Evaluation of High Temperature Operation of Natural Ester Filled Distribution Transformers: A Techno-economic Analysis

by

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ABSTRACT

The lifetime of a transformer is essentially determined by the life of its insulation system which is a time function of the temperature defined by its thermal class. A large quantity of studies and international standards have been published indicating the possibility of increasing the thermal class of cellulose based materials when immersed in natural esters which are superior to traditional mineral oils. Thus, a transformer having thermally upgraded Kraft paper and natural ester dielectric fluid can be classified as a high temperature insulation system. Such a transformer can also operate at temperatures 20°C higher than its mineral oil equivalent, holding additional loading capability without losing life expectancy. This thesis focuses on evaluating the use of this feature as an additional capability for enhancing the loadability and/or extending the life of the distribution transformers for the Phoenix based utility - SRP using FR3 brand natural ester dielectric fluid.

Initially, different transformer design options to use this additional loadability are compared allowing utilities to select an optimal FR3 filled transformer design for their application. Yearlong load profiles for SRP distribution transformers, sized conventionally on peak load demands, are analyzed for their oil temperatures, winding temperatures and loss of insulation life. It is observed that these load profiles can be classified into two types: 1) Type-1 profiles with high peak and high average loads, and 2) Type-2 profiles with comparatively low peak and low average load.

For the Type 1 load profiles, use of FR3 natural ester fluid with the same nominal rating showed 7.4 times longer life expectation. For the Type 2 load profiles, a new way of sizing ester filled transformers based on both average and peak load, instead of only peak load, called “Sustainable Peak Loading” showed smaller size transformers can handle the same yearly peak loads while maintaining superior insulation lifespan.

It is additionally possible to have reduction in the total energy dissipation over the year. A net present value cost savings up to US$1200 per transformer quantifying benefits of the life extension and the total ownership cost savings up to 30% for sustainable peak loading showed SRP distribution transformers can gain substantial economic savings when the distribution transformer fleet is replaced with FR3 ester filled units.

DEDICATION

I dedicate this to my father, mother and grandmother.

ACKNOWLEDGMENTS

This thesis becomes reality with the help and support from many individuals. Towards the end of this fruitful journey as Master of Science graduate from Electrical Engineering Department at Arizona State University, I would like to extend my sincere thanks to all of them.

Firstly, I would like to express my sincere gratitude to my research advisor Dr. George Karady for his continual guidance, support and encouragement for this project. Special thanks to Dr. Keith Holbert for being my chair after the sad demise of Dr. George Karady. His expertise and insight have been influential in writing this thesis. I would also like to thank my committee members, Dr. Raja Ayyanar and Dr. Anamitra Pal for their time and valuable feedback.

I am very grateful to SRP for giving me the opportunity to perform this research work by providing financial support. I would like to extend my gratitude to Michael Dyer from SRP for providing the practical and technical expertise in my research. My sincere thanks to Alan Sbravati and Jeff Valmus at Cargill Inc. from Minneapolis, Minnesota and Dana Point, California who provided directions and technical advice whenever needed.

I am also obliged to my parents and grandmother for believing in my dreams and providing unconditional support for this work. Lastly, I would like to thank my friends and colleagues at Arizona State University without whom I could not have gone that far.

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INTRODUCTION

The transformer is at the heart of an AC electrical system. Generation, transmission, distribution - every sector of the power industry - uses the transformer for economic and reliable transfer of electrical energy at a desired voltage level. Distribution transformers, installed over millions of miles of low voltage power lines in the U.S. electric grid, represent a significant cost to electric utilities. Lowering of transformer ownership cost and increasing overall asset utilization by improving transformer thermal loading and life expectancy can make a significant impact on a distribution utility's bottom line.

1.1 Transformer Aging Curve

Transformer life assessment is a critical part of power system operation. There are various reasons for the failure of a transformer. However the usual mode of failure is the failure of its insulation system. Hence, the lifetime of a transformer is essentially determined by the life of its insulation system.

Most transformers used by utilities in the distribution system are mineral oil (MO) immersed units. The oil, which also acts as a cooling medium, forms the main insulation while the winding insulation is formed by the paper and other solid insulating materials. The insulation aging is a thermo-chemical process in which aging progresses as a time function of temperature, moisture and oxygen content [1]. Advancements in oil preservation techniques have minimized oxygen and moisture contributions to the insulation life leaving insulation temperature as the controlling parameter.

In transformers, the temperature distribution is non-uniform, therefore the component that is operating at the highest temperature will undergo the greatest deterioration. Aging studies, in general, consider the aging effects generated by the highest (hot-spot) temperature. Experimentally, it is found that the insulation deterioration behaves nonlinearly in relation to time and temperature. The Arrhenius Reaction Rate Theory [1] describes per unit insulation life as follows:

$$Per\ Unit\ Insulation\ Life = Ae^{[\frac{B}{\theta_H+273}]} \tag{1.1}$$

Where empirical constant A is associated with liquid insulation and B with solid insulation material and θ_H is the winding hot-spot temperature in degrees Celsius. This equation is obtained by recognizing the aging of cellulose insulation as a result of chemical reaction and is called an Aging Curve where transformer life is treated as a per unit quantity. It isolates transformer temperature as a principal variable affecting thermal life which is related to loading and ambient temperature.

The aging acceleration factor is the rate at which insulation aging is accelerated compared with the aging rate at the reference hot-spot temperature of 110°C for 65°C average winding rise (AWR) transformer design. The per unit transformer insulation life curve is considered as a basis for the calculation of the aging acceleration factor for varying load and temperature profiles. As per [2] an insulation life of 180,000 hours at the rated hot-spot temperature of 110°C is considered as a unit life of transformer insulation.

1.2 Natural Ester Fluid: Alternative Liquid Insulation

It has been observed that the aging characteristics of a cellulose insulation system change with the change of liquid insulation in which it is immersed into. Ester based fluid is considered as one such alternative for traditional mineral oil [3].

In 1984, synthetic ester insulation was developed by Cooper Power Systems as a substitute for polychlorinated bi-phenyl [4]. This was used for specialty applications such as compact traction transformers where the first signs of improved transformer thermal performance were observed. In the 1990s, research on developing natural ester (NE) insulating fluid, having similar characteristics, was driven by the high costs of synthetic esters. The first prototype natural ester transformers were installed in 1996 with the success of overcoming major disadvantages of natural ester's susceptibility to oxidation and high pour point.

Cooper Power Systems sold "Envirotemp - Fire Resistant Third Generation (FR3)" natural ester fluid brand to Cargill Inc. in June 2012. Now Cargill is the largest manufacturer of natural esters in the U.S. with annual production of 10 million gallons [4]. Cargill has sold over 1.4 million transformers to over 200 utilities worldwide. The specific formulation of natural ester dielectric fluids are proprietary to the manufacturers. This thesis work considers Cargill manufactured "FR3" brand natural ester characteristics for the analyses.

1.3 Objective and Scope of Research

SRP in Phoenix, Arizona has approximately 96,000 installed single-phase conventional MO filled distribution transformers designed at 65°C average winding rise temperature and mainly serve residential loads. On the basis of the identified areas of investigating technical and financial benefits of natural ester filled transformer designs for SRP distribution transformers, the following are the major objectives of this research work:

1. To understand the physical, mechanical, chemical and electrical properties of natural esters as an insulator with focus on their thermal capabilities at high temperatures. Since the natural ester filled transformer is a relatively nascent technology, it involves careful understanding of IEEE research papers and IEEE standards.
2. Identification of manufacturers and utilities using natural ester filled transformers in the U.S. A review of the utility experience and their motivation behind adaptation of natural ester units.
3. Exploration of different ester filled transformer designs associated with different temperature rise limits and their suitability for different applications.
4. Redesigning of mineral oil filled distribution transformers with natural ester filled units by making use of their additional load capability at high temperatures. It consists of analysis of measured transformer load profiles for their oil and hot spot temperatures, insulation life and electrical losses.
5. Development of methodology to convert transformer insulation life to transformer life for calculation of life extension benefit of natural ester filled transformers.
6. Quantification of benefits of life extension and added load capability into cost benefits, calculating present value of investment and total ownership cost of the transformer.

The scope of this investigation process is to provide a systematic approach for utility planning engineers to economically evaluate the suitability of NE filled units for their distribution transformer fleet.

1.4 Thesis Outline

Chapter 1 provides an overview of transformer aging phenomenon and the concept of per unit transformer life based on transformer aging curve. The importance of transformer insulation oil in the life of a transformer is discussed. A brief history and motivation for natural esters as an alternative insulation fluid are reviewed. The rest of the thesis is organized as follows:

Chapter 2 presents a detailed literature review of properties of natural ester fluid. It focuses on the thermal characteristics of natural ester filled transformers and testing methods for determining life curves. Mechanisms defining the difference of cellulose aging in mineral oil and natural esters are understood. Based on the different temperature rise limits, different designs of ester filled transformers are discussed. Application of these designs based on the priorities of utilities determines benefits of them. Experience of contacted utilities in the U.S. using ester filled transformers is reviewed.

In Chapter 3, actual load profiles of SRP MO filled distribution transformers measured using smart metering data are analyzed for their thermal behavior. A transformer loading analysis algorithm is used to develop a transformer thermal model as per IEEE standard C57.91, IEC 60076 using load profiles and ambient temperature data. The load profiles are categorized into two types: transformers with high average load and with low average load. Loadability and insulation aging of these typical load profiles are analyzed. The same analysis is performed if these units were filled with ester fluid. With this, an optimal ester filled transformer design is suggested identifying the benefits of life extension, reduced losses and enhanced loadability/ size reduction.

Chapter 4 covers economic analysis of ester filled transformer units. For this, a methodology is adapted to convert benefits of increased transformer insulation life to the increased transformer life. Using financial parameters, a net present value benefit analysis is performed to quantify life extension benefits of ester filled transformers. Enhanced loading capability of ester filled units is compared by calculating cost savings on losses and total ownership cost of the transformer.

Chapter 5 draws a conclusion based on the results of the analysis and provides scope for the future work. It provides a guidance flowchart for the utilities to determine the most suitable natural ester transformer design for their priorities.

Chapter 2

LITERATURE REVIEW

This chapter covers a detailed literature review of physical, electrical, and chemical properties of the natural esters, like FR3, as an insulating fluid. It focuses on the thermal characteristics establishing the per unit life curve of the cellulose paper insulation in the NE fluids. Different FR3 filled transformer designing options are compared. At the end, experience of the utilities in the U.S. using FR3 filled units is discussed.

2.1 Characteristics of Natural Ester Fluid

2.1.1 Composition

Biodegradability, stability, electrical purity, physical properties, and availability are considered as the criteria for the selection of an insulating oil. Considering all these factors, vegetable oils having high oleic acid — a mono-unsaturated acid — are considered as the best choice [5, 6]. Natural ester dielectric fluids like FR3 are derived from 100% vegetable oils like soybean oil, canola oil, and sunflower oil [7]. However, these oils are unstable and are easily oxidized when exposed to air. Thus, addition of oxidation inhibitors helps to maintain its oxidation stability. Vegetable oils are more viscous than the mineral oils. Hence, pour-point depressants are added to maintain desired viscosity at low temperatures. Lastly, a green dye is added to distinguish it from mineral oil.

2.1.2 Fire Safety

Reliable and safe operation of the transformers is a goal of every utility. Natural ester dielectrics can play a major role in helping to achieve this goal. They have significantly higher flash and fire points as compared to the mineral oils. NE filled transformers have an excellent fire safety record of more than 10 years [8]. Flash point defined for NE by ISO 2719 [9] is 330°C and fire point defined by ISO 2592 [10] is 360°C. The corresponding values for MO are 160°C and 180°C respectively. The fluids having minimum open-cup fire point of 300°C are called less flammable as per the U.S. National Electric Code (NEC) [11]. Hence, by this definition, FR3 fluid is classified as 'Less Flammable/Improved Fire Safety' and listed as such by Underwriter's Laboratory and FM Global [6]. They are also classified as hazard class 'K' as per IEC 61039 whereas mineral oils are classified as hazard class 'O' [12].

