Detecting Distribution Transformer Faults

Increasing Distribution System Productivity

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June 2005

Published by:
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Abstract

Utilities are constantly looking for ways to increase productivity in the distribution system. This means reducing the total lifecycle cost of the system; improving labor costs, improving customer service and protecting assets. This includes the value of improved worker safety. One area showing considerable promise of increasing the productivity is rapid detection of internal faults in pole top transformers.

Introduction

Utility line crews re-energize single phase, pole-top transformers frequently[1]. Over time, vendors improved the quality of transformers, fuses and related tools and equipment, making it more challenging for the line worker to detect equipment failures. Additionally, the need for faster problem resolution with fewer resources is a constant management challenge. This paper outlines these challenges and describes a simple, direct, cost effective solution for utilities.

Pole top transformers are usually connected to the primary supply network via a fuse cutout. The fuse cutout is a protective device with two purposes. Firstly, by separating a downstream problem from the upstream supply, it limits the number of customers affected by the fault or overload. Second, by interrupting the flow of power to the fault, the risk of damage to equipment and injury to people is limited. The protective characteristics of the link are intended to serve both these purposes with a high degree of reliability, while also minimizing the frequency of unnecessary (nuisance) operations.

The reason for excessive current includes internal faults caused by failure of the transformer insulation system. However, unless the internal fault produces signs on the transformer's exterior, it may be difficult to reliably detect and confirm its presence without cumbersome and time consuming measures. For example, it takes at least 15 minutes to disconnect the secondary leads to enable the line crew to measure the impedance of the transformer and/or check the integrity of the insulation by applying a test voltage from a suitable source. Therefore, the challenge to utilities is how they can efficiently and reliably determine if an internal fault has occurred.

Transformer Facts

Service personnel often need to locate, diagnose and correct the causes of outages rapidly. The work is usually outside normal working hours, often in less than ideal working conditions and with a high workload relative to the number of skilled people available.

Consider these facts:

- There are over 50,000,000 distribution transformers in service in the USA and Canada.[2]
- On average between 3% and 5% of the in-service population of pole top transformers are re-energized annually,[3] which is between 1,500,000 and 2,500,000 transformers per year.
- Transformer fuse operations are the most common equipment failure on distribution systems, comprising as much as 40% in one study[4].
- Distribution transformer failures follow a 'bathtub curve'. That is, the highest failure rates are in the first few years of service and then decline. Failures increase later, towards the normal end of service life. In between, severe overloading or lightning cause most transformer failures.
- In most jurisdictions, lightning is one of the most commonly cited causes for outages and transformer failure. Twenty five percent is a typical number[5].
- In an Ontario study, it was noted that, while storms occur about 7% of the time, they account for 30% of all outages. Moreover, lightning is the most commonly cited cause of equipment failure during storms[6].
- Most lightning occurs during the evening and night – after hours[7], which because of the weather and limited visibility, field crews are often under additional pressure.
- The Canadian Electricity Association (CEA) analyzed how pole top transformer tanks actually fail in service. Of a population of over 400,000 units, there were approximately 20,000 fuse operations per

[1] N. Cuk, S.H. Hicks. "Development of an Internal Fault Detector For Pole-Top Distribution Transformers", Report No. T994700-5003 April 2002, prepared for and available from CEA Technologies, Inc.

[2] ORNL Report 6804/R1

[3] N. Cuk, S.H. Hicks. "Development of an Internal Fault Detector For Pole-Top Distribution Transformers", Report No. T994700-5003, April 2002, prepared for and available from CEA Technologies, Inc.

[4,5,6,7] M.V. Lat, J. Kortschinski, S.L. Cress, W.A. Chisholm, T.A. Gough, Ontario Hydro Technologies*: "Effect of Lightning on the Overall Reliability of Distribution Systems", Report No. 160D597 December 1998 prepared for and available from CEA Technologies, Inc.

year. This information was obtained by monitoring the Ontario Hydro (now Hydro One) system over a three-year period. In the 20,000 fuse operations, a total of 4,000 units failed per year. One in 270 fuse operations were explosive in nature. This rate of explosive failure is consistent with two previous unpublished studies, one by Ontario Hydro (1/300) and another by Nova Scotia Power (1/250).[8]

- These studies indicate that, on average, explosive transformer failures occur a few times every day in North America.[9]

Fusing Operations

The fuse cutout is designed to protect the transformer and related equipment and services. About 20% of the time when the cutout operates the transformer has failed. The rest of the time the cutout has operated for a non-transformer problem. However, unless the reason for the failure is obvious, the line worker has a time consuming problem determination process to follow. A tool that can readily identify when a component has failed saves time in all circumstances.

If a transformer has obviously failed, the Investigation can be stopped and the unit replaced and resources can be more quickly released to fix the next problem.

When the line worker knows the transformer is not faulted which is in approximately 80% of the refusing operations, the line worker can look to different causes for the fuse operating before starting the process of safely re-energizing. This allows the line worker to focus on the more likely outage sources and leads to a faster, safer resolution to the problem. So in all circumstances where the fuse has operated, the line worker saves time if there is a transformer failure identification tool.

Transformer Failures

The rate of transformer failures is often debated. Few utilities have good tracking systems however there are a few utilities such as Progress Energy and HydroOne who have maintained detailed records of transformer failures. This paper references these sources which are generally supported by engineering and operations staff. They are the best reference available for ‘numbers’. Line workers typically state “we rarely report failures, re-energizing faulted units happens all the time”.

This said, most transformer failures are uneventful. The combination of well built transformers and fuses, the fault progression inside the transformer, plus limitations on the available fault current provides a degree of protection to the system. When failures are described as ‘uneventful’, it is important to understand this is a relative term. It means the failure did not result in an explosive release of oil. However, the various techniques for internal fault identification include re-fusing, and if the transformer is faulted a fuse operation itself is a dramatic event for the line worker, just less so than a full transformer failure.

