Life Cycle Management of Utility Transformer Assets

by William H. Bartley P.E.
Hartford Steam Boiler
Inspection & Insurance Co.

presented at

Breakthrough Asset Management for the Restructured Power Industry
October 10–11, 2002
Salt Lake City, Utah

Life Cycle Management of Utility Transformer Assets

by William H. Bartley P.E.
Hartford Steam Boiler Inspection & Insurance Co.
Hartford, CT

INTRODUCTION

The deregulation of wholesale electricity supply has led to a number of changes and new challenges for the electric utility industry and the market participants. A couple years ago, there were predictions that 750 Gigawatts of new generating capacity would be installed worldwide, between 2000 and 2010. But, the rush to build powerplants in the U.S. has subsided, somewhat; many of the energy companies are now drowning in debt. In 2001, projects worth 91 GW of generating capacity were cancelled (out of 500 GW). And in the first quarter of this year, orders for 57 GW of capacity were cancelled. But despite this downturn, the construction continues... in 2001, the US utility industry brought on-line 47 GW of new capacity.

However, the expansion of the transmission systems has not coincided with the generation expansion. The failure to expand transmission has led to transmission congestion in various parts of the North American transmission system.

Increased equipment utilization, deferred capital expenditures and reduced maintenance expenses are all part of a modern utility's strategies for T&D Assets. The need to leverage more out of existing equipment must today be achieved with T&D assets that are nearing the end of their useful life. Large power transformers are the most significant portion of the T&D assets, and a major concern to every electric utility. Each one feeds a number of customers and its replacement will involve a considerable amount of time and expense. With today's capital spending on new or replacement transformers at its lowest level in decades, the average age of the installed U.S. transformer fleet continues to rise.

Many utilities are beginning to develop their own Life Cycle Transformer Management programs. This asset management approach is typically a three-step process:

1) Risk Assessment of transformer fleet
2) Condition Assessment of individual transformers
3) Life Cycle Decisions: retire, refurbish, replace, relocate

This paper will address: a) the legislative history that shaped the current utility industry; b) the congestion and transmission adequacy; c) the aging transformer fleet; d) the risk analysis process and e) the life cycle decisions.

HISTORY

To understand the premise of the issue in the US, one needs to review some of our legislative and regulatory history. The business model for the traditional large utility may not have been the most efficient in terms of building plants and operating them, but it worked for many decades.

The Public Utility Holding Company Act of 1935 ruled that utility holding companies could only own systems that were physically located in adjoining states. Because the utilities were effectively monopolies, the interstate wholesale markets and transmission were regulated by the

Federal Power Commission, which later became the Federal Energy Regulatory Commission (or FERC)

Then, in 1965, a blackout left 30 million people in the dark, across northeastern U.S and Ontario Canada. To prevent a recurrence of this magnitude, the electric utility industry in 1968, formed the North American Electric Reliability Council (or NERC). The membership of this organization is made up of ten Regional Councils (ERCOT, ECAR, MAAC, etc) and was responsible for overall reliability, planning and coordination of the electric supply in North America. However participation in NERC is voluntary and the participants in the industry are not required to follow the directions of NERC.

In 1978 Congress passed the Public Utility Regulatory Policy Act (PURPA), which encouraged the construction of Non-utility Generators (NUGs) and ordered the utilities to connect the Qualifying Facilities to the utility grid. But, the act prohibited utilities from owning a majority stake in the Qualifying Facility. This started another significant change in the electric power construction industry. In the past, the costs for new power plants were allowable and allocable in the rate requests that the utility would apply for in the amortization of such costs. But, after PURPA, utilities in the US had to utilize independent power producers (IPP's) to satisfy supply and meet demand. In this environment, it was possible that the utility's capital projects may not be afforded a favorable rate structure from the local PUC in an openly competitive market. Therefore, many utilities understandably stopped building the power plants.

In 1992, Congress enacted the most significant utility legislation to date, the Energy Policy Act. One important provision of this act completely turns around the rules in place since 1935. The Act created and encouraged entities called "Exempt Wholesale Generators" (EWGs) which were given access to the transmission grid and could compete to sell power at the wholesale level. The EWG could only sell energy on the wholesale market, but the EWG could be owned by a utility, and could sell energy to other utilities. The utilities were not required to purchase the output of the EWGs but they are still required to purchase any and all available energy from the NUG Qualifying Facility.

To help obtain the objectives of the Energy Act, the Federal Energy Regulatory Commission (FERC) issued Orders #888 and 889, in 1996, to remove impediments to competition in the wholesale markets and created "independent system operators". But, since 1996 there has been an exponential increase in trading at the wholesale level. And, deregulation of the utilities has reduced cooperation among the transmission owners, which adds to the complexity of the system reliability.

In December of 1999 FERC issued Order #2000, which encourages every utility that owns a transmission system to participate in a Regional Transmission Organization (RTO). This Order provided the industry with a flexible approach that permits different types of RTOs, like the non-profit independent system operator or the for-profit transmission companies. FERC did not mandate participation in the RTOs and did not establish any specific boundaries. But FERC envisions that the nation will eventually be served by just four regions (or possibly as many as six.). Each RTO must be independent; have appropriate geographic scope; have operational authority and exclusive short-term reliability authority. Although the deadline for forming the RTOs was December of 2001, many of the RTOs are still in the development process. Presently in the USA, the regionalization can be described as five (5) Independent System Operators

(ISOs) that are *in operation*. Four (4) of them: -the Pennsylvania Jersey Maryland (PJM) interconnection, California IS0 (CA ISO), IS0 New England (IS0 NE), and New York IS0 (NY ISO) are under FERC's jurisdiction. The fifth is the Electric Reliability Council of Texas (ERCOT), which is exclusively intrastate trade and thus not under FERC's jurisdiction. Two newly created ISOs: the Midwest IS0 (MISO) and Southern Power Pool (SPP) have FERC's conditional approval and will soon begin market trials. Three other RTOs are in the development process: RTO West, Grid South and Desert STAR. There have even been published reports about a merger between MISO, the Alliance RTO and PJM, and another merger between NY-ISO and ISO-NE [1].