NE fluids do not sustain flame as they do not have a high-energy source of ignition. Hence, it would require a high temperature fault lasting many minutes to raise the NE fluid from the operating temperature to its fire point. This potentially eliminates the requirement of a fire protection system and firewalls, which reduce insurance premiums, requirements on clearances and the footprint of the transformer.

2.1.3 Environmental Properties

FR3 dielectric fluid is made from the renewable and recyclable resource of vegetable oil obtained from seed based agricultural crops. Hence, it is considered as a sustainable fluid by United States Department of Agriculture (USDA) [13]. It does not contain petrochemicals, siloxanes or halogens. Transformers before the year 1979 used PCB containing dielectric fluids. Since MO and PCB are highly miscible, transformers from that period can still contain PCB contaminants. Replacing these transformers with NE dielectric is a conscientious option.

According to the Organization for Economic Cooperation and Development (OECD), FR3 is ultimately biodegradable, non-toxic and non-hazardous in soil and water [14]. It is considered as carbon neutral by Building for Environmental and Economic Sustainability (BEES) 4.0 life cycle analysis [15]. Also, it is considered as edible, aquatic non-toxic and classified as non-carcinogenic in California [16]. Environmental Protection Agency (EPA) OPPTS 835.3100 tests have proven its ultimate biodegradability period of 28 days as shown in Figure 1 [17]. Under spillage, NE fluids degrade rapidly due their lower oxidation stability, and the high viscosity avoids their seepage deep into the soil.

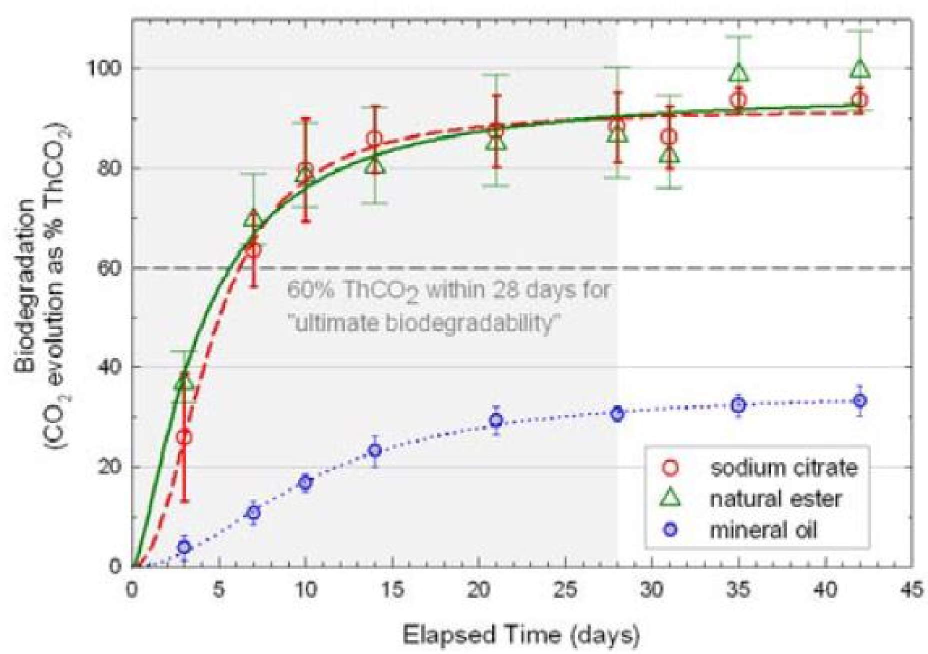

Figure 1. Aerobic aquatic biodegradation rate of NE, MO and sodium citrate as per EPA OPPTS 835.3100 tests [17].

2.1.4 Viscosity and Oxidation Stability

Oxidation byproducts of the oils cause formation of an insoluble sludge. The sludge acts as a barrier to the flow of heat from the core to the coils, to the cooling oil, and to the cooling unit [18]. Dielectric fluids must have adequate oxidation stability to efficiently cool and maintain desirable electrical characteristics over the life of a transformer. Therefore, insulating oils are investigated for their breakdown strength (generally measured by acid number) and viscosity over the aging period.

Accelerated aging tests in [19] show that natural esters do not form sludge precipitate as they oxidize differently from mineral oils as shown in Figure 2. American Society for Testing and Materials (ASTM) testing results obtained using laboratory grade spectrophotometer and ratio-turbidimeter are shown in Figures 3 and 4 [18]. They indicate that natural esters have significantly less decay products as trace impurities over the aging period.

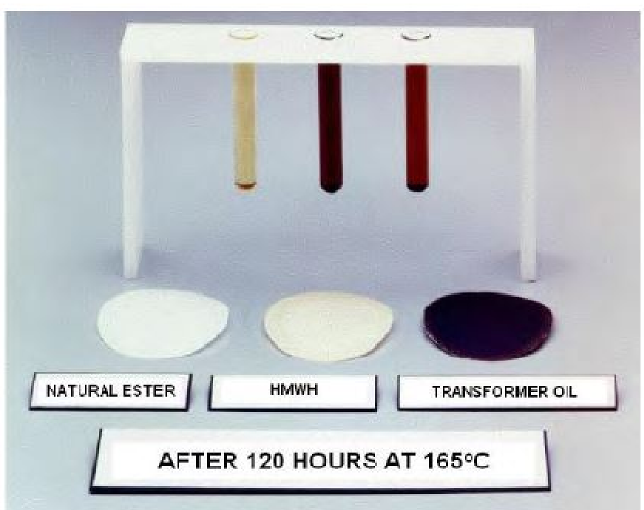

Figure 2. NE fluid, high molecular weight hydrocarbon and MO after oven aging. Filterable particulate oxidization products shown on filter papers [19].

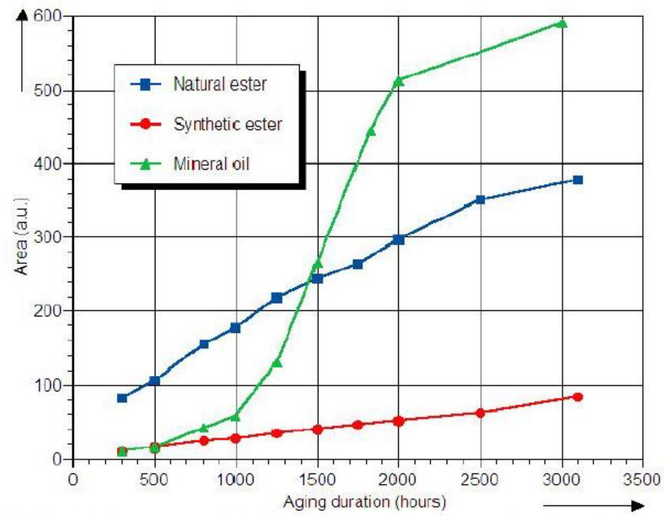

Figure 3. Dissolved oxidation decay products characterized from the absorbance curves according to ASTM D6802 [18].

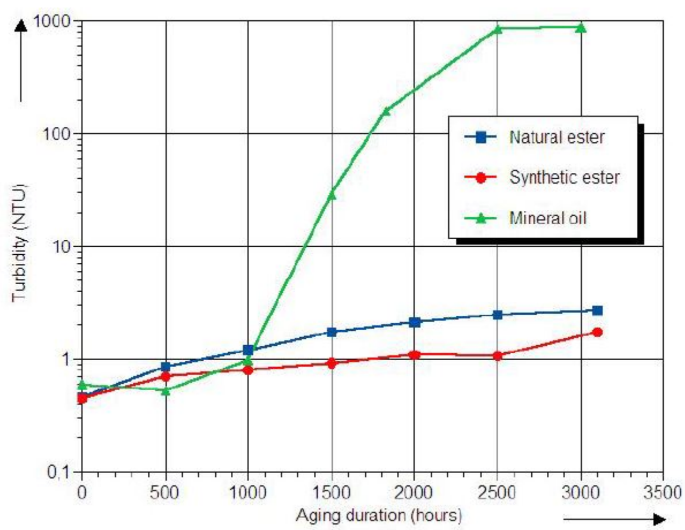

Figure 4. Turbidity as a function of aging duration as per ASTM D6181 [18].

Factors which affect the oxidation stability of the FR3 fluids are elevated temperatures, film thickness, air exposure time, type of surface, and exposure to ultraviolet rays [20]. Tests in [20] show that large quantities of FR3 fluid stored in uncovered tanks are affected significantly less by oxidation as compared to thin films of FR3. Thus, FR3 oil in transformer tanks is less susceptible to oxidation when exposed to air during transformer maintenance.

Oxidation of NE fluid leads to the formation of long-chain fatty acids. This makes the acid number of natural ester seventeen times higher than that of the mineral oil as per the experimental testing in [21]. Generally, an increase in acid number in insulating oil causes a decrease in its breakdown voltage. But the long-chain fatty acids in NE oils are non-corrosive compared to the short chain organic acids in MO. Thus, the high acid number of NE fluids does not affect its breakdown voltage. Experimental results in Figure 5 show that after aging time, the breakdown voltage of ABB Biotran-35 NE insulating oil decreased about 20% below its initial value, and the breakdown voltage of MO decreased to about 30% of its initial value. Hence, it is observed that the decrease in breakdown voltage of a transformer is lower for the natural esters than for the mineral oils over transformer lifetime.

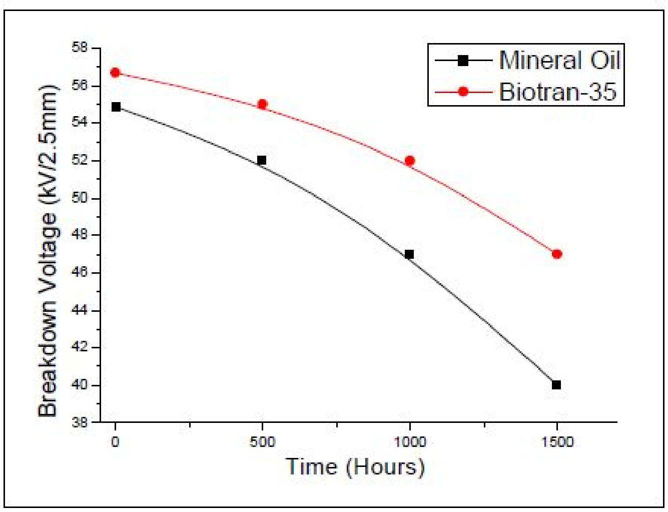

Figure 5. Breakdown voltage of Biotran-35 NE oil and MO over aging period [21].

The oxidation reaction in FR3 fluid is further slowed down by the addition of oxidation inhibitors like BHA (butylated hydroxy nisole), TBHQ (mono-tertiary butyl hydroquinone), DBPC (BHT, 2,6-ditertiary-butyl paracresol/ butylated hydrotoluene) and THBP (tetra hydro butro phenone) [22]. These inhibitors are oxidized and consumed when exposed to air, saving FR3 oil from oxidation. Table 1 summarizes test results performed on a 200 gallon tank of FR3 fluid after being exposed to ambient air for 5 years [20]. It is observed that while oxidation inhibitor content decreased, the viscosity did not increase significantly. Also, most other key fluid property values measured are within the acceptable limits for a new fluid.