Eventful Transformer Failures

Eventful transformer failures describe a tank failure where the tank is visibly damaged due to an internal fault. The damage may cause no significant impact, aside from the need to replace the tank, or it could be catastrophic. Distribution transformers always have the potential for eventful failure. As line voltages and fault currents have increased steadily over the years, and continue to rise, this potential is realized with increasing frequency. The fault energy available between inception of a fault and fuse clearing more frequently exceeds the withstand capability of transformer tanks and lids.

While current related failures are rising, lightning is still the leading cause of failures. High currents from lightning (or from other sources) can cause under-oil-arcing, either voltage surge through the arrestor or by moving the leads by means of the electromagnetic forces accompanying the surge[10].

In addition, the oil itself could release energy under fault conditions, when hydrogen is released as a breakdown product[11].

[8] Ray Piercy, Reinhard Filter and Steve Barret, Ontario Hydro Technologies*: “Distribution Transformer Internal Pressure Withstand Test”, Report 149 D 491A Dec 1997, prepared for and available from CEA Technologies, Inc

[9] Ray Piercy, Reinhard Filter and Steve Barret, Ontario Hydro Technologies*: “Distribution Transformer Internal Pressure Withstand Test”, Report 149 D 491A Dec 1997, prepared for and available from CEA Technologies, Inc

[10] Ray Piercy, Reinhard Filter and Steve Barret, Ontario Hydro Technologies*: “Distribution Transformer Internal Pressure Withstand Test”, Report 149 D 491A Dec 1997, prepared for and available from CEA Technologies, Inc

[11] S.L Cress, M. Puszczynski, T. Gough, D. Fischer, R. Beresh and S. Barret, Ontario Hydro Technologies*: “Characterizing the Overcurrents on Distribution Systems”, Report No. 161 D 917

A number of researchers have identified the failure mechanisms. All involve an arcing fault in the tank, which creates a shock wave or pulse (piston) of oil. The arc may be just under the oil, above the core/coil assembly or deep down in the tank. The arc energy causes a pressure pulse with a fast rise time and a high peak pressure in the air above the tank. The lid attachment of the tank is the usual weak point but the welded seam may also rupture[12,13].

One question that naturally arises when investigating an eventful failure is, "What is the threshold below which violent failures will not occur?" Despite numerous studies, the answers are far from clear. Several test programs show correlations with fault energy (I^2t), arc energy (joules or Watt-seconds), available asymmetrical fault current energy (I•t) and peak fault current. The results indicate that tank failure is unlikely at fault currents below 2,500 A symmetrical. This assumes all the mechanical components of the fusing system operate as designed and the transformer tank is free of structural defects.

Field Experience

If the tank failed just before the fuse operated, the consequences to the transformer might be limited. However, faults often do not cause eventful failure before the first fuse operation. Eventful situations often occur when the line worker is re-closing on already faulted units. This can place line crews in a hazardous situation.

Internal transformer faults develop to the point that the cutout will operate, but there may be no visible external indication of a transformer fault other than the fuse operation. It is often unclear whether the transformer has failed or the fuse has blown for some other reason in spite of a thorough external examination.

In this situation, a line crew will normally re-fuse and close back in the line. While many utilities require crews to test the transformer, this is often not done if everything appears okay. This is understandable, since most fuse operations can be attributed to lightning surges, short duration overloads, improper fuse selection or installation and secondary faults.

Unfortunately, if the transformer has already developed an internal fault, this can set up the conditions for an eventful failure, and put the line crew in a perilous situation when re-fusing the transformer. Far from being a hypothetical situation, there have been a number of injuries and even fatalities from this situation over the years. Almost any line crew with a decade or more of experience can recount at least one close call in a similar situation.

Most utilities have written procedures intended to mitigate this risk. Some require isolating the transformer and doing a ratio check of the windings. This involves climbing the pole, disconnecting the transformer, testing the transformer and then reconnecting it – obviously a time consuming process. This is a sound approach, one that should be encouraged. However, it is frequently not done due to pressure placed on the line crew to restore power, especially when weather conditions result in large numbers of service interruptions or other time pressures are imposed on the crew.

Some utilities may rely on a visual check of the transformer, combined with specific precautions by the workers to minimize their physical exposure should a violent event occur. Some linemen will pull the ring on the pressure relief device to see if the telltale odor of electrical burning can be detected (Note: this does not work well in cold weather if the transformer has had time to cool down. Pulling the ring will only allow the pressure release device (PRD) to suck in cold air, with no odor escaping. It is also an unreliable technique if there has been limited carbonization of the oil.) Moreover, the act of letting cold moist air enter the tank is bad for the transformer. Moisture is the enemy of paper insulation and a large factor in transformer aging.

Lightning storms are perhaps the best example of how a number of related factors can converge to produce a large risk of a faulted transformer. In a severe lightning storm, literally thousands of fuses can operate in a limited geographic area in a period of only a few hours. This creates tremendous pressure on linemen working to restore power. The temptation to move quickly by simply re-fusing transformers and closing back in is significant. At the same time, lightning may have created faults that could lead to violent failure when the unit is re-energized[14,15]. At times

December 1998 prepared for and available from CEA Technologies, Inc.

[12] Ray Piercy, Reinhard Filter and Steve Barret, Ontario Hydro Technologies*: "Distribution Transformer Internal Pressure Withstand Test", Report 149 D 491A Dec 1997, prepared for and available from CEA Technologies, Inc

[13] N.P. Cuk, Powertech Labs: "Oil Tank Explosion Resistance", Report No. 149D491 June 1990 prepared for and available from CEA Technologies, Inc.