TRANSMISSION CONGESTION AND ADEQUACY

The U.S. transmission system is being subjected to flows in magnitudes and directions that were not contemplated when it was designed. They were designed by individual utilities to move energy from local generation to serve the native load. The systems were not designed for open access and interconnection by hundreds of market participants. Portions of our transmission system are reaching their limits as customer demand increases and the systems are subjected to new loading patterns resulting from increased power transfers. In a speech delivered at the IEEE Power Engineering Society's Summer 2002 meeting, Clark Gellings from EPRI reported "the load growth in the US has been about 35% over the last 10 years. But our transmission capacity has only grown 18% over that period. To compound the problem, wholesale interstate and intrastate transactions have grown 400% during that time."

According to a recent NERC Reliability Assessment (2001 –2010), [2] only 7,276 miles of new transmission line (above 230kV) are proposed to be added by 2005, and a majority of that is in the Eastern Interconnect. This represents only a 3.5% increase in the total installed circuit miles, and most of these additions are intended to address local transmission needs (within a utility) or to connect to proposed new generators. These will not have a significant impact on the adequacy or capability to transfer power within the new RTOs.

The NERC report indicates the system reliability should be satisfactory in the near term (through 2005). But this reliability is highly dependent on coordination with surrounding systems and proper actions by the local independent system operators. In the long term, the delivery of energy will be highly dependent on the location of new generation sources. Unless siting problems can be resolved, and sufficient investment incentives are developed, we can expect very few new transmission facilities to be built.

In the future, the need for new transmission systems will likely be based on, or driven by access to competitive power supplies. Expansion and reliable future operation of our transmission system will depend upon cooperation and an open exchange of information among the owners of the assets. However, in a competitive industry, the stakeholders consider this asset information confidential, proprietary and commercially sensitive, which has hindered the regulators ability to resolve cost recovery issues for transmission investment.

NERC recently appointed a Transmission Adequacy Issues Task Force to identify key issues or obstacles that are impacting the planning and expansion of our transmission system. Their report was published in February of 2002, [3] and addresses four major issues: Planning; Cost Recovery; Siting; and Education. The Task Force also made a number of associated recommendations to reduce transmission congestion. But in the long term, it is not clear how NERC will coordinate with the new RTOs envisioned by FERC. NERC and its ten Councils set voluntary standards and guidelines. FERC holds the RTOs responsible for reliability within their regions. Also unclear is the jurisdiction, the standards and investment incentives for linking together neighboring RTOs. What does State government do if local reliability is not maintained for their constituents? Hopefully the ten Councils of NERC and the emerging RTOs will continue to work together voluntarily to develop new rules that are mandatory and enforceable.

TRANSFORMER AGING

Large power transformers are the most significant portion of our transmission system assets, and a major concern to every electric utility. Their replacement will involve a considerable amount of time and expense. The age of transformers in the U.S. electric utility industry deserves special attention. The world went through massive industrial growth in the post World War II era, causing a large growth in base infrastructure industries, especially the electric utilities. World energy consumption grew from 1 trillion to 11 trillion kwhr in the decades following the war. Most of this equipment is now in the aging part of its life cycle.

According to U.S. Commerce Department data, the electric utility industry reached a peak in new installations in the U.S. around 1973-74. That year, we added about 185 GVA of power transformers. Today, that equipment is about 28 years old. With today's capital spending on new or replacement transformers at its lowest level in decades, (about 50GVA /yr) the average age of the entire U.S. transformer fleet continues to rise.

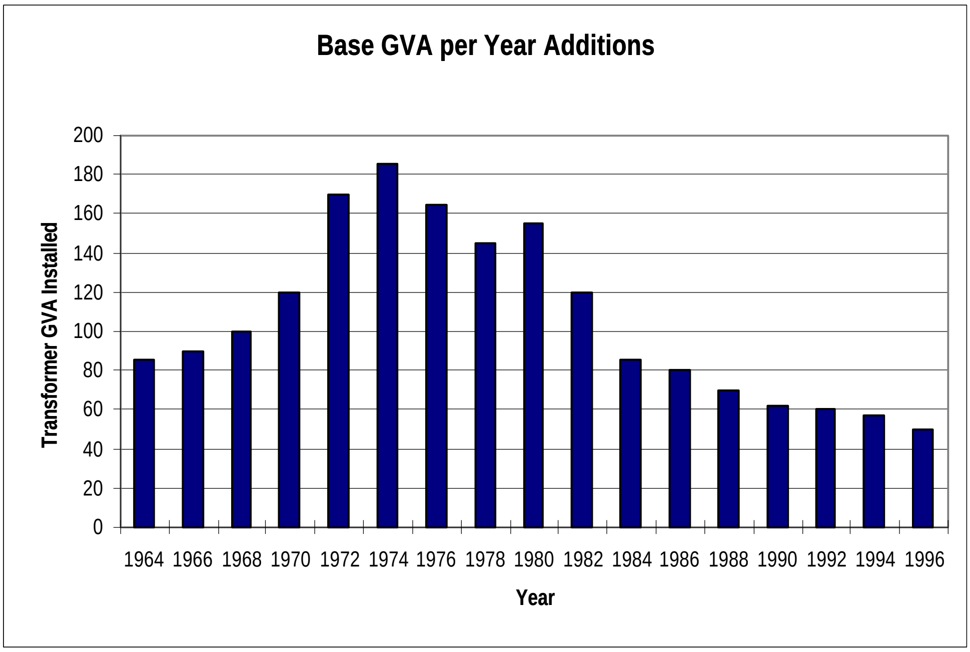

Figure #1 Total Additional U.S Transformer Capacity in GVA

Figure #1 is from a Doble Client Conference paper by M. Franchek and D. Woodcock [4], which depicts the total transformer capacity additions in the U.S.A. each year.

Due to the large number of aging transformers we insure, we developed a risk model of future failures. This was first published at the 2000 Doble Client Conference [5]. The instantaneous failure rate is defined as the probability of failure per unit time for the population of transformers that has survived up until time "***t***". Last year we revised our risk model, to include the frequency of random events (lightning, collisions, vandalism) *separate* from aging. Thus our risk model for future transformer failures can be expressed as:

$$f_{(t)} = 0.005 + a\, e^{bt}$$

where $f_{(t)}$ is the instantaneous failure rate, a is a constant; b is a time constant; and t = time(in years).