2.1.5 Cold Temperature Behavior

Transformers require dielectric fluid that acts as an insulator as well as a coolant in very cold conditions. The pour point of FR3 fluid is -21°C and that of the MO is -40°C [23]. FR3 fluid cold temperature performance is not only related to its flow but also to its ability to transfer heat from the coils to the fluid via thermal conduction and initiating convection [23]. In [24], when full load cold start tests are performed for FR3 filled transformer at -30°C, temperatures remained well within IEEE C57.91 limits. It is also noted that, unlike MO, NE fluids maintained the dielectric strength and continued to work even when pour point is reached. Thus, freezing of NE fluids has no effect on their physical, chemical, and electrical properties. In case of FR3 fluid, the performance is further improved by addition of a pour point depressant like polyvinyl acetate oligomers and polymers, and/or acrylic oligomers and polymers [22].

Physical, electrical, and chemical properties of FR3 fluid and the corresponding ASTM/IEC/ISO requirements are included in the FR3 fluid sell sheet.

Table 1. Summary of Test Results Performed on FR3 Fluid Sampled from 5 years Old Uncovered Tanks [20]

Tests Performed	**ASTM Test Methods**	**Envirotemp FR3 Fluid Sampled from 5 yr Old Uncovered Tank**	**IEEE C57.147 Acceptance Limits For New FR3 Fluid**
Color and Condition	D1500/ 1524	clear, light green	clear, light green
Dielectric Strength (kV)	D1816	32	>=35
Dissipation Factor 25°C (%)	D924	1.39	<=0.20
Dissipation Factor 100°C (%)	D924	21.0	<=4.0
Moisture Content (ppm)	D1533	322	<=100
Acid Number (mg KOH/g)	D974	0.06	<= 0.06
Pour Point (°C)	D97	-19	-10
Flash Point (°C)	D92	323	>=275
Fire Point (°C)	D92	357	>=300
Viscosity at 40°C (cSt)	D445	35.2	<=50.0
Viscosity at 100°C (cSt)	D445	8.3	<=15.0
Volume Resistivity (Ohm-cm)	D1169	8.2×10^{11}	-
Inhibitor Content (%)	D4768	0.22	-

2.2 Thermal Properties

Liquid dielectric in fluid-filled transformers affects the life of the cellulose paper used to insulate transformer windings. Researchers have studied the impact of natural ester liquids on cellulose materials using functional and accelerated aging experiments [18, 21]. They observed significant reduction in the aging rate of a cellulose insulation in natural ester when compared to that in mineral oil. The lower aging rate extends the range of application beyond the mineral oil cellulose insulation system by allowing higher load capabilities at higher temperatures without reducing the insulation life expectancy or by lowering the nameplate rating of a transformer to serve the same load.

2.2.1 Aging of the Cellulose Insulation in Natural Esters

There are three methods to test the thermal life of a transformer: small scale testing called functional life test (sealed tube test), large scale testing called accelerated aging test (Lockie test), and a modification to the sealed tube test called the dual temperature test [24]. These tests are defined in the standard IEEE C57.100 [25]. End-of-life for an insulation system is considered when the test specimen cannot withstand any one of the series of tests intended to simulate the abnormal currents or voltages that are commonly experienced in actual service [25]. As per IEEE C57.91 [1], industry proven end-of-life criteria are (1) retained tensile strength of 25% or 50%, and (2) the degree of polymerization value of 200.

In a sealed tube test, a tube filled with dielectric fluid along with paper insulation and a copper plate are exposed to different temperatures in an oven. The fluid is then tested for one of the end-of-life criteria. In the Lockie test, an actual transformer is tested instead of just the dielectric oil. A dual temperature test mimics an actual transformer. It uses copper loop wire wrapped in the candidate insulation through which controlled current is passed. At least three temperature points are used to develop the Arrhenius Curve of per unit transformer insulation life. Natural ester filled distribution transformers are tested by the first two tests as it is not possible to simulate layer insulation of a distribution transformer in the dual temperature test.

Sealed tube tests performed at the three different temperatures in [5, 26, 27, 28, 29] show that paper aged at 170°C in NE fluid takes 5 to 8 times longer to reach the end-of-life points defined by the IEEE standard C57.100 than paper aged in standard MO. Aging rates at each temperature are determined by first and second order linearization of the Arrhenius Curve. In [30], ABB performed the sealed tube test with cellulose paper and showed a 20°C advantage in the life of natural ester filled transformers as compared to the per unit life defined by the standard IEEE C57.91 [1]. In other words, the ester filled transformer was observed to have the per unit insulation life at the hot spot temperature of 130°C whereas the per unit life for the standard mineral oil filled transformer is at the temperature of 110°C. Accelerated aging tests performed by Chongqing University, University of Stuttgart and Doble Engineering observed similar results [30].

Results for the Kraft (cellulose) as well as for the thermally upgraded Kraft (TUK) paper with natural esters in [31, 32] showed a 20°C improvement in hot-spot temperature at the unit life. Cooper Power Systems performed an accelerated aging test on their Biotrans-35 natural ester oil, and observed significant improvement in the life of insulation in natural ester oil [33]. Single temperature type testing performed in [34] simulated much harsher temperature conditions of 170°C continuously for 2160 hours, and obtained similar results.

Mineral oil units retro-filled with natural esters are tested for the accelerated aging tests in [35, 36, 37]. Mineral oil units reached both end-of-life criteria at 150°C. The retro-fill cellulose paper did not reach end-of-life till 170°C. At 170°C it reached the 50% tensile strength criterion, however it did not reach the 200 degree of polymerization criterion. This shows that both new and retro-filled NE transformers have lower insulation aging than the MO units.

Testing of in-service natural ester units started in 1997. Several single-phase pole mounted and three-phase pad-mounted units were tested for the dissolved gas analysis after one year of operation [38]. Analyzing the fluid showed negligible degradation in the key fluid properties. Lockie tests performed on single-phase and three-phase FR3 ester oil prototype transformers assisted in establishing the life curves for FR3 natural ester filled transformers [3, 39, 40]. In [41], the laboratory testing of new and in-service FR3 filled transformers re-iterated its thermal capabilities. Zero failure rates from 10,000 in-service FR3 filled transformers ranging from 10 kVA to 10 MVA are noted in [42]. A standard assessment of the dielectric fluid properties and dissolved gas analysis was performed in the 10th year of operation of two 225 kVA units, 200 MVA-161 kV, and 50 MVA-69 kV generator step up transformers filled with FR3 fluid [43]. The data collected from this power transformer testing indicated excellent fluid stability with acceptable chemical, physical and electrical properties of the FR3 fluid.

Long term performance of FR3 fluid under severe loading condition was tested by CPFL - a Brazilian utility [44]. Two FR3 filled units of rated size 75 kVA were put in service for 12 years to handle a load of two 112.5 kVA rated mineral oil units. The average loading of the transformers was 82 kVA with peak load recorded of 123 kVA.

After 12 years, the oil was tested by laboratories in the U.S. Results show no sludge formation with all properties close to the the acceptance values of a new FR3 fluid, and no sign of its degradation.

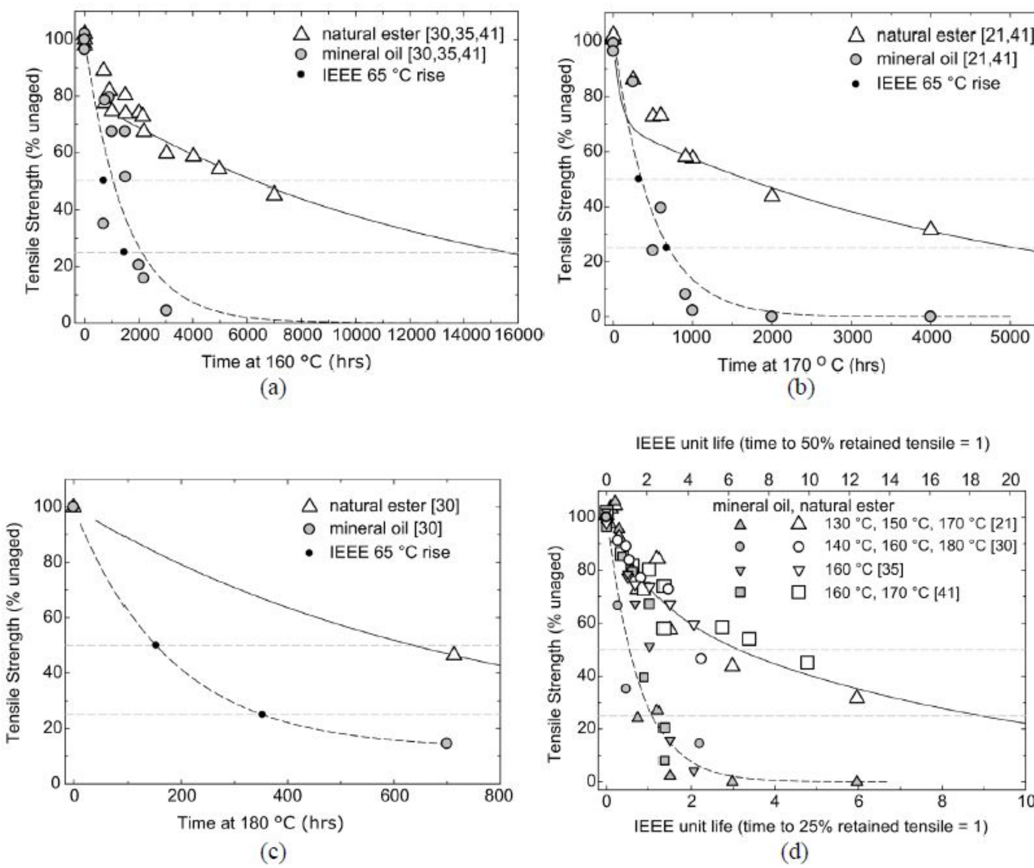

Figure 6. Tensile strength accelerated aging results of thermally upgraded Kraft paper in mineral oil and natural ester liquid: tensile strength versus a) time at 160°C, b) time at 170°C, c) time at 180°C, and d) time at temperature normalized to IEEE unit life [45].

IEEE C57.154 [45] includes the accelerated aging test results for TUK and cellulose based paper insulation systems at different temperatures. For TUK paper, tensile strength and degree of polymerization aging test results are shown in Figures 6 and