[14] Ray Piercy, Reinhard Filter and Steve Barret, Ontario Hydro Technologies*: "Distribution

like this, the line crew needs all the help it can get.

Built-In Internal Fault Detectors

Before the development a specific internal fault indicator, all other approaches relied on indirect measures, such as the logical approach of CSP transformer designs. (The one exception is off-line testing technology, which is somewhat complex and time consuming to use when the line worker is on the pole.) The industry needed an innovative way to identify internal faults 'directly' and flag the fault outside the tank so a line worker could easily see it.

When utilities began moving to higher distribution voltages and higher available fault currents in the 1970s, the increases in available fault energy resulted in most utilities experiencing an increasing frequency of eventful transformer failures. Several research projects were designed to gain an understanding of the physical phenomena underlying these events. The gas generation mechanism was quickly identified as the main culprit.

The first work on internal fault detection technology occurred in the late 1980's, when engineers were conducting transformer withstand tests. Testing showed internal faults produce unique pressure signals. All other pressure changes in a transformer's air space occur 1000 or more times slower than the rate of rise during the pressure surge created by internal arcing faults. So, the rate of pressure rise can be used to reliably identify the occurrence of an internal arcing fault.

The IFD™

One detection method measures the pressure differential across a flexible membrane to activate a fault signaling mechanism. One device that incorporates this principle is the Internal Fault Detector (IFD™), developed by IFD Corporation. The IFD was in development for over a decade, and represents the result of a collaborative R&D effort involving financial and technical support by a group of utilities. The objectives of the IFD were to improve lineman productivity, enhance customer service, and, increase lineman safety associated with transformer failures[16].

The IFD only responds to internal transformer faults. The purely mechanical design provides inherent advantages over other sensing schemes. The sensor is a specialized membrane that is sensitive only to a rapid rise of pressure in the air above the oil. This rapid pressure rise occurs only during an internal fault. When the membrane moves in response to the rapid pressure rise, it releases a spring-loaded, readily visible indicator on the outside of the tank. It does not carry the sensitivity vs. selectivity design compromises inherent in thermal and electrical over current or waveform signature sensing devices.

The IFD requires no power supply, is insensitive to its electrical environment and does not depend on the electrical status of the transformer to operate. The IFD does not react to electrical or magnetic fields or even temperature changes (within the limits of the transformer design). It operates reliably in an environment that would destroy most electronic devices.

On a practical note, the simple mechanical design and construction of the IFD make it economic to manufacture and install in distribution transformers, where large volumes make unit cost an important selection factor for utilities.

The IFD also includes a static pressure relief device (PRD) that operates like a standard PRD. Customers asked that this function be included in the IFD so the solution would not require another hole (point of failure) in the tank. This also reduces the current total tank cost due to elimination of the welded tank boss required in most standard transformer designs. The IFD can easily be added to an existing transformer and only requires a punched hole to install. This makes it easy for utilities to retrofit IFDs into existing transformers, when they are returned to stores, or when they are refurbished or rebuilt.

Transformer Internal Pressure Withstand Test", Report 149 D 491A Dec 1997, prepared for and available from CEA Technologies, Inc

[15] M.V. Lat, J. Kortschinski, S.L. Cress, W.A. Chisholm, T.A. Gough, Ontario Hydro Technologies*: " Effect of Lightning on the Overall Reliability of Distribution Systems", Report No. 160D597 December 1998 prepared for and available from CEA Technologies, Inc.

[16] J.P. Chisholm, N. Cuk and S.H. Hicks, IFD Corporation: "Development of an Internal Fault Detector for Pole-Top Distribution Transformers": Report No T994700-5003 December 1998 prepared for and available from CEA Technologies, Inc. or IFD Corporation.

Figures 1 and 2 show a cross sectional drawing and mode of operation.

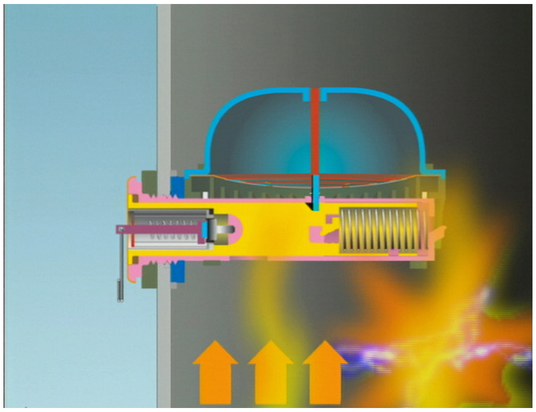

Figure 1
Prior to operation, the pressure detecting membrane and its trigger shaft (red and blue vertical rod) are in the lowered position, locking the indicator (yellow) in place. The large spring on the right side stores the energy to push the indicator out; the small coaxial assembly on the left is the pressure relief device (PRD).

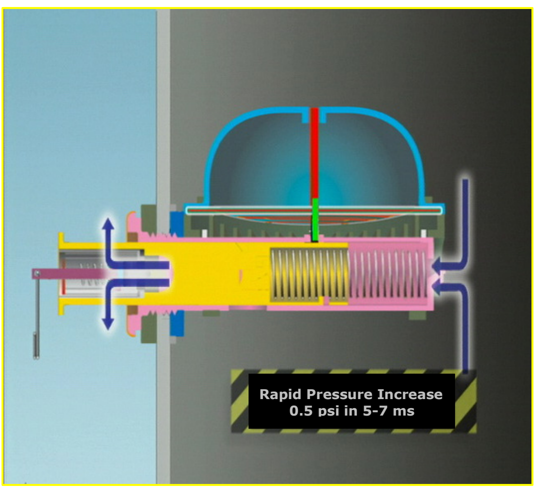

Figure 2
When the membrane reacts to pressure pulse caused by an internal fault, it moves up, carrying the trigger shaft with it (red and green). This releases the indicator, which is pushed out by the spring. Once this happens, pressure is relieved through the IFD. The blue arrows indicate the flow of gas through the indicator assembly.