Admittedly, the correlation between calendar age and insulation deterioration is subject to some uncertainty. (Not all transformers were created equal.) This prediction is a simple statistical model and does not take into consideration individual design differences or loading history. Our model is based only on the calendar age of the transformer fleet, and the population explosion, and is intended to illustrate the magnitude of the problem facing the utility industry. This is the corresponding exponential curve for a 50% failure rate at the age of 50.

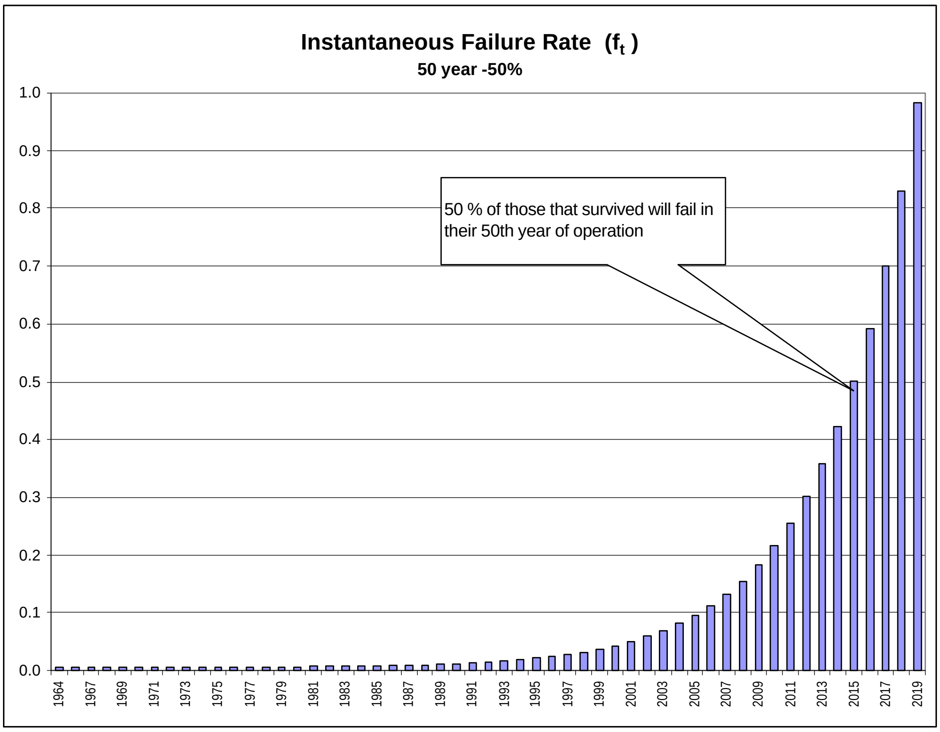

Figure 2 – 50% Failure Rate

If we then take one-thousand (1000) transformers from 1964, and apply this instantaneous failure rate, the predicted number of failures for this vintage is shown in Figure 3. Note that the greatest number of failures is in the year 2008; in that year 15% of those that have survived will fail. After this point, the rate of failures (percent of population) is escalating rapidly, but due to the declining population, the actual number of failures becomes smaller each year.

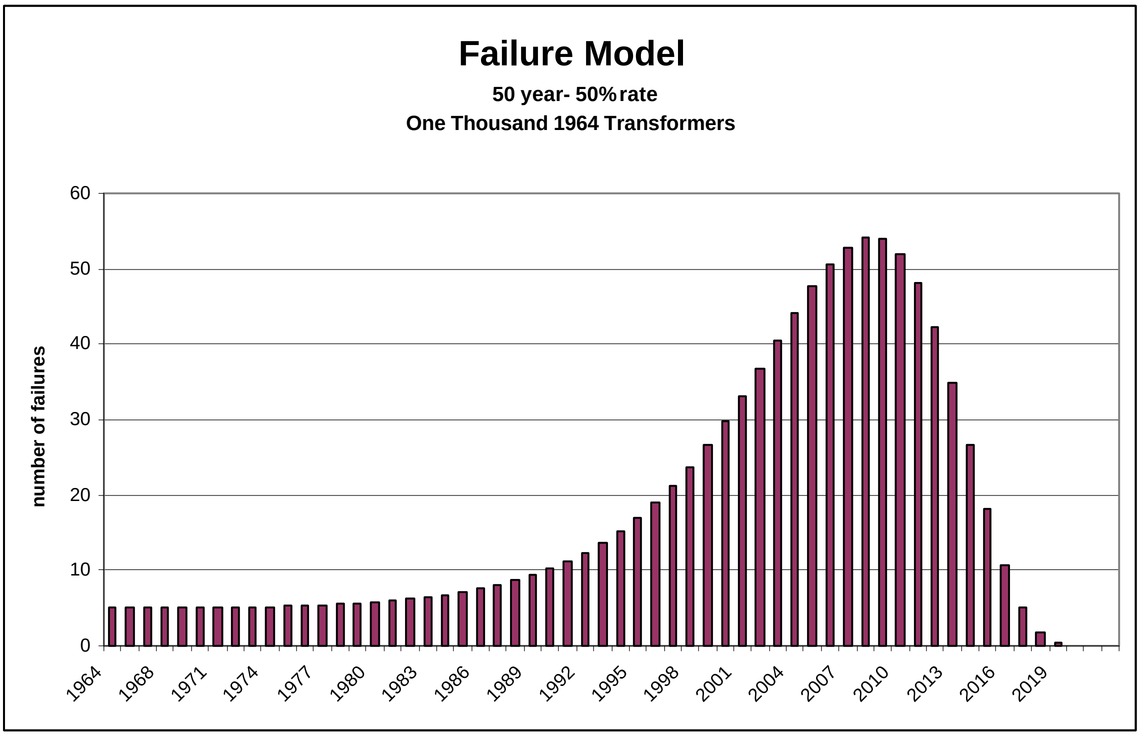

Figure 3 – Predicted Failures for 1964 Transformers

With a failure rate model and population estimate for each vintage, we then modeled the future failures for several different vintages of transformers, by multiplying the failure rate x the population of the vintage:

Number of failures (in GVA) at year "t", **=[Failure rate] x [population** that is still surviving**]**

Using the population profile from Figure #1, we plotted the predicted failures for all U.S. utility transformers, built between 1964 and 1992. Figure #4 is the failure distribution. The X-axis is the year of predicted failures. The Y-axis is the population of the failures (expressed in GVA). It should be noted that the graph is a failure rate of those that survived, until time "t". When a transformer fails, we assumed it was replaced with new. Replacements are not included in this graph. In this graph, a vertical line depicts each vintage. By 1975, each year has a cluster of six different vintages and after 1992, each cluster is 15 vintages.

