

LIFE-CYCLE CONSIDERATIONS OF LOADING TRANSFORMERS ABOVE NAMEPLATE RATING

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I. **INTRODUCTION: The Electric Transmission and Distribution Challenge**

In today's world of deregulated electric utilities, the concepts of transformer life extension, increased loading, and reduced maintenance are often discussed. These ideas at first appear to be contradictory in nature, but all strive for the same results; reduced operating costs and improved reliability in the delivery of electricity. In fact, for substation transformers, all of these goals can be obtained with the implementation of a strategic "Life Cycle Management Program". This paper addresses the primary concepts of life extension and increased loading of transformers, and how these issues are interrelated.

Power transformers are the single largest capital item in substations, comprising almost 60 percent of the total investment. The utility expenditures associated with this investment in acquisition, installation, operation and maintenance typically do not reflect the magnitude of this investment. The cost of premature and unexpected failure of one of these assets can be several times the initial cost of the transformer. There is not only the refurbishment or replacement cost but also costs associated with clean-up, loss of revenue, and possible deterioration in the quality of power delivery.⁽²⁾

As competitive pressures within the utility industry mount, and the transmission and distribution infrastructure continues to age, the lack of utility attention to these critical assets will become very visible to management, stockholders and customers, alike. Future demands will include reductions in forced outages and failure rates which can only be achieved with significant changes in the way utilities manage, operate and care for transformers. These changes will include acquisition of new transformers along with strategic "Life Cycle Management Programs" for existing units.

So, with tongue firmly in cheek, we can summarize by saying the challenge for the utility engineer is easy:

- Leverage the most out of existing transformer assets
- Avoid cost of sudden equipment failure and forced outages
- Defer capital expenditures
- Minimize operating and maintenance costs.

II. **Loading transformers above Nameplate Rating - Not Only for Emergencies**

Transmission and distribution substation transformers have historically been loaded beyond nameplate rating to accommodate emergency or contingency conditions. Until recently, the operation of transformers would fit into one of the following loading categories.^(3,4)

1. Normal life expectancy loading - Continuous Load

As the term implies, this is the constant loading at rated nameplate output (kVA) when the transformer is operated under a constant 30° C ambient condition. This condition implies a continuous hot spot conductor temperature of 110° C, which is the sum of the following temperatures: 65° C (ave. winding rise) + 30° C (ambient) + 15° C (hot spot rise) = 110° C. Of course, this loading condition rarely happens over the life of a transformer, where both load and ambient temperature vary over time.

2. Normal Life Expectancy Loading - Cyclical Load

This loading implies a cyclical load at a normal constant ambient (30° C) where the hottest spot conductor temperature varies above and below the normal 110° C, as the load cycles above and below the nameplate kVA of the transformer. From the thermal aging standpoint, this cycle is equivalent to the case of rated constant load at normal ambient temperature (30° C). This is the case because, thermal aging is a cumulative effect over time and temperatures above 110° C are permitted provided the transformer is operated for much longer periods below 110° C. Of course, maximum allowable hot spot and top oil temperatures can not be exceeded.

3. Long Time Emergency Loading

This operation results from the prolonged outage of a system component which causes transformer loading that results in hottest spot conductor temperatures in the range of 120 - 140° C. This type of occurrence would be rare and would be expected to happen two to three times over the transformer life and each event may last weeks to months. This type of operation causes accelerated aging of the transformer insulation system, and may have other associated risks. Loss of insulation life calculations should be made to assure it is acceptable for such an event and top oil temperatures should not exceed 110° C.

4. Short-time Emergency Loading

This loading condition is unusually quite high, and is caused by one or more events which seriously disturb normal system loading and are expected to occur rarely, two to three times over the transformer life. This loading condition can cause hottest-spot conductor temperatures as high as 180° C for a short period of time. Significant acceleration in insulation loss of life can occur during this event, and calculations should be made to determine if the loss is acceptable. Because of the rapid aging, load must be reduced fast, typically within one hour. This type of loading has several risks associated with it, such as, reduced dielectric strength, stray flux heating and exceeding ancillary equipment ratings.

A new loading condition has now come into existence. The condition is driven by the need to utilize assets more effectively, without compromising the overall life expectancy of the transformer. This new loading condition is:

5. Planned Loading Beyond Nameplate - Normal Operation⁽³⁾

This loading results in the conductor hottest-spot or top-oil temperature exceeding the limits suggested for normal life expectancy loading. This loading is accepted by the user as a normal, planned-for operating condition. There is no associated equipment outage or emergencies with this type of loading. Cyclic loads resulting in hottest-spot conductor temperatures in the range of 120° - 130° C would be associated with this loading requirement. This type of loading would occur frequently, and in some cases daily, during a short part of the transformer's load cycle. Loss of insulation life calculations must be done to make sure it is acceptable for this loading condition.

TABLE 1 shows the suggested maximum temperatures given in ANSI/IEEE C57.91-1995 and IEC Standard 354 for the four types of transformer loading. In addition to this criteria, it is always advisable to calculate the loss of insulation life and make sure it is acceptable for the loads beyond nameplate. Acceptable limits of loss of insulation life for various loadings is very important for an utility loading policy.

TABLE I

Suggested Maximum Temperature Limits - °C
IEC vs. IEEE

		Normal Life Expectancy	Planned Loading Beyond NP	Long-Time Emergency 1-3 Months	Short-Time Emergency 1/2-2 Hours
Insulated Conductor Hottest Temperature	IEEE	120°C	130°C	140°C	180°C
	IEC	120°C	(N/A)	130°C	160°C
Other Metallic (Supports, core, etc.)	IEEE	140°C	150°C	160°C	200°C
	IEC	(N/A)	(N/A)	(N/A)	(N/A)
Top Oil Temperature	IEEE	105°C	110°C	110°C	110°C
	IEC	105°C	(N/A)	115°C	115°C
Load Factor Per Unit Current	IEEE	(N/A)	(N/A)	(N/A)	1.5 pu
	IEC	1.3 pu	(N/A)	1.3 pu	1.5 pu

The top-oil temperature is limited to 105° - 110° C in IEEE/ANSI because of the ancillary equipment located in the top oil of the transformers. Bushings which do not utilize thermally uprated insulating paper are components which typically set this upper limit. Transformer loading studies should include, in addition to winding, hottest spot and top oil temperatures, calculation for the temperature rise of the other current carrying components such as: bushings, tap changers, cables, etc. For example, both the steady state and transient hottest spot temperature can be calculated for bottom connected bushings, using the method described in ANSI/IEEE C57.19.100, “Guide for Application of Power Apparatus Bushings”.⁽⁵⁾

The steady state (S.S.) temperature rise can be calculated using Equation #1.

$$\Delta\theta_{HS} = K_1 I^n + K_2 \Delta\theta_o \quad \text{(Equation \#1)}$$

Where: $\Delta\theta_{HS}$ = S.S. Hottest Spot Rise Over Ambient (°C)

$\Delta\theta_o$ = S.S. Immersion Oil Rise Over Ambient (°C)

I = Per Unit Load Current Based on Bushing

n, K_1, K_2 = Constants Specific to Bushing

The transient hottest spot temperature of the bushing can also be calculated using a transient approach which includes calculation of top oil temperatures. A more conservative single step method can also be used to calculate the final hottest spot temperature. ⁽⁵⁾

The contact temperature for tap changes and temperature rise of lead cables should also be calculated to make sure they do not limit the load capacity of the transformer. Relay settings must be checked so load is not dropped unintentionally and oil expansion space may also become critical at higher loads.

Additional care must be used when evaluating large power transformers loaded beyond nameplate due to stray flux heating. The sensitivity of transformers being loaded beyond nameplate rating is very dependent on size. As size increases, leakage flux density and short circuit forces will also increase. The increased leakage flux of larger units at loads beyond nameplate may cause additional eddy-current heating of metallic structural components in the transformer. It can also be more difficult to accurately determine the hot spot temperature on larger units.

Because of these considerations, and the magnitude of the consequences of failure, larger transformers (>100 MVA) require a more individual approach to loading criteria beyond nameplate than smaller units. It is also recommended that dissolved gas analysis tests be conducted after any significant loading beyond nameplate along with other diagnostic tests to evaluate the result of such loading.

The use of planned loading of transformers beyond their nameplate rating, not only for emergency conditions but for normal operation, has initiated an IEEE/ANSI Standard, (C57.119) specifically designed to enable factory testing of units for this capability. During this test, the transformer's thermal characteristics are evaluated at loads beyond nameplate. These thermal characteristics can then be applied to the transformer thermal model for better prediction of performance at loads beyond nameplate.