The IFD cannot be reset from outside the transformer. This ensures the IFD on a faulted transformer is not reset and the transformer should not be re-energized without first removing and inspecting the transformer in the shop.

The IFD is also designed to minimize the chances that it will 'falsely operate' under conditions other than a fault, such as mechanical shocks. With distribution transformers, this type of condition sometimes occurs during transportation and, perhaps, installation. To avoid this problem, the IFD is equipped with a plastic shipping lock that is easily removed once the transformer is mounted on the pole. The shipping lock has a jagged shape and is bright orange, so if it is inadvertently left in place, a line crew can easily identify the lock from the ground.

Technology Value to Utilities

Challenges for utilities to continuously improve cost/performance and service have never been greater. This is compounded by the fact that industry forces constantly shift and changes take a long time to implement. Distribution systems must integrate new and old technologies in an evolutionary, cost effective way. Strategically, utilities have to consider the value of technical solutions over the life of the system, where key forces include changing experiences and skill levels of line workers, a drive to reduce costs and improve service levels. Importantly, safety is high in the corporate mission and objective statements.

Productivity Improvements with IFD

- Timesaving…over 20% of costs in 'Distribution Resource Commitment' are labor costs.
- Problem determination time is reduced. Many utilities estimate IFD cuts anywhere from 15 minutes to 30 minutes from the time needed to determine the problem.
- Efficient crew utilization…right people, right place, and right time; particularly during storms and other high visibility events.
- The average number of crews called out for any given storm situation can be minimized for a constant service level.

These considerations were all a key part of looking for low cost, simplicity and reliability in a transformer fault detection tool. The end goal is to assist in the journey of 'doing it right the first time.'

The IFD provides financial benefits to utilities in the following areas:

Restoration Cost Savings through Productivity Improvements

Over 20% of costs in the distribution resource commitment are labor. Therefore, improvements in labor utilization will improve the bottom line.

The most obvious benefit of the IFD lies in the ability of line personnel to quickly spot transformers with internal faults.

This benefit will vary by utility, depending on their practices with respect to outage management.

Refer to the table located in Appendix B for a list of potential costs a utility may experience due to a faulted distribution transformer. The following examples are illustrative:

Situation Analysis
Two Man Crew

In this example, a two-man crew, using a bucket equipped vehicle or material handling aerial device, investigate the outage. The crew may be dispatched from a local office or central operating center. The hourly rates for this combination are quite high, including two skilled trades' people, expensive work equipment and often, overtime pay rates.

While this arrangement has impressive work capacity, most of the outages handled involve inspection, re-fusing and re-closing. If the utility adheres to a 'test before re-close' practice, the crew will spend a great deal of their time isolating, testing and reconnecting transformers with no internal faults.

Now consider the same operation, where transformers are equipped with IFDs. If the transformer has actually failed, the crew will in all probability, know immediately by looking at the IFD. If it has not operated, the crew proceeds with its normal practice, just to be sure. If the IFD has operated, they can order a new transformer without even getting out of the truck.

In this case, (because the crew did not set the outriggers or raise the boom) it can quickly proceed to the next trouble call. The workers can either go back to the original location when the new transformer has arrived, or leave it for the crew that brings out the replacement unit. If they are lucky, the line workers may have the correct spare on the truck.

Most utilities reviewing this scenario believed the IFD would save at least ½ hour, on average. One standards engineer provided the following savings range estimate.

Descripton	**COSTS**
Truck and two crew (per hour)	$100-750
Estimated fuse costs	$5-25
Financial analysis when an IFD is installed on the faulted transformer	**SAVINGS**
Truck and two crew (1/2 hour savings)	$50-375
Fuse savings (increase this by number of attempts)	$5-25
Savings per transformer	**$75-370**
Less IFD cost	$35-$45
Net Savings per transformer	**$30-335**

Situation Analysis
Two Man Crews During a Storm

Cost savings increase if we use the same example above, but expand it to address a typical storm restoration. As mentioned earlier, about 30% of outages occur during storm situations. Further, most storms hit outside normal working hours. In these situations, most of the available crews will be involved in restoring power. If the utility can save ½ hour of problem determination time per transformer when paying time and a half or double-time, the cost savings add up very quickly.

For illustration purposes, consider the following storm example:

Descripton	**Units**
Transformers out of service	100
Transformers showing the IFD flag (faulted)	20
Problem determination time reduction (1/2 hour multiplied by 20 transformers)	10
Financial analysis when IFD are installed on the faulted transformers	**SAVINGS**
Labor cost savings (10 hours multiplied by $200 to $1,400 (overtime rate))	$2,000–14,000
Fuse savings (20 units multiplied by $5 - $25) (assumes only 1 fuse attempt)	$100-500
Savings overall per 100 transformers	**$2,100 - $14,500**
Savings per transformer	**$21-145**

These savings of time and money are related to more than this one crew. By making trouble crews more productive, utilities can delay (or avoid) calling in additional crews. Improving the efficiency of the first crew thus has a magnifying effect on overall savings.

Situation Analysis
Critical Event

In this example, a two-man crew, using a bucket equipped truck investigates an outage. The transformer has an undetected internal fault, and there are no external signs of a failure. When the line worker closes the line back in, the transformer has a catastrophic failure. The line worker(s) is injured and can be expected to be off the job for an extended period of time. Other assets are damaged and repair is extensive.

Costs include: Time lost from work, time dedicated to accident investigation and reporting, uninsured medical costs covered by company, employee's loss in earning power, economic loss to the injured person's family, legal costs, occupational health and safety worker wages, supervisor time, management time, medical and compensation insurance, cost of training temporary or new employees, oil clean up, pole replacement, landscaping, potential penalties, potential fines and negative public relations.

