharge which was detected by DGA for UHF scanning.

c) High Moisture
Transformers that are considered to have unacceptable levels of moisture.

d) High Furans
Transformers that are considered to have high levels of furans or low DP values.

e) Thermal Fault
Transformers that are considered to have some form of fault related to a high temperature condition eg. Overloading, circulating currents, poor connection etc.

f) High Acidity
Transformers that are considered to have unacceptable levels of acidity.

It must be noted that some transformers will fall into a combination of the above faults for an example a transformer may have a discharge fault and have high levels of moisture.

Dielectric Condition
The dielectric condition takes into consideration the following faults:
(a) Discharge faults detected from the DGA and Partial Discharge scanning.
(b) High levels of furans
(c) High levels of moisture
(d) High levels of acidity

Discharge faults
The discharge type faults are the most prominent fault within the transformer fleet. These faults were identified from the DGA and on-site Partial Discharge scanning. The extent of damage that is caused by the partial discharge can only be effectively assessed by performing electrical tests as part of the phase two approach. The figure below illustrates the number of discharge type faults per manufacture. The discharge type faults are prominent on the older transformers.

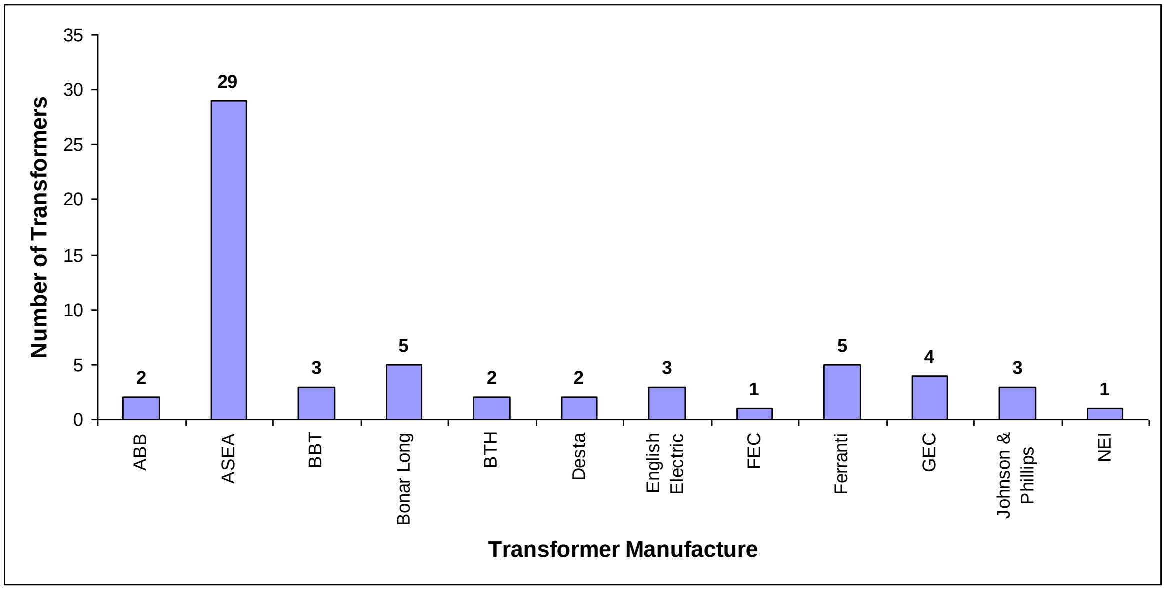

Figure 9: Discharge type Faults

High Furans
The levels of furans and the rate of increase of furans between samples is an excellent indicator of the age of paper insulation. However it must be noted that it is not possible to be precise about the extent of paper aging, but from the lab analysis it seems a reasonable estimate of the DP of the paper insulation. Furan analysis is recommended on an annual basis to establish trend. The trending is important as there is an influence from the transformer load on the amount of furan measured in the oil as the equilibrium between the paper/oil changes with temperature. Further, furans are reduced in concentration by some maintenance activities like oil purification and regeneration. The figure below illustrates the distribution of transformers that are considered to be of risk due to the furan levels.

Unfortunately, the concentrations of furans were not received for 94 transformers; as a result the condition of the paper insulation cannot be assessed with confidence. Urgent furan analysis is required on these units.

When new, paper has a DP of approximately 1,000. When the paper has aged to a DP of 200 then practically all mechanical strength has been lost. This DP of 200 is accepted criterion for the effective end of life for paper used in transformer insulation.