III. Transformer Life Cycle

This planned loading demands that operators be willing to accept an accelerated loss of insulation life in order to avoid the cost of a replacement transformer. As load grows this will occur more and more often. The withstand stress of a transformer

decreases with time as the insulation system ages. The aging of the insulation system reduces both the mechanical and dielectric withstand of the unit. Unfortunately, the applied stress tends to increase with added load or reduced protection over time. ⁽¹⁰⁾ The concept is illustrated FIGURE 1:

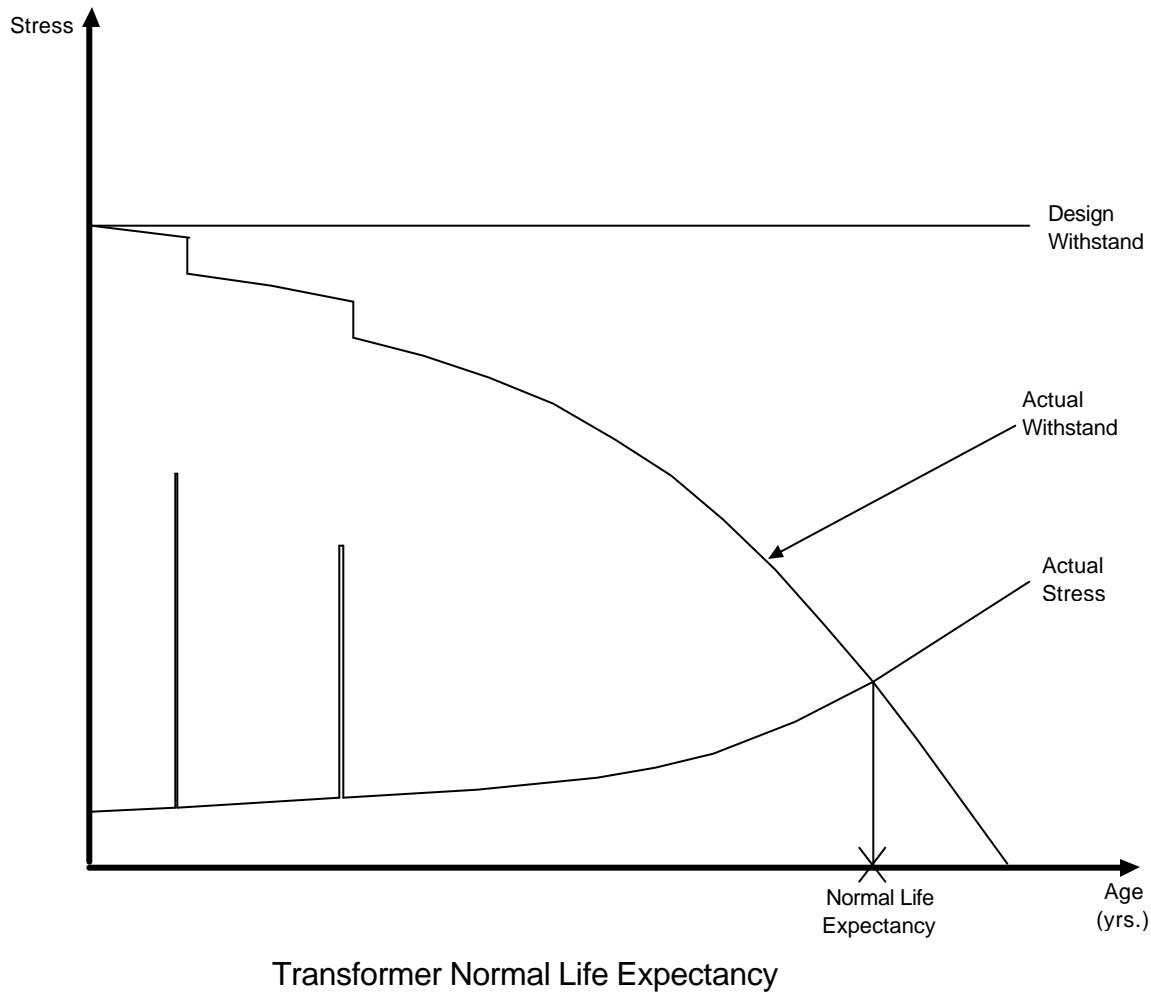


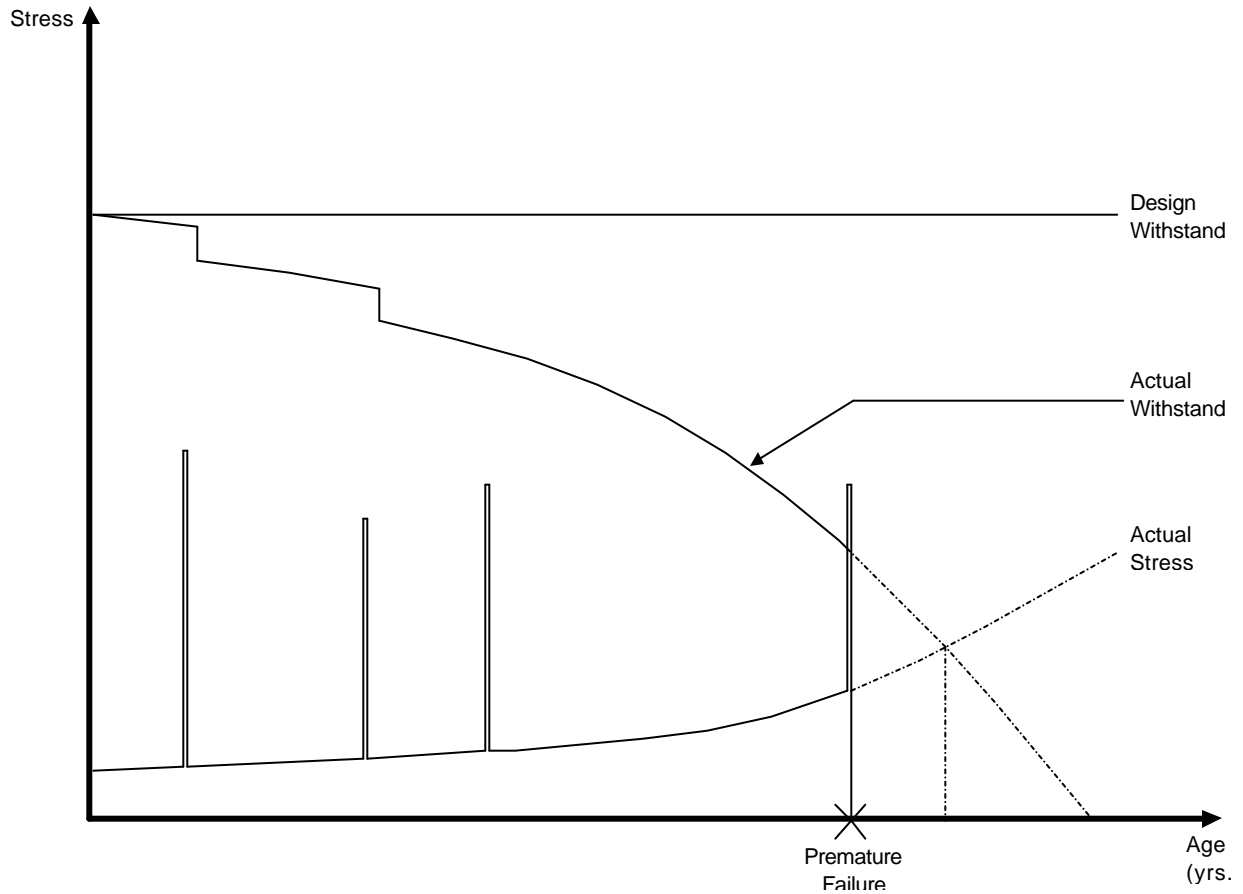
FIGURE 1

When installed, a transformer has an inherent strength to withstand short circuit faults, over-voltages, and other transient events. This withstand level is significantly higher than the average design and operating stress levels. This higher withstand strength allows the transformer to operate through a fault event (short-circuit, lightning, system over voltage, etc.) without failure. The upward spikes in the operating stress curve shows these sudden large increases in stress that occur during these events.

As the transformer ages, due to through faults which result in high radial and compressive forces, and normal loss of insulation life, the withstand strength gradually decreases. Unfortunately, at the same time the operating stress gradually increases due to the increasing demands of the operators to maximize the utilization of the assets on the system.

FIGURE 1 shows the normal life cycle of a transformer which has been able to withstand the periodic faults on the system. Load has grown gradually and withstand decreased due to normal aging. Finally, at the end of life, the transformer can no longer withstand the operating or fault stresses, which in many cases is significantly higher than the original designed for stress.

FIGURE 2 shows a premature failure of a transformer where, because of accelerated aging and through faults, the transformer is not able to withstand a high stress event without failure. This can occur if load growth is accelerated faster than originally expected and planned loading above nameplate become more routine, causing an accelerated reduction in withstand strength. A typical failure mechanism is insulation system aging, causing a reduction in the mechanical strength of the conductor insulation. The conductor insulation is then weakened to a point where it can sustain mechanical damage during a through fault and subsequent coil movement. The damaged turn to turn insulation then causes a dielectric failure within the windings. Other failure modes can include loosening of the winding clamping pressure which reduces the transformer's ability to withstand short circuit forces without deformation of the windings. Short circuit forces are both axial and radial with magnitudes of tens of thousands of pounds.



Transformer Life-Premature Failure

FIGURE 2

Proper restraint of windings during short circuit faults is necessary for the long-term reliable operation of a power transformer. A life cycle management program that includes transformer condition appraisal can identify known defects or weaknesses and correct them before a premature failure occurs. Things that can be done may include re-tightening and blocking of loose winding, reprocessing oil, added cooling, etc. These fixes can significantly increase the withstand strength. In addition, a condition appraisal program, to be discussed later, can identify units that could be re-deployed to a location with a lower operating stresses and be operated effectively for years. FIGURE 3 shows the representative increase in withstand strength from modifications in the field.