It is difficult to consider this potentiality, and the topic is often avoided due to its infrequency and the nature of the subject. Nonetheless, the costs for this type of incident are always extensive and range from hundreds of thousands of dollars to millions[17].

Return on Investment Considerations

The rate at which operational benefits can be realized will vary from utility to utility. However, all of the elements include improved operations, better customer service, an improved safety environment and better environmental protection.

Over the past number of years, the population of linemen has reduced to about 110,000, half by some measure of what it was 20 years ago.[18] Utilities have restructured and outsourced. This means utilities have to increase the efficiency of the line crews. Additional savings will be harder to come by and will require utilities (at least those that have not already done so) to modify their operating structure and practices. The trend to improved productivity will continue and better tools are key to achieving the business objectives.

Two complementary strategies are at work to create continued productivity improvements, particularly in outage management.

The first (and in some ways the easiest step to implement) is to increase the amount of information available to the utility to manage outages. This includes weather information, crew locations, lists of available material and data sent in from utility systems. This provides for efficient central dispatch of the right quantity and type of resources. Going under the catch-all title of 'distribution automation', systems providing this type of data include SCADA, GIS, DMS and outage management. Every utility implementing these systems seems to have its own unique mix of capabilities, but the general trend for outage management is the same.

The second strategy takes advantage of the opportunities provided by these systems. With centralized information collection comes centralized dispatch. For large utilities, this effectively removes the role of the local dispatch center. The result can be significant reductions in dispatch operations, facilities and overhead costs, but also fewer and more widely dispersed operations centers.

This step also results in an increase in average travel time. Effectively, the availability of skilled trade resources is reduced and the unit cost of the workforce (wrench time) increases. Today, the real, total burdened cost of wrench time for a two-man crew with a bucket truck can be in the hundreds of dollars per hour (as shown in the earlier illustration).

Aside from the need for the utility to focus resources more carefully, a new risk is also introduced. With fewer available resources, the utility is at a greater risk when large storms hit. Against this background, the IFD can be seen as a key information source, providing enhanced and quick trouble shooting diagnosis.

For those utilities looking toward a future of greater automation and even higher focus on productivity and cost, the IFD is a valuable part of the solution. Seen another way, the IFD provides utilities with one of the most common information requirements in outage management.

Aging Physical Infrastructure

In a survey by Navigant Consulting/Electric Perspectives titled "The Outlook for the North America Power Industry", 91% of the executives surveyed rated aging physical infrastructure as critical or most critical problem facing the utility.[19]

As utilities become more focused on life cycle management of their assets, many have adopted both refurbishment (life extension) and replacement programs, driven by asset condition criteria and capital planning requirements. This creates an opportunity for utilities to more rapidly increase the penetration rate of IFDs on their systems and accelerate realization of the service and operational improvements presented by the IFD.

Customer Service

In the era of electric utility deregulation and competition, reliability of service to the customer has become an important issue. Today, more and more jurisdictions regulate utilities based directly on customer service levels. Outages and customer interruptions can be very costly. Typical reliability measurements being adopted are SAIFI (System Average Interruption Frequency Index), SAIDI (System Average Interruption Duration Index), and MAIFI

[17] www.capschell.com\\CapSchell, Inc_ Research & Education Services.htm

[18] Jonathan Barnes and Richard Korman "High-Voltage Power Line Work Is A Peril," in McGraw_Hill Construction, [online magazine] (02/23/04); http://www.enr.com/features/bizlabor/archives/040223.asp

[19] Navigant Consulting/Electric Perspectives Survey, "The Outlook for the North America Power Industry", May / June 2004

(Momentary Average Interruption Frequency Index).

In a study done by a large US utility, the SAIDI cost of each outage currently result in an expense to the utility of about $2 million per outage minute. With 1.5 million customers this becomes $2M/1.5M or $1.33 per customer per minute. For utilities in these circumstances, the efficiency benefits of the IFD in reducing outage time can be directly calculated both in labor savings and in avoided penalties.

When utilities' reliability performance deteriorates, regulators often step in with specific directives. These can be quite expensive, as they often require crash programs of component replacement or maintenance. Clearly, keeping the customer happy with respect to reliability is good business for the utility.

By making diagnoses faster and improving the efficiency of trouble crews, utilities can reduce average outage duration (SAIDI). As regulators and other agencies become more sophisticated, utilities can expect to be pushed to continue to improve operational efficiency, worker safety and customer service. The IFD is not a panacea for any of these issues, but it does provide part of the solution.

Risk Assessment

As mentioned in an earlier section, eventful transformer failures do occur. These events can be costly to a utility depending on the impact of the event. Each utility has its own experience, will likely know its own cost of accidents and injuries, and can assign a value on worker protection and accident prevention. Most large utilities have enough actual experience to make this calculation. Even the cost of reporting an incident with the potential for injury, or where a spill has required environmental cleanup, can quickly reach thousands of dollars.

Accidents that result in injuries cost much more and the costs of the investigation, treatment, and increased insurance premiums can significantly impact the bottom line. From this angle, any improvement in worker safety yields a direct bottom line benefit.

Risk Assessment Considerations

- Avoiding re-energizing faulted transformers means reduced 'events'
- Supports safety for utility employees and the general public
- "Opportunity for accident/incident cost reduction is significant…bottom line savings…competitive advantage"

The 2000 RIMS Benchmarking Study revealed on average, that utilities spend $.50 of every $1,000 of revenue paying workers' compensation claims, but some utilities report spending as much as $1.05 of every $1,000 of revenue, or a weighted average of $.86 per $1,000 of revenue.[20]

Recent studies by Liberty Mutual Insurance Company and others indicate that for every hard dollar spent on risk management situations, three to five times that amount is spent in 'soft' dollar support due to:

- Lost wages
- Public relations efforts
- Lost time
- Regulatory involvement
- Cost of replacement workers
- Retraining for the injured workers
- Lower employee morale and productivity

The opportunity for accident cost reduction is significant. An 'event' can quickly move into the million-dollar cost category. In this era of intense competition and escalating insurance rates, a reduction in this type of workers compensation will generate noticeable bottom line savings and directly impact a utility's competitive advantage.

