Practical Experience Gained from Dissolved Gas Analysis at an Aluminium Smelter

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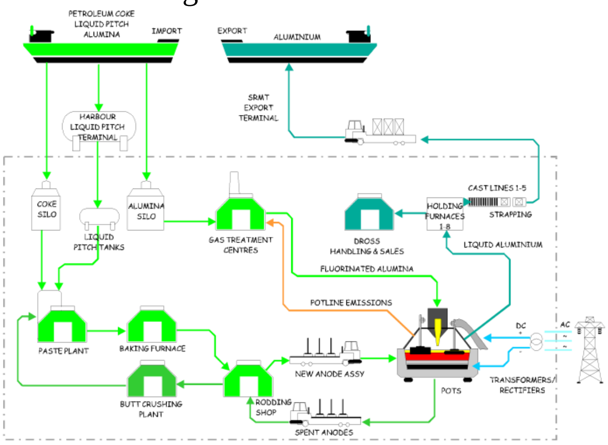
ABSTRACT

The Hillside aluminium smelter is located in Richards Bay, 200 kilometres north of Durban, KwaZulu- Natal province, South Africa. The operation is fully owned and operated by BHP Billiton.

Construction of Hillside Aluminium began in 1993. Hillside's two plotlines cast their first metal in June 1995.

In February 2003, Hillside was expanded with a further half pot line. First metal was poured from this half pot line during October 2003. This increased production at Hillside from 535 000 to more than 700 000 tons per annum, making it the largest aluminium smelter in the Southern hemisphere and South Africa's major producer of primary aluminium. It is one of the worlds most advanced and efficient AP30 smelters and produces T-bars and primary aluminium ingots.



The Hillside smelter consumes 1 100MW of Electrical power, with approximately 147 installed transformers at 1995. The units capacity range from 90.8 MVA Regulators/93.5 MVA Rectifiers/35 MVA Auxiliaries on the 132 kV system: 6.3 -1.6 MVA on the 22 kV system and 600-200 KVA on the3.3 kV systems.

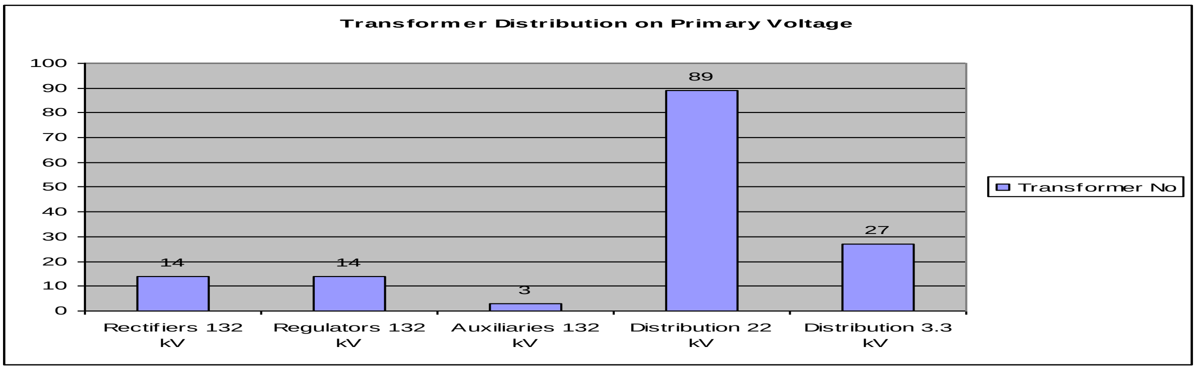


Figure 1-Transformer Distribution on Primary Voltage

Introduction

Dissolved Gas Analysis (DGA) has been a widely accepted preventive maintenance tool for the electric power industry for over thirty (30) years. Though DGA continues to be a vital component of assessing transformer condition, the demands imposed by the increased loading of transformers and the aging of the transformer population require new assessment tools and diagnostic approaches. It has been suggested that over 70% of transformer condition information is contained within the insulating fluid and that many transformer failures are attributable to manageable problems. Many of these problems are identified only after a thorough understanding of the complex relationships that exist between DGA data and information obtained from analysing the insulating fluid in transformers.

Dissolved gas analysis (DGA) of oil samples is probably the most effective means of monitoring the condition of oil-filled electrical equipment such as transformers, for several reasons. Firstly, nearly every possible fault generates one or more gases arising from the consequential increased degradation of adjacent oil or cellulosic insulation, so DGA can be said to be comprehensive in responding to many faults. Furthermore, since in the early stages these ‘fault’ gases dissolve in the oil and can then be detected at some subsequent point in time when an oil sample is taken, DGA can detect intermittent faults. Also, because fault gases can be detected at very low levels, the DGA technique is very sensitive and eminently suitable for detecting faults at an early stage. Most guides for interpreting DGA results include, and indeed concentrate on, schemes for diagnosing faults, usually by analysing the relative concentrations of the various fault gases, so the technique can also be described as discriminating and contributing to diagnosis as well as the detection of faults.

The main difficulty in making use of DGA results, which arises from its very good sensitivity, is that it is not easy to draw the line between normal and abnormal results, i.e. to be sure that a fault really exists. Most, but not all, interpretation schemes include a normal condition as one of the diagnostic outcomes, but have not been particularly effective in reliably identifying a normal condition.

This paper will provide a summary of Hillside Smelter Transformer faults detected by Dissolved Gas analysis at Early Life and will act as an aid and guide to the Power Engineer.*“ When the transformer should be removed from service”*. See figure 2 Transformer Life Cycle Model

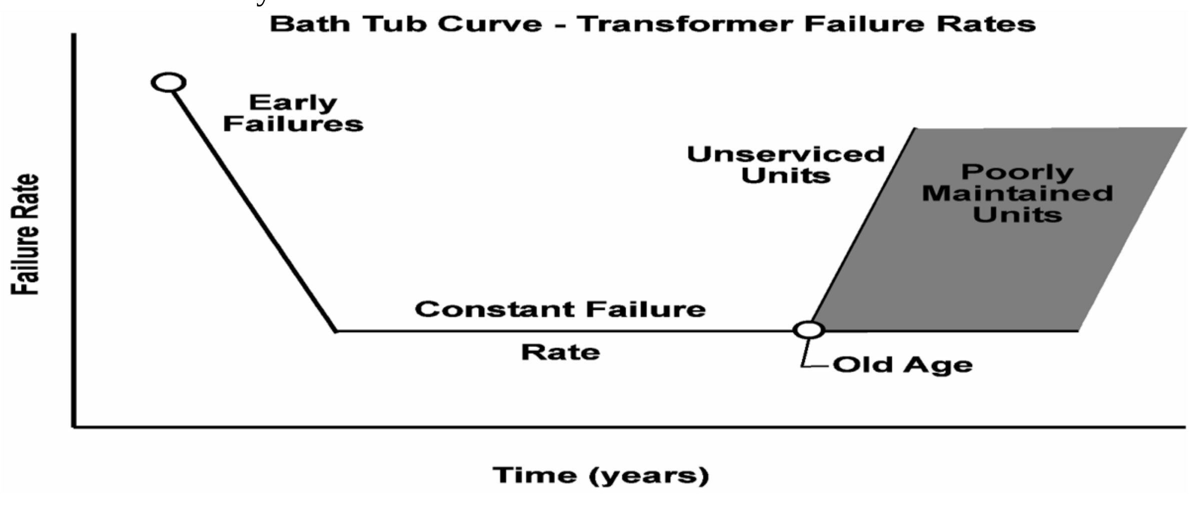


Figure 2 Transformer Life Cycle Model

Transformer Design and Construction

Transformers are normally very reliable items of electrical equipment, but when faults occur they can lead to the loss of what is usually the most expensive item of equipment in the substation. In addition, some faults can develop catastrophically, with the potential to cause substantial collateral damage to nearby equipment and posing a risk to personnel.

The modern power transformer is designed with far less insulation material and electrical clearances due to the pressure of driving down costs. This factor needs to be considered with the failure rate at the Hillside smelter. See Table1 comparing transformers between the 1970's and 1980's

Table 1
Transformer Comparisons between the 1970's and 1980's

• 12% decrease in total weight
• 11% decrease in case weight
• 10% decrease in oil weight
• 13% decrease in core & coil weight
• 7 to 33% decrease in electrical clearances
• 9% decrease in no-load losses
• 3.5% decrease in load losses
• 25% increase in number of pumps

See Figure 3 showing how the design and construction of 1500 KVA transformer has changed from 1945 to 1970.

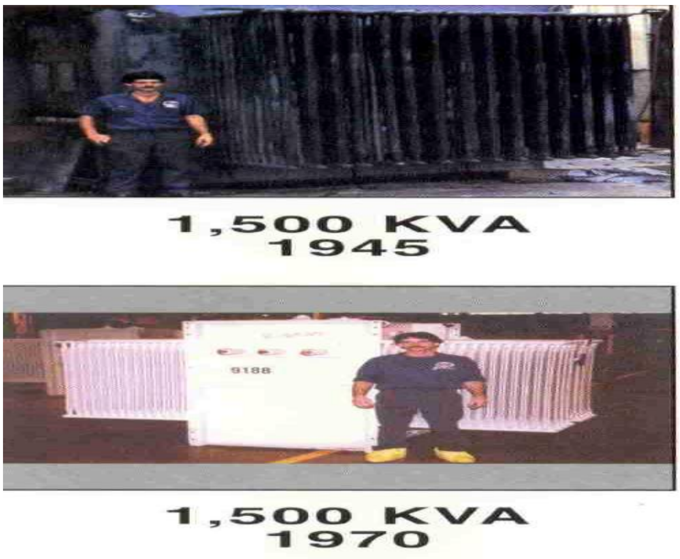


Figure 3: Transformer Construction from 1945 to 1970

What Causes a Power Transformer to Fail?

It is generally believed that failure occurs when a transformer component or structure is no longer able to withstand the stresses imposed on it during operation.

It is also important to distinguish the fault and the failure. A fault is mainly attributed to permanent and irreversible change in transformer condition. The risk of a failure occurrence depends not only on the stage of the fault developing but also the transformer functional component involved. The failure could be repairable on site, depending on the type of fault as well as the severity of the failure.

Power transformer failures are commonly associated with localised stress concentrations (faults), which can occur for several reasons, including:

Design and manufacture weakness, e.g. poor design of conductor sizing and transpositions, poor joints, poor stress shield and shunts, poor design of clamping, inadequate local cooling, high leakage flux, poor workmanship, etc.

Weakness in transformer design, construction and materials could be covered by low loading. However, increasing loading and extended periods of in-service usage will uncover these weaknesses

In the event of failure, the force applied to the structure may approximate 360 PSI due to the steep wave front and high velocity, representing a loading sufficient to distort the container or shear the holding bolts and possibly cause a transformer oil fire. See Figure 4 showing catastrophic transformer failure

Figure 4
Catastrophic transformer failure

Dissolved Gas

Origin of gases in Transformer oil
Corona (partial discharge), thermal heating (pyrolysis) and arcing cause gases to be produced in insulating oil. This is due to the breakdown products of the oil under electrical and thermal (heat) activity.

•*Partial discharge*
Key gases: Hydrogen and methane
This is a fault of low level energy which usually occurs in gas-filled voids surrounded by oil impregnated material. Bubbles in the actual oil may cause a partial discharge, especially when the bubble is in a high electrical stress area. However, main cause of decomposition resulting in partial discharge is ionic bombardment of the oil molecules. The major gas produced is hydrogen and the minor gas produced is methane.

•*Thermal Faults*
Key gases: Hydrogen, methane, ethane and ethylene
A small amount of decomposition occurs at normal operating temperatures. As the fault temperature
rises, the formation of the degradation gases change from methane (CH_4) to ethane (C_2H_6) to ethylene (C_2H_4).

As the temperature increases so there is a gradual shift from methane to ethane gas generation. As the temperature increases further there will be a higher production of ethane and ethylene.

A thermal fault at low temperature, typically lower than 300° C, produces mainly methane and ethane with some ethylene.

A thermal fault at higher temperatures, typically higher than 300° C, produces ethylene. The higher the temperature becomes the greater the production of ethylene.

Extremely high temperatures ~ 1000° C may bring on the presence of acetylene.

•*Arcing*
Key gases: Hydrogen and acetylene
An arcing fault is caused by high-energy discharge. In most cases the discharge has a power follow through. In arcing, the major gas produced is acetylene. Power arcing can cause temperatures of over 3000°C to develop. If the cellulose material (paper, insulating board etc.) is involved, carbon monoxide and carbon dioxide are generated.

•*Cellulose Aging*
Key gases: Carbon monoxide and carbon dioxide
A normally ageing conservator type transformer should have a CO_2/CO ratio of about 7. Any CO_2/CO ratio above 11 or below 3 should be regarded as perhaps indicating a fault involving cellulose provided the other gas analysis results also indicate excessive oil degradation.