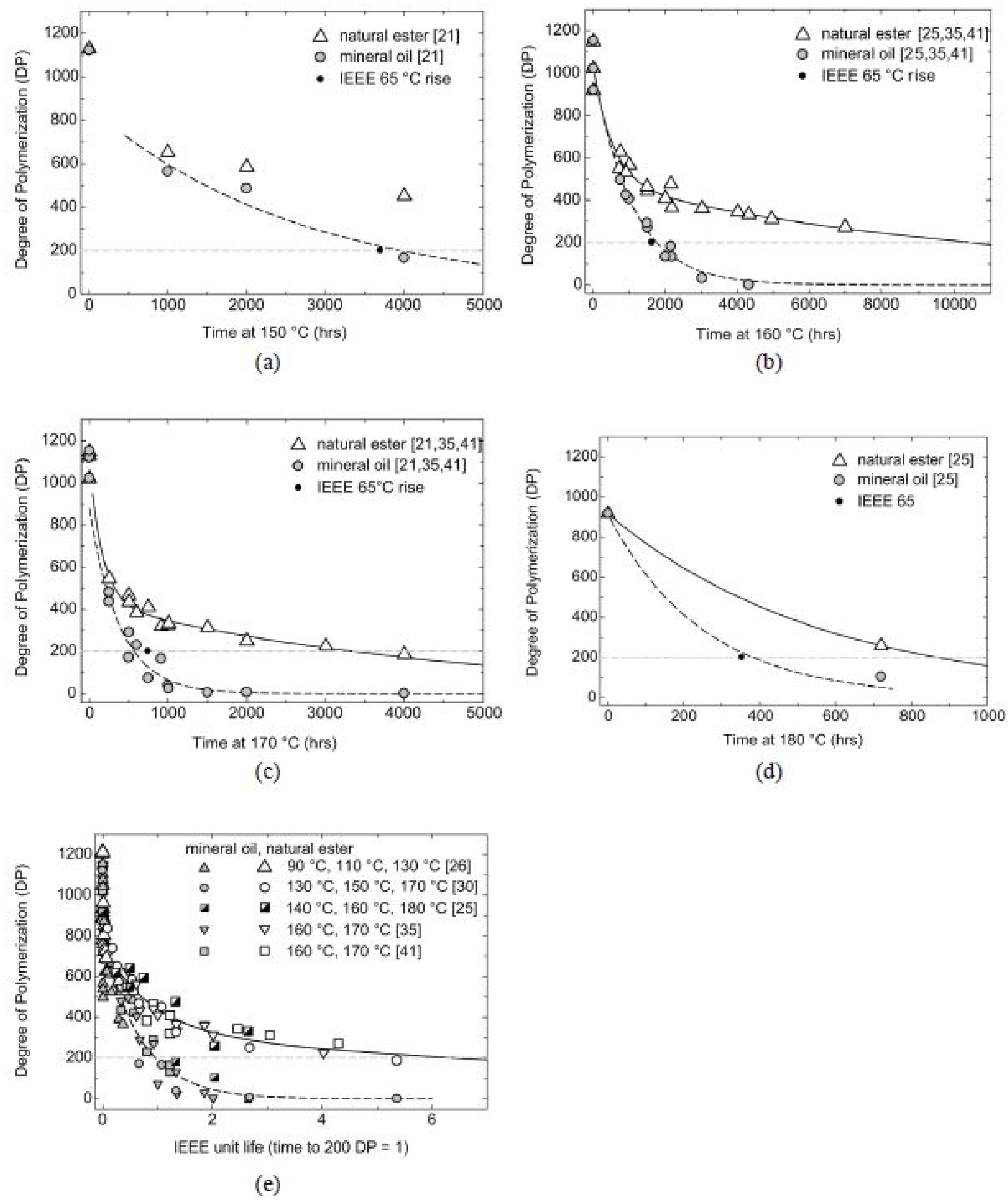

Figure 7. Degree of polymerization accelerated aging results of thermally upgraded kraft paper in mineral oil and natural ester liquid: tensile strength versus a) time at 150°C, b) time at 160°C, c) time at 170°C, d) time at 180°C, and e) time at temperature normalized to IEEE unit life [45].

7 respectively. The curves show that aging of TUK paper in natural ester fluid is significantly lower than in the mineral oil.

The tensile strength and the degree of polymerization aging test results for the cellulose paper insulation are shown in Figures 8 and 9 respectively. From the curves, it is clear that at all temperatures, the cellulose paper insulation aging takes place at much lower rate in the natural esters than in the mineral oils. Acceptance of these test results in IEEE standard C57.154, in the year 2012, provides a strong basis for the fact that aging rate of cellulose paper decreases in natural esters like FR3.

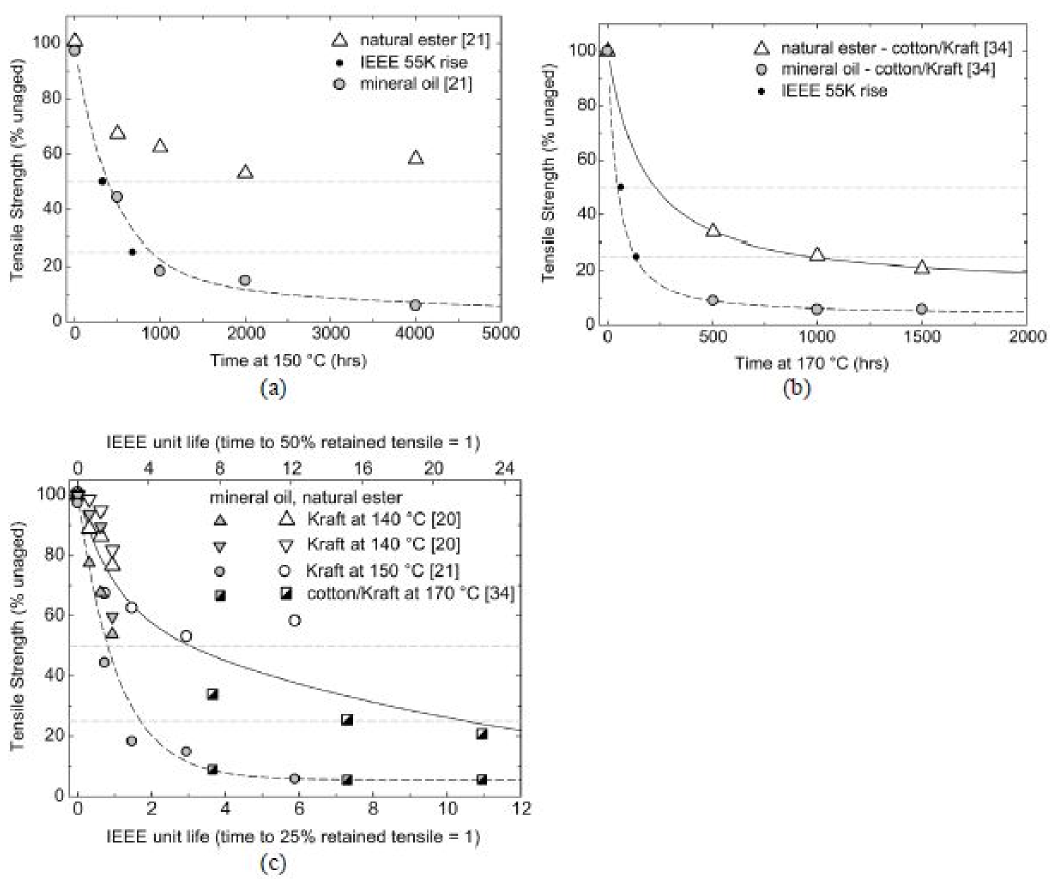

Figure 8. Tensile strength accelerated aging results of cellulose-based paper in mineral oil and natural ester liquid: tensile strength versus a) time at 150°C, b) time at 170°C, and c) time at temperature normalized to IEEE unit life [45].

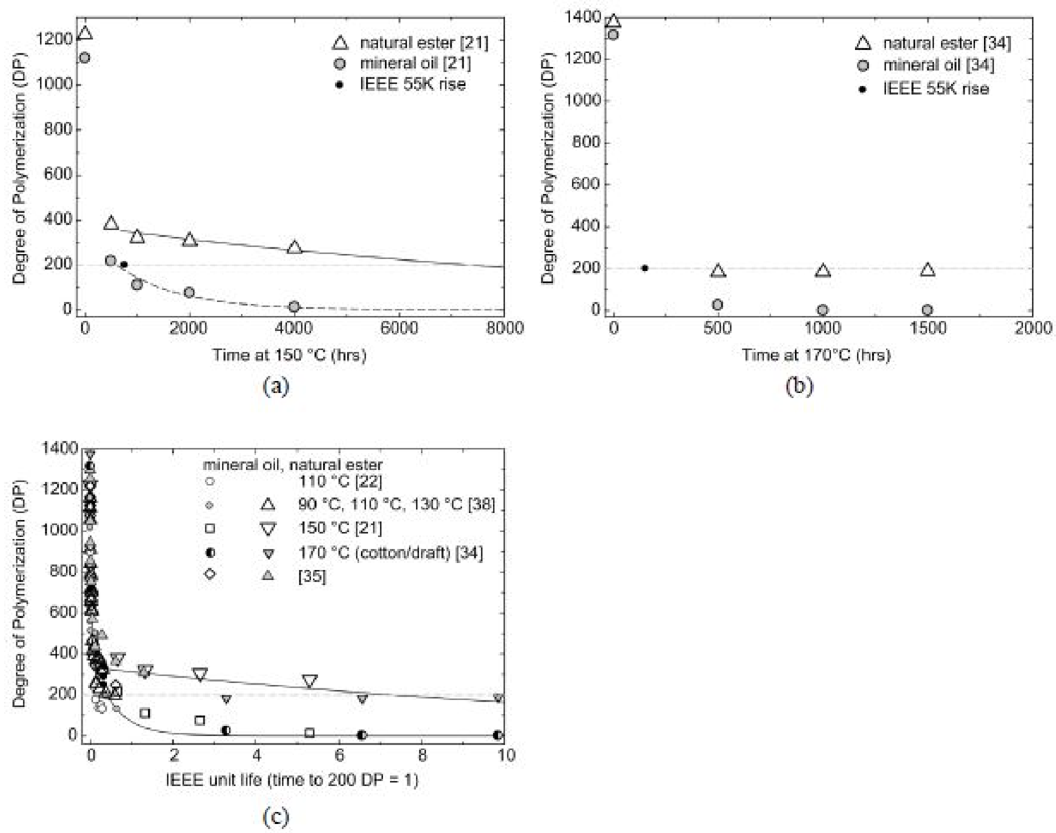

Figure 9. Degree of polymerization accelerated aging results of cellulose-based paper in mineral oil and natural ester liquid: tensile strength versus a) time at 150°C, b) time at 170°C, and c) time at temperature normalized to IEEE unit life [45].

2.2.2 Interaction Mechanisms of Natural Ester and Cellulose Insulation

Cellulose paper insulation degrades when its dielectric strength decreases to a value below the acceptable limit. Presence of water in the cellulose insulation is the primary reason for its failure [45]. There are two sources of water in the paper. The first source is the residual water present due to incomplete drying of paper during its production. Good manufacturing practices can keep this value small, between 0.3% to 0.5%. The second source is the water generated by breaking of chemical bonds in the cellulose due to heating of the transformer.

Natural esters like FR3 behave differently from mineral oils in two ways. First, they have sixteen times higher solubility limit than mineral oil at room temperature and about four times higher at 100°C [45]. Because of this difference in saturation level, they can absorb more water than mineral oil to reach the same relative saturation level in both liquids [29, 45, 46]. Since water is produced as a byproduct of the aging process, water content of mineral oil increases over the period. This increase in moisture content of mineral oil has to be matched by increase in moisture content of cellulose in order to maintain equilibrium, thus lowering its life [47]. Aging studies done in [48, 49, 50] with different moisture content in paper proved this fact. When natural ester is tested, it is observed that moisture rises initially with the aging time, peaks and then declines for rest of its life [29].

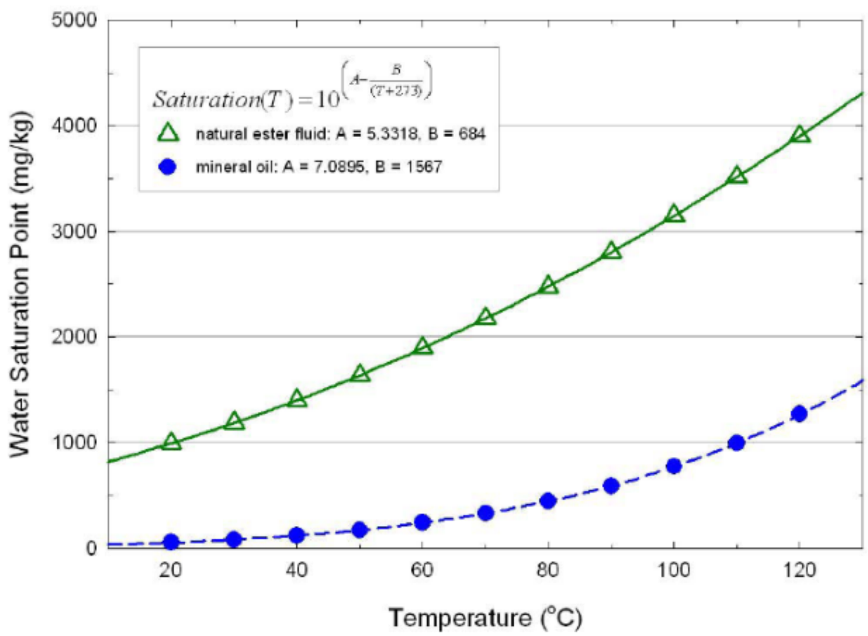

Figure 10. Water saturation versus temperature for natural ester fluid and conventional transformer mineral oil [46].