Due to the high levels of furans ten transformers (DP from 250 to 150) we would rank the transformer as showing signs of significant ageing and should be considered as an early or immediate candidate for asset replacement. The other twenty five transformers that fall in the range between 250 and 400 would require close monitoring in the form of furan analysis every three to six months (Recommendations are give in the reports).

The ASEA transformers have show to be the most problematic with thirteen transformers showing sign of significant paper aging.

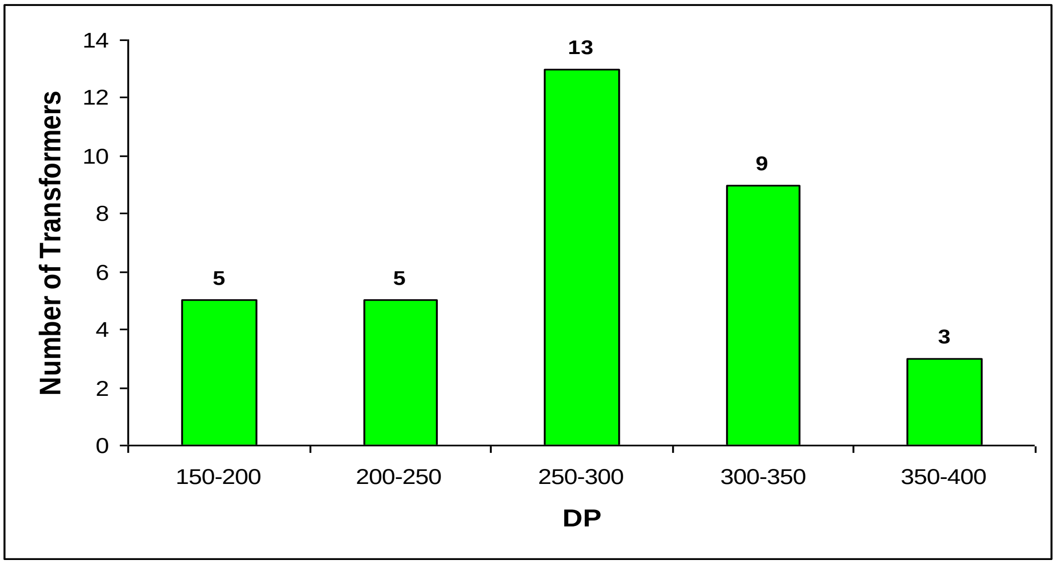

Figure 10: Low DP values for Transformers

Moisture

Moisture in the insulation influences the life of a transformer in many ways: accelerating aging, increasing losses, reducing insulation strength and introducing the risk of bubble formation during overload. Moisture enters the transformer from the outside from leaks and poor breather systems. However, some of the moisture is developed from within as the oil and solid insulation ages and oxidises over time. When the moisture content of the solid insulation doubles the expected life of the transformer is halved. The figure below illustrates the transformers that have high moisture content. There are a total of 42 transformers that have unacceptable levels of moisture that require urgent purification.