IFD Reliability Standards

The IFD must always sense a fast transient overpressure (tested at 0.5 psi with 5-7 milli-second rise time). Therefore the IFD must meet the following standards:

- The overall design must exhibit constant or increasing sensitivity over time. The IFD must last at least as long as the transformer. The materials used are designed for 30+ years of life.
- Even after installation, the transformer may experience mechanical shocks and vibrations that have nothing to do with its electrical operation. Trees hit lines, cars hit poles, inspection people hammer the pole to test for soundness, etc. These types of shocks have also been simulated with IFD equipped transformers and none have caused a false activation.

Testing for Reliability

The IFD is designed and production tested to detect dynamic pressure pulses as low as 3.5 kPA (0.5psi) over 5-7 milliseconds. This sensitivity ensures it will respond to energy releases well below levels that would result in expulsion of oil from the transformer. By detecting faults at these levels, the line worker

[20] RIMS, RIMS & Ernst & Young, "RIMS Benchmark Survey 2000", May 2001

can avoid triggering a more serious fault should the transformer be re-energized.

IFD Reliability in Service

To date, there are tens of thousands of IFDs in service that have an excellent track record. The IFD's reliability is achieved through a simple, sturdy design. Each IFD is tested prior to shipping to the transformer manufacturer or utility. However, the IFD is a mechanical device and, as is the case with any mechanical device, it is possible that it could fail. Therefore, equipment and work procedures must incorporate the 'multiple barrier' (aka 'defense in depth') concept.

While IFD's have detected the vast majority of transformer faults, IFD is aware it cannot detect all transformer faults. Where the available primary fault current is quite low, or where the transformer experiences a burnout inside the windings (i.e., in the secondary windings or inside a winding where the short is not exposed to oil), the mechanical energy released into the oil and the air above it may be insufficient to trigger the IFD. However, these types of faults are not likely to place personnel at risk or create an oil spill.

The IFD is designed to reliably detect faults that could present a personnel or environmental hazard. The fact that it will also operate on most faults that fall below the threshold levels for a violent failure is an important, but secondary benefit.

Operational experience to date tells us:

- When the IFD has operated, the transformer has failed internally and needs to be taken down.
- If the IFD has not operated, a primary arcing fault has not occurred. In this instance, existing utility safety procedures should be followed.

The reliability of an indicating sensor needs to be viewed in two ways: the likelihood of a false positive (the sensor indicates a condition that hasn't occurred) and a false negative (the sensor failed to indicate a condition that has occurred).

To date, there have been no operations of an IFD after the transformer had been installed, in which the transformer had not failed (i.e., zero false positives).

To date, no IFD has failed to operate on a transformer that subsequently suffered an eventful failure when it was re-fused. However, the general principal of providing line workers with overlapping safety barriers should be retained. For this reason, it is recommended that, before re-fusing any transformer, line workers should observe existing utility safety procedures (e.g., ratio check or remote energization).

At the time of writing, three transformers have failed non-violently without activating the IFD. These units were torn down and the failure evaluation showed there was only 40-100 amps of fault current available and the faults were likely due to manufacturing flaws…all three units were in service less than 24 hours. All the fuses took 'minutes' to operate.

To understand the occurrence of false negatives, one needs to consider the physical conditions that cause most transformer failures and the intent of the IFD. Most internal failures are caught by the protection system before migrating to a violent failure. However, it is not usually obvious the transformer has failed internally.

Violent transformer failure is the result of arc energy released in or above the transformer oil, which causes a rapid pressure pulse that either ruptures the tank, or more commonly, causes the lid to vent or blow off.

For a failure to occur, the arc must be under the oil or in the air space above the oil. In test programs, faults within windings have not caused violent failures. It is likely that this occurs because the fault energy available from the system may be too low to support a high energy arc, or there is neither the space nor the fuel (oil) immediately available to generate a large gas bubble.

However, even relatively benign transformer burnouts will usually be detected by the IFD. Field reports have indicated successful operation of the IFD in locations where the available maximum primary fault current would be less than 1kA (symmetrical).

Other Transformer Fault Detection Methods

Fuses

For over a century, the primary method of detecting internal transformer faults is with fuses. These devices have simple and direct operating principles; high current melts a wire, which is either sufficient in itself to interrupt the flow of current or it initiates a mechanical (or chemical-mechanical) sequence in a cutout.

The advantage of these devices is that they both detect and interrupt the fault current and, in the case of overhead cutouts, visibly indicate operation. Their limitation is that they cannot inherently discriminate between high current caused by a faulted transformer and a high current flowing through the transformer due to another cause, such as overload. Furthermore, fuse links are subject to age related problems (caused by duty and environmental conditions) that can alter their characteristics slightly over time. The art of over-current protection design and coordination is devoted to improving the level of discrimination achievable, but the variables of overloads, cold load pickup, lightning surges and so on dictate that protection design will always compromise sensitivity and selectivity.

Current Limiting Fuses

In high fault current areas, current limiting fuses (CLFs) are now used by many utilities to extend the interrupting range of the cutout and prevent explosive failures. Any electrical arc generates a 'back voltage' when it forms, and CLFs are designed to internally generate many small arcs, whose total back voltage is sufficient to quickly cut off current flow to the fault.