According to our model, the number of failures for 1964-vintage transformers continues to rise, reaching a peak in 2008. But, due to the population increase, the failures of 1972- vintage transformers will overtake the failures of the 1964-vintage in 2006; and by 2008, the instantaneous failure rate of 1974-vintage transformers will easily exceed the failures of the Sixty-Four vintage transformers. In our next chart, Figure 5, we take a closer look at predicted failures over the next six years (2003 to 2008). Again, this prediction ignores rebuilds and rewinds of previous failures.

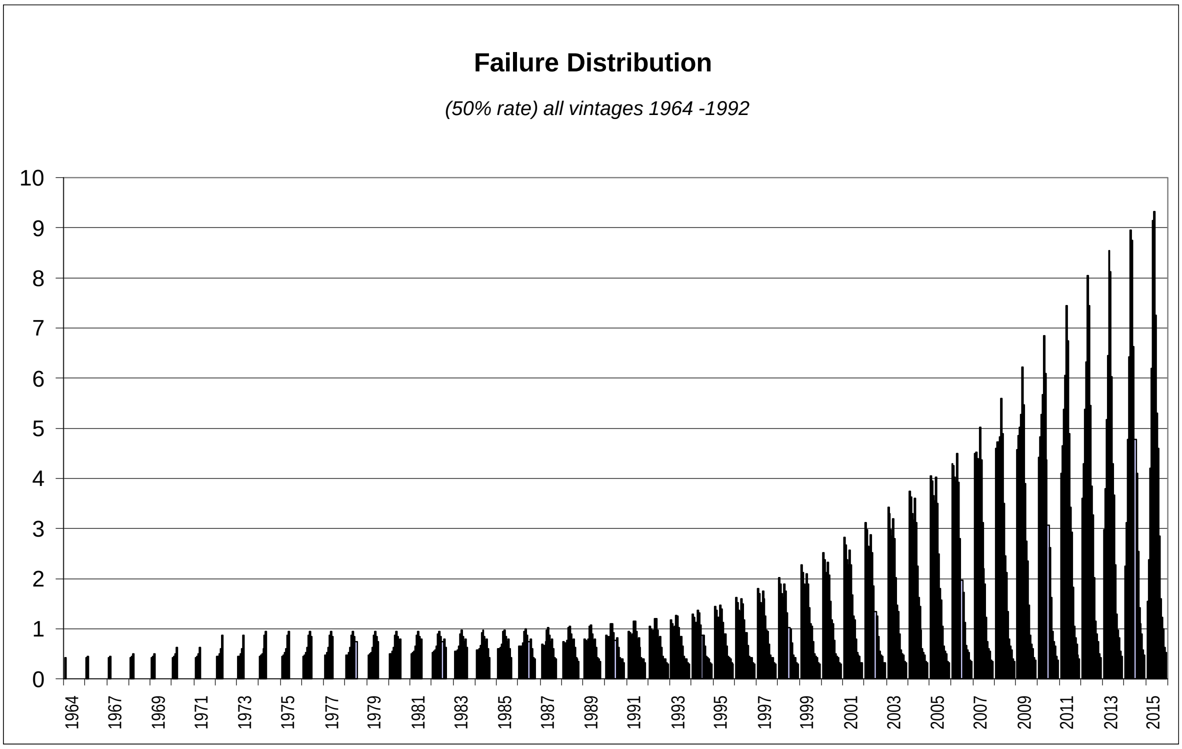

Figure 4 – Failure Distribution - all vintages from 1964 - 1992

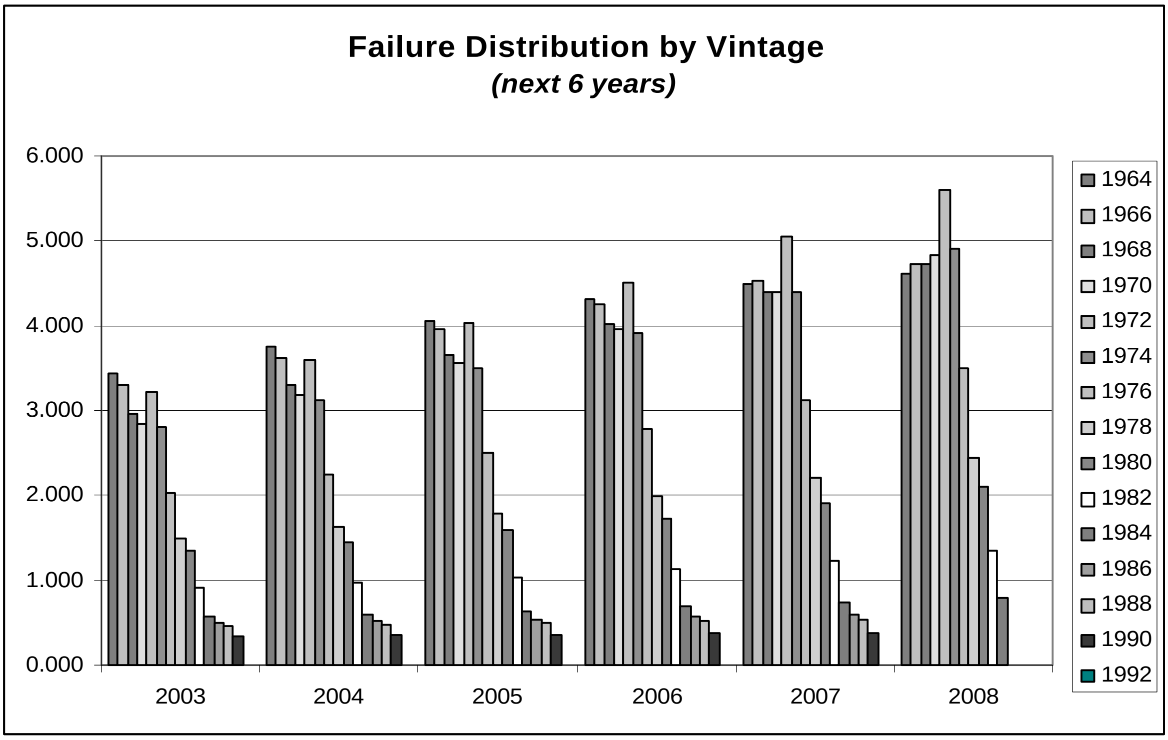

Figure 5 - Failure Distribution –Next 6 Years

In order to examine the total predicted transformer failures in any given year; we can take the sum of the individual vintages, for each year. Figure 6 illustrates such a prediction.

Figure 6 Failure Distribution - all vintages

Meeting the growing demand of the grid and at the same time maintaining system reliability with this aging fleet will require significant changes in the way the utility operates and cares for its transformers. A number of electric utilities have adopted a strategy that includes a life assessment and a life cycle management program.

Risk Assessment

Increased equipment utilization, deferred capital expenditures and reduced maintenance expenses are all part of a modern utility's strategies for T&D Assets. The need to leverage more out of existing equipment must today be achieved with T&D assets that are nearing the end of their useful life. The first step in a life cycle asset management strategy is a risk assessment process for the utility's fleet of transformers.

In the most general sense, risk is defined as "future's uncertainty". It has two basic components: the *frequency*, or how often undesirable events occur; and their *severity* or consequences. For example, every transformer has an end-of-life, so the severity of the event is known. The risk comes from not knowing when it will occur – the frequency of failure. Risk-based methods generally use the product of both the frequency and severity events together, in the analysis process. Whether the frequency and severity data is subjective, qualitative, or quantitative, a risk-based decision process provides a logical framework to capture and portray several layers of complex data in one cohesive, easily interpreted format.

These are a few basic tenets that are important to keep in mind when developing and implementing new project strategies that incorporate risk management principles.

Risk Perception