Interpretation of Dissolved Gas Analysis (DGA)

There are various international codes and guidelines on interpreting DGA data. The guidelines show that the interpretation of DGA is complex.

Ratio Methods

Dornenberg Ratio Method

One of the earliest methods in which two ratio of gases are plotted in a log-log axes

IEC 60599 Ratios

IEC 599 is the most up to date of the ratio methods. This method uses only three ratios as opposed the four used in the Rogers ratio method.

Rogers Ratio

The Rogers Ratio method uses four ratios of dissolved gas concentration to generate a code that will determine the nature of the fault.

Duval Triangle

This method is a more graphical method than the ratio methods previously discussed. Each of the gases is calculated into a ratio. These values are then plotted on the triangle. The point of interception falls into a zone in the triangle which depicts the fault the transformer is experiencing.

Gas Concentration limits

The IEC 60599 serves as a good guide. The tables based on voltage classification and transformer type can be used as a quick reference to determine if further investigating is required. There are numerous International guidelines.

Key gas Method

Thermal Oil: Decomposition products include ethylene and methane, together with smaller quantities of hydrogen and ethane. Traces of acetylene may be formed if the fault is severe or involves electrical contacts. Principle gas–Ethylene. See Figure 5- Overheating Oil

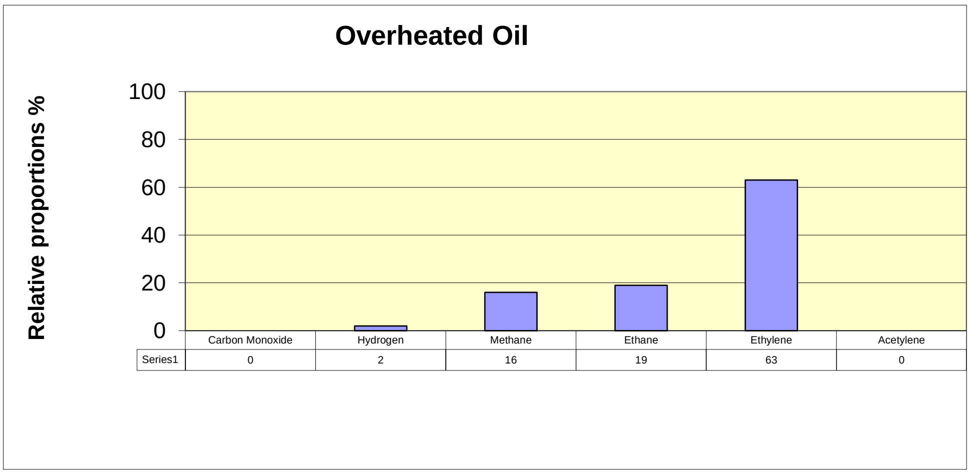


Figure 5
Overheating Oil

Key gas Method

Electrical Corona: Low energy electrical discharges produce hydrogen and methane, with small quantities of ethane and ethylene. Comparable amounts of carbon monoxide and dioxide may result from discharges in cellulose. Principle gas – Hydrogen. See Figure 6-Corona in Oil

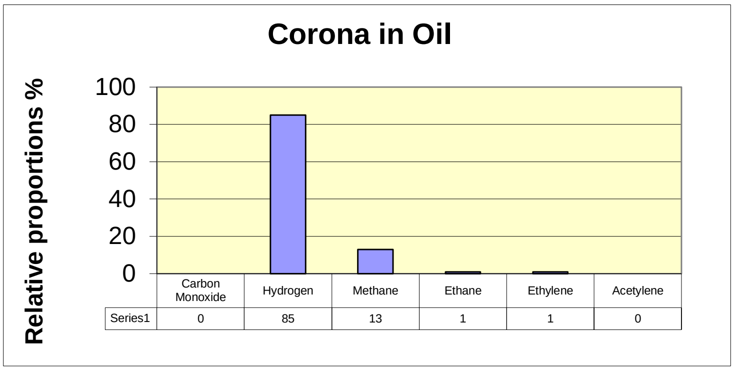


Figure 6
Corona in Oil

Thermal Cellulose: Large quantities of carbon dioxide and carbon monoxide are evolved from overheated cellulose. Hydrocarbon gases, such as methane and ethylene, will be formed if the fault involves an oil impregnated structure. Principal Gas – Carbon Monoxide. See Figure 7-Overtheated Cellulose

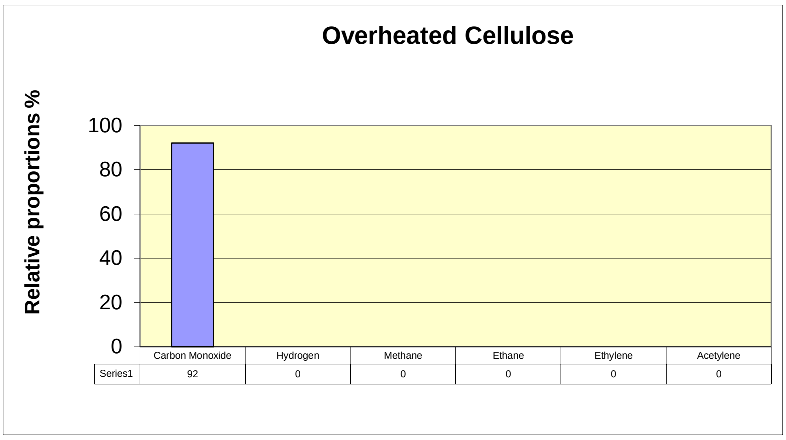


Figure 7
Overheated Cellulose

Key gas Method

Electrical Arcing: Large amounts of hydrogen and acetylene are produced, with minor quantities of methane and ethylene. Carbon dioxide and carbon monoxide may also be present if the fault involves cellulose. Oil may be carbonised. Principle gas–Acetylene. See Figure 8-Arcing in Oil.

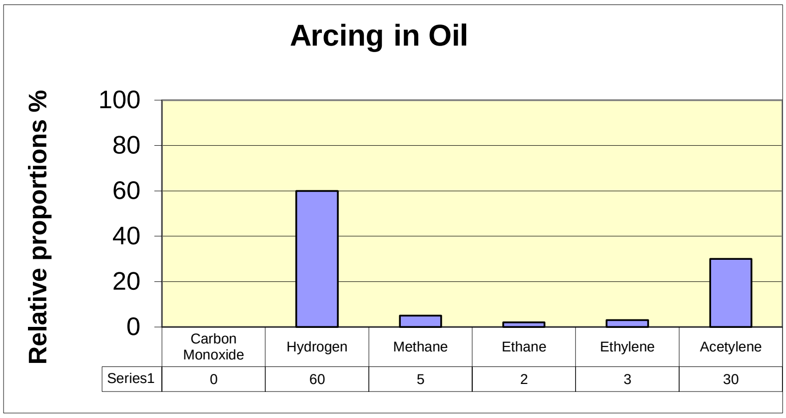


Figure 8
Arcing in Oil

Condition Codes

Total Dissolved Combustible Gases (IEEE C57.104-1991)
Actions based on sampling intervals and Operating for Corresponding Gas Generation Rates

This method was developed by IEEE society, and covers not only the determination of a fault severity and its nature, but also offers some indication to the follow-up action that is necessary.

Daily Production Rate Method.

This method calculates the daily rate of gas increase between samples. The IEC 60599 gives reference values.

Advantages and Disadvantages

The advantages and disadvantages of the various Codes and guidelines are listed in the Tables 3

Table 3
Advantages and Disadvantages of DGA Diagnostic codes

Advantages	Disadvantages
Rodgers Ratio	
Has the ability to ignore small laboratory errors	Unable to diagnose multiple faults.
Uses three or four ratios (the 3 ratio method is the latest method and the 4 ratio method an older version of the	Complex to calculate. Ratios can render codes that have no comment
Comprehensive diagnosis comments.	Sufficient gases are needed.
IEC 60599 Ratios	
Has the ability to ignore small laboratory errors.	Unable to diagnose multiple faults.
Uses three ratios.	Complex to calculate
Comprehensive diagnosis comments.	Sufficient gases are needed (gases need to exceed minimum level)
Internationally recognized	Ratios can render codes that have no comment.
Continuously upgraded by IEC committee	
Dornenberg ratios	
Has the ability to ignore small laboratory errors.	Has only three levels of diagnosis, thus very limited
Uses four ratios	Complex to calculate
Has diagnostic values for pure gas (not DGA)	Sufficient gases are needed (Gases need to exceed minimum levels).
	Ratios can render codes that have no comment
Duval Triangle	
Graphic in interpretation	Difficult to construct
Easy establishment of the problem	Time consuming if done by hand
	Misleading interpretation at very low concentrations of
Key Gas Analysis	
Simple to use	Unable diagnose multiple faults easily
Graphic representation	Sensitive to fluctuation in sample analysis
Gas Concentration limits	
Simple to use	Does not take production rate into account.
Set limits indicate typical fault	Simplistic in approach does not take a combination of gases into consideration
	Does not take volume of oil into account.
	Sensitive to fluctuation in sample analysis.
	Needs to be used in conjunction with production rates.
Production per Day	
Rate of change	Needs to be related to oil volume (limits are calculated for 50m3)
Determines risk (how quickly the fault is occurring)	Does not take a combination of gases into consideration
Simple to use	Sensitive to fluctuation in sample analysis.
Quick calculation.	
Trend analysis	
Individual or combination gases can be analysed.	Sensitive to fluctuation in sample analysis.
Points / samples can be removed	Time consuming.
Production can be seen	Knowledge of sample interpretation needed.
Graphic representation	Misleading if incorrect principals are used

New DGA Diagnostic Methods

DGA Signature

This method uses the key gas method to present DGA used by IEEE method. The relative proportions of the combustible gases CO, H_2, CH_4, C_2H_4, C_2H_6 and C_2H_2 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. See Figure 9

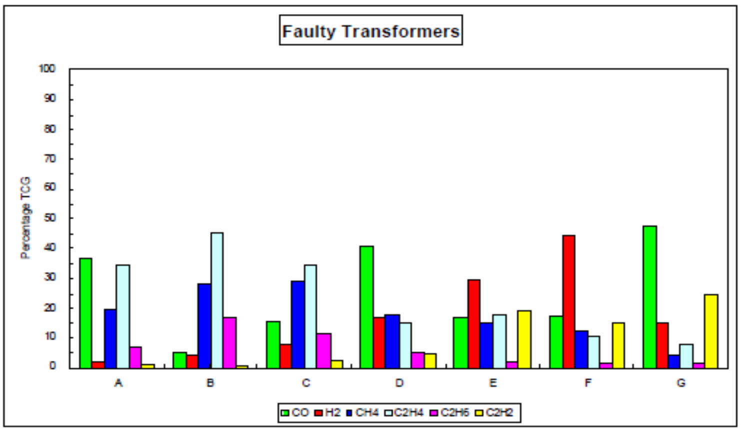


Figure 9
DGA Signature

Doble DGA Scoring System

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 60and more serious problems would score around 100.
The Doble method of interpreting dissolved gas analysis results is seen to tackle the main weakness of existing schemes i.e. the difficulty of defining a normal condition. A simple scoring system based on results from known problems is used to provide a consistent and objective assessment of the seriousness of results, to improve the effectiveness of life management decisions.
Because of this the DGA score will usually increase if the absolute levels of the key diagnostic gases increase, but the most important factor resulting in an increase in score will be a change in the gas signature towards what is perceived as a more serious case. See Figure 10.

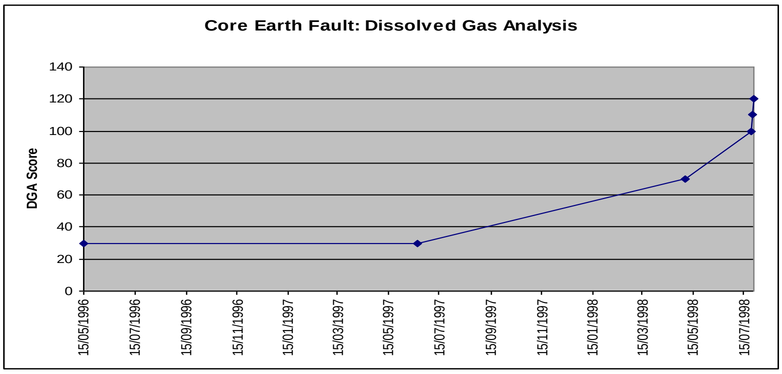


Figure10: Doble scoring system

The Vector Algorithm

The Vector Algorithm is based on the chemical and physical principles of the Rogers Ratios and Duval Triangle. All three methods are consistent with Halstead's thermodynamic reasoning

The new approach is not restricted to analysing a single type of fault condition. These activities can occur at different intensities in different parts of the apparatus, in different time frames, or even concurrently in the same component. For example, it is conceivable that a partial discharge activity could be a precursor to limited or full-fledged arcing. A hot-metal fault is likely to be surrounded by regions at somewhat lower temperature.