In a well-coordinated application, the current limiting fuse will only operate when it experiences a high current fault and will allow enough energy through to ensure operation of the expulsion fuse. Ideally, on a low fault current, the expulsion fuse should be the only fuse to operate.

Clearly, CLFs play an important role in the prevention of catastrophic failures and help ensure that high current faults are cleared properly. However, as good as they are, CLFs have limitations:

1. They do not visibly indicate when they have operated, causing a procedural problem. Testing the fuse in place can be difficult to do safely because of the position of the fuse on top of the cutout. This problem can be overcome with increased vertical clearance or horizontal mounting of the CLF.

2. Following its operation, the cutout usually drops out, but this does not indicate where the problem is. Normally, the assumption should be that the transformer has faulted, since CLFs cannot usually 'see' far past the secondary terminals of the transformer. So, diagnosing the cause of a fuse operation where a backup CLF is present can be a tedious process, involving a test of the CLF and/or a ratio test of the transformer before deciding on a course of action.

3. CLF installations take up space. Backup CLFs, mounted vertically, require additional space so that line workers can safely remove them. This will not always change the requirement for pole length, but it can on occasion.

4. The CLF itself is a fairly costly item and needs to be installed by skilled power line workers, whose 'wrench time' costs more. For these reasons, most utilities limit CLF installation to locations where the available primary line-to-ground fault current is 3,000 A symmetrical or more. [21]

5. As with all devices, CLFs also have their problems. To operate properly, they must remain dry on the inside throughout their service life. Defects in seals or improper assembly can lead to failure and/or high replacement costs. Unlike composite insulator cores or surge arrestors, CLFs do not reveal moisture ingress until they are required to operate.

None of this discussion is meant to suggest that backup CLFs should not be used where there are high available fault currents. Their value in preventing catastrophic failures outweighs their shortcomings. However, CLFs should be seen as a part of the solution – along with safe work procedures and other measures.

Stronger Transformer Tanks

One way to address the problem of violent failures is to make stronger transformer tanks that can withstand the energy of an internal fault and not fail, leak or vent hot gases. This design has been used in both distribution transformers and other equipment, and it provides a degree of fault protection. However, this approach is expensive relative to the current, low cost of 'regular' distribution transformers.

To date, a test procedure that can reliably mimic the energy dynamics of an internal arcing fault has not been developed and thus cannot be included in standards. However, some utilities have moved toward requiring a higher standard for tank strength.

Completely Self Protected Transformers (CSPs)

Completely self protected transformers (CSPs) combine an internal, under-oil primary fuse

[21] S.L Cress, Ontario Hydro Technologies* and R.M Godfrey, Acres International: "Application Guide for Distribution Fusing", Report 288 D 747 August 1998, prepared for and available from CEA Technologies, Inc.

(either a 'weak link' or a CLF) and a secondary breaker with the standard transformer and surge arrestor. For faults beyond the secondary terminals, the breaker operates. If the internal primary fuse operates, the transformer is assumed to have faulted.

The 'all internal' design of the over current protection on CSPs, plus use of transformer mounted surge arrestors, makes for a compact installation, which preserves valuable pole space and is less visibly intrusive. Moreover, the secondary breaker provides ready indication of overloads or secondary faults.

Unfortunately, there are several problems with the CSPs:

1. All fuse operations require a change out of the transformer to replace the fuse, even when the transformer is not faulted.

2. Weak-link fuses can be blown by factors other than a transformer fault. If the arrestor operates as it is designed and other factors stay within design limits, nuisance operations of the weak link should never happen. However, the real world experience of many utilities over the years has been different.

3. CLFs in transformer tanks have to be under the oil. The seals have to last for the life of the transformer and the element has to perform reliably for 30 years. Good lightning protection is a must. As discussed before, a line worker will not discover that a CLF seal is leaking unless and until the CLF is called on to perform. Because a crew will have to take down the transformer to replace the fuse, internal fuses must be well protected against non-fault operations. Therefore, CLFs must not be exposed to lightning surges that could cause operation. In theory, the position of the arrestor next to the bushing should provide for close to ideal surge protection. In practice, lightning arrestors do not always last as long as transformers. In short, the odds of a CSP/arrestor combination lasting 30 years are not all that strong.

4. With CSPs, the secondary breaker is always on and requires some energy to function. This adds to the life cycle cost of the transformer.

5. The secondary breaker must also maintain its operating characteristics for 30 or more years over a broad range of temperature variation.

6. CSP transformers inherently cost more than non-CSPs.

7. CSPs do not provide visual indication of a primary fuse operation, which has to be inferred during customer outages and the secondary breaker being in the 'normal' position. This inference can be incorrect. (For example when the secondary has become disconnected or broken for some reason.)

8. If the utility is actually paying for its system losses (either directly or via performance based regulation incentives), thousands of secondary breakers can add a real cost burden. If the utility is not paying for losses, it should consider that one day it might have to incur these costs.

9. Finally, many linemen do not like CSPs because CSP tanks cannot be energized via a cutout. Furthermore the esthetic benefits of more compact construction can reduce working clearances. Energizing any apparatus with a live line clamp is an operation that makes all experienced trades people nervous. Some utilities mitigate this risk by energizing the CSP transformer with the first upstream switch, but this brings with it a reduction in service to the other customers downstream of the switch. To counter the service impact of this practice on main feeders, some utilities have taken to adding cutouts to CSP installations in these locations. This is a logical approach, but it negates many of the benefits the CSP offered in the first place.

Refer to the chart in Appendix A for a comparison of options for fault detection.

Conclusion

- The presence of an internal fault is difficult to detect without disconnecting the load and testing the integrity of the insulation.
- Re-energizing a faulted transformer will cause further damage due to the escalation of the fault. Also, the transformer can fail violently during this operation, increasing the safety risk to the line crew and increasing utility costs and service delays.
- The transient pressure rise in the airspace of the distribution transformer is a 'finger print' common to all internal arcing faults.
- Detecting and signaling the presence of an internal fault with a built in detector can:
    - Eliminate long interactive diagnostic procedures that are prone to human error,
    - Accelerate restoration of customer service, and
    - Improve line crew safety.