Some managers are driven by high-severity events, while other managers are driven by high-frequency events. Some people are more susceptible to remember the high frequency type of events. After all, for these problems, there is an abundant amount of data to analyze, and data-availability can be a potential trap. Applying financial resources to resolve problems that have the highest amount of data may not be the best way to reduce risk – in the long term. The key to a good risk strategy is to find the right recipe between what is real and what people perceive to be real. For example, the general public perceives high severity-low frequency events as higher than the actual risk. They also perceive low severity-high frequency events as lower than the actual risk. As an illustration, Table 1, below, lists a number of undesirable events we face in life everyday.[6] What is the asteroid risk? A few years ago, preceding the launch of the Cassini mission to Saturn, NASA determined that the probability of a one-mile wide asteroid hitting earth was two in a million (0.00002). They also estimated the fatalities would reach 1.5 billion. If we multiply the frequency and severity and compare this risk with other more earth-bound statistics from 1999 US National Safety Council, another property of risk management principles is seen.

The point is not all "risks" of the same value are equal. Other than the Asteroid risk, the events in this table are frequency driven which implies they are somewhat predictable. The relatively high number of events gives us data to understand their causes, which then helps plan loss prevention efforts. Severity driven risks, like the asteroid example, possess little to no event data to define effective loss prevention activities. Even though risk management can involve a fair amount of mathematics, it is an art – not a science. The essence of risk management is maximizing the areas where we have some control over the outcome and minimizing the areas where we have no control. As a general rule, corporate risk managers tend to insure the low frequency /high-severity risks which can easily result in severe financial problems.

Accidental Deaths per Year

Event	**Risk**
Workplace	5,100
Drowning	4,000
Fires	3,700
Choking	3,300
Asteroid risk	***3,000***
Firearms	1,500
Gas Poisoning	700

Table 1

Relative ranking of various issues can result in a better risk management strategy. The first step in developing a risk assessment program is to identify the two major components:

1. Determine the likelihood (frequency or probability) of the unwanted event. This involves analysis of known history, statistical data, and judgment by experts -- specific characteristics that contribute to the overall risk.

2. Evaluation of the consequences -- the possible repair or replacement costs of the transformer, plus any other site-specific potential costs.

As a risk-ranking example, we have plotted the cause of transformer failures, from our claims data for 1995 through 2000. This is a log-log scatter plot, or sometimes referred to as an "F-N curve" (frequency –number curve). The number of failures for each cause is on the X-axis, and the dollars paid for each cause is on the Y-axis. According to our claims database, the Line Surge (or Line Disturbance) is the highest risk for all type of transformers. The category includes switching surges, voltage spikes, line faults, and other T&D abnormalities.