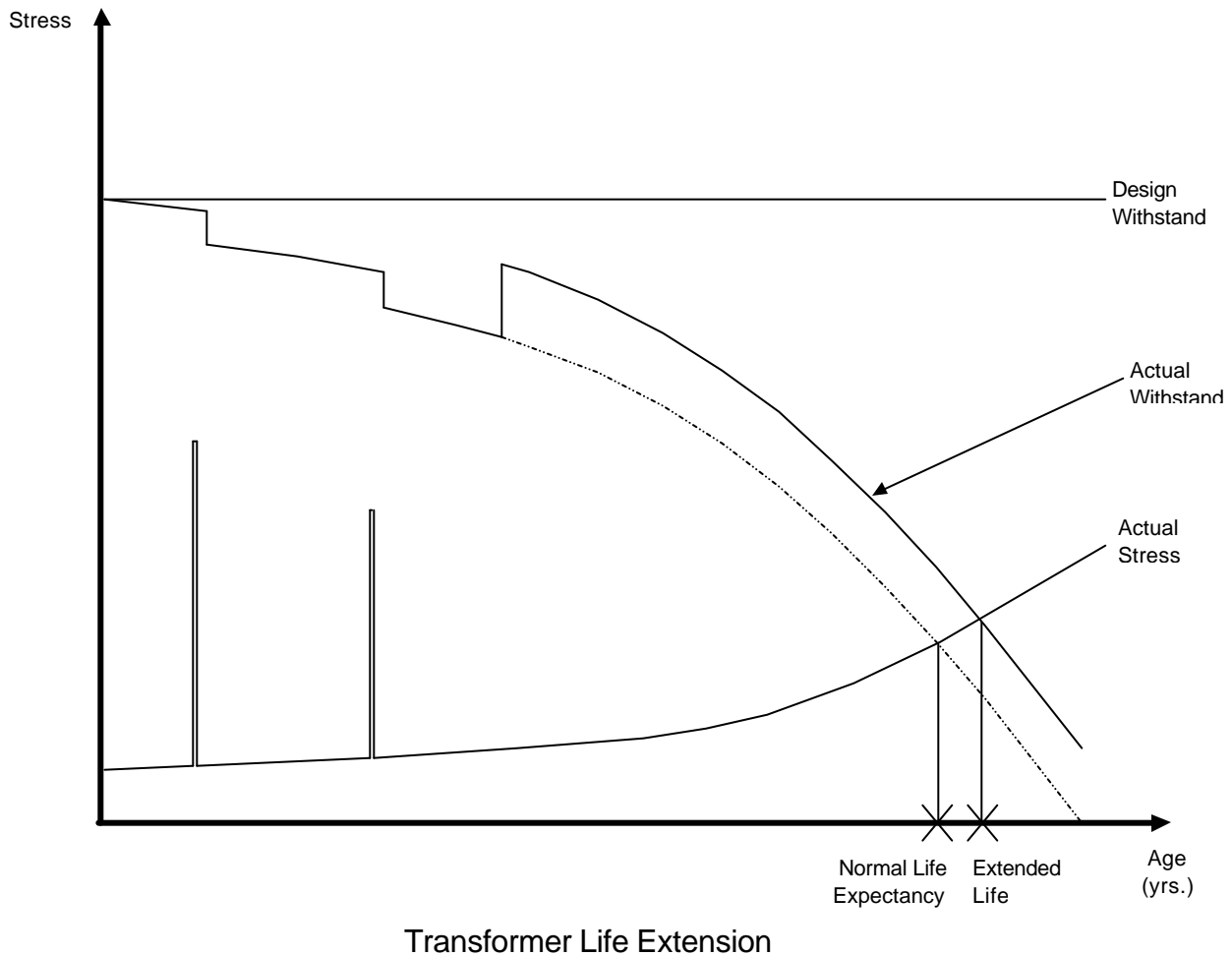


FIGURE 3

It must be remembered that these figures show only general depictions of the transformer life cycle. There are many factors that influence the shape and length of these curves. Factors like vintage, manufacture, operating history, design margins, and others effect the life cycle and must be identified in a complete condition appraisal that includes diagnostics, to get the most of this expensive asset.⁽¹⁰⁾ This type of appraisal, in conjunction with load studies and load optimizations, will be discussed later in this paper.

IV. Today's Loading Practices - An Industry Survey

A survey was conducted with a representative sample of U.S. utility companies to try to understand, in a general way, what loading practices are followed today. The survey discussed both specific limits used and in general what factors are evaluated when determining a loading policy. A summary of the results shows the following:

TABLE II
Survey Results (Yes/No)

<u>Questions</u>	<u>Yes</u>	<u>No</u>
1. Do you use values in C57.91 to determine loading?	82%	18%
2. Do you adjust loading limits based on changes in load profile?	68%	32%
3. Do you adjust loading limits based on changes in ambient temperature?	78%	22%
4. Do you have a computer based planning program for loading beyond nameplate?	63%	37%
5. Do you consider bubble formation in your loading criteria?	25%	75%
6. Do you consider age and vintage of the transformer?	28%	72%
7. Do you adjust loading based on equipment condition appraisal or ranking system?	24%	76%
8. Do you adjust loading based on the use of on-line monitoring?	3%	97%
9. Do you have the same loading limits for distribution, transmission, and generation units?	45%	55%
10. Are you considering changing from a static to a dynamic transformer loading practice?	28%	72%

The range of answers for specific temperature limits is shown in TABLE III:

TABLE III
Survey Results

	Normal Loading		Contingency Loading	
	Range	Most	Range	Most
Top Oil Rise	65 - 110° C	110° C	105 - 110° C	110° C
Average Winding Rise	65 - 95° C	65° C	65 - 110° C	65° C
Hot Spot Temp.	110 - 180° C	110° & 180° C	110 - 180° C	180° C
% Loss of Life/Day	0 - 5%	.0369%	0 - 5%	5%
Peak Load P.U.	.5 - 2.0	1.5	1.0 - 2.0	2.0

The first area of surprise was that most utilities indicated the use of the current IEEE/ANSI Loading Guide (C57.91-1996), but when asked the specific limits, the range of answers was extremely wide and rarely corresponded to the standards. It was also interesting that very few respondents utilize monitoring or diagnostic tests to help in deciding how to load transformers more effectively and reliably. Good diagnostic tests like dissolved gas in oil analysis (DGA) and Doble power factor test are critical components in determining condition. Selective monitoring of critical units can also be a useful tool in transformer operation.⁽¹¹⁾ It is also clear from the survey that U.S. utilities do consider several outside factors when establishing the loading limits of their transformers. The most common ones used to adjust loading limits are load cycles and seasonal average ambient temperatures. It appears that most also use some type of loading software to help in this decision.

Another surprising response is that very few transformer users consider the age, vintage, or overall condition of the transformer before establishing loading limits. A condition appraisal program and criticality index are becoming a significant tool in the

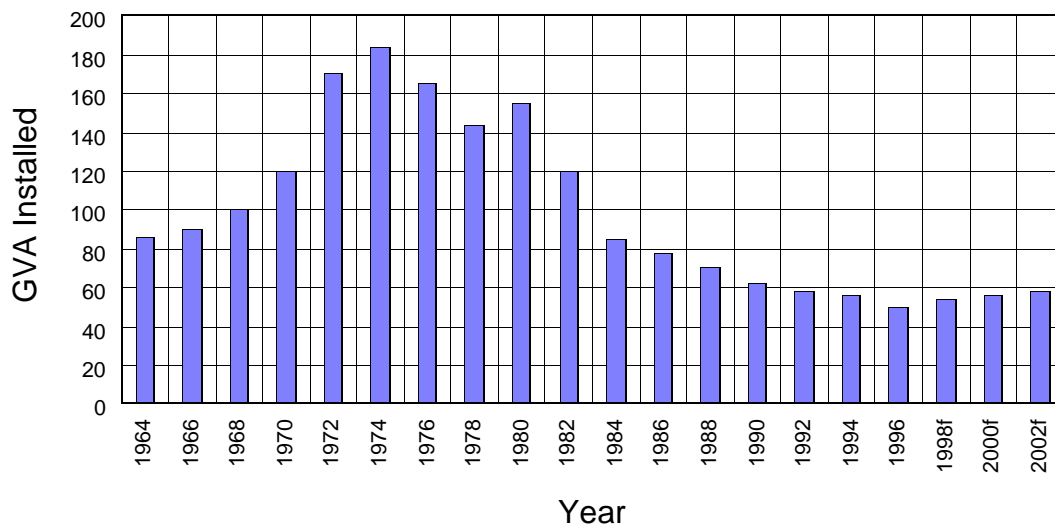
transformer maintenance but are still not used in determining the extent to which a transformer can normally be loaded beyond nameplate, or for emergency conditions. The current philosophy focuses only on influences outside the transformer to set loading limits. This assumes that all transformers regardless of age, vintage, manufacture, past operating history, and diagnostic test results are all considered equal in the eyes of loadability. Remember all transformers are not created equal and in time, they most likely become less equal. Knowing which are the best, average, weak or endangered can be a significant tool in deciding how to load the aging transformer population most effectively and direct maintenance where needed.

V. Industry Pressures Changing Loading Policies from Static to Dynamic

The issues of deferring capital expenditures, getting more from existing assets and ever-increasing utilization rate of transmission and distribution transformers will require more effective and flexible loading policies. Current Standards will dictate the temperature limits in which these policies can be structured, but all factors outside and within the transformer will be needed to obtain the optimum loading within these limits.

Capital deferment, and getting more out of existing assets has been the policy of many companies for more than ten years. This has led to the increased overall utilization of transformers in the T&D System. In the 1970's and 1980's the addition in new capacity to build infrastructure was immense as shown in FIGURE 4.⁽¹³⁾

Base GVA per Year Additions



Transformer Capacity Additions (GVA)

FIGURE 4

Due to the steady growth in power consumption over the past fifteen years, it is evident that the utilization factor has increased and will begin to accelerate beyond the year 2000. FIGURE 4 also dramatically shows the aging of the transformer infrastructure. With today's capital spending on new and replacement transformers at its lowest in decades, the average age of the installed units continue to rise.

There are some solutions to this looming problem. One is to purchase more new units to replace this aging infrastructure with larger capacity units. This, of course, is contrary to our challenge of deferring capital expenditures. To maintain the current utilization rate, with an estimated 1.8 - 2.2 percent per year load growth, a ten year projected short fall of approximately \$5.5 billion, this may become an overwhelming problem.

The second option is to re-engineer and refurbish existing units after a failure or when the unit is close to the end of it's useful life. This, of course, can also be expensive, but identification of the right candidates, with an indexed ranking system based on condition appraisal, and thermal uprate analysis can make this a very viable option. The third and perhaps most attractive option is to load the existing transformers more, but in an way that does not effect the overall reliability and failure rate. This can be done by finding the optimum load capability in the existing units, within predetermined company guidelines or industry standards. Dynamic loading of power lines is already a reality and is currently in use by several utilities across the country. ⁽¹⁵⁾ Another practical strategy is to increase the load capability by uprating units in the field or redeploying them to where they can be better utilized.