Results from the experimental investigation are summarized in Figures 10, 11, and 12 [46]. Figure 10 shows that the water saturation point of natural ester increases exponentially with temperature and is always higher than the mineral oil. With aging, water content of Kraft paper in natural ester decreases while that in mineral oil increases as observed in Figure 11. In Figure 12, it is seen that the water content in natural ester initially increases with aging time, peaks and then declines; while that in mineral oil increases continuously with aging. Moisture migration results for accelerated aging test at 80°C are shown in Table 2 [45]. Initial moisture content of paper in both fluids is kept constant. It is observed that the final moisture content of paper in natural esters is consistently lower than in the mineral oil.

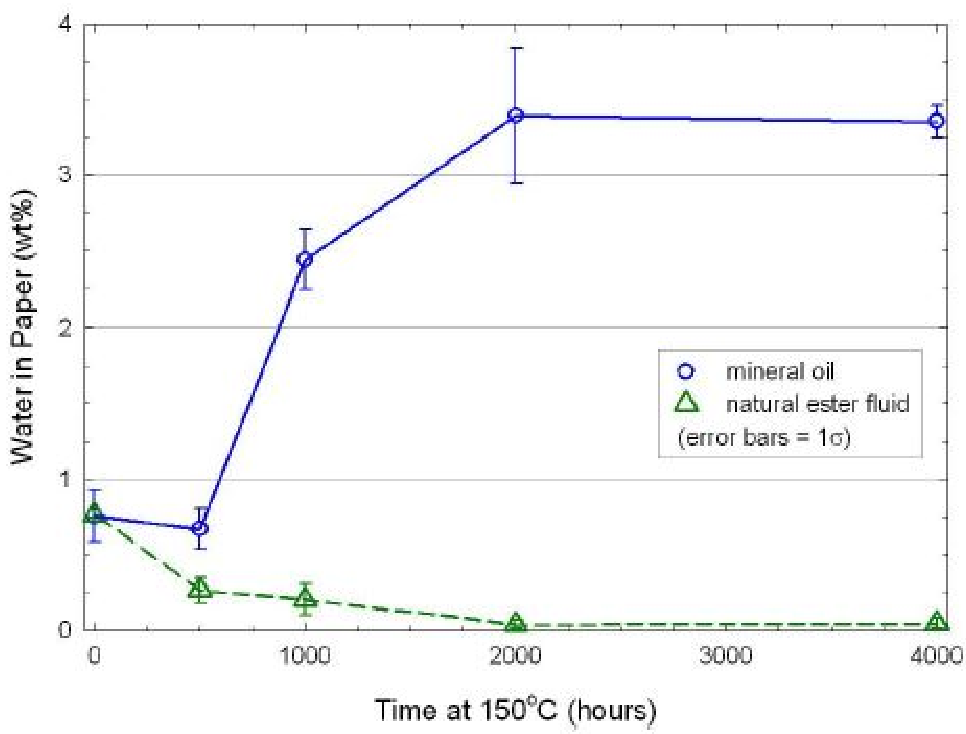

Figure 11. Water content of Kraft insulation paper aged in natural ester fluid and conventional transformer oil [46].

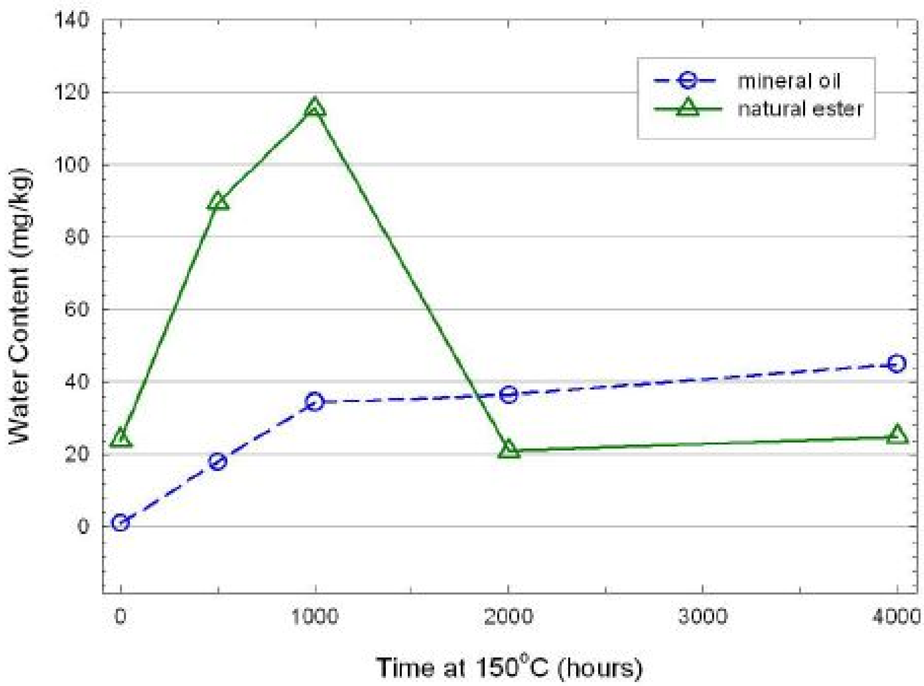

Figure 12. Water content of natural ester fluid and conventional transformer oil after accelerated aging [46].

Table 2. Results of Moisture Migration Calculations for Natural Ester and Mineral Oil at 80°C Equilibrium Temperature [45].

Liquid Type	**Pass #1**		**Pass #2**		**Pass #3**	
	NE	**MO**	**NE**	**MO**	**NE**	**MO**
Starting moisture in cellulose (%)	2.00	2.00	1.64	1.93	1.39	1.86
Final moisture in cellulose (%)	1.64	1.93	1.39	1.86	1.21	1.80

The second difference between the two oils is the chemical reaction of water with natural esters. Water reacts with the triglycerides in natural esters via hydrolysis to form long chain fatty acids. The reaction consumes the water causing additional water to move from paper to fluid shifting the cumulative equilibrium. Three water molecules are needed to add -H and -OH groups to break the ester bond [51]. This gives one molecule of glycerol and three molecules of long chain fatty acids. Acids produced during hydrolysis react with cellulose in the paper. The reactive -OH group on cellulose molecule having high electron density become esterified with fatty acid hindering cellulose degradation mechanisms utilizing these sites thus preventing ingress of water in the paper. This process is called trans-esterification. Evidence of trans-esterification has been seen using Fourier transform infrared spectroscopy, nuclear magnetic resonance and x-ray photoelectron spectroscopy [45, 46, 49, 52, 53].

The mechanisms explaining lower aging rate of cellulose in natural esters are summarized in the flowchart of Figure 13.

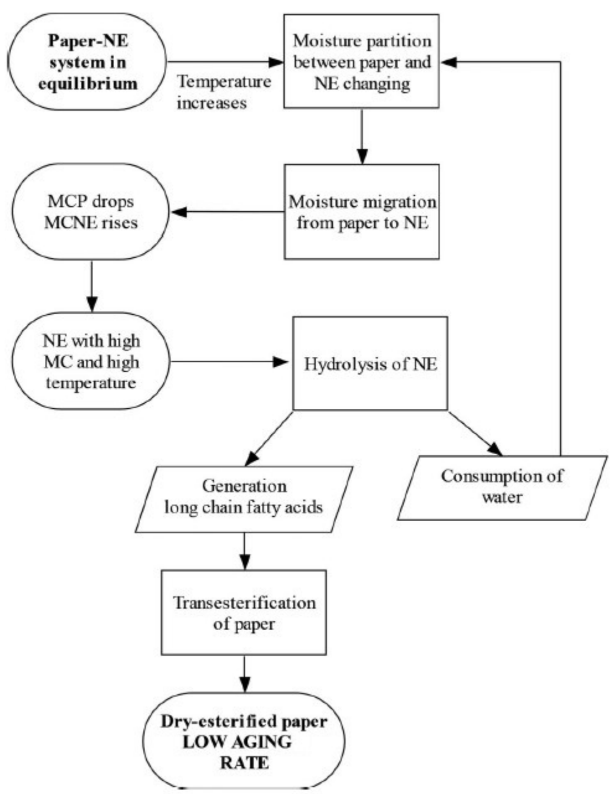

Figure 13. Lower aging rate flowchart (MCP-moisture content in paper) [48].

2.3 Design Capabilities of Natural Ester Filled Transformers

Testing and analysis of thermal performance of natural esters, as discussed in Sections 2.2.1 and 2.2.2, resulted in the development of a unit life curve for the natural ester filled transformer. This life curve is included in Annex B of IEEE standard C57.154 [45].

2.3.1 Life Curve of Natural Ester Filled Transformer

The natural ester transformer unit life curve as shown in Figure 14 is obtained by fitting 'A', in the Arrhenius reaction equation in (1.1), to the end points from accelerated aging test results of cellulose and Kraft paper shown in Figures 6, 7, 8, and 9 [45]. Curve fitting techniques described in the IEEE standard 1.0 are used [54]. The calculated constants and resulting temperature indices are shown in Table 3.

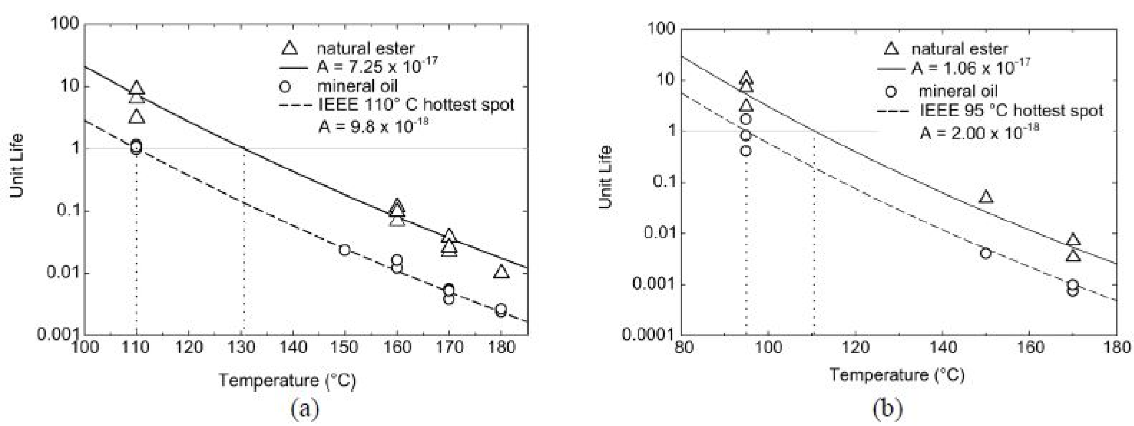

Figure 14. Unit life versus temperature: a) TUK paper in MO (IEEE 110°C hot spot) and NE liquid (least squares fit of natural ester aging data) and b) cellulose-based paper in MO (IEEE 95°C hot spot) and NE liquid (least squares fit of natural ester aging data), IEEE C57.154 [45].

Table 3. Aging Curve Constants and Comparison of Aging Results, IEEE C57.154 [45].