As an example, if we look at the historical DGA results of a transformer, we see that all of the hydrocarbon gases show an abrupt increase in September 2003. However, it is difficult to see from this graph what type of fault is developing. See Figure 11.

If we look at Vector method, we can see that a major PMO fault has developed. There are also signs of PDO, suggesting a worsening situation. The primary diagnostic, using this new approach, is consistent with the Duval Triangle and the IEEE Rogers Ratios, both of which indicated a "Thermal Fault >700°C". See Figure 12.

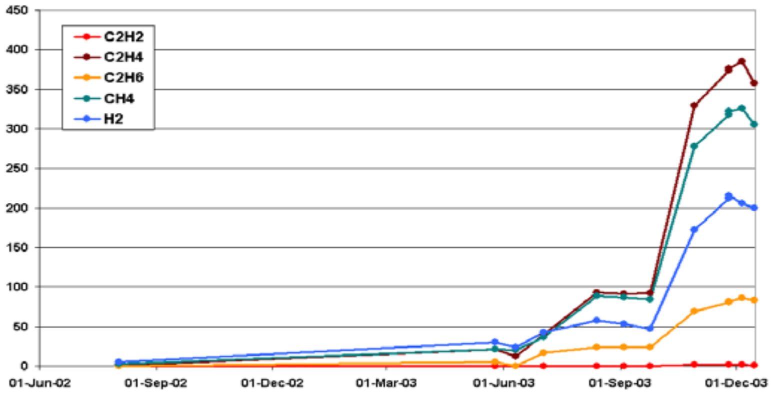


Figure 11
Historical DGA results of a transformer

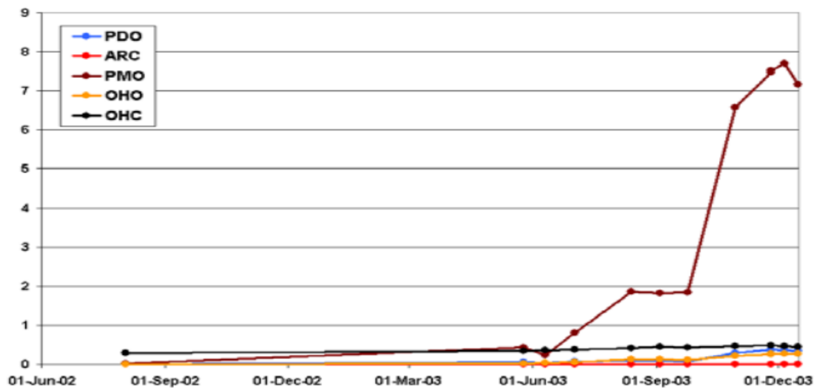


Figure 12
Vector Method

Dissolved Gas Measurement

Frequent sampling and analysis will produce variation in Dissolved Gas results.
This analytical variation is caused by the following:

The sampling procedure

The insulating oil samples are taken at different points in time and by different sampling personnel. If the correct sampling procedure is followed the impact on analytical variation will be small.

The Dissolved Gas analytical procedure

With any Analytical Chemistry test there will always be variation, this is referred to as Analytical variation or **Uncertainty of Measurement.** This is the measure of the dispersion that may reasonably be associated with the measured value. It is the range within which the true value lies. In certain cases the nature of the test method may preclude rigorous, metrological and statistically valid, calculation of uncertainty of measurement. In these cases the laboratory shall at least attempt to identify all the components of uncertainty and make a reasonable estimation, and shall ensure that the form of reporting of the result does not give a wrong impression of the uncertainty. Reasonable estimation shall be based on knowledge of the performance of the method and on the measurement scope and shall make use of, for example, previous experience and validation data.

See Table below from ASTM D3612-Standard Test Method for Analysis of Gases Dissolved in Electrical Insulating Oil by Gas Chromatography-An estimate of the repeatability of this test method was obtained from one laboratory by performing the measurement of twelve 15-mL aliquot portions of a sample collected from an open-breathing transformer. The results are given in Table 4

Table 4
An estimate of the repeatability ASTM D3612 Method C

D 3612 – 02

TABLE 7 Interim Precision Statement for Repeatability for One Laboratory

Run	H_2	O_2	N_2	CH_4	CO	CO_2	C_2H_4	C_2H_6	C_2H_2	C_3H_8	% Gas
#1	21	9636	42123	19	813	7300	248	27	94	8	6.0
#2	20	9727	42306	19	819	7332	248	27	91	9	6.1
#3	20	9906	43632	19	839	7382	251	29	88	9	6.2
#4	17	9847	43288	20	843	7566	262	30	91	9	6.2
#5	20	10303	44100	19	824	7165	242	27	83	9	6.3
#6	22	9483	43011	20	822	8170	281	33	94	9	6.2
#7	21	9831	42619	19	743	7615	262	30	86	9	6.1
#8	24	10588	45971	20	880	7736	264	31	87	9	6.6
#9	20	9865	42422	19	815	7629	262	28	85	9	6.1
#10	14	8964	38558	19	760	7477	266	31	86	9	5.6
#11	21	10636	45149	19	843	7461	255	30	83	9	6.5
#12	23	10612	50340	21	947	7818	261	29	88	9	7.0
Average	20	9950	43627	19	829	7554	258	29	88	9	6.2
SD	3	506	2792	1	52	270	10	2	4	0.3	0.3
RSD, %	13	5	6	4	6	4	4	6	4	3	5.4

The Dynamic Behaviour in the Transformers Insulation system

Dissolved Gas concentration varies within the insulating oil due the following:
See Figure 13 showing the variation of Dissolved Gas measured by an On line Gas Chromatograph

Absorption

A little-known fact that is that gasses are both absorbed by the paper insulation during decreasing temperature (ppm-in-oil decreases) and return to the oil (ppm-in-oil increases) during increasing temperature. This causes highly variable and mystifying results in periodic DGA

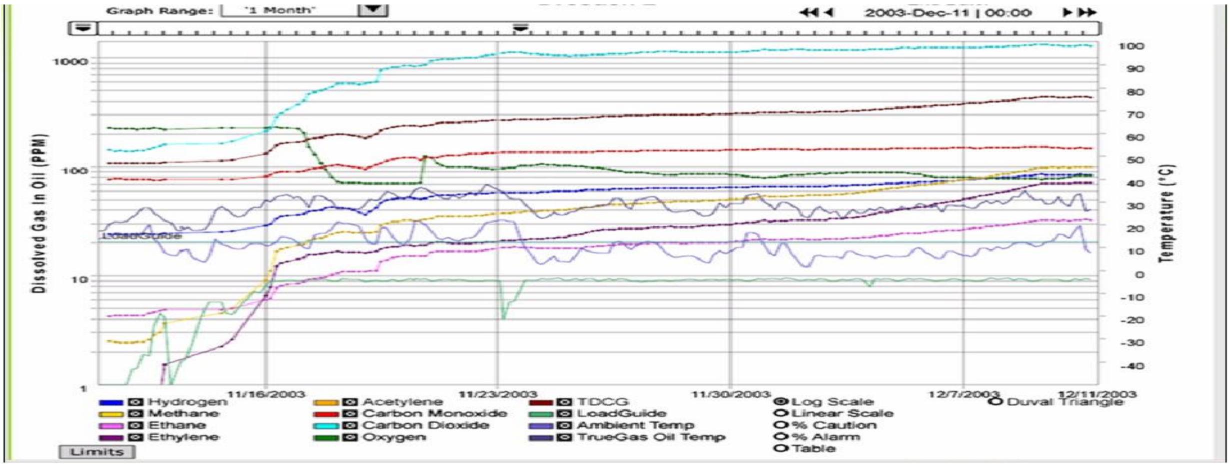
Diffusion

In the case of air-breathing power transformers, losses occur very slowly with time by diffusion through the conservator or as a result of oil expansion/temperature cycles, with the result that the measured gas levels may be slightly less than the gas levels actually formed in the transformer. However, there is no agreement concerning the magnitude of this diffusion loss in service.
Gas solubility changes as a function of Temperature.

Partitioning

Gases move back and forth between the surface of the oil and a headspace "chasing" equilibrium (same relative-saturation)
All gases slowly diffuse back & forth (chasing equilibrium).

Additional factors affecting dynamic behaviour of CO and CO_2 are: a) diffusion in and out of the oil impregnating the insulation chasing equilibrium and b) movement back and forth between the oil surface and a nitrogen blanket chasing equilibrium
Temperatures inevitably vary with daily and seasonal ambient temperature, load and cooling operation, so gases slowly diffuse in and out of the oil impregnating insulation "chasing" equilibrium with the main oil.



See Figure 13 Variation of Dissolved Gas measured by an On line Gas Chromatograph

Comparison of Different DGA Methods

Traditional oil testing methods are off-line sampling and laboratory techniques.
The terminology of off-line is confusing as the samples are taken while the transformer remains energised.

Modern technology has permitted the development and commercialisation of mobile on-site test and on-line methods with intelligent electronic devices which can record and trend results and trigger alarms.
On-line testing also eliminates the problems associated with oil sampling. After all, the test results are only as reliable as the samples obtained. So does this mean we will see the demise of current off-line interval based oil testing practice? Is the future of oil testing exclusively in on-line predictive diagnostics?

To answer this question we firstly need to understand the principles behind interval based oil tests for preventative maintenance.

These established off-line tests provide virtually all of the information required to determine the condition and operating status of a transformer.

They should be performed a minimum of once a year and more frequently for critical transformers. When a fault is detected sampling frequency must be increased to determine the deterioration rate.

In general the DGA tests performed in laboratory environments use far more sensitive equipment when compared to these portable and on line dissolved gas analysers.

Some On-Line monitors operate on the principle of measuring one or two key parameters namely hydrogen.
These monitors only supply a partial solution to the problem of On Line DGA.
Complete DGA monitors on the other hand offer the advantage of a full analysis and would seem to offer the ideal solution. Unfortunately they are very costly and suffer from maintenance and calibration issues. There are questions about their capability of operating in extreme environments. They are therefore not regarded as practical predictive diagnostic tools for general application, but do find use in the most urgent and critical situations.

Interval based DGA testing for preventative maintenance offers the advantages of presenting a complete picture of the condition and operating status of a transformer, provided sampling is sound. But there is a risk of not detecting rapidly developing faults. Cost is low at normal test frequency.

Continuous on-line fault detector/condition monitors will find application on critical units where the cost of faults not detected by traditional methods exceeds the cost of the monitors. They do not measure DGA real time as there is an interval between samples, usually hours. The analysis also takes some time complete as there is a sample preparation step followed by the measurement. This process normally takes about 20 minutes depending on the equipment.

Traditional periodic DGA oil testing will always have its place for reasons of lower cost and more comprehensive diagnostics capability.

Failure Event Regulator Transformers

On the 25/03/2005, the Regulator Transformers from BAY 12 and 21 tripped when undergoing energised testing without Load. The trip occurred due to the supply cables being cross phased at the Pot room.
The nameplate information for the Regulator transformers is as follows in Table 11.

Table 11: Regulator transformer nameplate data

Make: TRAFO UNION	Year Manufactured: 1994	Primary Voltage: 132 KV
VA Rating: 90.8 MVA	Vector Group: YNo2.5,d15	Impedance: 0.69%
Tap Changer: On Load	Oil Volume Liters: 35057	Conservator: YES

Insulating oil samples were sent for urgent DGA testing. Samples had been taken on the 03/031995 prior to energisation for compliance to IEC 60442 and to establish a DGA base line. The results listed Table 12 shows clearly the significant increase in DGA, indicating that both Regulator transformers had internal damage of an Arcing condition.

Table 12: Bay 12 and 21 Regulator transformer DGA data

	BAY 12	BAY 12	BAY 21	BAY 21
	06/03/1995	25/03/1995	06/03/1995	25/03/1995
Hydrogen H_2	0	**772**	0	**468**
Methane CH_4	0	155	0	131
Ethylene C_2H_4	0	61	0	237
Ethane C_2H_6	0	179	0	17
Acetylene C_2H_2	0	**171**	0	**541**
Carbon Monoxide CO	24	14	38	59
Carbon DioxideCO_2	203	249	249	205

DGA Diagnostics

The IEC 60599 Ratios indicated a Discharges of High Energy in both cases
The Key Gas method showed Arcing in Oil as did the other Ratio methods. The Gas concentration method would be confusing due to the high levels of gas.
There was significant gas increase in both units with the IEEE (c57.104-1991) giving a Condition 2: OPERATING PROCEDURE-Exercise extreme caution. Plan outage.
The recommendation was for an internal inspection of both units.

Internal Inspection

As the transformers were under warranty the inspection was conducted under the direction of OEM.
It was found that there was major damage to the internal 22kV reactor in both cases. The concern was that transformers should have been able to with stand the fault condition, this required further investigation. Unfortunately no photographs were allowed by the OEM as this was a new design that had resulted in them being awarded the tender, based on price. They did not want any competing Manufacturer to have access to this design.