In reality, the solution to the aging, more highly loaded transformer infrastructure will be a selective combination of all the options above. The key to meeting the challenge that faces the industry today will be to develop the tools that utility engineers need to make the right planning and loading decisions for their transformers.

VI. Static Dynamic Loading Criteria - Driven by the Challenges

Most utilities today still continue to use loading criteria which were established many years ago. Typically, the upper limit value is based on some load above Nameplate Rating, or in most cases, the nameplate value is the governing rule. In many cases, these upper limits vary on the selected operating condition such as normal loading, short-time or long-time emergency loading. As was shown in TABLE 1, the IEEE and IEC Standards have established some maximum temperature limits for these conditions. These limits, of

course, are based on the thermal limits of the materials used in the construction of the transformer. The cellulose based insulation that insulates the winding conductor is a 105° C insulation class material, and can tolerate maximum hot spot temperatures up to 120° C. (6) At temperatures only slightly higher than this, the cellulose material undergoes accelerated decomposition which will reduce the transformer's ability to withstand the operating stress and fault conditions. The insulation loss of life is in fact the aging criteria that the current IEEE and IEC Transformer Loading Guides are based upon.

There has been great debate over the years in industry standards groups, if using insulation life is appropriate for judging transformer life expectancy. In addition, lengthy discussions were had in the area of appropriate aging rate constant and the life end-point criterion. Both of these issues are addressed in the current IEEE/ANSI C57.91, "Guide For Loading Mineral Oil-Immersed Transformers", but four (4) end point criteria are presented and left to the users to decide which to use based on class of transformer and user experience.

T.W. Dakin recognized that the aging of cellulose was in fact the result of a chemical reaction. Thus the rate of change of a measured property, like tensile strength, can be expressed in the form of a reaction rate constant, K_V . The reaction rate constant can be expressed in the familiar Arrhenius reaction rate equation. (4,8)

$$K_o = A \text{ EXP } [B / (\theta + 273)] \quad (\text{Equation 3})$$

Where: A & B = Empirically derived constants, based on material characteristics.

θ = Aging Temperatures (°C)

An agreement was required for the two empirically derived constants A and B for 65° C cellulose insulation systems. A review of the literature discovered a range of B, the aging rate constant for cellulose, in the range of 11,000 - 18,000. After careful review, a value of 15,000 was selected for the new loading guide. The rate constant equation was then placed on a per unit basis derived from the selection of 110° C as the cellulose temperature established for "one per unit life". This assumes an average 24 hours ambient of 30° C. (65° C winding rise + 30° C ambient + 15° C hot spot rise.)

$$\text{p.u. life} = A' \text{ EXP } [15000 / (\theta_H + 273)] \quad (\text{Equation \#2})$$

This equation has aging rate dependent on temperature alone and a full definition of “1 pu life” in units of time (hours) can encompass the end-point criterion including other variables that effect insulation life.

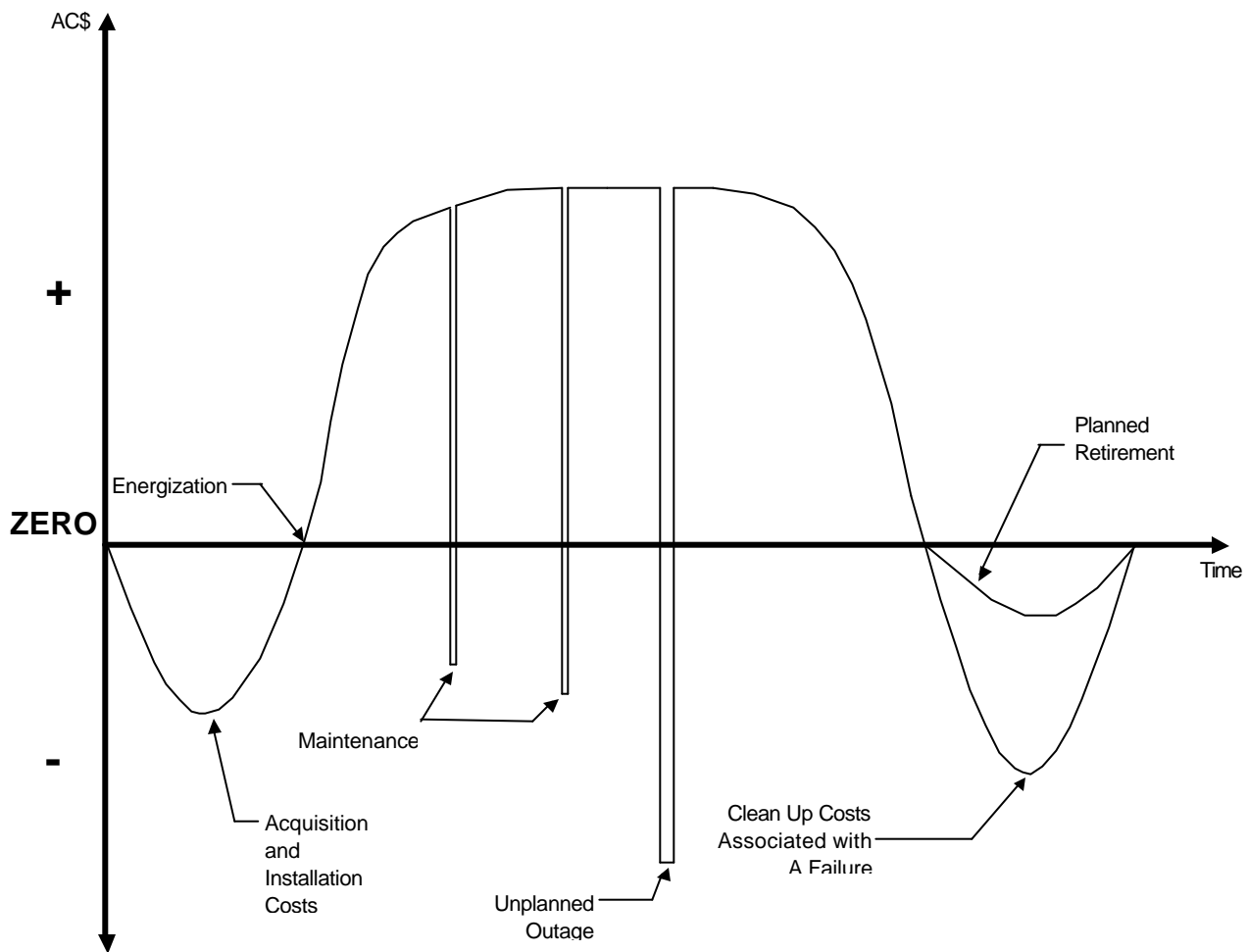
As cellulose ages, there are in fact three mechanisms responsible for its degradation. These mechanisms are hydrolysis, oxidation, and pyrolysis and the respective agents are water, oxygen, and heat. In most end-point criterion, heat is the only variable that is considered i.e., absolute temperature of the cellulose. The other two mechanisms of aging have a significant influence on aging rate and need to be controlled or at least considered in the end point of life determination. The aging rate of the cellulose is approximately proportional to the amount of water in the cellulose. This simply means going from 0.5% moisture to 1.0% accelerates the aging rate about two fold. In the case of oxygen, the difference between a free-breathing transformer compared to a low oxygen transformer is at least a two time acceleration factor.

The other aging influences mean that operating temperatures alone can not be used to determine the end-point criteria for your transformer or the ultimate load carrying capability. Understanding the transformer’s overall condition, including: moisture, and oxygen levels becomes considerably more important when operating at higher loads. When operating these units at these higher load levels, transformer condition appraisal, including diagnostic tests and selective monitoring are essential.

VII. Transformer Life Cycle Costs - Why Dynamic Loading?

There are two objectives associated with transformer life cycle management. Both go back to the challenges we mentioned in the introduction. The first is to reduce total transformer life cycle cost. This comes in the form of reduced maintenance cost through reliability centered maintenance (RCM) or predictive maintenance practices. Also in the area of reducing the risk of sudden unexpected failure, which can have a tremendous impact on life cycle cost.

The other area of the challenge is to maximize total life cycle benefits from the operation of the transformer. This may in fact become the most important challenge for the future. This can be accomplished by enhancing the equipment performance and/or extending its useful life. These concepts can be depicted on a time graph of asset contribution dollars (AC\$) from the operation of the transformer. FIGURE 5 shows what a simplified curve might look like.



Transformer Life Cycle vs. AC\$

FIGURE 5

The objective is to maximize the area above the zero AC\$ line and minimize the area below. By doing this, we can maximize the value of transformers in use. In order to maximize this value in use, we must understand the optimum dynamic load capability of the unit above nameplate. This provides transformer planners and operators the opportunity to increase flexibility with the maximum capability of transformers without adversely effecting failure rate. A key element is to establish a condition appraisal ranking system which sets

optimum load limits and provides direction for maintenance spending based on the condition and capability of the unit. This is accomplished by identifying which units can be loaded higher and to what extent. The condition appraisal ranking can also identify weaker units that may require maintenance or the correction of known defects.