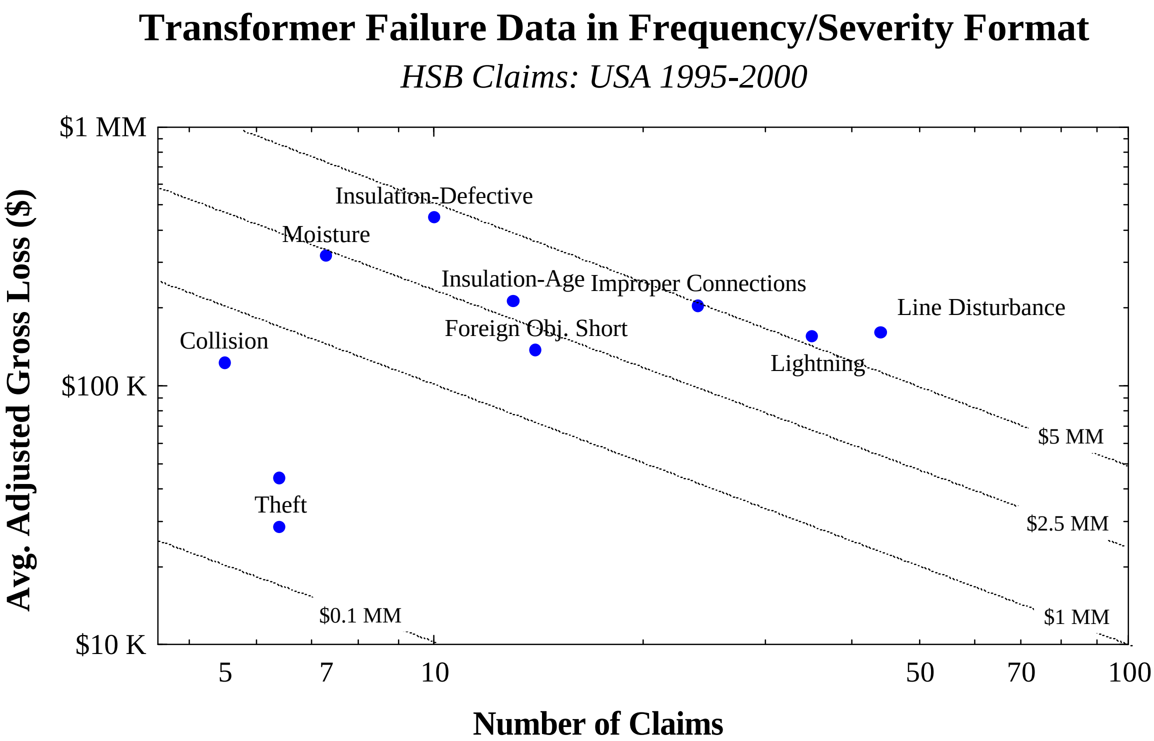

Figure 7 - Transformer Risks by Cause of Failure

Risk Assessment for a Transformer Fleet

There are many different risk assessment methods and strategies available to the utility industry for a large family of power transformers. The following method is a preliminary process that will help the utility identify the transformers that need additional condition assessment, additional testing, or other actions that need to be taken in order to bring the entire population up to an acceptable risk level. Each transformer in the utility can have its risk index compared, or ranked, to all other transformers on the company's balance sheet. However, due to the very high consequence issues, some utilities have chosen to divide the transformer assets into two groups:

1) Large generator step up transformers and large transmission class transformers (>100MVA)
2) Distribution transformers, and Class 1 power transformers ($\leq$69kV).

Every transformer in the group can then be evaluated and ranked accordingly with others in their group.

HSB prefers the frequency/severity plot for risk ranking; but it does require two data points for each transformer. For those that prefer a single-number ranking system, the Transformer Risk Index number (TRI) is a number that can be used to rank the entire transformer population and help determine the extent to which each transformer is inspected, tested, maintained and operated in the future. The TRI is a product of the Consequence Factor (CF), and Probability Factor (PF); or

$$TRI = CF \times PF.$$

The **Consequence Factor** is comprised of the probable maximum loss, in dollars, and the strategic impact of the transformer. Strategic impact includes issues such as system reliability, critical customers, and public service (hospitals etc). The probable maximum loss would include such items as the possible repair or replacement costs of the transformer, plus the environmental damage and clean-up costs, damage to adjacent equipment, lost revenues and litigation costs, as well as any other site-specific potential costs. (For Generator Step-Up transformers, the lost revenue can far-outweigh any and all other costs.)

The probable maximum loss can be developed for any transformer, or substation based on historic data. But the strategic impact is a subjective multiplier that must be developed by the utility. Sometimes a committee of asset managers and engineers is used to make this judgment. For example, the system reliability could have a multiplier of 1.0 to 1.5, critical customers could have a range of 1.0 to 1.3, and public service might have a multiplier of 1.0 or 1.5 (e.g. if the substation served a hospital, or not). It makes no difference if you add or multiply these factors, as long as you apply the formula consistently. Of course additional strategic issues that affect the consequence can also be added to the formula. Note that strategic issues affect the outcome or severity of a failure. These issues are not affected by the condition of the transformer, or its probability of a failure. In our example, if the probable maximum loss for a certain power transformer is $300,000 and the "committee" assigned strategic impact multipliers of 1.3, 1.3 and 1.0, the Consequence Factor would be: 300,000 x 1.3 x 1.3 x 1.0 = 507,000

Probability Factor There is no single scientific method available to determine the exact probability of failure, or to calculate the end-of –life of a power transformer. A team of designers, chemists and engineers are needed, along with a rigorous inspection and extensive testing to arrive at this judgment. However, a probability factor can be created as part of this screening technique, by first developing a list of critical issues that are based on the known conditions. Each critical issue is then assigned a index number, which can be differently weighted. The probability factor is then calculated by multiplying the various indices. For example:

$$PF = (CI_1) \cdot (CI_2) \cdot (CI_3) \cdot (CI_4) \cdot (CI_5) \cdot (CI_6)$$

The following critical issues can affect the frequency or probability of failure, but not necessarily the consequence or severity of the failure:

Vintage and **Manufacturer** may be indicative of transformer quality, material and component condition. Transformers manufactured in the United States before 1967 were likely designed without advanced computer programming. They have higher loading capability being conservatively rated, but may lack adequate provision for leakage flux and have a higher probability of localized hot spots. In the late 1960's, industry standards were revised invoking more stringent short circuit duty, which earlier designs do not meet. Large shell form transformers manufactured by Westinghouse before 1978 did not have insulation on a vertical T-beam, which can result in an unintentional core ground. Thermally upgraded cellulose insulation was not available before the late 1970's, and those transformers are more susceptible to insulation degradation from heating and high moisture. (An index of 1.0 (*favorable*) to 1.5 (*unfavorable*) could be used.)

Calendar Age, as described above, can have an affect on the mechanical strength of the transformers insulation and hence its ability to withstand common short circuit forces that are inherent in a transmission /distribution system. Admittedly, a direct correlation between calendar age and insulation deterioration is subject to some uncertainty. But combined with other issues listed here, the calendar age is a significant issue. (The exponential aging formula, above, could be used as an index if you a add "1.0" such that the index could range from 1.005 to 1.50, depending on age. *The factor we used for random events (0.005) can be ignored for this calculation.*)

Operating History - The operational loading experience and/or loading philosophy of the transformer should be reviewed comparative to original design philosophy and any limitations noted. Extended periods of overload with an excessive ambient or partial cooling may result in sustained high temperatures, which will degrade the winding insulation. (An index of 1.0 (*favorable*) to 1.5 (*unfavorable*) could be used.)