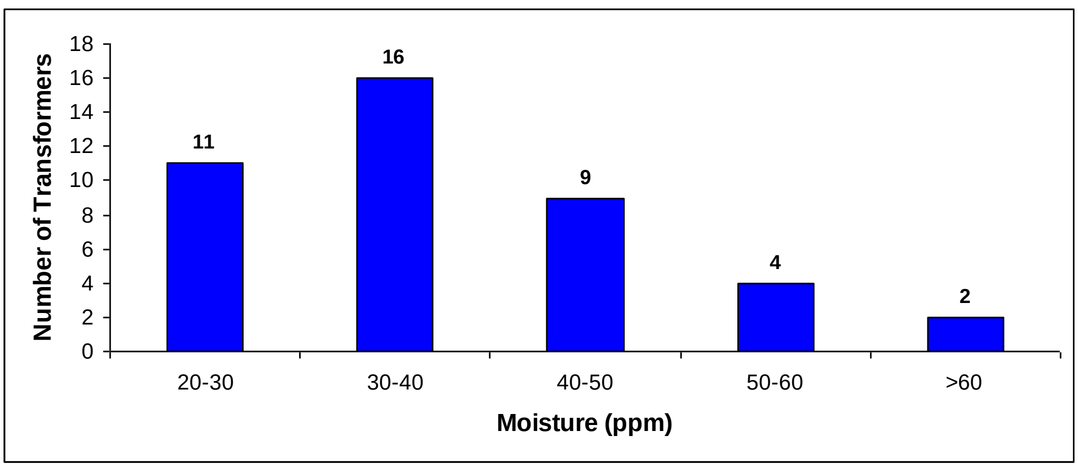

Figure 11: High Moisture Levels for Transformers

Acidity
Acids in the oil originate from oil decomposition/oxidation products. Acids can also come from external sources such as atmospheric contamination. An increase in the acidity is an indication of the rate of deterioration of the oil, with sludge as the inevitable by-product of an acid situation which is neglected.
This sludge adheres to the solid insulation, in cooling ducts and cooling fan which results in a substantial increase in operating temperatures. Apart from the increase in operating temperature the acid also attached the paper insulation which is irreversible.
The figure below illustrates the transformers that have high acidity. There are a total of 22 transformers that have unacceptable levels of acidity that require urgent regeneration.

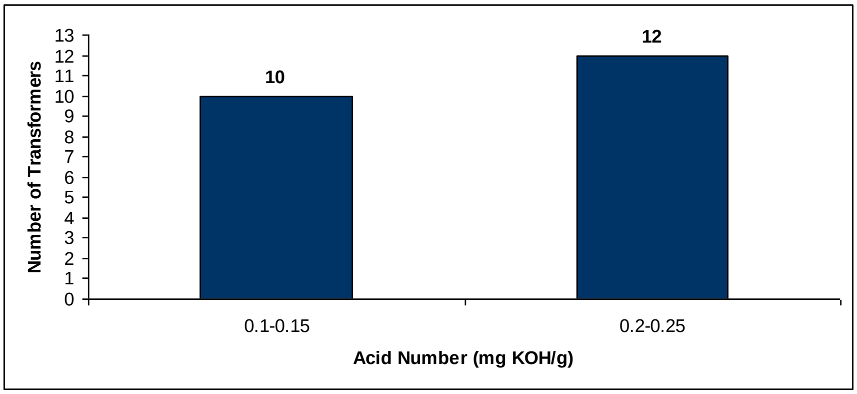

Figure 12: High Acid Number for Transformers

Thermal Condition
The thermal condition of the transformer is assessed by considering faults that result in excessive temperature rise in the insulation or other parts of the transformer. The typical causes are:
(a) Insufficient cooling;
(b) Excessive currents circulating in adjacent metal parts (as a result of bad contacts, eddy currents, stray losses or leakage flux);
(c) Excessive currents circulating through the insulation (as a result of high dielectric losses), leading to a thermal runaway; and
(d) Overheating of internal winding or bushing connection lead.

The transformer assessment revealed only two types of thermal faults which were as follows:
(a) circulating current of a 'bare metal' type (bad contacts, eddy currents, stray losses or leakage flux) rather than a covered conductor; and
(b) overheating/overload fault that is possible the effect of loading issues or poor cooling (possibly blocked cooling ducts, inadequate radiators, and faulty fans) or design related issues.

The figure below illustrates the transformers that fall within the different thermal classes. There are a total of 27 transformers that have thermal faults.

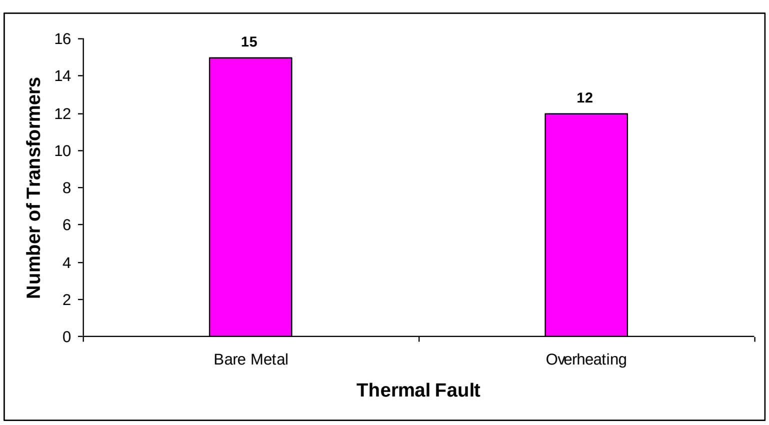

Figure 13: Thermal Faults for Transformers

CONCULSION

Transformer condition assessment program can be effectively introduced by using this two phase approach. This method of condition assessment can be implemented irrespective of the amount of information. It allows utilities to finally have answers to the following situations:

- When to have maintenance outages
- How to respond to a protection trip
- To know capability to increase transformer rating
- To know when to replace (5, 10, 15 years) transformers

An added advantage is that this method forces the utilities to make the bold move to condition based maintenance. A further advantage is the risk assessment and residual life can finally be achieved through sound engineering principles.