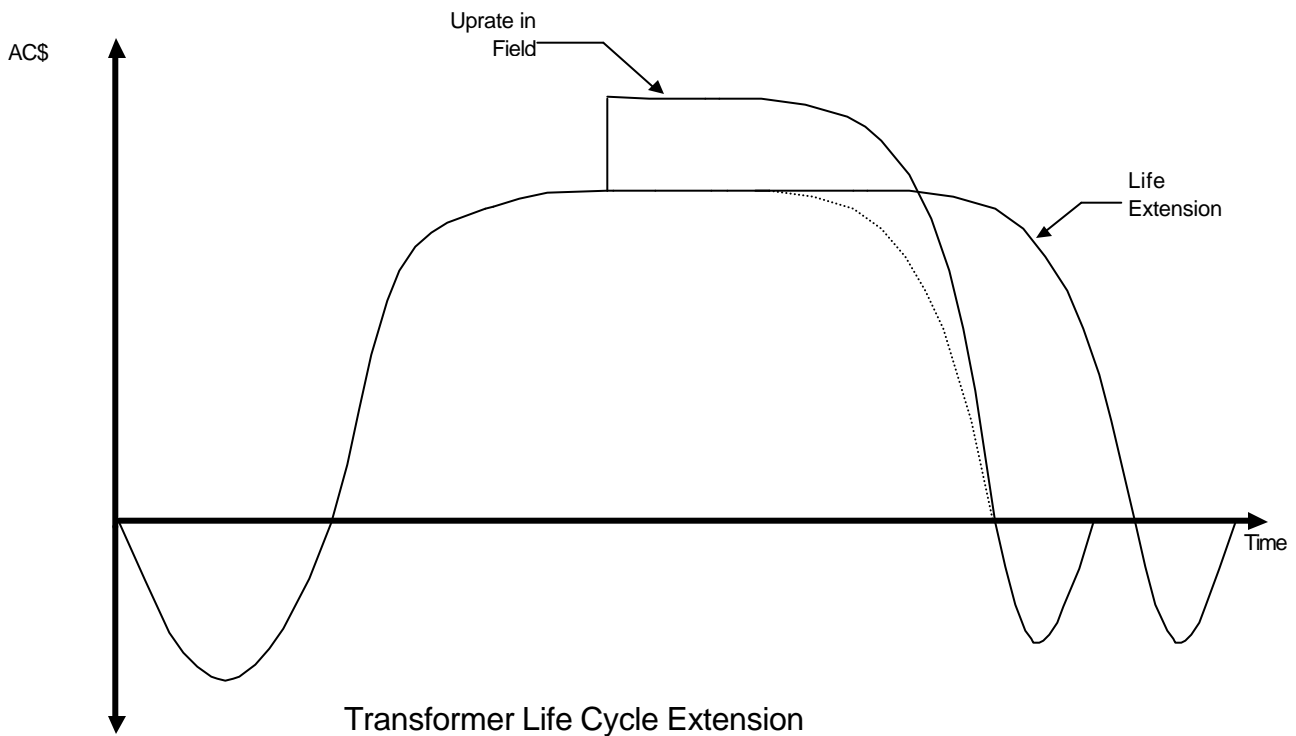


FIGURE 6

The third way of maximizing the useful value is to identify which units can be thermally uprated on-site. These units are identified in the condition appraisal process and can add value by improving load capability or extending insulation life or both. This not only raises the AC\$ curve but makes it longer. With a dynamic loading criteria, combined with an increasing ability to move load around the system, planners and operators get appreciably more out of existing transformers.

The end of this life cycle curve which is very important to overall AC\$, represents retirement or decommissioning versus sudden failure and force outage. The latter event can in fact cost several times the cost of a new transformer. If the end of life can be

anticipated, a planned retirement or redeployment can be a cost effective alternative. The identification of the transformers near the end of life is a very complex question with no easy solutions. A comprehensive condition appraisal program that includes diagnostic tests is essential in starting this identification process. This must also be coupled with on-going diagnostics and most likely some on-line continuous monitoring to act as an early warning systems for problems on units identified to be at a critical point in their life cycle. The initial condition appraisal part of this process which ranks the units in order of overall condition can also identify units at risk and lead to recommendations on which units should be watched carefully for signs of sudden failure. This is analogous to what happens with critically ill patients in the hospital; until they are well enough or problems corrected, they are highly monitored in the hospital's intensive care unit. Here any sudden changes in condition are identified and quick action can be taken to save the patient.

Of course, condition appraisal or ranking systems can only identify those transformers that are at greater risk of developing problems. Spontaneous and sudden failures can still happen. The goal would be to reduce this number significantly. The non-failed problem transformer can then be dealt with by retirement, in field refurbishment, on-line monitoring or even re-engineering and rewinding these units to improve performance characteristics. This re-engineering can, in most cases, be done at less cost than a new replacement transformer of the same MVA. So, dynamic loading will become routine, enabling operators to make better decisions on how to maximize the transformer life cycle asset value (AC\$) and minimize the risk of sudden failure or forced outage.

VIII. Maximum Loading Analysis + Condition Appraisal = Optimum Loading

1. Enhancing Transformer Load Capability-

The development of this practice was driven by the need to maximize the asset value of transformers in operation. These units have a wide range of ages, conditions, and amount of insulation aging. More importantly, there is typically limited information available about the thermal performance of older units. Many of these units were not given heat run tests to determine thermal performance and temperature rises were calculated by comparing the design to a previously tested "thermal duplicate". The definition of thermal duplicate did not have strict guidelines to be used by producers to determine units with like thermal characteristics. Calculating the optimum load capability needs to be more than a theoretical mathematical exercise. The real world load capability of an aging transformer needs to be made in association with a detailed condition appraisal project.

2. Condition Appraisal - Overview

Condition appraisal is a benchmarking project which differentiates theoretical upper limit loading from optimum or practical load limits for a specific transformer. A complete

condition appraisal for a selected key group of transformers is a vital element in any life cycle management and/or dynamic loading program. The key transformers are typically chosen based on a criticality index. This index is often established by the utility based on age, critical loads, load growth, size, etc., and may be a variation of the criticality index selection used for a RCM program. A complete condition appraisal is a benchmarking project that ranks the selected transformers according to its present condition as compared to the other transformers being evaluated. After this ranking is complete, a condition assessment (which is an on-going process of diagnostics and monitoring) can be established to determine aging, fault or incipient failure.

The condition appraisal is a fundamental part of any transformer life cycle management program and the benchmarking of these units facilitates the following:

- Prioritizing maintenance resources for transformers.
- Development of load planning database which includes transformer optimum load, present utilization, and temperature rise.
- Direction to focus future diagnostics or on-line monitoring spending, to effectively avoid forced outages.
- Making decisions on field re-engineering to extend transformer life, such as updated cooling, filtration, and oil preservation system.

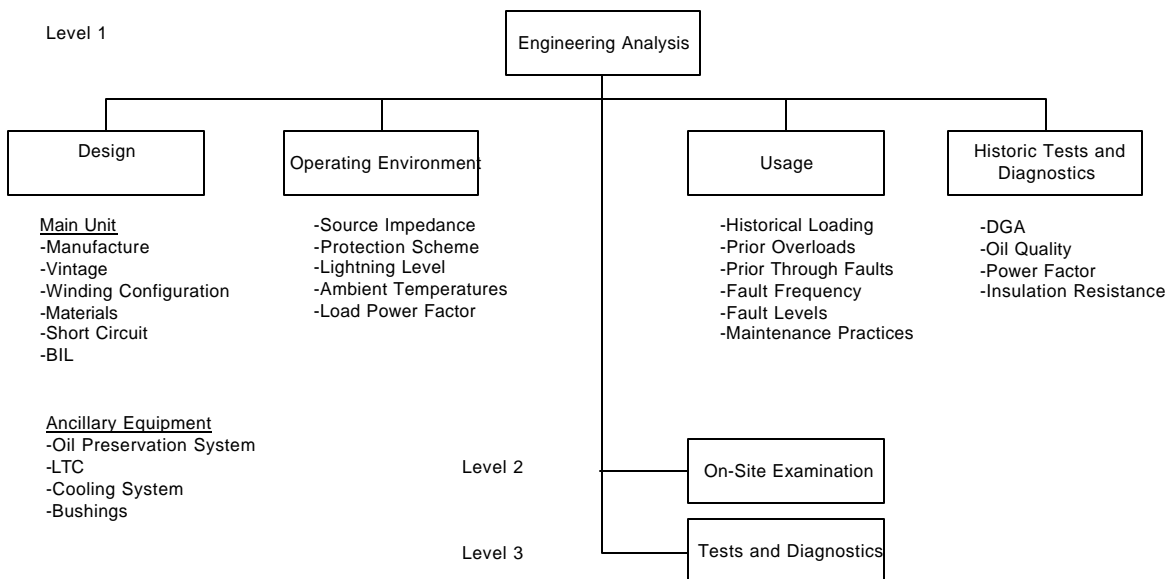
3. Complete Condition Appraisal Program

A complete condition appraisal program must include the following levels:

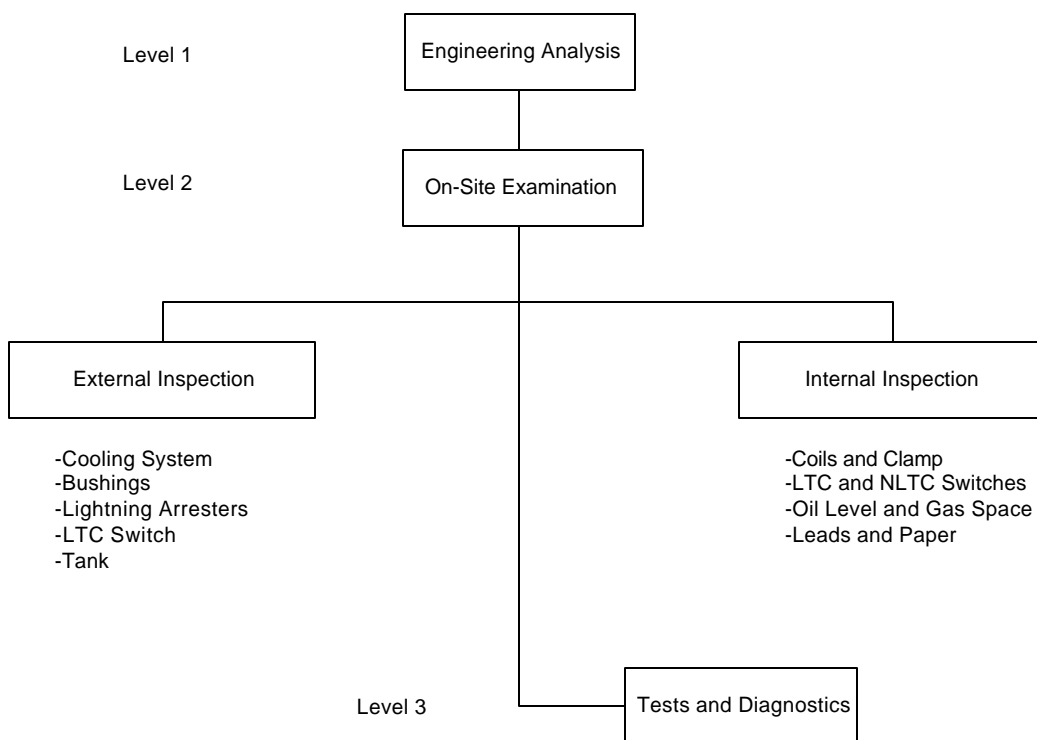
- Level 1 - Transformer Engineering Analysis
- Level 2 - Internal and External Field Inspection
- Level 3 - Testing and Diagnostics

Each one of these steps has several elements which facilitate the benchmarking process. These elements also will many times identify defects or deficiencies, some of which may be reversible and possible lead to transformer life extension or improved load capacity.