Operating Environment - Loading, maintenance, and protection against overstressing and contamination influence transformer useful life. The level of exposure to system faults, and frequent switching operations may be an indication of thermal and/or mechanical degradation of the transformer. If the transformer was stored for a significant period of time between periods of service, the conditions of storage should also be taken into consideration. (An index of 1.0 (*favorable*) to 1.5 (*unfavorable*) could be used.)

Failure History - A review of transformer's history may identify minor failures in the past. Failures of similar transformers in the utility's asset list may indicate a generic trend. Industry data can supplement internal failure information, particularly when the transformer population is small. Records of repair history and maintenance data may also indicate incidents of an isolated or reoccurring nature. Documentation of any field inspections and maintenance reports of the transformer should be reviewed as it may indicate the need for increased maintenance frequency for a suspect condition or known defect. (An index of 1.0 (*favorable*) to 1.5 (*unfavorable*) could be used.)

Oil Testing History - Contamination and thermal aging can be monitored through diagnostic testing. Over the past 20 years, many utilities have accumulated a significant amount of data from their oil testing programs. An analysis of the transformer oil's chemical and physical characteristics can help to diagnose both internal electrical problems and physical deterioration of the oil. Analysis of test data may help ensure that the transformer oil is free from harmful impurities and capable of continued service; or it may indicate the need for increased frequency of testing to monitor a suspected condition or a known defect. (An index of 1.0 (*favorable*) to 1.5 (*unfavorable*) could be used.)

The above index values for each issue are just suggested ranges. Each of these critical issues should be assigned a subjective multiplier that is developed by the utility, based on local circumstances. Again, a committee of asset managers and engineers may be used to make this judgment. Of course additional critical issues that affect the frequency of failure can also be added to the formula. (Note that critical issues do <u>not</u> affect the outcome or severity of a failure.) The committee can also assign weighting factors to certain issues, if they don't consider all issues to be of equal importance. In our example, if the "committee" assigned critical issue indices of 1.2 (for vintage), 1.25 (for age), 1.1 (history), 1.0 (environment), 1.1 (failures) and 1.1 (oil) , the Probability Factor would be: PF = 1.2 x 1.25 x 1.1 x 1.0 x 1.1 x 1.1 = 1.99

To complete our example, the Transformer Risk Index would be:

$$TRI = CF \times PF = [507{,}000] \times [1.99] = 1\,008\,930$$

CONDITION ASSESSMENT

As stated earlier, a Life Cycle Transformer Management is typically a three-step process:

1) Risk Assessment of transformer fleet
2) Condition Assessment of individual transformers
3) Life Cycle Decisions

The Risk Assessment, described above, is a screening process, using statistical methods to identify and prioritize those transformers that represent the highest risk. But this does not identify the actual condition or the vulnerability of the individual transformers. The second step in the process, a condition assessment, involves a rigorous inspection and extensive testing of the transformer. The results of this process will help the utility in the last step, the life cycle decisions.

There have been a number of excellent papers written in recent years on the assessment of transformer life and the techniques employed by engineers to establish transformer condition and decide on remedial action. [7, 8, 9, 10, 11, 12] In addition, a number of engineering organizations (such as IEEE Transformer Committee, CIGRE and EPRI) are developing their own guidelines for evaluating the condition of individual transformers. [13, 14, 15, 16] Many of these are listed in the references for this paper. Hence, a guideline for assessing individual transformers is outside the scope of this paper.

LIFE CYCLE DECISIONS

After the risk assessment is completed and the condition assessments are finished for the high priority units, the next step is called a Life Cycle Decision. However, the list of variables and the individual utility circumstances that govern the technical and financial decision-making are such that it is impossible to establish an industry-wide set of rules or standards for managing the life cycle of aging transformers.

One strategy suggests that all the transformers be left in service until they fail, and let the insurance pay for it. But insurance programs have high deductibles, and probably do not cover all the costs. The cost of an unexpected failure can be several times the cost of the original transformer installation, when you consider system outages, lost power sales, and possible environmental clean up costs. The time required for rewinding or rebuilding a large power transformer could take six to twelve months, or more!

The ideal strategy is a life cycle management program, that establishes a loading policy for individual transformers, and provides asset management direction to identify: a) transformers that can continue to operate as-is (*some loaded beyond nameplate*), b) transformers that can be modified or refurbished; c) transformers that should be re-located and d) transformers that should be retired.

<u>Loading</u> - In a recent survey by Weidman Systems [9], approximately 30% of U.S. utilities reported that they are already developing some form of dynamic loading (or over-loading) policy for their transformers, based on thermal limits (top oil temperature, hottest spot temperature, etc). As David Woodcock at Weidman points out, it is inappropriate to establish over-loading limits that are based on thermal considerations only. Transformers that have only been moderately loaded for an extended period of time may have reduced dielectric strength, shrinkage, and loss of integrity for structural insulation parts (compared to a new transformer). In addition, ordinary faults on the grid system will cumulatively result in reducing the transformer's ability to withstand the stress associated with higher loading (and higher temperatures). In addition to the increased risk factor for aging transformers, loading limits beyond the transformer nameplate should also take into consideration the temperature rise of the other current-carrying components, such as bushings, tap changers, leads, etc.

<u>Modification or Refurbishment</u> – The most extensive (and expensive) refurbishment is a complete rewind of the transformer coils. However, in the decision to rewind versus replace old transformers, it is important to include the costs of transformer losses. The cost of core and copper losses for a 1950's transformer may be twice that of a new transformer. In several recent cases, our customers have decided to replace the transformer (instead of rewinding it) because the reduction in core losses could economically justify it.