Root Cause and the next step

The root cause was found to be a weakness in the Regulator transformer design. This had significant cost implications. The manufacturer had to change the design to an External 22kV Reactor for each Regulator transformer, which had later implications. Also one additional Transformer Bay was required for Pot line 1 and 2 at a cost of approximately R 70 Million per transformer bay.

Failure Event Interconnector

On the 23/10/2005, a gas alarm was triggered by the Buchholz relay on the Interconnector system. The Interconnector links the Regulator and Rectifier through a system of oil filled compartments using paper insulated copper conductor. This event occurred approximately 6 months after energisation.
See Figure 14 showing the how the Rectifier and Regulator Transformers are interconnected; the Cable Housing is to the right of picture.

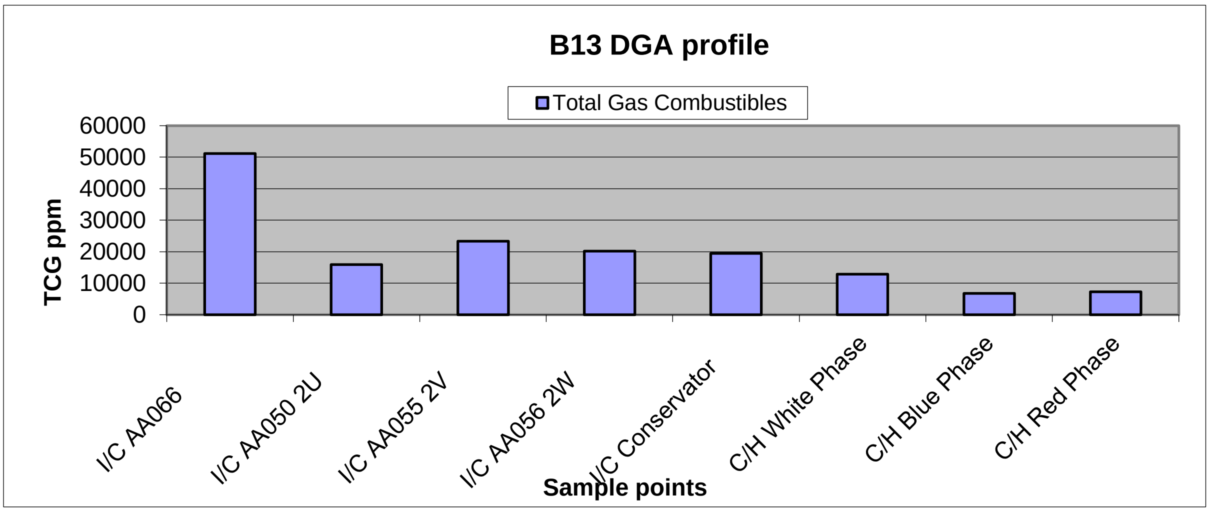
Figure 14
Interconnection system for the Rectifier and Regulator Transformers.

The OEM suspected a Corona (Partial Discharge-PD) problem on the Cable housing to be the cause of the gas generation. The repair of this kind of fault would involve a lengthy outage with specialist staff and equipment that would have to been flown in from Germany.

Samples were taken of the Buchholz gas and oil from the various sample points on the Inconnector system. The strategy was to use the DGA to classify the type of fault condition and to identify the compartment with the fault.

There is very little oil circulation in the interconnector so in theory the fault would be in the compartment with the highest gas concentrations. The Total Combustible Gas (TCG) levels as Listed in Table 13 show clearly that the location of the fault was not in the Cable Housing but at sample point (AA066), the main compartment between the transformers.

Table 13
DGA profile of samples



Diagnosis of DGA results

The results of the Main Compartment sample point AA066 where the greatest Dissolved Gas in oil were found is compared to the sample taken of the Buchholz gas.
See Table 14.
It is necessary to convert the concentrations of the various gases in the free state into equivalent concentrations in the dissolved state, using the Ostwald coefficients, before applying the gas ratio method, and to compare them to the dissolved gas concentrations in the oil of the relay and the main tank.

The calculation is made by applying the Ostwald coefficient (k) for each gas separately.
K=[gas in liquid phase] ÷ [gas in gas phase]

Table 14
DGA results of Buchholz gas and Main compartment

DGA ppm	Buchholz Gas	I/C AA066
Hydrogen H_2	12034	12299
Methane CH_4	25855	14892
Ethylene C_2H_4	16722	12220
Ethane C_2H_6	5120	11295
Acetylene C_2H_2	20	65
Carbon Monoxide CO	560	424
Carbon Dioxide CO_2	2885	3733
TCG	51195	12299

IEC 60599 DIAGNOSIS: Thermal fault of medium temperature range 300°C-700°C
Typical Examples: Local overheating of the core due to concentrations of flux. Increasing hot spot temperatures; varying from small hot spots in core, overheating of copper due to eddy currents, bad contacts/joints up to core and tank circulating currents

IEEE (c57.104-1991): Condition Code 4: OPERATING PROCEDURE-Exercise extreme caution. Plan outage.

Internal Inspection and findings

The internal inspection of the Main Chamber found burnt (overheated) connections. See Figures 15A-B the connections overheated because they had not been tightened to the Manufacturers specification.

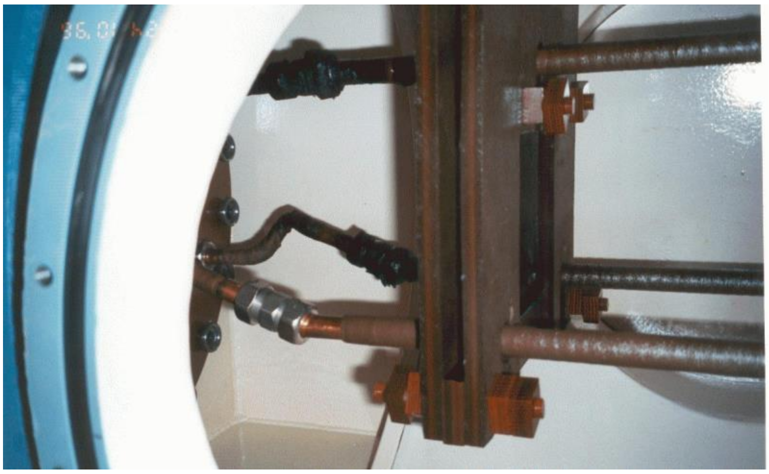


Figure 15(A)
Burnt (overheated) connections

Figure 15(B)
Burnt (overheated) connections

Root Cause and Savings

The root cause was found to be being non-conforming quality control during installation Savings in the R Million range: By accurately diagnosing the fault type and location the manufacturer saved significant time and equipment to effect repairs.
The smelter saved minimum down time on production

Predicted fault on the Reactor Transformers

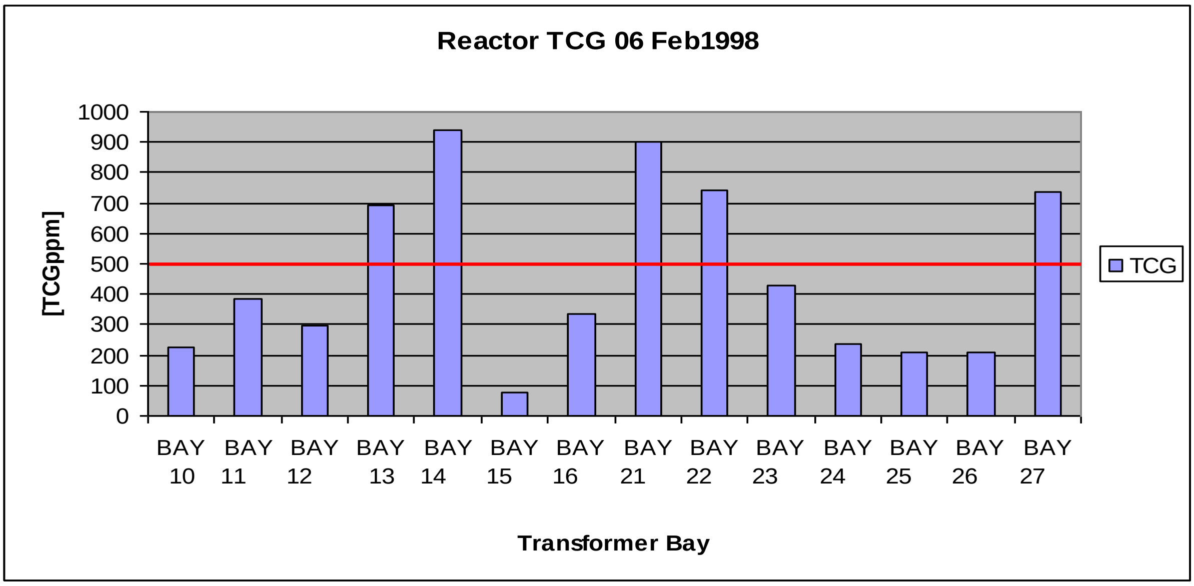
The program of installing External 22 kV Reactors onto the main Regulator started in July 1996. The Reactor name plate details are listed in Table 15. Insulating oil samples were taken prior and after Energisation in accordance to IEC 60422 with all results being normal. The transformers were then sampled on a regular basis as part of a Condition Monitoring program.

Table 15
Reactor transformer nameplate data

Make: TRAFO UNION	Year Manufactured: 1995	Primary Voltage: 22 KV
VA Rating: 1075 kVar	Oil Volume Litres: 2874	Conservator: YES

Routine DGA samples taken on 06/02/1998 showed a significant increase of Total Combustible Gas in a number of Reactors. See Table 16 showing the profile of results. The transformers from BAY 13: 14: 21:22 and 27 showing the most significant increases.

Table 16
Total Combustible Gas profile of Reactors at 06 February 1998



Diagnosis of DGA results

The IEC 599 Ratio for transformers with Combustible Gas levels >500 ppm gave the fault condition as a Thermal fault of high temperature range >700°C.
The IEEE (c57.104-1991) gave a Condition Code 2 with the operating procedure in certain cases being to Advise Manufacturer or Plan outage.

It was recommended to remove one of these transformers from service for an internal inspection.

The manufacturer's contention was that these were normal gassing patterns for Reactor transformers as there was an internal resistor bank that generated heat during normal operation.
This theory is not supported by the Halstead model. The science behind gas production and temperature was published in J. Inst Petroleum 1973 by WD Halstead of CEGB R&D.
The evolution of gases from oil is a function of the Decomposition Energy (temperature).
In simple terms, from a Chemist's perspective, a Transformer is a chemical reactor that just happens to transform electricity.
The other anomaly was the different gas levels in the Reactors. If there was normal internal operation, the gas levels would be expected to be uniform.

The frequency of oil sampling was increased as the transformers were under warranty and the manufacturer ultimately had the final decision on whether to remove a transformer from service for inspection.

BAY 22 Reactor Transformer.

All the reactor transformers were sampled on a frequent basis following the significant rate of DGA rise in February 1998. The frequency of sampling was decreased when it was observed that the Dissolved Gas levels had stabilised. However a sample taken on 20th July 1999 from BAY 22 Reactor showed a more than significant increase. A further sample was taken 24th July 1999 for confirmation and to monitor the Gas production. See Figure 16 giving the Graph trend and Gas Signatures.