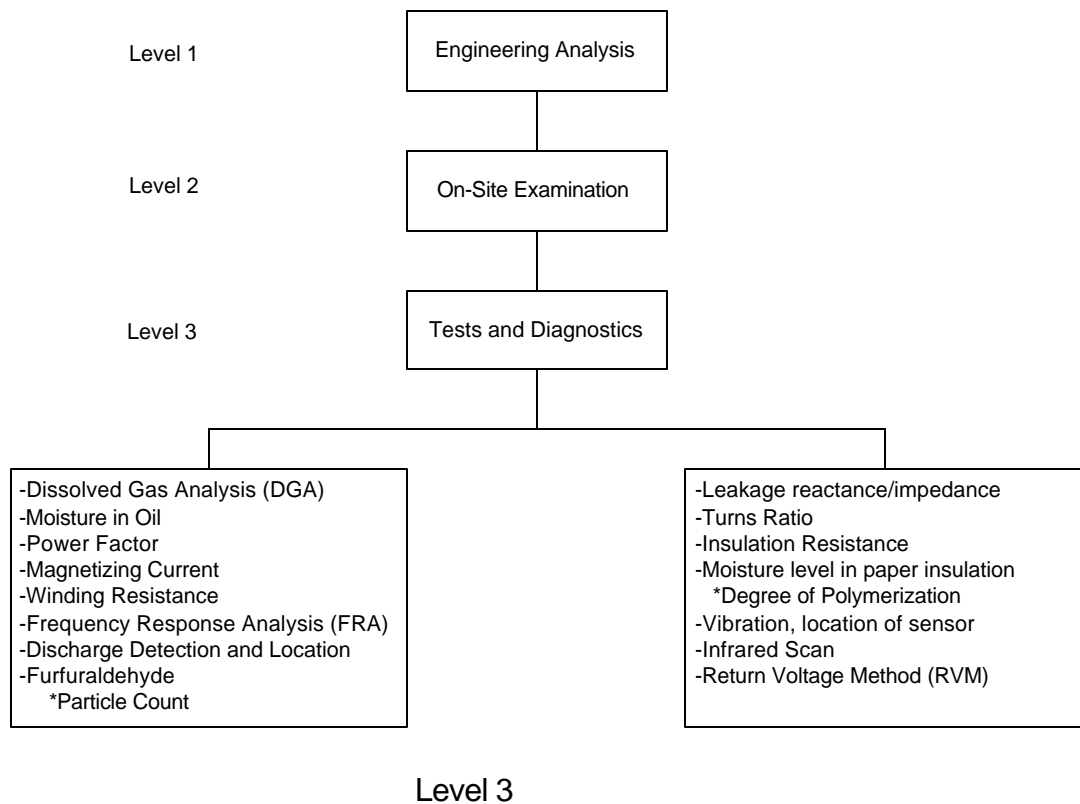
Condition Appraisal - Level 1



Condition Appraisal - Level 2



Condition Appraisal - Level 3



At the conclusion of all levels of the condition appraisal process, the transformers are assigned a numerical index according to the results. This index number will provide the utility with better tools to manage the life cycle costs of the transformer including:

- Providing a starting point condition to increase the effectiveness of predictive or reliability centered maintenance.
- Identifying problem units and taking action to correct known defects or to re-deploy units. These units can then be used more effectively.
- The field tests performed as a part of condition appraisal can be used to refine the thermal model used to predict internal transformer temperature which are used to determine optimum load and/or end-point of life criteria.
- The condition appraisal project can also identify units that can be uprated via cooling modifications in the field or units that should be retired.

- Managing the end of life of endangered transformers, the utility can save a significant amount of money versus a catastrophic failure and associated clean-up costs.

In future load planning scenarios, these thermal model characteristics for each transformer would be programmed and be available real time against which actual performance would be monitored. Transformer performance characteristics, in addition to information on both ambient temperature and loading cycle are critical in determining the transformer load available for normal operation and emergency events. In dynamic loading, these inputs are evaluated in real-time to allow the operator flexibility in deciding how much the unit can be loaded at any given point in time. This mathematical thermal model is then used to predict the individual transformer's internal temperatures and insulation loss of life. A computer program is utilized to calculate temperatures of the winding, hottest-spot and top oil with various loading and ambient scenarios. These what-if cases allow the user to determine the effects of load condition have on the life and health of the transformer.

IX. Load Optimization with Computer Thermal Model

To effectively run the different cases of load and ambient on the thermal model, one must first establish loading criteria which is acceptable for the transformer. This loading criteria is typically established for normal loading, planned loading above nameplate, long-time emergency and short-time emergency cases. Each of these loading patterns has an increasing level of risk associated with it. This risk is balanced with the need to meet certain load condition periodically throughout the life of the transformer. In addition to the loading needs, and risk maximum loading criteria should reflect the overall condition of the transformer and its ability to withstand this additional stresses. The condition assessment can help in establishment of an end-point of life criteria (number of hours) the information can be used in the new per unitized life equation to predict percentage of loss of life.

In a new transformer, or one that is appraised as "good to excellent", a typical loading criteria will be different than a transformer in just "fair to poor" condition. By applying these loading criteria to the thermal model of the transformer and the loading and ambient temperature cycles maximum absolute loads (kVA) capacity can be determined for individual transformers. Where anticipated loads exceed the transformer capability for one or all of these cases, cooling upgrade studies are conducted to determine if these loads can be accommodated with improved cooling. Other options may be the re-deployment of units not capable of carrying the load within the criteria with transformers that are capable because of rating or overall condition.

X. Loading Above Nameplate Studies

A major Southern utility with high load growth, had several substations which were at or above the utilities loading criteria. This meant that new projects had to be placed on the 1998 Capital Budget to replace these transformers with new units. The results of one of the load studies and condition appraisals identified options a utility may have when faced with these decisions and armed with loading data, and a condition index for the transformers.

1. Case 1

Transformer Type:	Three-phase, LTC Autotransformer
Manufacturer:	General Electric - Pittsfield, MA
MVA & Cooling:	90/120/150//168, 55/65°, OA/FA/FOA
Voltage:	230,000v Grd Y/132,800 - 69,000Y/39480
H.V. No-Load Taps:	+/-5% 4 x 2.5%
L.V. Load Taps:	+/- 10% 30 x 0.625%

The above unit serves the utilities 69 kV system and is in parallel with a larger capacity unit. In 1997, the peak load at this station exceeded 250 mva (1.67 times the maximum 55° C rating) which is greater than the utilities' established limit for contingency loading in a two unit substation. This criteria did not take load cycle, ambient or transformer condition into consideration. Meeting this limit meant purchasing a larger transformer in 1998 to alleviate the perceived problem. The maximum loading capabilities, temperature and loss of life were based on the original temperature rises from the heat run data, specified load and ambient temperatures.

A. Limiting Criteria for Loading

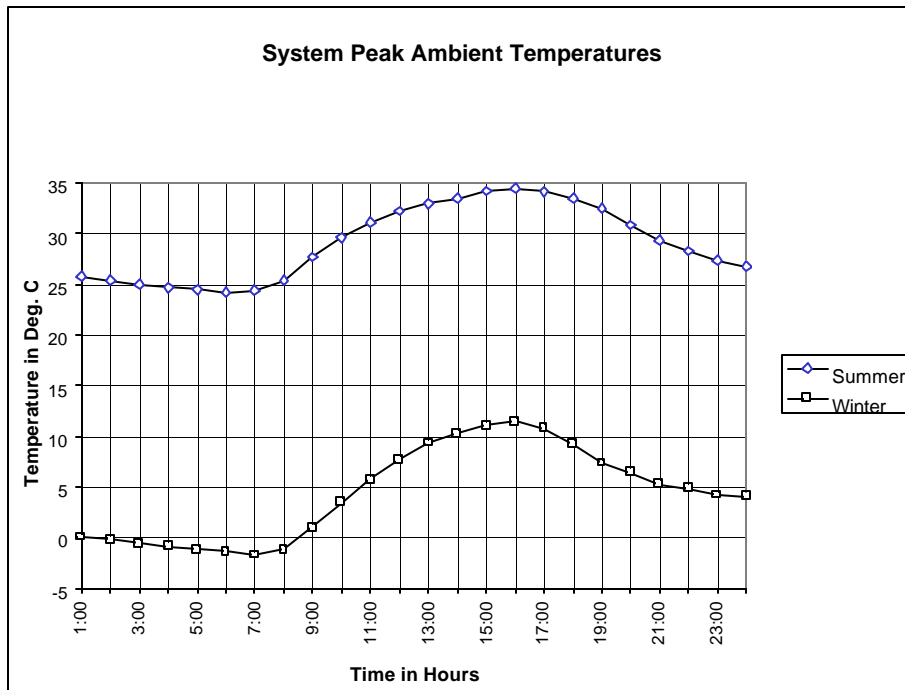
The following temperature limits were used in this study and loss of insulation life during contingency operation (TABLE IV). These limiting criteria were agreed to limits of the utility for the operation of this type of substation transformer. These limits may vary between utilities.