	Constant A	**Temperature T (°C)**	**Thermal Index**	**Thermal Class**
IEEE MO/TUK Paper	9.80 x 10^{-18}	110.0	110	120
NE/TUK Paper	7.25 x 10^{-17}	130.6	130	140
IEEE MO/ Cellulose Paper	2.00 x 10^{-18}	95.1	95	105
NE/Cellulose Paper	1.06 x 10^{-17}	110.8	110	120

Mineral oil distribution transformers used by utilities like SRP generally have TUK paper insulation and are rated at 110°C average winding rise (AWR) temperature. It is observed that the degradation rate of the TUK paper in NE fluid is reduced by a factor of 7.4, obtained by division of the life curve equations for the paper immersed in the two liquids, and using constant 'A' from Table 3 as shown below:

$$\frac{Per\ Unit\ Life_{\text{ TUK Paper NE}}}{Per\ Unit\ Life_{\text{ TUK Paper MO}}} = \frac{A_{\text{NE}}\ e^{\left[\frac{15000}{\theta_H+273}\right]}}{A_{\text{MO}}\ e^{\left[\frac{15000}{\theta_H+273}\right]}} = \frac{7.25 \times 10^{-17}}{9.8 \times 10^{-18}} = 7.4 \qquad (2.1)$$

Life curves from IEEE C57.154 for TUK paper in natural esters like FR3 and in MO are repeated in Figure 15. The curves show that the FR3 filled transformers with TUK paper insulation can maintain unit life when operated at a hot-spot (and hence average winding rise) temperature that is 20°C higher than their MO equivalents [3, 29]. Estimations from IEEE C57.91 show that there would be an increase of 1% on the loading for every additional degree of AWR temperature. Thus, FR3 filled units

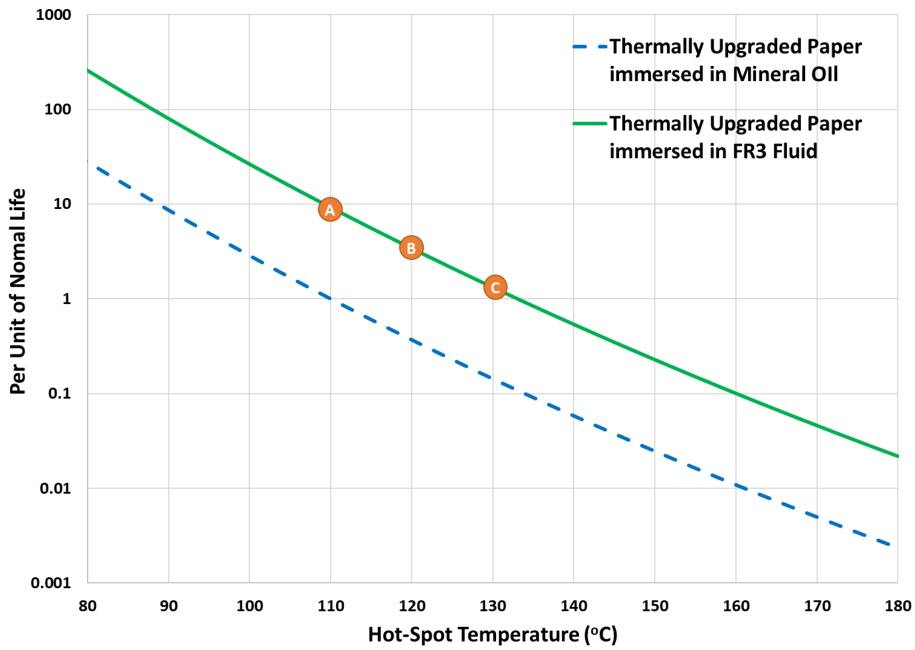

Figure 15. Operation points for FR3 fluid filled transformer in relation to IEEE C57.154 life curve [45].

operated at hot-spot temperature of 130°C can have additional loading capability of 20% of the same nameplate rated MO unit without additional loss of life.

This leads to three different points of operation for NE filled transformers to use the additional loading capacity:

1. **Operation Point A:** Extend insulation life by operating at the hot spot temperature of 110°C.
2. **Operation Point B:** Benefits of insulation life extension and increased load capability without additional loss of life by operating at the hot spot temperature of 120°C.
3. **Operation Point C:** Increase load capability up to 20% by operating at the hot spot temperature of 130°C.

2.3.2 FR3 Filled Transformer Designs

MO filled transformers designed with 65°C AWR temperature are limited to hot spot temperatures of 110°C to maintain per unit life, minimize thermal degradation and risk of failure due to bubbling and gas formation. Hence, they are designed with the rated capacity defined close to the annual peak demand. High temperature operation of the FR3 filled transformers enables utilities to design the transformers with more flexibility in loadability and better asset utilization. Since nameplate rating is directly associated with temperature rise limits, selection of these limits leads to different capabilities for NE filled transformer as described below.

1. **Conventional Loading:** This is the simplest design of natural ester filled transformers. Mineral oil is replaced with FR3 fluid without any further modifications to the existing design and its nominal rating. The average winding temperature rise is kept at 65°C with hot spot temperature rise limited to 110°C. As a result, the transformer can be permanently loaded by 20% more than the same size mineral oil unit maintaining the same per unit life. As the transformer can handle severe load conditions without becoming damaged, this design may be used to avoid an extra unit at 'N-1' contingency. Conventional loading design is best suited for the applications where there is a continuous increase in demand postponing the addition of higher size unit. Most utilities using natural ester filled transformers have used this design to enjoy the benefits of extended transformer insulation life.
2. **Compact Loading:** In this type, FR3 filled transformers are designed for 75°C AWR temperature at rated load conditions. The continuous high temperature operation is achieved by optimized use of iron and copper reducing the overall

footprint and the weight of the transformer. Decreasing the amount of iron decreases the no load losses. Due to lower use of copper, it has higher load losses under rated load conditions than its mineral oil equivalent. Since core losses constitute a major portion of the energy consumption of a transformer, this design has potential of having lower dissipated energy during its service. There is a reduction in the cost of material (iron and copper) but increase in the cost of oil (as ester oils are typically 10% to 15% costlier than mineral oils) making overall initial cost competitive to the mineral oil unit. Mostly, the design is suited for large power and distribution transformers due to optimized size and weight.

3. **Sustainable Peak Loading:** These transformers are designed for an average winding temperature rise of 65°C for one load step smaller than the nominal load. For example, a mineral oil transformer serving a 50 kVA load can be designed with sustainable peak loaded FR3 transformer of nominal rating 37.5 kVA (next lower rating to 50 kVA). This transformer will maintain 65°C average winding temperature at the nominal load of 37.5 kVA. The objective of this design is to achieve higher average loading for the given load profile. The nominal rating of the transformer is selected studying the average and peak loads to be served. This design provides highest load flexibility, and hence is used for the load profiles having high seasonality in demand. This transformer design has smaller nominal rating for same load reducing the initial cost. Further, the transformer may have cost savings on total energy dissipation provided it has lower average loading.

Table 4 compares the capability differences of each design with conventional mineral oil units.

Table 4. Comparison of FR3 Designs with Conventional Mineral Oil Transformer

Parameter	**Conventional Loading**	**Compact Loading**	**Sustainable Peak Loading**
Avg. Winding Temperature	65°C	75°C /85°C	65°C
Additional Load Capacity	20-50%	10-30%	0-5%
Overloading Capacity	Highest	Higher	High
Transformer Life	≈ 1.5X	≈1.33X	Minimum 1X
Initial Cost	10-15% higher	Comparable	Lower
Electrical Losses	No change	Comparable	Comparable / lower
Footprint	No change	Smaller	Smaller
Suitability	Power, distribution transformers	Large power, distribution transformers	Power, distribution transformers

2.4 Utility Experience Using FR3 Filled Transformers

Major utilities in the U.S. using FR3 filled transformers were contacted in November 2017. The survey was focused to understand the experiences of using FR3 transformers. Responses received from five utilities using FR3 filled transformers are summarized below:

1. **Seattle City Light:** Seattle City Light has been using FR3 filled transformers since the year 2010. They have not reported any failures of their transformers due to the FR3 fluid. The potential behind converting mineral oil units to FR3

filled units, for them, is to take advantage of their environmental benefits. They are not allowing the transformers to operate at higher temperatures and hence have not performed any economic analysis for it. Seattle City Light is not using any FR3 retro-filled units. Since the installations are quiet new, they have not established any temperature tracking system to measure their life or overloading capacity.

2. **Waverly Light and Power:** They have been using FR3 filled transformers since 1997. All of their FR3 filled units are still in service and they have not reported any fire or failure of the transformers. Initially, they started installing new FR3 filled units. From the year 2005, some of their power and distribution transformers were retro-filled with FR3 oil. The motivation behind transferring from mineral oil to FR3 is to extend transformer life, eliminate fires, and have an environmentally recyclable unit. In last 20 years, they have never faced any problem related to the spillage of the FR3 oil. Their preferred FR3 transformer vendors are ABB, Ermco, and Cooper Power systems. Before installation of the FR3 filled units, Waverly Light performed the lifecycle cost analysis for FR3 units giving promising results. They never faced any difficulty in retro-filling or installation of new FR3 filled transformers and the annual sampling tests performed on FR3 oil till November 2017 have shown extremely positive results.
3. **Tampa Electric Company:** Tampa Electric has been using FR3 filled units since 2015. Two of their pole mounted FR3 filled units failed due to improper design of the transformer by the manufacturer. Investigation of the failure showed that these transformers had insufficient volume paths provided in the transformer tank for the circulation of FR3 fluid under overloaded conditions. However, FR3 fluid behaved as expected under those overloaded conditions.

They performed a cost benefit analysis in which FR3 filled transformer is justified based on its life extension benefit. Since the installations are relatively new, they are not able to make any definitive determination about the actual life of FR3 filled units.

4. **San Diego Gas and Electric (SDG&E):** They have been using FR3 transformers since 2005 and have not reported any failures of FR3 units due to the reasons of insulation breakdown, overloading or heating. SDG&E has not performed any cost benefit analysis for the high temperature FR3 installations but decided to use FR3 filled units for their improved fire safety.
5. **Pacific Gas and Electric (PG&E):** They have been using FR3 filled units from 2014 and have not faced any failures since then. The main objective of PG&E was to ensure fire safety of their transformers. The cost benefit analysis performed by them was justified based on the lifecycle cost benefits due to increased life of the transformers.

2.5 Conclusion

The literature reviewed in this chapter shows that physical, electrical and chemical properties of natural esters, as a dielectric fluid, are superior than those of mineral oil. Experimental testing indicates that the cellulose insulation in natural ester FR3 fluid can have life extension up to 7.4 times that of the conventional mineral oil. Also, the per unit life curve and the mechanisms proposed for the increase in insulation life are accepted and included in the IEEE standard C57.154.

Cargill has performed over 250 tests as per the ASTM/ IEEEE standards, showing FR3 fluid as a better alternative to mineral oil with improved fire safety and environmental benefits [55]. Testing of in-service transformers with zero reported failures and permissible oil degradation values from the surveyed utilities, show that FR3 fluid can be considered as a reliable technology.

Utilities using the FR3 filled units have justified their use based on the benefits of fire safety and environmental friendliness. However, evaluation of load profiles and the cost benefit analysis would determine its use at high temperatures to achieve transformer size reduction and/or life extension.

Chapter 3

ANALYSIS OF LOAD CURVES

Analyzing the suitability of FR3 filled transformers requires development of a transformer thermal model as per SRP load profiles. This chapter covers, in detail, the development of the distribution transformer mathematical model to understand its thermal behavior, loss of life and electrical losses. By analyzing the models for mineral oil and FR3 filled transformers, and the nature of the load, the most suitable FR3 filled transformer designs are suggested to SRP. This methodology provides a systematic approach to the planning engineers for the investigation of the compatibility of FR3 filled units based on the typical load profiles.