Another major Refurbishment option is reblocking and reclamping the transformer coils. Over time, thermal and mechanical cycling can result in a gradual decrease in the vertical clamping pressure (axial) on the coils. These forces can decay at a different rate for different windings or for different layers of the same winding. At some point the coil clamping may fall below the level required to hold the coils stable during through-fault events. One important aspect of coil reclamping is to ensure that all windings are taking their share of the clamping load. This is a bit of an art, and should not be attempted by the inexperienced. The transformer is typically reclamped to the original values specified by the manufacturer. <u>However</u>, if there is any possibility of internal insulation damage or conductor "tilting", due to previous faults, the reclamping process should be avoided. Reclamping, in this case, may exacerbate the pre-existing condition, and accelerate a failure.

Other refurbishment options include the repair or replacement of ancillary equipment, such as surge arresters, bushings, fans, pumps, radiators, pressure relief devices, oil and winding temperature gauges, liquid level gauges, fault-pressure relays, gas detector relays, load tap changer maintenance /upgrade (contacts), and oil dry out/reclamation.

Relocating transformers should not be overlooked in a life cycle program. Transformers may be re-located for several reasons: a) better voltage regulation; b) loading/overloading limitations; and c) customers that require more reliable power source. In future load planning scenarios, those transformers that have insufficient thermal characteristics, and those that have limited withstand strength, due to advanced age can be re-located to another substation and still provide many years of useful service. 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.

Retirement is the final step in a life cycle program. Some utilities used to retire (and replace) a transformer when the associated load reached 100% of transformer nameplate capacity. Some utilities also used to retire a transformer when its calendar age reached an arbitrary value of 30 to 35 years. Due to the extraordinary growth in power consumption during the late 1960’s and 1970’s, many transformers were simply retired and replaced with larger units. But today the continued operation of aging transformers is crucial to the financial performance and economic viability of the electric utility. The transformer engineer and/or the asset manager is regularly expected to make timely retirement decisions on aging transformers. Transformer retirement is no longer a unilateral or arbitrary decision process. Substantial technical and financial data specific to the individual transformer, plus demographics, load growth, and overall performance of the transformer population must be taken into consideration. The decision to defer a retirement /replacement should no longer be a simple Net Present Value analysis. The decision should also include an increased risk calculation. (Recall that probability of failure for an “old” transformer is not constant; it is increasing exponentially each year.) Obviously, this requires an in-depth knowledge of the corporate risk tolerance, current investment strategy (and “hurdle rates”), and the prevailing business and regulatory environment.

CONCLUSION

The vertically integrated utility industry that existed for decades has been transformed into horizontal organizations of "GenCos", "TransCos", and "DistCos". The winners in the deregulation game will undoubtedly be those who find prudent, innovative ways to be the low cost producer. Some will do this swiftly, perhaps developing brilliant ways to adopt best practices and transform culture. …Others will become a low cost producer … but may in the process abandon good engineering practice and forget …that you win at this game by being consistently reliable and available over the long haul.

REFERENCES

[1] “*Restructuring Grid Operations in the Midwest*”, Electrical World magazine, Second Quarter 2002, Vol 216, No. 2

[2] *Reliability Assessment 2001 –2010*, North American Electric Reliability Council, October 2001

[3] *Transmission Expansion: Issues and Recommendations*, North American Electric Reliability Council, February 2002

[4] M.A. Franchek and D.J. Woodcock, Weidman Systems, *"Life Cycle Considerations of Loading Transformers Above Nameplate Rating"* Proceedings of the Sixty-Fifth Annual International Conference of Doble Clients, 1998, Sec 8-10.1

[5] William H. Bartley, HSB, *Analysis of Transformer Failures*, Proceedings of the Sixty-Seventh Annual International Doble Client Conference 2000

[6] Dr. Richard B. Jones Enron Energy Services, and W. H. Bartley, HSB, *"Risk And Transformer Assessment"*, Sixty-Eighth Annual International Doble Client Conference, 2001

[7] Paul Boman, HSB, *Investigating Reliability by Understanding Why!* ICMEP China 2000.

[8] M. Perkins, L.Pettersson, N.L.Fantana, T.V.Oommen, S.Jordan, *"Transformer Life Assessment Tools with Special Application to Nuclear Power Station Generator Transformers"* IEEE Transformer Committee Meeting, November 1999, Monterrey Mexico

[9] David J. Woodcock, Weidmann Systems International, Inc. "*Condition-Based Loading of Power Transformers*" Sixty-Ninth Annual International Doble Client Conference, 2002

[10] Stan Lindgren & Barry Ward, EPRI, "*Management of Aging Power Transformers*" CEA Electricity Conference, 1999

[11] J. Aubin, Andre Bourgault, Claude Rajotte, Pierre Gervais, *"Profitability Assessment of Transformer On-Line Monitoring and Periodic Monitoring"*, EPRI Substation Equipment Diagnostics Conference, February 2002

[12] Tom S. Molinski, P.E., *Managing the Life Cycle Cost of Power Transformers*, 2001 CIGRE Colloquium, (SC 12.20) Dublin

[13] IEEE P C57.XX Draft 10, October 2001, "IEEE Guide for Application of Monitoring to Liquid Immersed Transformers and Components", Donald Chu, Chair

[14] IEEE P C57.140, Draft 8, October 2002, IEEE Guide for the Evaluation and Reconditioning of Liquid Immersed Power Transformers, Rowland James, Chair

[15] IEEE Std C57.91 –Draft 2, April 2002 Guide for Loading Mineral Oil Immersed Power Transformers, Linden Pierce, Chair

[16] CIGRE 12-20 Guide on Economics of Transformer Management (draft 23.7.02)

<u>The author:</u>

William Bartley, P.E. has a BSEE from University of Missouri at Rolla. His professional career began at Hartford Steam Boiler, in 1971. Today, Mr. Bartley is HSB's Principal Electrical Engineer, specializing in large electrical apparatus- primarily generators and transformers- used in power generation and distribution. He is responsible for developing company standards, OEM relations, fleet problems, large failure investigations, repair procedure development, and new testing technologies. Mr. Bartley established many of the HSB Engineering standards for electrical power apparatus, and laid the foundation for their loss prevention programs in all type of electrical apparatus. He is a Senior Member of IEEE and serves on the Transformer Committee and Synchronous Machines Subcommittee. He has authored numerous papers on Transformer Failures.