TABLE IV

Load Limiting Criteria

Parameter	Normal Life Load	Long-Time Contingency	Short-Time Contingency
Max Hot Spot Temp	120° C	140° C	160° C
Max Top Oil Temp	105° C	110° C	110° C
Max Loss Of Life/Cycle	0.037%	1.0%	1.0%
Bubbling in Oil	No	No	No
Allowed Method for Improved Rating	Fans & Rads	Fans & Rads	Fans & Rads

The other system information needed to complete this study is shown below:



Summer & Winter Ambient Cycles

FIGURE 7

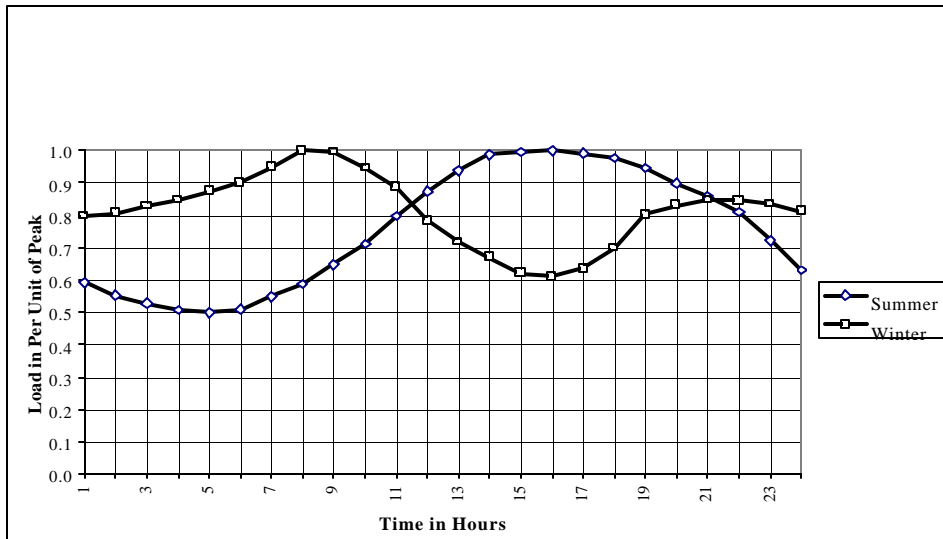


FIGURE 8

Load Cycles - Winter & Summer

The results for the actual limits for the four loading conditions are shown in the following FIGURE 9:

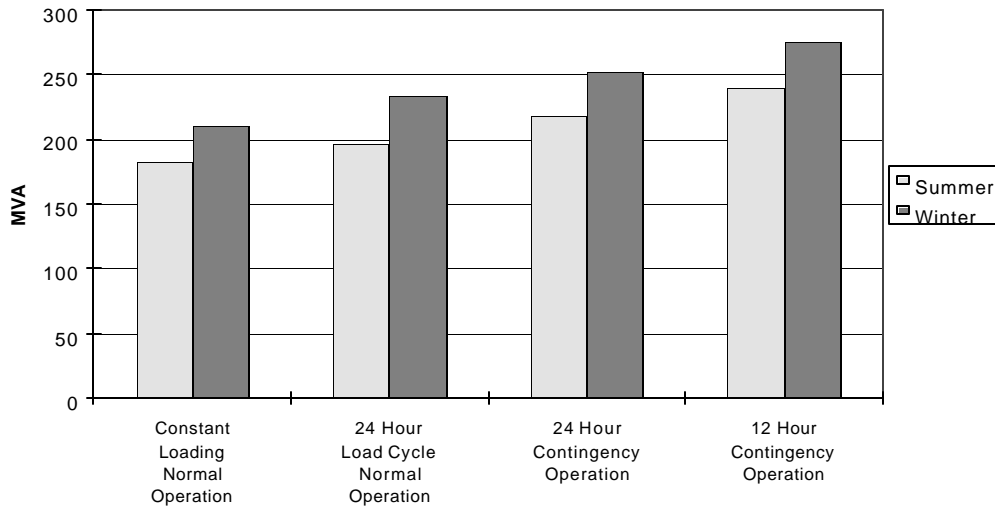


FIGURE 9

Dynamic Loading Comparison Base Case

The graph shows that the transformer would be capable of carrying a Peak Winter short-time contingency load of 275 MVA. During this contingency, the loss of life for each daily cycle is 0.44% which is less than half the upper limiting criteria of 1.0%. The limiting criteria was in fact the hottest spot temperature of 160° C, which from the detailed computer tabulation, it can be seen that it occurs approximately 2 hours after the peak contingency load. If the hottest spot temperature is allowed to go to the maximum allowed by standards 180° C the load could theoretically even be higher.

The FIGURE 9 also shows that the transformer would be capable of carrying a peak winter long-time contingency load of 252 MVA. The loss of life for each daily cycle is 0.1% which is an order of magnitude below the 1% limit established. Once again, the hottest spot limit of 140° C was the limiting factor for the loading. All of the summer loading capabilities are less than the winter, but in the case of this substation, worst case loading occurs during a winter peak cycle.

B. Cooling Uprate - Fans

The transformer was also evaluated for an on-site cooling upgrade and the additional capacity that could be obtained for this relatively inexpensive upgrade. During a transformer condition appraisal, it was determined that an upgrade could easily improve the transformer cooling with the addition of 14 fans. This increased the fan count to 32. All the same limiting criteria loading and ambient cycles were used. The results showed that for short-time contingency loading, the transformer was capable of 291 MVA and the hot-spot was still the limiting criteria. TABLE V shows the transformer's thermal characteristics before and after the cooling upgrade. The added cooling improved the loading capacity by 16,000 kVA with an estimated cost of material of \$11,500.00 Total cost would be approximately \$20,000.00 or just over \$1.00 per additional kVA in this case.

C. Uprated Design - Re-engineering and Rewind

An uprate estimate was also completed for this unit to evaluate the feasibility of sending the unit to a repair facility and have an uprate re-design done on the unit. This option, of course, would be more costly, but could give a significant increase in capacity at significantly less cost than a new unit.

TABLE V

TRANSFORMER LOAD AND COOLING UPGRADE STUDY
Distribution Substation

Bank #2, General Electric S/N: D566421

90/120/150//168 MVA, OA/FA/FOA, 230-69 kV, LTC

Transformer Thermal Characteristics & Cooling Data

	<u>Existing</u>	<u>Upgraded</u>
Hot Spot Rise (HSR) - °C	68.9	58.4
Top Oil Rise (TOR)) - °C	37.2	26.2
Avg. Winding Rise (CuR)) - °C	61.9	51.4
Hot Spot over Top Oil (HS Grad)) - °C	31.7	32.2
Avg. Oil Rise (AOR)) - °C	35.2	24.7
Avg. Wdg. Over Avg. Oil (Cu Grad)) - °C	26.7	26.7
Top Oil over Avg. Oil (Half DT)) - °C	2.0	2.0
# of Radiator Banks	4	4
Radiator Height - (in.)	154	154
# of Plates	39	39
Plate Width - (in.)	5.25	5.25
# of Fans	18	32
Diameter - (in.)	26	26
RPM	1750	1750
# of Blades	4	2
Fan Loss (watts)	10800	19200
Fan Noise - (dB)	81.5	85.0
Upgrade Cost Estimate (materials) - (\$)	0.0	11500
Effective MVA Increase	0.0	16.0
Cost of Additional MVA (\$/kVA)	-	0.72

The following FIGURE 10 compares the base case (original unit), to the cooling upgrade (Option A) and the re-engineered transformer (Option B).

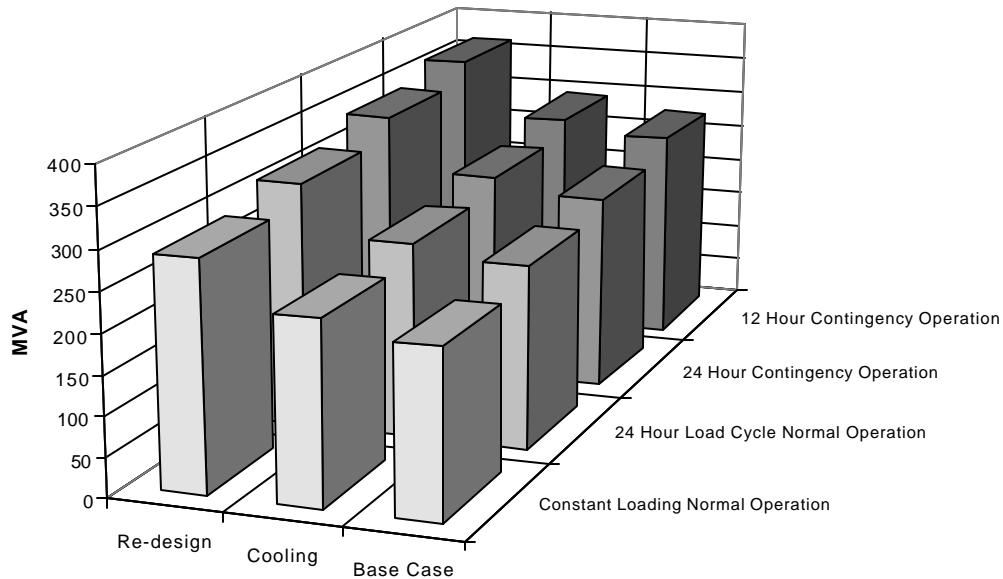


FIGURE 10

Winter Loading Capability

D. Ancillary Equipment -

In addition to transformer loading, current carrying ancillary equipment must also be evaluated for their ability to carry the added load current. This must be done without exceeding established limits for these devices. All of these devices must be looked at, but the most important are bushings, tap changers and current transformers.

E. Bushings- *

The current Standards set the following limits on bushings:

- Maximum Ambient Air - 40° C
- Maximum Immersion Temperature - 110° C
- Maximum Emergency Current - 2x rated current
- Bushing Hottest Spot - 150° C

*Bushings do not utilize thermally upgraded paper and have an insulation temperature rating of 95° C.