3.1 Development of Data-driven Thermal Mathematical Model of Distribution Transformer

The thermo-chemical process of insulation aging progresses as a nonlinear function of the absolute temperature. The transformer temperature, in turn, is affected by its loading cycle and ambient temperature. The thermal time constants of a transformer make the relationship between loading and temperature highly dynamic. The temperature at a given time step is dependent not only on the present load but also on the recent loading. Hence, it is important to develop a data-driven mathematical model of a transformer which takes into account the effect of transformer loading cycle and ambient temperature data.

3.1.1 Data Provided by SRP

In order to analyze the suitability of FR3 natural ester filled units for SRP transformers, it is important to know the thermal model of the SRP distribution transformers. SRP uses 15 kV distribution systems in the Phoenix, Arizona area with approximately 96,000 single-phase pad-mounted transformers. Their typical distribution transformer sizes are 25, 50, 75, 100, and 167 kVA. Table 5 shows the number of installed and purchased transformer units by SRP.

Table 5. SRP Distribution Transformer Fleet

Transformer Size in kVA	**Installed Number of Units**	**Quantity Purchased Between 2002-2017**
25	10,000	4,540
50	42,000	22,358
75	44,500	27,943
100	2,200	1,110
167	150	42

Load profiles of multiple units of the above mentioned sizes are analyzed. Loading data of 15 minute time intervals, measured by smart meters for the year 2017 are made available by SRP. Ambient temperature data for the city of Phoenix are obtained from the National Oceanic Atmospheric Administration data bank [56].

Temperature rise tests provide transformer winding temperatures, oil temperatures, and time constants at rated kVA load. SRP has provided the temperature rise test reports for the mineral oil and equivalent size FR3 filled transformers. A summary of these data is provided in Table 6.

Table 6. Summary of Temperature Rise Test Results (at transformer rated kVA)

Size (kVA)	**25**		**50**		**75**		**100**	
	MO	**NE**	**MO**	**NE**	**MO**	**NE**	**MO**	**NE**
Top Oil Rise Over Ambient (°C)	34.1	34.2	51.6	47.1	52.9	48.2	54	48.2
Copper to Oil Gradient (°C)	11.4	13.1	7.8	8.9	10.2	9.9	9.5	9.9
Top Oil Time Constant (Hours)	5.3	4.8	6.4	6.4	5.8	5.8	7	5.8
No Load Loss (W)	69	69	104	109	119	141	194	194
Load Loss (W)	304	304	535	498	787	646	856	856

3.1.2 Temperature Rise Calculations

Industry has developed transformer loading analysis algorithms to mathematically model the transformer thermal behavior. Standards IEEE C57.91 and IEC 60076-2 provide such simplified mathematical models. Based on the available data from the temperature rise tests, and the simplified models from the mentioned standards, a mathematical model for SRP transformers is developed in this section.

SRP distribution transformers have concentric windings regularly distributed along the core limbs. For this type of transformer construction, the simplified mathematical model assumptions as per IEC 60076-2 are applicable. Following is the list of assumptions:

1. The top oil temperature is the temperature of the liquid at the winding exit. The bottom oil temperature is the temperature of the oil at the entry of the winding.

2. Average oil temperature is the average of top oil and bottom oil temperatures.
3. Temperature rise of the liquid inside the windings of the transformer is assumed rising linearly with the height of the windings.
4. The heat, transferred from the winding to the liquid all along the winding, requires a temperature drop between winding and surrounding liquid. This drop in temperature is assumed to be constant at all levels of height with the exclusion of the winding extremities.

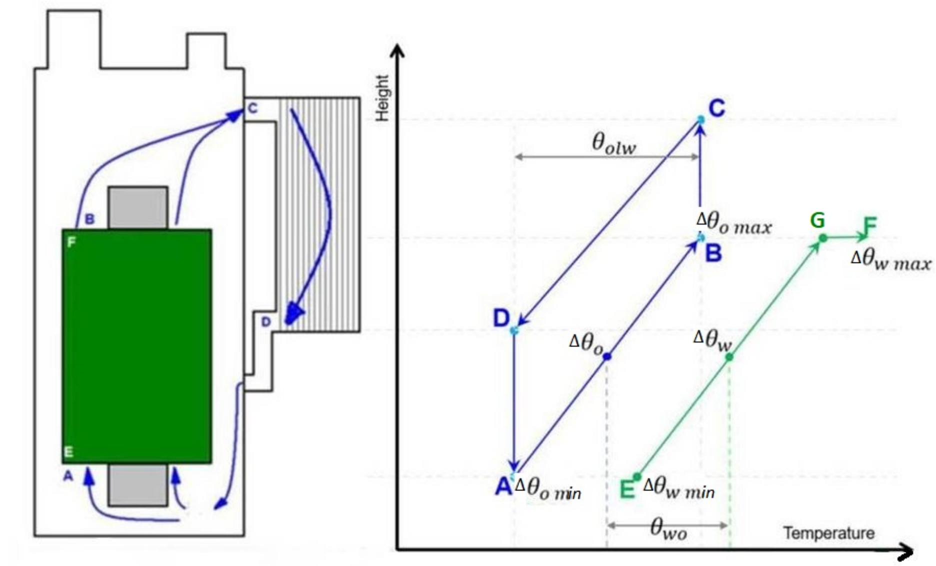

Figure 16. Representation of oil flow in a transformer with reference to IEC 60076-2 transformer model.

The above assumptions can be explained with an oil flow representation diagram shown in Figure 16. The oil temperature rise and winding temperature rise are represented by two parallel lines. Line AB represents oil temperature rise along the height of the winding. Line EG represents winding temperature rise along the winding height. Line CD represents the drop in oil temperature along the radiator. Bottom and top oil temperatures (points A and B respectively) are assumed to be same as those at the bottom and top of the radiator (points D and C respectively). Hence line CD representing the drop of temperature along radiator is also parallel to line AB.

3.1.2.1 Definitions

With reference to Figure 16 and assumptions of the model, important quantities are defined in this section. These quantities are further used in the calculations of transformer temperatures.

1. Average winding temperature rise ($\Delta\theta_{\mathrm{W}}$): It is the average of top winding temperature rise and bottom winding temperature rise. It is calculated as follows:

$$\Delta\theta_{\mathrm{W}} = \frac{\Delta\theta_{\mathrm{Wmax}} + \Delta\theta_{\mathrm{Wmin}}}{2} \tag{3.1}$$

2. Average oil temperature rise ($\Delta\theta_{\mathrm{O}}$): It is the average of top oil and bottom oil temperatures. It is calculated as follows:

$$\Delta\theta_{\mathrm{O}} = \frac{\Delta\theta_{\mathrm{Omax}} + \Delta\theta_{\mathrm{Omin}}}{2} \tag{3.2}$$

3. Copper to oil gradient (θ_{WO}): Copper to oil gradient, also called average thermal gradient, is the difference between average winding temperature rise and average oil temperature rise. Hence,

$$\theta_{\mathrm{WO}} = \Delta\theta_{\mathrm{W}} - \Delta\theta_{\mathrm{O}} \tag{3.3}$$

4. Hot spot factor (H): The hot spot is located at the upper extremity of the winding because of concentration of additional loss due to deviation of leakage flux lines and variations in the liquid ducts at the top of the windings. Therefore, there is a hot spot factor H, which takes into account these two factors. From the literature provided in IEC 60076-2, this factor is 1.1 for the transformers below 50 MVA rating.

5. Hot spot winding temperature rise ($\Delta\theta_{\mathrm{Wmax}}$): The hot spot winding temperature rise is the sum of top oil temperature rise ($\Delta\theta_{\mathrm{Omax}}$), and product of copper to oil gradient and hot spot factor as shown below [57]:

$$\Delta\theta_{\mathrm{Wmax}} = \Delta\theta_{\mathrm{Omax}} + H\theta_{\mathrm{WO}} \tag{3.4}$$

6. Vertical oil gradient (θ_{OLW}): It is the gradient of oil temperature along the winding. It is calculated as the difference between top and bottom oil temperature rises as shown below:

$$\theta_{\mathrm{OLW}} = \Delta\theta_{\mathrm{Omax}} - \Delta\theta_{\mathrm{Omin}} \tag{3.5}$$

   Hence, from the definitions of average oil temperature rise in Equation (3.2), we can derive following relation

$$\theta_{\mathrm{OLW}} = 2(\Delta\theta_{\mathrm{Omax}} - \Delta\theta_{\mathrm{O}}) \tag{3.6}$$

For a multi-step load cycle analysis with a series of short time intervals of 15 minutes, it is important to calculate top oil and winding hot spot temperatures for every time step to understand transformer thermal behavior. The hot spot and top oil temperatures calculated at every load step are derived from average winding and oil temperatures at every load step as discussed in following subsections.

3.1.2.2 Calculation of average oil temperature

For a given load interval, the ambient temperature is assumed constant. Hence at the end of every load interval, the average oil temperature is the sum of the average oil temperature rise and the ambient temperature.

By IEEE C57.91, the effect of variable ambient temperature is considered as follows:

1. For ambient temperatures that increase during the load cycle, the instantaneous ambient should be used.
2. For decreasing ambient temperatures, the maximum ambient during a long prior cycle of about 12 hours should be used.

This effect is taken into account while calculating the transformer temperatures in this analysis.

The top oil temperature rise at a time step after a step load change is given by an exponential expression in IEEE C57.91. Since the vertical oil gradient is assumed as a straight line in the model, this equation can be used for the calculation of average oil temperature rise over ambient temperature for every step load change. The exponential equation is given as follows:

$$\Delta\theta_{\mathrm{O}} = (\Delta\theta_{\mathrm{Ou}} - \Delta\theta_{\mathrm{Oi}})(1 - e^{\frac{-t}{\tau_O}}) + \Delta\theta_{\mathrm{Oi}} \tag{3.7}$$

where,

$\Delta\theta_{\mathrm{O}}$ is the average oil rise over ambient in °C,

$\Delta\theta_{\mathrm{Ou}}$ is the ultimate average oil rise over ambient temperature for load L in °C,

$\Delta\theta_{\mathrm{Oi}}$ is the initial average oil rise over ambient temperature for time $t = 0$ in °C,

τ_{O} is the oil time constant of the transformer for any load and for specific temperature differential between the ultimate top oil rise and the initial top-oil rise.

For a multi-step load analysis, with short time intervals, Equation (3.7) is used for each load step. The initial average oil temperature rise for a given load step is the ultimate average oil rise calculated at the end of the previous load step.

The ultimate average oil rise is calculated as follows:

$$\Delta\theta_{\mathrm{Ou}} = \Delta\theta_{\mathrm{OR}} \left[\frac{K^2 R + 1}{R + 1} \right]^n \tag{3.8}$$

where,

$\Delta\theta_{\mathrm{OR}}$ is the average oil rise over ambient at transformer rated kVA in °C,

K is ratio of ultimate load L to rated load in per unit,

R is the ratio of load loss to no load loss at transformer rated kVA,

n is an empirically derived exponent used to calculate the variation of average oil temperature with changes in load. The value of n is selected for each mode of cooling to approximately account for effects of change in resistance with change in load from Table 4 in IEEE C57.91. For natural oil cooling its value is 0.8.

3.1.2.3 Calculation of oil time constant

The exponential heating Equation (3.7) is based on the average temperature rise of the lumped mass. The time constant at rated kVA load is available from the heat run test report of the transformer and is provided by SRP for all transformer sizes.