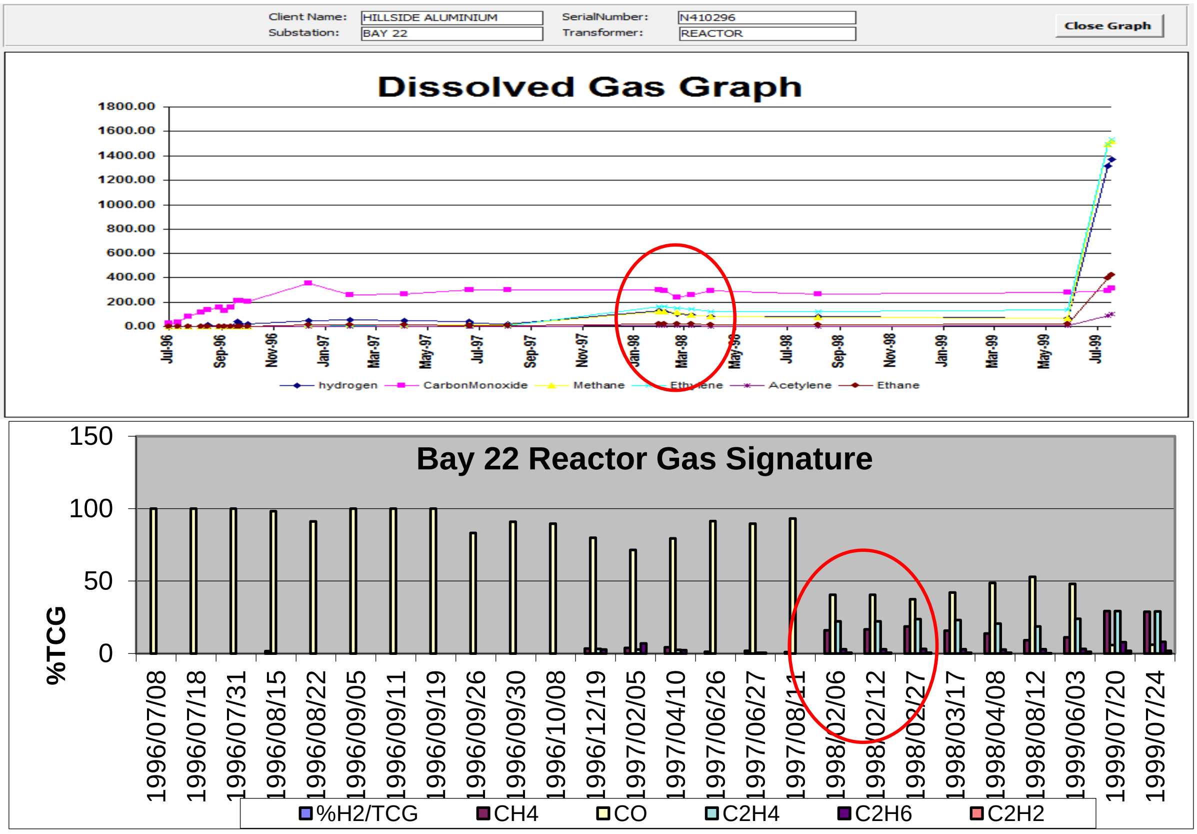


Figure 16
DGA graph trend and Signature

Diagnosis of DGA results

The fault classification had not changed from 06/02/1998 with the IEC 599 Ratio's giving a Thermal fault of High temperature range >700°C. The other Ratio methods gave a similar fault condition.
The IEEE (c57.104-1991) gave a Condition Code 4 with the operating procedure to plan an outage.
The individual Gas production was far in excess of normal levels as defined in the IEC 60599 and by Morgan-Schaffer.
It was recommended to remove this unit from service immediately as the risk of catastrophic failure was considered to be too great. See Figures 17 and 18A/B

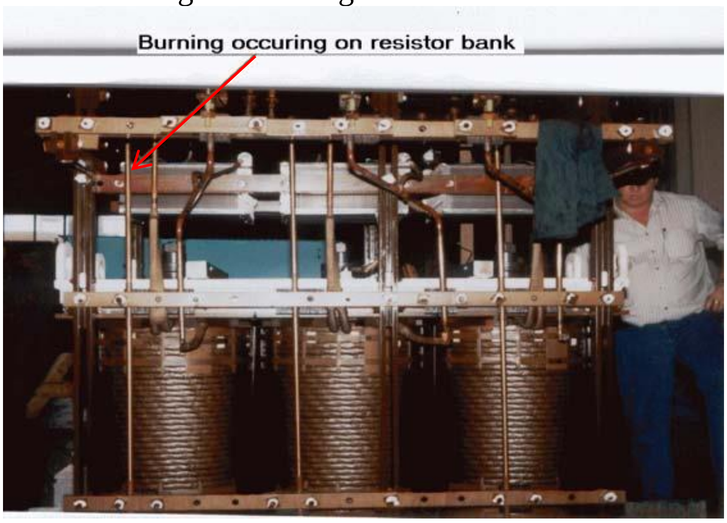
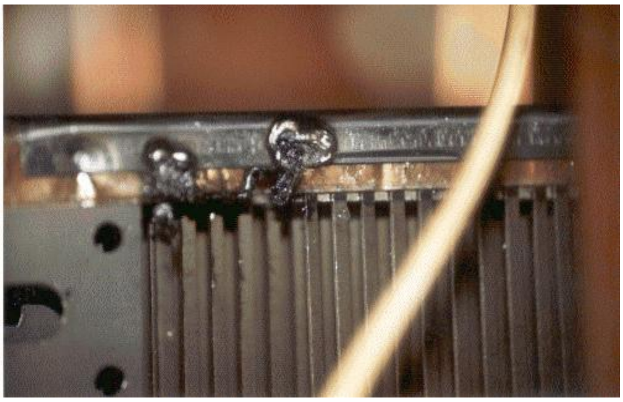


Figure 17
Showing the point on the Resistor bank where the Overheating was occurring



(A)

(B)

Figure18
A-showing the actual point of burning on the resistor bank point and 18 B-showing a metal strip that had burnt off the resistor bank.

Root cause

The unit was returned to service after repairs but the root cause had not been established. The initial theory was that the cross sectional area of the metal strips was insufficient for the magnitude of the current.

BAY 13 Reactor Transformer

On the 05th November 1999, a gas trip was triggered by the Buchholz relay. The urgent DGA on the oil sample confirmed an arcing condition (IEC 599-Discharge of high energy). This transformer also had a gassing pattern showing a thermal fault with the initial indication in February 1998. See Figure 19 giving the Graph trend.

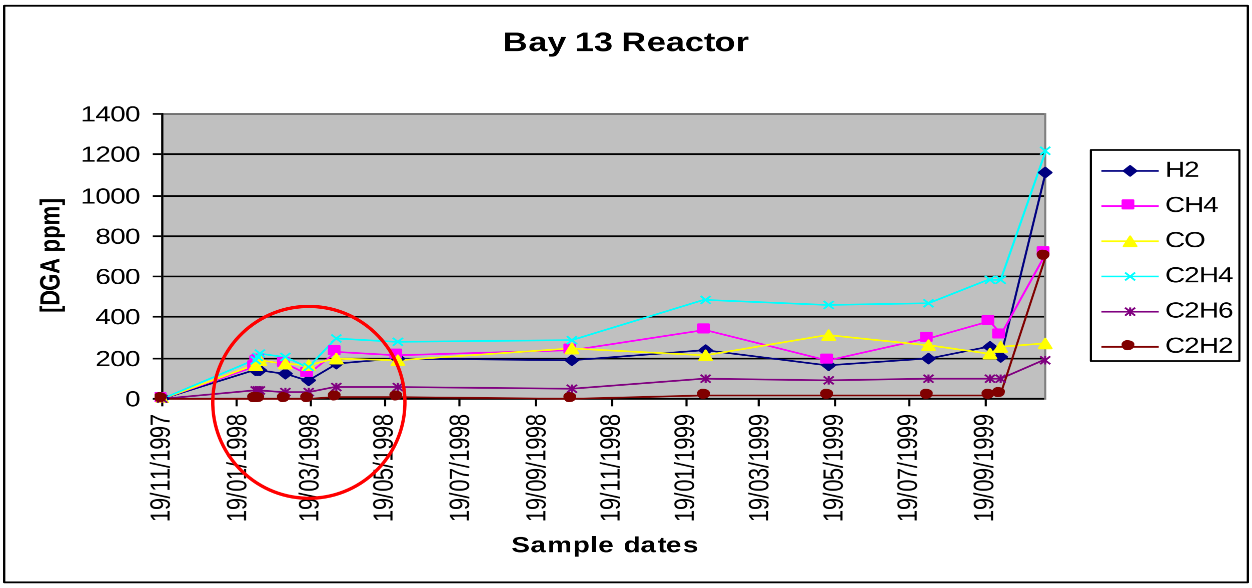


Figure 19: DGA trend

The transformer was removed to a Works Facility for Inspection and repairs. See Figure 20

Figure 20: Reactor transformer being De-tanked at the Works facility

Internal Inspection and findings

The internal inspection found overheating and burning on the resistor bank and a flash-over had occurred on the bare copper conductor above the resistor bank. See Figure 21.
Figure 22 A-shows the actual point of overheating on the resistor bank point and 22 B-shows the point of flash-over with the carbonisation on the copper conductor.

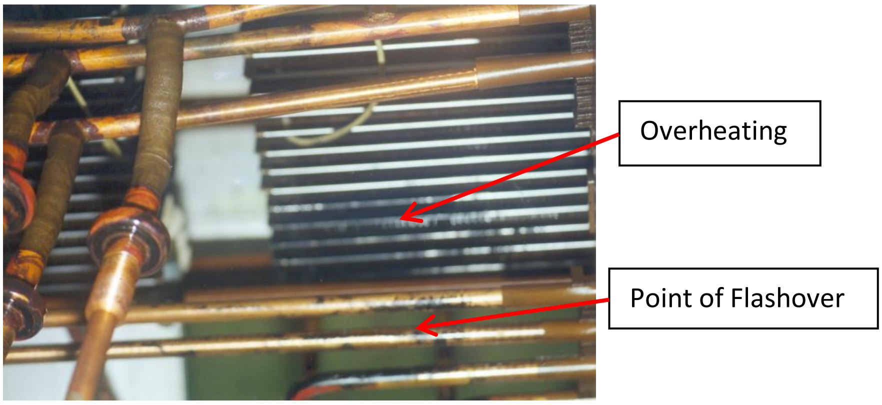
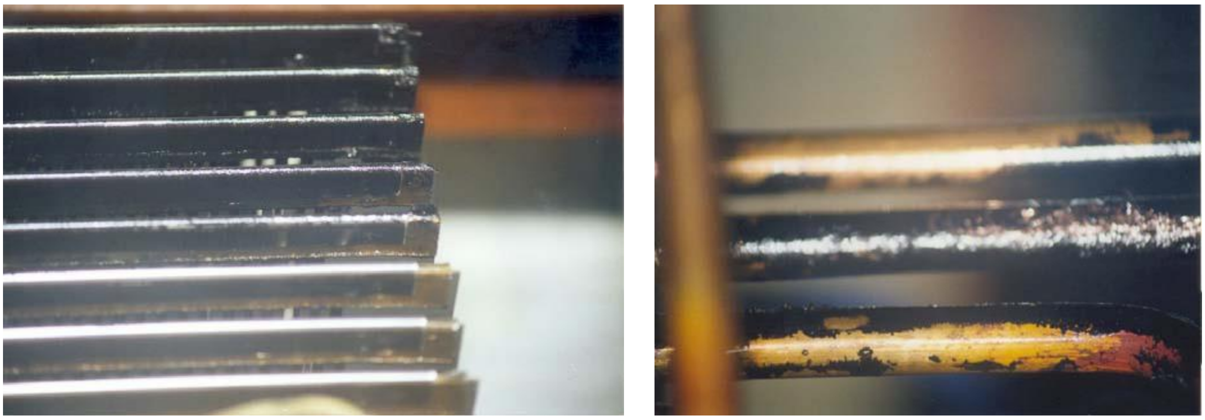


Figure 21
Showing the overheating on the resistor bank and the point of flash-over



(A) (B)
Figure22 A-B
Showing the overheating on the resistor bank and the point of flash-over

Mechanism of the flash-over and Root cause.

The overheating on the resistor bank as a result of voltage stress caused gas bubble formation. Gas bubbles have a lower dielectric strength than either oil or the oil-impregnated solid insulation under normal conditions. Bubbles therefore can be a source of partial discharge activity or in this case a discharge of high energy.
The voltage stress is inversely proportional to the dielectric constant and therefore gas bubbles are much more stressed than the surrounding oil and solid insulation.

The root cause of the overheating or overstressing of the resistor bank had still not been established. The manufacturer appointed specialist consultants to investigate the problem.

BAY 13 Reactor Transformer

On the 21/01/2001, another gas trip was triggered by the Buchholz relay. The urgent DGA on the oil sample again confirmed an arcing condition (IEC 60599-Discharge of high energy). It is interesting to note that the sample taken 24/12/1999 was already indicating a discharge of high energy due to the overstressing of the resistor bank. See Figure 23 giving the Graph trend.

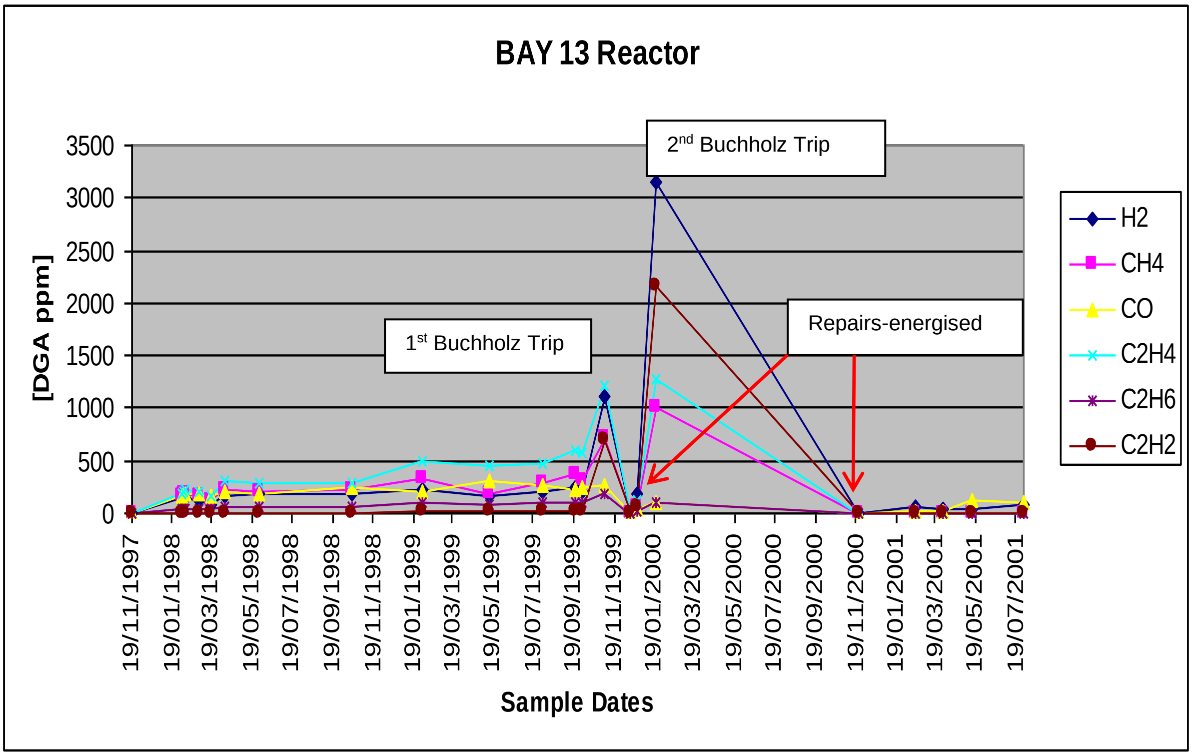


Figure 23
DGA Trend

Root cause and the next step

After extensive studies by the Specialist Electrical consultants the root cause was established as the Fifth Harmonic being amplified within the transformer causing it be subjected to 10 times its rated current for a couple of milli-seconds. Design fault involving the power factor correction. (Weakness in design).