Temperature rise calculations were completed for low voltage, and high voltage bushings and they did not exceed the limits. One reason the temperature was not

exceeded was a relatively low top oil temperature due to outside ambient temperature at the time of the peak winter contingency.

F. Tap changers -

Maximum contact temperature rise of tap changers is also limited by ANSI standards. Contact temperature for maximum short-time contingency was calculated and was within the 20° C limit.

2. Case II - Industrial Plant Transformer Loading Above Nameplate

In this case study, the transformer serves a critical industrial load. The load is relatively constant since the plant operates 24 hours per day. This substation is dedicated to a single customer and was designed to be fully redundant when the plant was built. The transformer is rated as follows:

Type:	Three-phase, Load Tap Charges
Manufacturer:	McGraw Edison Company
MVA Cooling:	12/16/20//22.4 55/65° C, OA/FA/FA
Volts and Connection:	67,000 Delta - 13090Y/7560
H.V. No-Load Taps:	+/- 5% 4 x 2.5% Steps
L.V. Load Taps:	+/- 10% 32 x 0.625% Steps

In recent years, the plant has expanded and the load has increased to a peak of 27 mva, which is above the maximum rating of either unit at the plant. This would require the purchase of an additional unit to cover the failure of either unit.

The limiting criteria for loading and ambient temperature cycles are the same as in Case 1. The loading of this industrial plant transformer was nearly a constant 24 hours per day.

The results of the summer and winter cycles and four types of loading are shown in FIGURE 11 below.

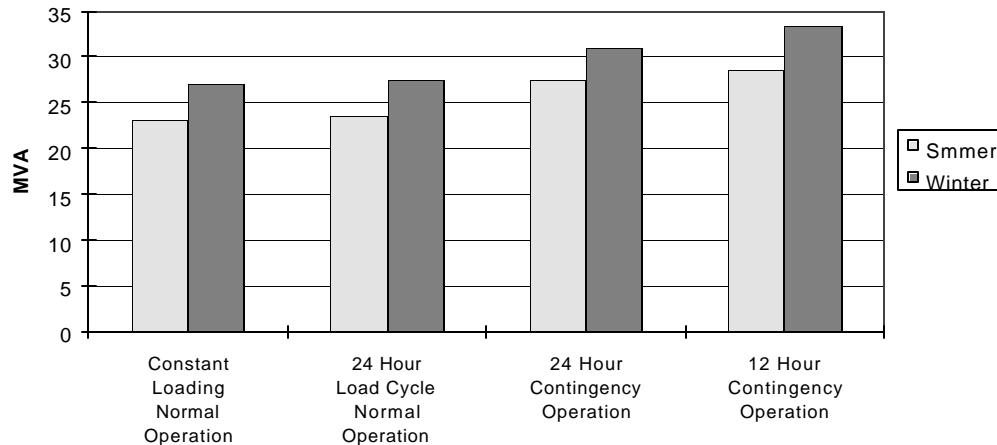


FIGURE 11

Dynamic Loading Comparison Base Case

The figure shows that the existing transformers would be capable of individually carrying a peak summer long-time contingency load of 27.5 MVA. The loss of life for each cycle would be 0.44% which is less than half of the limiting criteria. The limiting criteria was the hottest spot temperature of 140° C which was at the time of the highest ambient. The tabulation of results shows that the existing units can just handle this peak contingency condition.

A. Cooling Upgrade Study -

The possibility of a cooling upgrade was investigated to reduce the hottest spot temperature at the 27 MVA contingency load or to give the transformer extra capacity. Options were evaluated during the on-site transformer inspection. The following options were considered:

- Option A. Add 1 fan
- Option B. Add 1 fan and 2 Radiators on the H.V. Side
- Option C. Add 9 fans and 2 Radiators
- Option D. Add 1 fan and change other fans to high CFM fans.

The loading capabilities of both transformers can be increased by modifying their cooling systems. FIGURE 12 below shows the resulting capacity of the transformers for each of these cooling options. They have been ordered on the graph in increasing effectiveness in improving MVA. Since load is relatively constant throughout the day and year, summer is the worst case, due to the higher ambient.

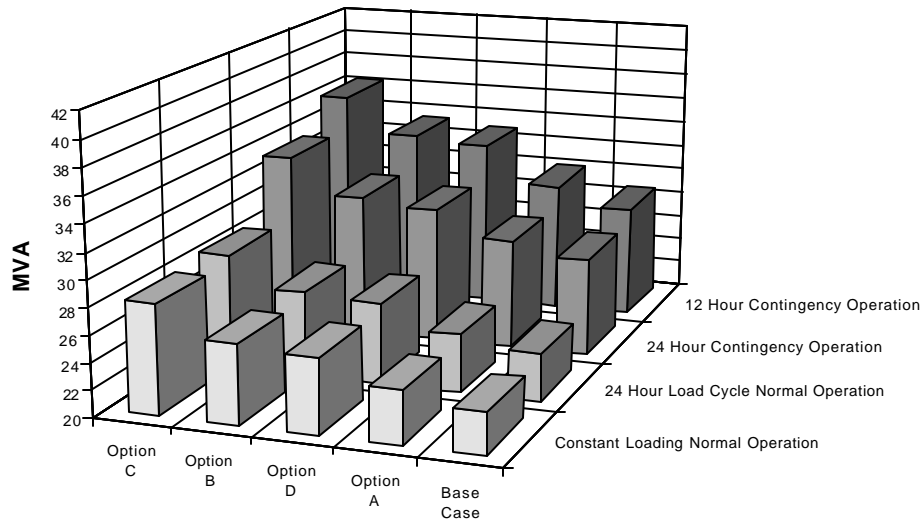


FIGURE 12

Summer Loading Capability

TABLE V below shows the details of the transformer's thermal characteristics and cooling data.

Option D, the addition of one additional and 9 replacement high CFM (cubic feet per minute) fans appears to be the most economical and easiest solution to improve the capacity of the transformer to carry 27 MVA. All ancillary equipment that carry current were also checked for temperature rises, and found to be within specified limits.

In both of these cases studies, the utility was able to avoid or at least delay, the purchase of a new transformer with knowledge about how the transformers responded with the dynamic conditions of load and ambient cycle and their overall ability to carry loads beyond nameplate. In addition, viable options of performance enhancements were explored and will further delay the need for a new unit.

TABLE VI
 TRANSFORMER LOAD AND COOLING UPGRADE STUDY

Industrial Substation

McGraw Edison S/N: C-06720-5-1 & 2

12/16/20//22.4 MVA, OA/FA/FA, 67-13 kV, LTC

Transformer Thermal Characteristics & Cooling Data					
	<u>Existing</u>	<u>Option A</u>	<u>Option B</u>	<u>Option C</u>	<u>Option D</u>
Hot Spot Rise (HSR) - °C	76.4	72.3	63.0	54.7	64.6
Top Oil Rise (TOR)) - °C	51.2	46.8	37.0	28.3	38.7
Avg. Winding Rise (CuR)) - °C	61.4	58.1	50.8	44.3	52.1
Hot Spot over Top Oil (HS Grad)) - °C	25.2	25.5	26.0	26.4	25.9
Avg. Oil Rise (AOR)) - °C	38.2	34.9	27.6	21.1	28.9
Avg. Wdg. Over Avg. Oil (Cu Grad)) - °C	23.2	23.2	23.2	23.2	23.2
Top Oil over Avg. Oil (Half DT)) - °C	13.0	11.9	9.4	7.2	9.8
# of Radiators	3	3	5	5	3
Radiator Height - (in.)	120	120	120	120	120
# of Plates	31	31	31	31	31
Plate Width - (in.)	15	15	15	15	15
# of Fans	7	8	8	16	8
Diameter - (in.)	26	26	26	26	26
RPM	1140	1140	1140	1140	1750
# of Blades	4	4	4	4	2
Loss (watts)	2310	2640	2640	5280	4800
Fan Noise - (dB)	66.5	67.0	67.0	72.0	79.0
Upgrade Cost Estimate (materials) - \$	0.0	650	8700	16000	7500
Effective MVA Increase	0.0	0.8	2.8	5.1	2.5

Cost of Additional MVA (\$/kVA)	-	0.81	3.11	3.14	3.00
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XI. Conclusion: Dynamic Loading of Transformers - Future

Dynamic loading of transformers means more than setting loading criteria based on varying historical load and ambient cycles. Re-rating transformers to operate above nameplate rating requires establishing maximum acceptable load criteria in the form of internal transformer temperatures, ancillary equipment capability, and insulation loss of life criteria, and in real-time calculation, the maximum optimum load. In order to effectively implement such a program, several important steps should be followed.

1) Condition Appraisal -

- Benchmarking and index rank of units
- Ancillary equipment evaluated for capability
- End-point criteria of life identified-relative
- Indexed ranking of units

2) Load Optimization -

- Criteria Set % Loss of life, maximum temperatures
- Ancillary equipment temperature rise and current capability
- Options to improve capacity with cooling upgrade.

3) Dynamic Loading Program -

- Use of new temperature sensors - top, bottom, hottest spot, ambient, LTC Compartment, etc.
- Transformer thermal model and aging criteria established
- Algorithm for transformer model developed for monitor
- Monitor to convert loading and ambient to loss of life and temperatures in real time
- Calculation of cumulative loss-of-life done continuously.
Insulation Life Dosimeter

The dynamic loading program would consider all the transformer and outside factors that influence hottest spot temperature and loss of life and establish the upper loading limits of the transformer in real time. This loading would be established for normal life loading, planned loading beyond nameplate, long-time emergency loading and short-time emergency loading. This dynamic loading would give the operators specific information on the loading capability of the transformer under any condition.

Dynamic loading programs would make the most effective use of transformer and give the operator real time information on how to load the system units. With this type of loading, more appropriate decisions could be made as to when new units should be purchased or identify units to be re-deployed for more effective use or to extend their life.