The internal fault detector (IFD) was developed with the participation of a number of utilities to enable crews to quickly identify transformers with potentially dangerous internal faults. With over 70,000 in service, it has proven itself to dependably perform this function.

More strategically, the IFD represents another small step on the journey to a distribution system where, more and more, information is used to improve customer service and the effective utilization and safety of more valuable resources.

About the Author

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Robert Panting, retired from utility operations after a 40+ year career.

Robert Thompson, transformer manufacturer with over 25 years industry experience.

Mal Swanson, P. Eng. Over 30 years electrical industry experience.

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Appendix A: Fault Protection and Identification Options and Benefits

Description	Productivity & Customer Service Improvement?	Visible Isolation of Transformer?	Visible Transformer Fault Indication?	Safety Improvements & Environmental Protection?	Material Cost	Labor Cost
Standard transformer & cutout (base case)	No	Yes**	No	No	NA	Standard line crew rates
Cutout with Backup CLF	No	Usually	No	Yes	$60-100*	Standard line crew rates
Completely Self Protected Transformer	Yes	No	No	Yes	$200-300**	Standard line crew rates
Internal Fault Detector	Yes	Yes**	Yes	Yes	$35-50	Less than 5 minutes at standard transformer manufacturer labor rates

* Does not include changes to pole height or installation cost. The offset cost of no longer installing a standard PRD in the transformer tank is not included.

** From cutout operation

Appendix B: Cost Analysis – Possible Costs Associated with Transformer Faults

The following costs will vary by utility. This table was compiled from data gathered from engineers and experts with experience in managing distribution systems. The cost ranges represent different methods of accounting for costs and/or different cost structures or utility practices, depending if the costs are fully burdened Furthermore, this section touches on possible costs when there is an injury. Although the concept of putting a price on injuries may be offensive to some, many utilities may track these figures.

Description	Effort (hours)	Estimated Costs
Operational Cost Savings		
2 line crew & truck (hourly)	.25 - .75	$100-750
Lineman & scout truck	.25 - .75	$60-400
Materials Cost Savings		
Lightning arrestors	.25 - 1	$40-80
Bushings	.25 - 1	$50-100
Fuses	.25 - 1	$3-50
Poles	.25 - 1	$250-500
1ph structure material	.25 - 1	$31-192
3ph structure material	.25 - 1	$134-475
9.5m pole cca	.25 - 1	$130-200
12.5m pole cca	.25 - 1	$250-400
Anchor	.25 - 1	$30-100
Epoxy arm 1ph	.25 - 1	$65-150
Epoxy arm 2ph	.25 - 1	$100-200
8' wood cross arm	.25 - 1	$40-100
Arrestor 9kv	.25 - 1	$30-70
Arrestor 27kv	.25 - 1	$50-80
Arrestor bracket	.25 - 1	$5-30
Cutout 15kv	.25 - 1	$60-100
Cutout 27kv	.25 - 1	$80-140
Potential Cost Reduction Associated with IFD Use		**Avoided Costs per Incident**
Transport time	.5 - 2	$100-1500
Clean up crew	.5 - 10	$100-10,000
Supervisor time	.5 - 10	$100-10,000
Paperwork to announce spill (1 cupful or greater)	1.0 - 4.0	$100-5,000
Environmental officer	.5 - 10	$100-10,000
Spill clean up kit		$75-150

Description	Effort (hours)	Estimated Costs
More Serious Events – Potential Cost Reduction		
Damaged tank removal (additional time)	.5 - 4	$100-1,500
Transport time	.5 - 2	$100-1,500
PCB lab test & shipment	.5 - 10	$100-10,000
Contaminated soil disposal fee/ barrel		$0-50,000
PCB clor-n-oil test kit		$100-500
Clean Up crew	2.0 - 16.0	$200-10,000
Supervisor time	2.0 - 16.0	$200-10,000
Paperwork to announce spill	2.0 - 16.0	$200-10,000
Environmental officer time	20 - 100	
Fill repair/sod/landscaping resources	2.0 - 16.0	$200-10,000
Permit to dispose of soil		$0-200
Digger truck	2.0 - 4.0	$400-3000
Pole replacement - labor only	1.5 - 3.0	$175-1,000
Load pole	.25 - .75	$100-500
1 ph pole assemble & install	.5 - 2	$75-200
3ph pole assemble & install	1.0 - 3.0	$100-500
Transfer 1ph xfmr c/w c.o.	1.0 - 3.0	$100-500
Transfer 3ph xfmr bank c/w c.o.	2.0 - 5.0	$200-1,000
Connections at xfmr	.25 - .75	$50-200
Connections at ser. Ent	.25 - .75	$50-200
Span of triplex run	.25 - .75	$50-200
Span of prim 1 ph run	1.0 - 3.0	$100-500
Arrestor installation	.25 - .75	$50-200
When Injuries are Involved		
Legal fees	10 - 100	$3,000-500,000
Occupational health and safety worker	10 - 100	$1,000-100,000
Supervisor time	10 - 100	$1,000-100,000
Management time	10 - 100	$1,000-250,000
OSHA		
Medical expenses		
Compensation insurance		
Cost of training temporary or new employees		
Time lost from work by injured employees		
Lost time by workers other than those injured buy who were directly or indirectly involved in injuries		
Uninsured medical costs covered by company		
Employee's loss in earning power		
Economic loss to the injured person's family		
Potential penalties		
Potential fines		
Customer Service Costs		
Failure to fulfill customer commitments		
Unrealized Revenue		
- Business		
- Consumer		