This had significant cost implications. The manufacturer had to change the design of the power factor correction.
This also involved removing all the External 22kV Reactor transformers from service.

Partial Discharge in 22 kV Transformers predicted by DGA

Partial Discharge (PD) activity

A partial discharge is an electrical discharge or spark that bridges a small portion of the insulation between two conducting electrodes.

Partial discharge can occur at any point in the insulation system, where the electric field strength exceeds the breakdown strength of that portion of the insulating material.

Partial discharge can occur in voids within solid insulation, across the surface of insulating material due to contaminants or irregularities, within gas bubbles in liquid insulation or around an electrode in gas (corona activity).

The process of deterioration can propagate and develop, until the insulation is unable to withstand the electrical stress, leading to flashover.

The ultimate failure of HV/MV assets is often sudden and catastrophic, producing major damage and network outages.

Partial Discharge (PD) Detection and Measurement Technologies

There are four main PD techniques that are available.

- Oil sampling to detect dissolved gases (DGA).
- Surveys using UHF interference detection
- Electrical measurement of individual discharges using sensors on the bushing tap, neutral or inserted into the tank.
- The use of probes to locate the PD site

In 1996 a number of Plant Distribution transformers showed severe Partial Discharge (PD) activity detected by DGA in samples taken part of the Condition Monitoring program. The typical nameplate information is as follows in Table 16.

Table 16
Transformer nameplate data

Make: GEC	Year Manufactured: 1994	Primary Voltage: 22 kV
VA Rating: 1600 KVA	Vector Group: Dyn11	Secondary Voltage: 400V
Tap Changer: Off Load	Oil Volume Litres: 1316	Conservator: No

Case Example 1: Significant Partial Discharge activity.

The DGA on this transformer showed abnormal levels of hydrogen and methane and a further sample found significant increases in these gasses. See table 17-DGA results.

Table 17
DGA results

DGA[ppm]	29/11/1996	03/02/1997
Hydrogen H_2	10721	13079
Methane CH_4	729	855
Ethylene C_2H_4	0	14
Ethane C_2H_6	223	239
Acetylene C_2H_2	0	0
Carbon Monoxide CO	285	336
Carbon Dioxide CO_2	2609	2562
TCG	11958	14514

Diagnosis of DGA results

Various DGA diagnostic codes are compared for the DGA data on 03/02/1997.
The ratio methods are listed in Table 18. Key gas and signatures are given in Figure 24 A and B.
Table 18 gives the Gas production rates.
The operating procedures are given in the Westinghouse guidelines-Table 20 and the IEEE (c57.104-1991) in Table 21.

Table 18
IEC 60599: Rogers: Duval Ratios

IEC 599 DIAGNOSIS OF GAS SAMPLE DATA

C_2H_2/C_2H_4	C_2H_4/C_2H_6	CH_4/H_2	$C0_2/C0$
0	0.1	0.1	7.6

Normal C02/C0 Ration (>3 and <11)

Fault: Partial discharges of low energy density

Typical Examples: Discharges in gas-filled cavities resulting from incomplete impregnation, or super-saturation or cavitation or high humidity

ROGERS RATIO DIAGNOSIS

CH_4/H_2	C_2H_6/CH_4	C_2H_4/C_2H_6	C_2H_2/C_2H_4
0.07	0.28	0.06	0

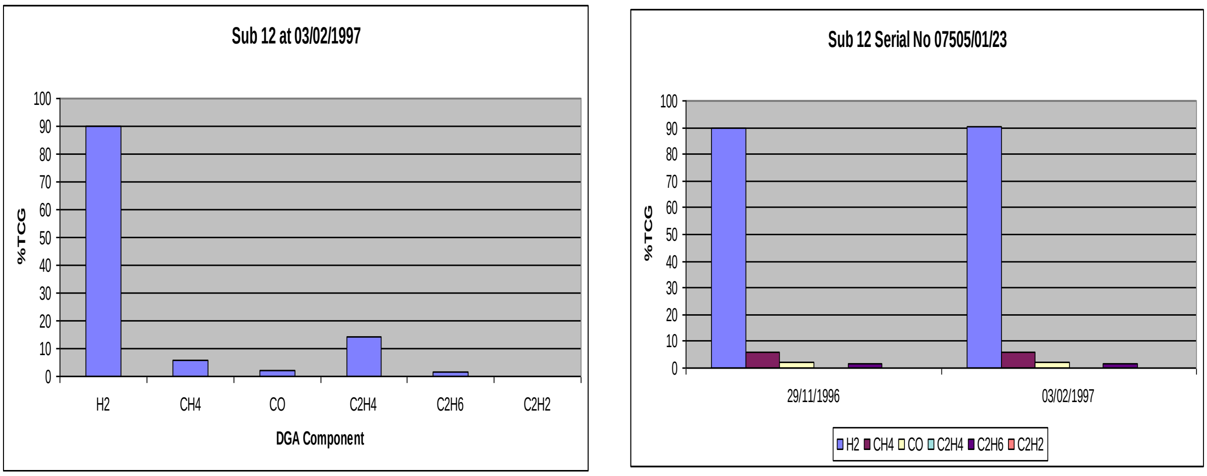
Suggested Diagnosis: Slight Overheating-to 150°c

Duval Triangle

% CH_4	%C_2H_4	%C_2H_2
98	2	0

Symbol: PD-Fault Partial Discharges

Examples: Discharges of the cold plasma (corona) type in gas bubbles or voids, with the possible formation of X-wax in paper.



(A) (B)

Figure 24 A/B
Key gas method and DGA signatures

Table 18
Gas Production Rates

GAS PRODUCTION RATES			MORGAN-SHAFFER TABLES	
From 29/11/1996 to 03/02/1997				
Dissolved Gas		ppm/day	Norm	Serious
HYDROGEN	(H2)	**35.72**	0.1	2
METHANE	(CH4)	**1.91**	0.05	6
ETHANE	(C2H6)	**0.23**	0.05	6
ETHYLENE	(C2H4)	**0.21**	0.05	6
ACETYLENE	(C2H2)	0	0.05	1
CARBON MONOXIDE	(CO)	0.77	2	10
CARBON DIOXIDE	(CO2)	-0.71	6	20

Table 19
Westinghouse Guidelines

TOTAL COMBUSTABILE GAS LEVEL (Westinghouse guideline)	Recommended Action
Total Combustible Gas(TCG): 14523 ppm	Make weekly analysis to determine gas production rates. Contact manufacturer

Table 20
IEEE (c57.104-1991) Condition codes

IEEE (c57.104-1991)		
TOTAL COMBUSTIBLE GAS (TCG)	PRODUCTION RATES ppm/day	OPERATING PROCEDURE
From 29-11-1996 to 03-02-1997	220.0	Condition 4: Consider removal of service

All the DGA diagnostic methods indicated a problem with the conclusion that the transformer be returned to the manufacturer for inspection and repairs.

Internal Inspection and findings

The initial response from the manufacture was that the unit had passed all Electrical testing prior to leaving the factory.
The following electrical tests were performed prior to the Visual inspection.

- Winding insulation Resistance: Satisfactory
- Induced Over voltage at 75%.
- Separate Source at 75%.
- Core Insulation Resistance: measured at 5000 MOhms. After detanking, 5000 MOhms.

Internal Inspection

The following is a list of the findings:
The internal earth strip that links the core with the external core bushing was found to be loose. See Figure 25 A
Sediments were detected to be deposited over the top frame channel as well as on the bottom of the tank. Carbon marks were detected over the bottom core-clamp insulation-See Figure 25B.

(A)

(B)

Figures 25
A and B showing the findings

Root cause.

The discharges were produced between adjacent core loops due to inappropriate insulation.

Continuation of Partial Discharge problem

The transformer was repaired by the manufacturer in February 1997; however DGA samples taken after re-energisation showed that the repairs had not been effective. The unit was returned to the manufacturer in August 1999 for further repairs that were effective.
See Figure 26 Showing the DGA trend which also acts as a timeline.

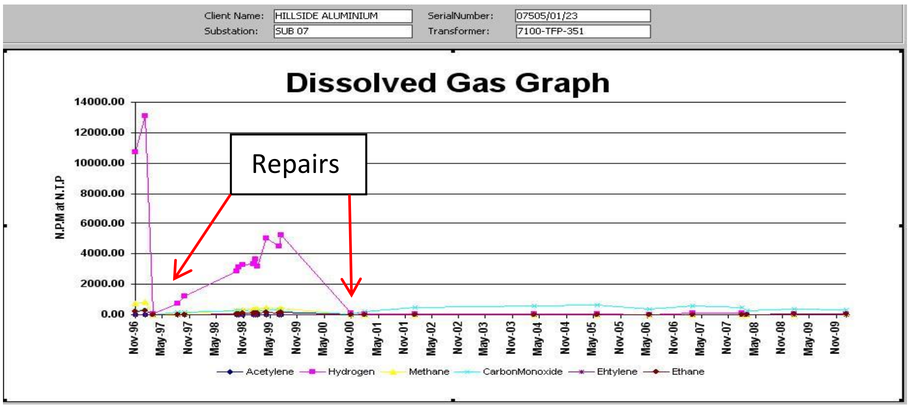


Figure 26
DGA Trend

Case Example 2: Significant Partial Discharge activity

The DGA on this transformer showed abnormal gas production of hydrogen and methane. See Table 22 giving the name plate data and Figure 27-shows the DGA trend. Although the actual levels were only in the elevated range according to the CSUS, the production rates and Ratio methods provided enough evidence of serious Partial Discharge activity. The design review was also considered when taking the decision to remove it from service for an internal inspection. Previously four similar transformers had been returned to the manufacturer.
In all of the cases DGA had identified the Partial Discharge.

Table 22
Name Plate Data

Make: GEC-ALSTHOM	Year Manufactured: 2007 1994	Primary Voltage: 22 kV
VA Rating: 2000 KVA	Vector Group: Dyn11 YNo2.5,d15	Secondary Voltage: 400V
Tap Changer: Off Load	Oil Volume Litres: 1529 35057	Conservator: Yes

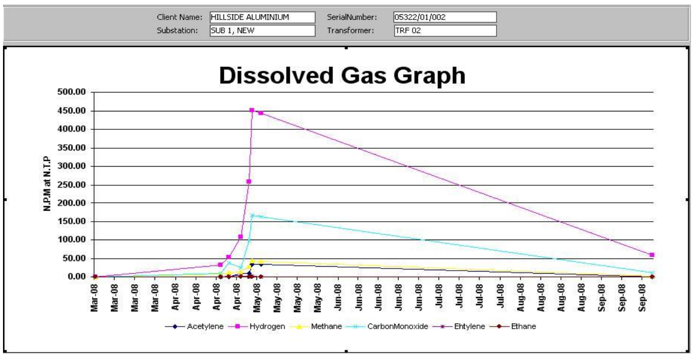


Figure 27
DGA trend

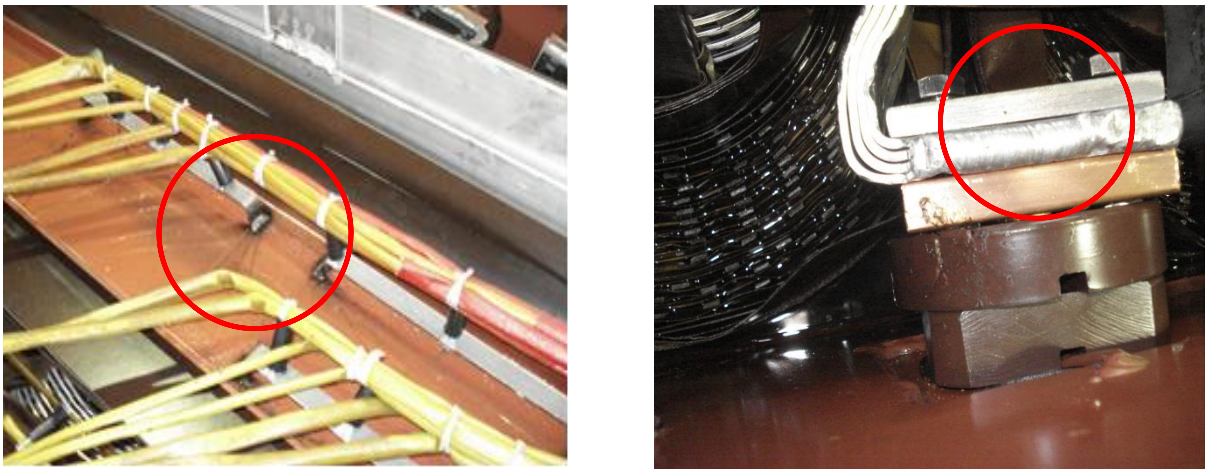
Internal Inspection and findings

Partial discharge-See Figures 28 A: B: showing the activity.

- Partial discharge activity evident between the bottom of the U-frame and bottom of the tank.
- Electrical activity observed on the U-frame fixing brackets and bolting arrangement.
- Partial discharge activity manifests in pitting and carbon deposits.
- Alstom is of the opinion that the partial discharge observed is the root cause of the excessive gas generation.
- The rest of the active part shows no additional signs of tracking or discharge.

Quality issues

- LV busbar welded connections from winding to bushing showed cracks on at least three areas
- Bushing crack observed on LV c phase
- Bushing damage observed on LV a phase



(A) (B)

See Figures 28 A and B
Showing the Partial Discharge activity

Root Cause and Savings

The root cause was established to be weakness of design and non-conforming quality control during manufacture.

Savings in the R Million range was achieved by accurately diagnosing the fault type during warranty. The transformers were repaired under warranty.

Thermal Faults detected by DGA.

Case Example 1: Jockey Rectifier Transformer

The DGA on this transformer showed abnormal gas production of hydrogen, methane, ethylene and ethane about 20 months after Energisation. The fault condition was diagnosed as a thermal fault of medium temperature in the range 300°C-700°C. The recommendation was to remove from service for Inspection. See Table 23 giving the name plate data and Figure 29-shows the DGA trend and Figure 30 the DGA signature.

Table 23: Name Plate Data

Make: VTD(VALDAGNOY)	Year Manufactured: 2002 1994	Primary Voltage: 22 kV
VA Rating: 5160 KVA	Vector Group: Dyn11 YNo2.5,d15	Secondary Voltage: 120V
Tap Changer: Off Load	Oil Volume Litres: 12644 35057	Conservator: Yes

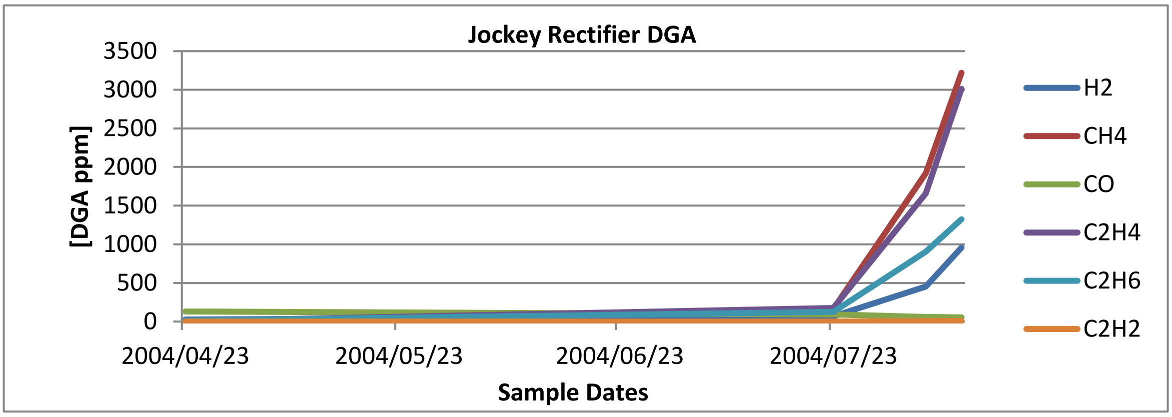


Figure 29: DGA Trend

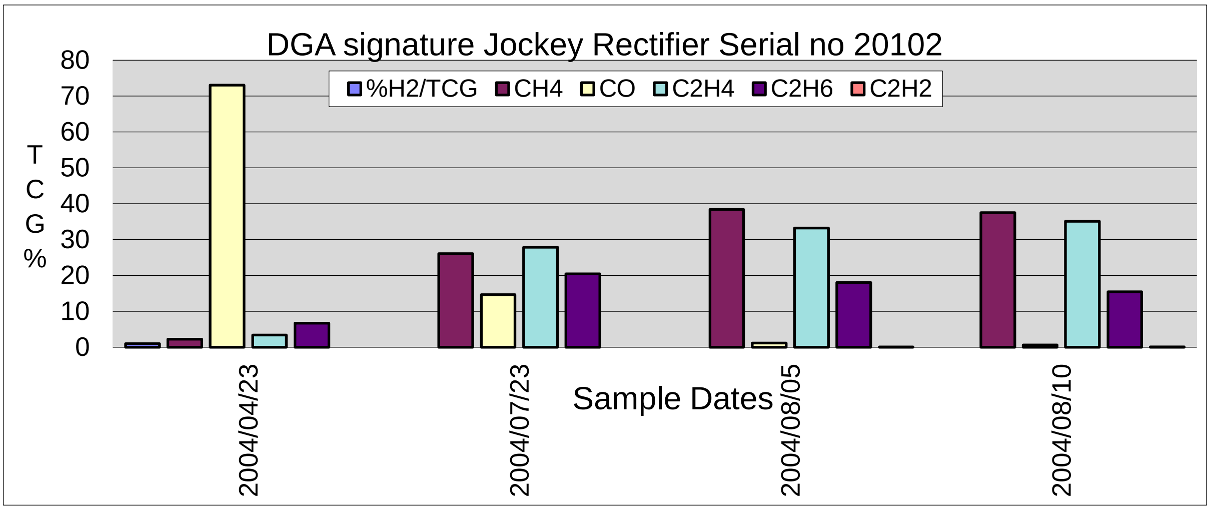


Figure 30: DGA signature

Internal Inspection and findings

Further inspection revealed the existence of at least one more closed loop formed by the earthing connections of the other steel parts for the neutral clamping structure.

The overheating occurrence only became evident because the connection presented high resistance for the unintentional circulation current in service. See Figure 31.

In addition, the clamping bolts for the six sets of phase windings were also found to have created at least two major loops for circulating currents due to unintended multiple earthing. The clamping bolts and the upper and lower metal frames formed loops into which current was induced.

These loops were the result of obvious mistakes in application of the insulation for the clamping bolts to maintain single point earthing for the frames and metal clamping rings for the windings. Each set of windings has its own metal clamping frames and clamping rods. It was evident that similar situations were created for circulating currents on both the upper and lower sets of windings.

At least one insulation washer between a bolt and an upper frame exhibited signs of overheating by the flow of circulating currents.

The earthing via the clamping bolts was obviously intended to earth the split metal winding clamping rings without creating loops between the upper and lower frames. This was however not achieved in practice.

One clamping bolt was identified as having incorrect insulation washers. That is, insulation on the one side of the hole through the frame but none on the other side.

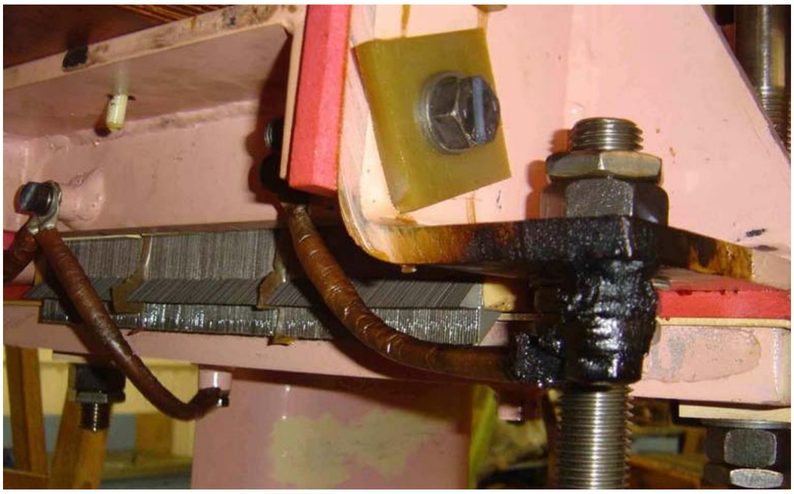


Figure 31: Termination for potential connection became a hot spot due to circulating current

Conclusion

The transformer was repaired at a works facility under the warranty of the OEM.

Case Example 2: Rectifier Transformer

The DGA on this transformer showed abnormal gas production of hydrogen, methane, ethylene and ethane about 20 months after energising. The fault condition was diagnosed as a thermal fault of Medium temperature in the range 300°C-700°C. The recommendation at 30/09/1996 was to remove the unit from service for Inspection.
See Table 24 giving the name plate data and Figure 32-shows the DGA trend with Figure 33 showing the DGA signature.

Table 24: Name Plate Data

Make: TRAFO-UNION	Year Manufactured: 1995	Primary Voltage: 132 kV
VA Rating: 93.5 MVA	Vector Group: 111,D11+1	Secondary Voltage: 1060V
Tap Changer: On Load	Oil Volume Litres: 33908	Conservator: Yes

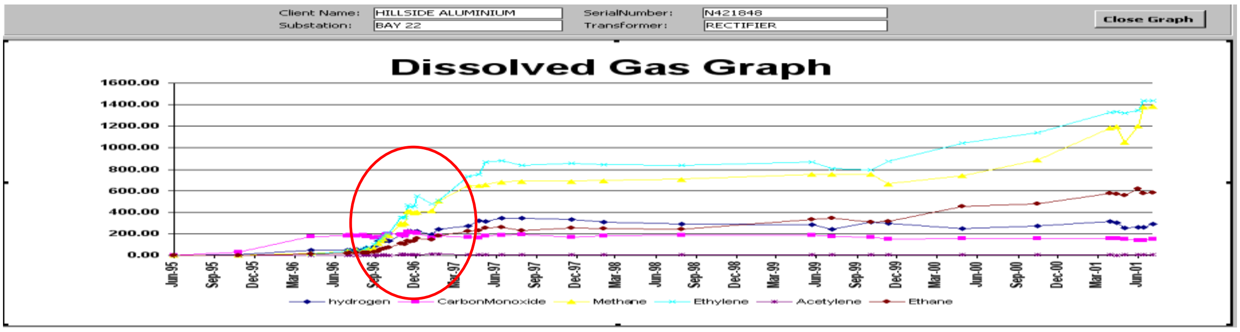


Figure 32
DGA trend up to July 2001

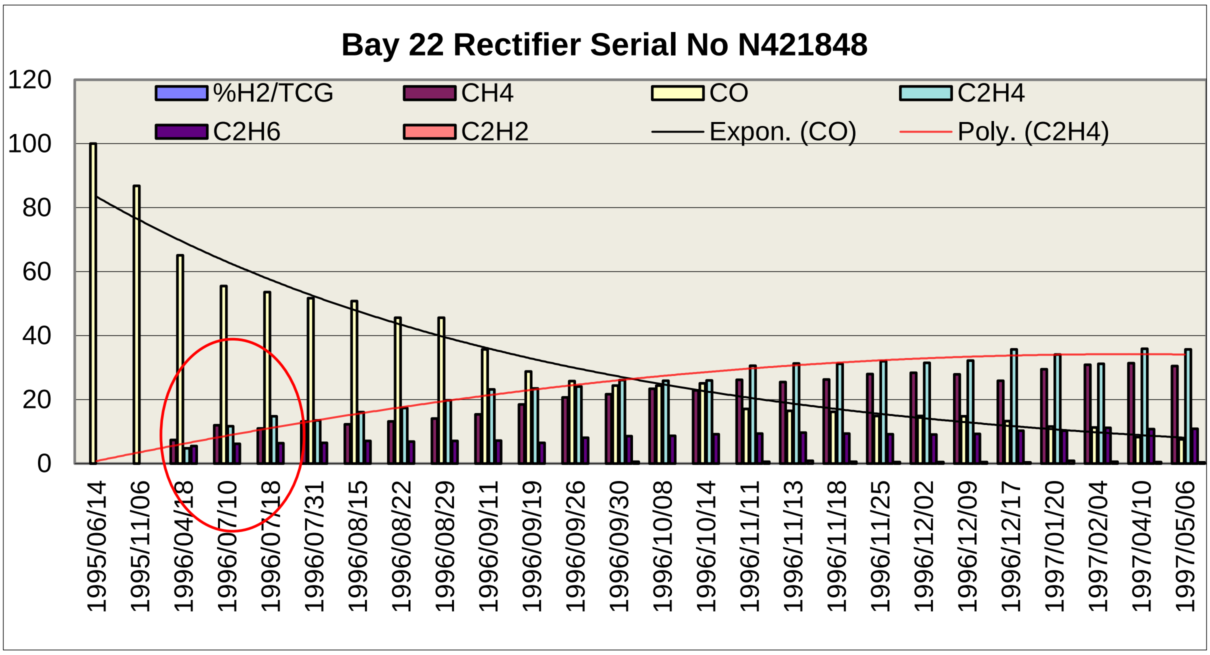


Figure 33
DGA Signature up to July 2001

Condition Monitoring and failure event: Bay 22 Rectifier

The manufacturer's contention was that, although this was not a normal gassing pattern it was not serious enough to warrant removing the unit from service. The manufacturer's in-house expert advice was to monitor the gassing pattern until exponential increase was seen.
The exponential rise can be seen from 1996 to 1997. See Figure 34.

The frequency of oil sampling was increased as the transformer was under warranty and the manufacturer ultimately had the decision on whether to remove a transformer from service for inspection.
It is interesting to note the gas production after July 1997 showed only a slight rate of rise. See Figure 29. However, after the oil de-gassing in July 2001, the same phenomenon of exponential gas production followed by a levelling off was seen. See Figure 32. This can be explained in part by the IEC 60599 code that reports that there can be gas diffusion losses for in service equipment. However, there is no agreement concerning the magnitude.

There are also reports of gas adsorption by the solid (paper) insulation.

This transformer was ranked as having the highest risk of failure, based on the DGA-Total Combustible Gas profile-See Figure 31 showing all Rectifier transformers at July 2001.
The condition was monitored by regular oil samples. On-line DGA was considered.

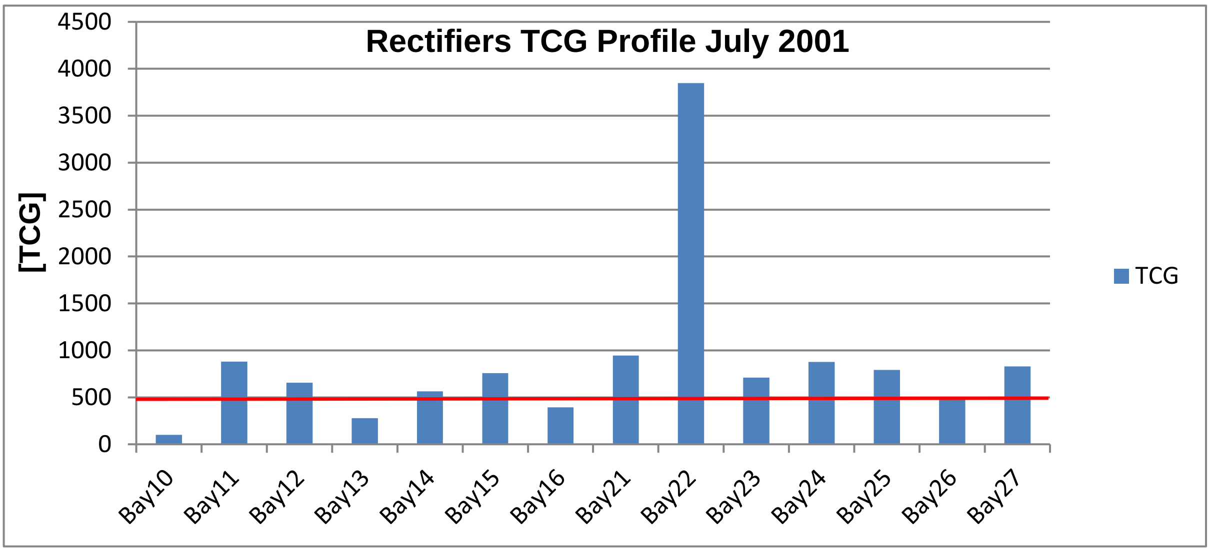


Figure 34
Total Combustible Gas Profile at July2001

Failure Event

At 16:32, on the 18 November 2005, Transformer T22 failed catastrophically. An urgent DGA sample confirmed that a discharge of high energy (Arcing) had occurred. See Figure 35 showing the DGA trend

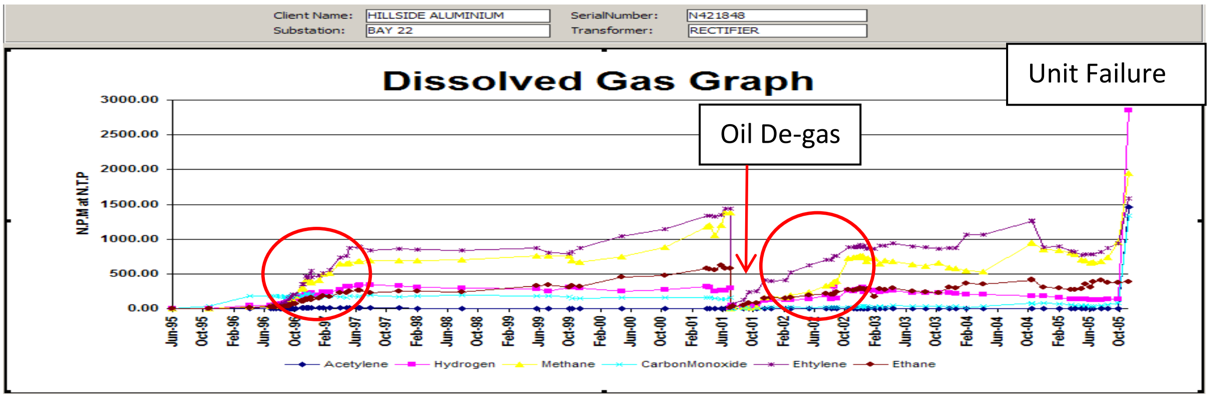


Figure 35: DGA trend

When T22 transformer failure developed the entire sequence of events, equipment failures and trips were over in approximately one second.

- T22 faulted internally caused upstream circuit breaker to trip and simultaneously induced a high voltage in the rectifier and Potline 2 d.c. busbar system.
- The d.c. busbar system, now at elevated voltage, flashed over at the point of lowest insulation level. This happened to be at reverse current relays at T23 and T27, which had been supplied with metal screws instead of insulated screws originally.
- Effectively, as a result of the flash-over, potline voltage (1000V higher) was "connected" to low voltage circuits at the rectifiers. This caused various low voltage equipment failures at the rectifiers and the loss of Potline 1 as well. (The 125V d.c. supply is common between Potline 1 and 2.
- The elevated voltage on the potline d.c. bus resulted in the insulation level of the Potmicros being exceeded, damaging a number.

Fault type. Red phase,HV-LV-Core-Tank-Earth Fault

Consequence of the Failure

- 900 MW wiped off the National Grid
- Potline 1 offline for 75 min
- Potline 2 offline for 145 min
- Major impact to Production (output and process stability)
- Damage to critical Control circuits
- Loss of N-1 redundancy in Transformer Supply

Disaster Averted

An outage of more than 180 minutes often leads to a prolonged shutdown of an Aluminium plant – up to a year
Zero injuries sustained.

Failure Investigation

On the 21-12-05 the transformer HV and LV winding on the ‘A’ phase were removed and the core exposed.
‘A’ Phase High Voltage winding open circuit and flashed to core. See Figure 36.
The flash mark on the A-phase LV winding was on the outer surface of the disc at the bottom of the winding. The blocks underneath the winding showed movement as a result of the flash over between the A- phase HV winding and core.

Figure 36
Shows the damage on the HV winding

Burning in the vicinity of the top core earth strap between A and B phases as a result of the fault currents during the HV flash over. See Figure 37A.
Overheating of the Core. See Figure 37 B.

(A)

(B)

Figures 37 A and B
Show the sites of Overheating

Mechanism of the flash-over and Root cause

The production of gas in the HV winding seems to have leaked past the LV winding affecting the dielectric strength of the oil between the LV winding and the tank. This resulted in a secondary flash over from the LV winding to the tank.
The root cause was not established at this stage. To establish the root cause a tear down was planned for Bay 21 Rectifier as this transformer was ranked as having the highest risk of failure of the surviving units

Investigation: Bay 21 Rectifier

As part of the investigation, Doble Engineering was requested to electrical test and review the DGA data. The findings are as follows:
The excitation current tests were performed at 1 kV for all phases. It was found that the exciting currents were higher than expected. The abnormal exciting currents generally are a result of two conditions which are as follows:

(a) Core related defects:
(i) Shorted laminations (increase in eddy currents); and
(ii) Circulating currents in the core, frame and tank.
(b) Defective bolted or welded joints on current carrying parts.

The Sweep Frequency Response Analysis revealed significant problems with the HV winding.

The Doble DGA scoring system scores this transformer between 80 and 100. The DGA signatures are indicative of a localized thermal fault probably of the 'bare metal' rather than 'covered conductor'. This type of gas generation is indicative of the following:

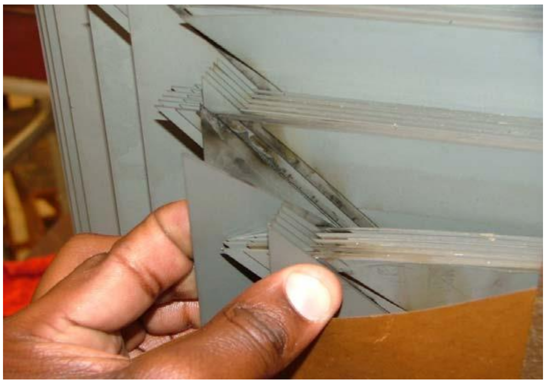
(a) General overheating, namely, abnormal rise of the oil temperature due to cooling deficiency, poor distribution of oil flow, core overheating
(b) Local core overheating associated with the main magnetic flux
(c) Local core overheating associated with stray flux
(d) Clamps in magnetic shields
(e) Current carrying connection as a result of joints which will increase contact resistance and oil overheating.

However, the absence of hydrogen and acetylene discounts any form of winding (paper) involvement and arcing/sparking.

Internal Inspection and findings

- Striking resemblance of core defect between T22 and T21. See Figures 38 A and B.
- Caused by stray magnetic fields induced by high currents on LV winding
- Field interaction with core at overlapping joints causes local heating
- Local heating gives rise to gassing

Root cause of gassing was attributed to a poor shielding design or reduced cross sectional area of core



(A)

(B)

Figures 38 A and B
Show the Core overheating. A is T21 and B is T 22

Conclusions

Fault and failure investigations on power transformer components have an important role in improving reliability and managing the risk of transformer failure. The identification of the primary cause of failure and the subsequent analysis enable, recommendations for corrective action to be made that hopefully will prevent similar failures from occurring in the future.

When design error and/or weaknesses developing over time are uncovered, enhanced monitoring/investigation on sister units built by same manufacturer will help in preventing future failures and therefore aid in managing the risk of unexpected failure.

Transformer manufacturers need to balance the cost of equipment with reliability.
The transformer problems at the Hillside smelter fit the Bath Tub Life Cycle Model
The application of DGA was 100% successful in identify the faults at early life. DGA oil testing is typically a critical first step in any power transformer analysis.

The D.G.A. technique detects newly formed faults both accurately and consistently, and will locate a fault that cannot be detected in any other way. When abnormal gassing patterns have been established the unit should be removed from service as soon as it is practically possible.

Document first year in-warranty problems before out of warranty failure. As one example, National Grid (UK) has reported, "A number of faults have been detected, although in each case the transformer had satisfactorily passed the routine tests"

CIGRE REPORT 1984 states that "Dissolved-gas-in oil chromatographic is successfully applied to fault detection in the maintenance of large power transformers. Savings achieved are in the 100MILLION $ range.

Independent Professionals and Consultants are only able to offer their opinions.

Experience and understanding of the diagnostic methods is required to make DGA a more exact science and not an art.

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Biography

Ian Gray is a Member of the South African Chemical Institute and is the Founder and Managing Member of Transformer Chemistry Services (TCS), which is an independent laboratory, and consulting firm that specializes in diagnostic testing of insulating materials used in high-voltage electrical equipment. Located in Durban, South Africa, it was established in 1992 as the first commercial laboratory to offer gas-in-oil and Furanic analysis in South Africa.

He graduated from Vaal University of Technology with a National Diploma in Analytical Chemistry and has completed various certificates in Chromatography at the Durban University of Technology -Advanced Analytical Training Unit.

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He has authored several publications and has presented at Conferences on Transformers oil analysis and Condition Monitoring of High voltage electrical equipment in Southern Africa.