The average oil time constant of a transformer for any load L and for any specific temperature differential between the ultimate top oil rise and the initial top oil rise in hours is given as follows:

$$\tau_O = \tau_R \frac{\frac{\Delta\theta_{\mathrm{Ou}}}{\Delta\theta_{\mathrm{OR}}} - \frac{\Delta\theta_{\mathrm{Oi}}}{\Delta\theta_{\mathrm{OR}}}}{\left[\frac{\Delta\theta_{\mathrm{Ou}}}{\Delta\theta_{\mathrm{OR}}}\right]^{\frac{1}{n}} - \left[\frac{\Delta\theta_{\mathrm{Oi}}}{\Delta\theta_{\mathrm{OR}}}\right]^{\frac{1}{n}}} \tag{3.9}$$

Where,

τ_R is oil time constant in hours at rated kVA with initial average oil temperature rise of 0°C.

This completes the calculation of average oil temperature for each load step.

3.1.2.4 Calculation of average winding temperature

The average winding temperature is calculated by adding the average winding temperature rise to the ambient temperature at the end of each load step.

Since the winding temperature rise is assumed to be a straight line in the model, the equation used for the winding hot spot rise can be used for average winding temperature rise calculations. The procedure in IEEE C57.91 considers an exponential equation similar to Equation (3.7), which uses initial and ultimate winding average temperatures in the given load step, and the winding time constant at the average winding temperature location. However, this information is not available in the heat run test reports for SRP transformers.

The alternative is to use the average winding temperature and copper to oil gradient. The equation for the average winding temperature rise at any load L is derived from Equation (17) in IEEE C57.91 as follows:

$$\Delta\theta_{\mathrm{W}} = \Delta\theta_{\mathrm{O}} \ + \theta_{\mathrm{WO}} K^{2m} \tag{3.10}$$

where,

$\Delta\theta_{\mathrm{W}}$ is the average winding temperature rise at load L in °C,

$\Delta\theta_{\mathrm{O}}$ is the average oil temperature rise at load L in °C calculated in Section 3.1.2.2,

θ_{WO} is the copper to oil gradient of the transformer in °C at transformer rated kVA,

m is empirically derived exponent used to calculate the variation of $\Delta\theta_{\mathrm{W}}$ with changes in load. The value of m is selected for each mode of cooling to approximately account for effects of changes in resistance and oil viscosity with changes in load from Table 4 in IEEE C57.91. For natural oil cooling its value is also 0.8.

3.1.2.5 Calculation of top oil temperature

The top oil temperature is calculated by adding top oil temperature rise to the ambient temperature for each load step.

The top oil temperature rise is calculated from the definition of the vertical gradient of temperature as per Equation (3.6). The vertical gradient of temperature is normalized to the step load L by multiplying with factor K for the given load step and added to the average oil temperature rise at load L, which is obtained in Section 3.1.2.2. Hence, the equation for top oil temperature rise for load L is as follows:

$$\Delta\theta_{\mathrm{Omax}} = \Delta\theta_{\mathrm{O}} \ + K\frac{\theta_{\mathrm{OLW}}}{2} \tag{3.11}$$

where,

$\Delta\theta_{\mathrm{Omax}}$ is the top oil temperature rise at load L in °C,

θ_{OLW} is vertical gradient of transformer at rated kVA in °C,

3.1.2.6 Calculation of winding hot spot temperature

The winding hot spot temperature is calculated by adding the winding hot spot temperature rise to the ambient temperature for the given load step.

Equation (3.4) in Section 3.1.2.1 gives winding hot spot temperature rise at the rated load. The winding hot spot temperature rise at any load L is obtained by finding the top oil rise and copper to oil gradient at load L. The top oil temperature rise at load L is obtained from Section 3.1.2.5. The copper to oil gradient θ_{WO} needs be modified to take into account the effect of change in load.

The equation for the winding hot spot rise at any load L from the top oil rise is as follows [58]:

$$\Delta\theta_{\mathrm{Wmax}} = \Delta\theta_{\mathrm{Omax}} + \theta_{\mathrm{WOL}} H \tag{3.12}$$

where,

$\Delta\theta_{\mathrm{Wmax}}$ is winding hot spot temperature rise at load L in °C,

H is the hot spot factor,

θ_{WOL} is copper to oil gradient at load L obtained as follows [58]:

$$\theta_{\mathrm{WOL}} = \theta_{\mathrm{WO}} K^{2m} \tag{3.13}$$

This finishes the development of thermal model of the distribution transformer from the heat run test data.

3.2 Calculation of Loss of Life

The per unit insulation life curves of the transformer are used for the calculation of loss-of-life. As per IEEE C57.91, loss-of-life is the aging of transformer insulation at the reference hot spot temperature. Hence, the per unit loss of life is calculated by following equation:

$$Per\ Unit\ Loss\ of\ Life = \frac{1}{Per\ Unit\ Insulation\ Life} \tag{3.14}$$

The thermal model of the distribution transformer from Section 3.2 provides the hot spot winding temperature of the transformer at every 15 minute time interval. This temperature is used in the calculation of the per unit insulation life of the transformer using Equation (2.1), in turn, giving the per unit loss of life. The total loss-of-life (in hours) in the year 2017 is calculated by adding loss of life for all 15 minute time intervals. Since the transformer unit life is 180,000 hours, the insulation system life is calculated as follows:

$$Insulation\ Life\ (hours) = \frac{180,000}{Per\ Unit\ Loss\ of\ life} \tag{3.15}$$

A flowchart summarizing the calculation of temperatures and loss of life is shown in Figure 17.

3.3 Calculation of Electrical Losses

To determine the financial benefits of ester filled transformers requires a comparison of the total power losses with those from the mineral oil unit. From the heat run test

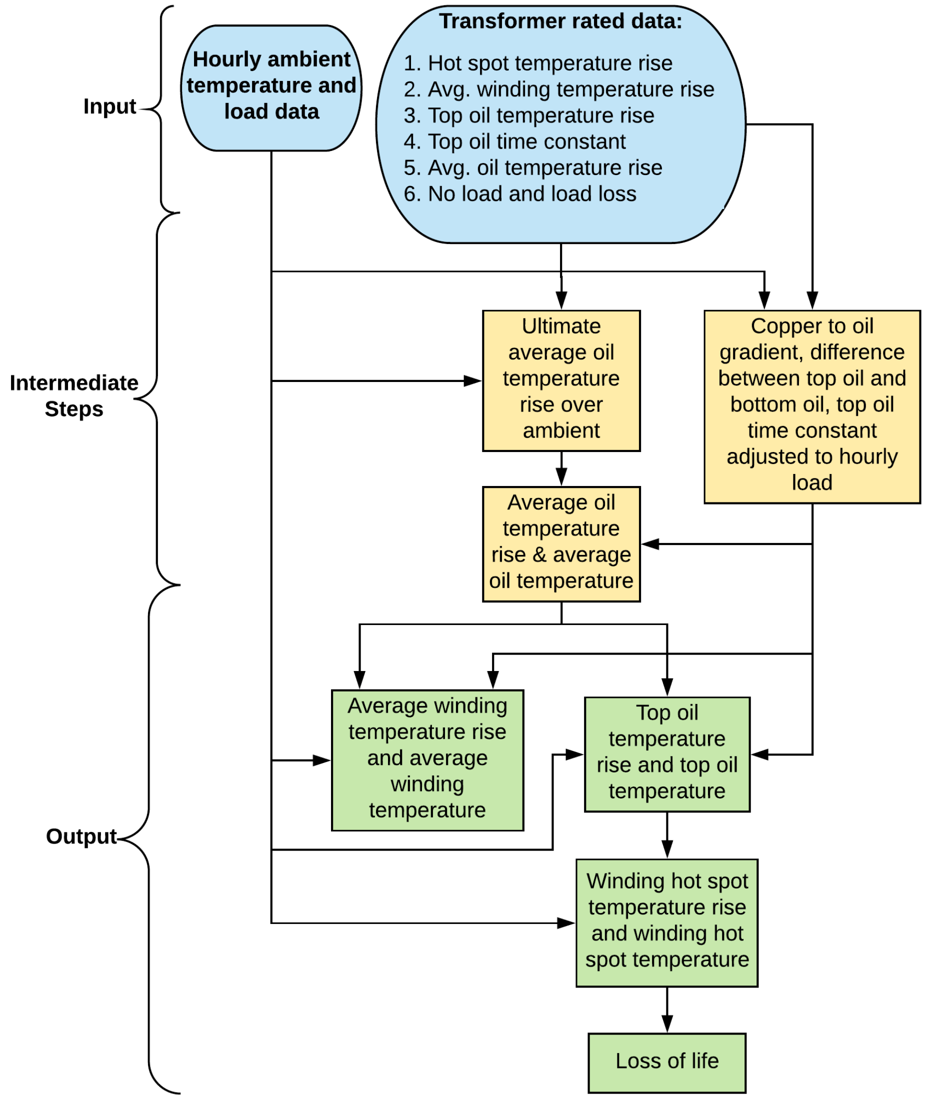

Figure 17. Flowchart for calculation of temperatures and loss of life.

data, the core and copper losses of the transformer at rated load and test ambient temperature of 30°C are available. The core losses of the transformer are independent of temperature and loading. However, I^2R and stray load losses vary with temperature and load.

IEEE C57.12.90 provides temperature correction for load losses. The I^2R component of load losses increases with winding temperature. The stray loss component diminishes with winding temperature. Since separate information on stray load and I^2R losses is unavailable, all losses are treated as the I^2R losses in this analysis. The load losses known at test temperature T_{m} are converted to another winding temperature T using the following equation:

$$P(T) = P(R)\,\frac{T_{\mathrm{k}} + T}{T_{\mathrm{k}} + T_{\mathrm{m}}} \tag{3.16}$$

where,

$P(T)$ is the load loss at average winding temperature T in °C,

$P(R)$ is the load loss measured at the test temperature T_{m} in °C at rated load and,

T_{k} is 235°C for copper conductors [58].

Now, the effect of change in load is considered by the factor K as follows:

$$P(K) = P(R)K^2 \tag{3.17}$$

where,

$P(K)$ is loss at load ratio K.

Thus, Equations (3.16) and (3.17) are combined to take into account the effect of change in temperature and load on the load losses as follows:

$$P(T,K) = P(R)\frac{T_{\mathrm{k}} + T}{T_{\mathrm{k}} + T_{\mathrm{m}}}K^2 \tag{3.18}$$

where, $P(T,K)$ is the load loss at any average winding temperature T in °C with per unit load ratio K.

This calculation is performed at every load step. Then the average load loss for the year is calculated. It is the average of load losses of all the load steps in a year.

3.4 Results for SRP Load Profiles

Load profiles for the SRP distribution transformers are analyzed with the transformer mathematical model developed in Section 3.1. Loss of life and average losses are calculated using the methodology described in Sections 3.2 and 3.3 respectively. The load profile with 15 minute time interval has 35,040 load data points for the year 2017. The average load of a transformer (%) is the average of all data points divided by the transformer rating expressed as a percentage. Peak load of a transformer (%) is the peak load of the transformer divided by the transformer rating expressed as a percentage. It is observed that the SRP load profiles can be categorized into two types based on their average and peak loads for the year.

1. Type 1: Load profiles having an average load in the range of 40%-50% and peak load of 160%-190%. These transformers have high average and peak loads.
2. Type 2: Load profiles having an average load in the range of 20%-30% and peak load of 120%-150%. These transformers have low average and peak loads.

The Type 1 load profiles are observed among 25, 50, 75, and 100 kVA transformer units. Type 2 load profiles are observed only for 25 kVA and 100 kVA transformer units. Based on the thermal models of the transformer load profiles giving top oil temperature, hot spot temperature, loss of life, and electrical losses, two different FR3 filled transformer designs are suggested for the two types of load profiles.

3.4.1 Conventional Load Design of FR3 Filled Transformer for Type 1 Profiles

The Type 1 load profiles have substantially high average and peak load throughout the year. Figures 18 and 19 show hot spot and top oil temperatures respectively over the year for 50 kVA Unit No. BC140109.

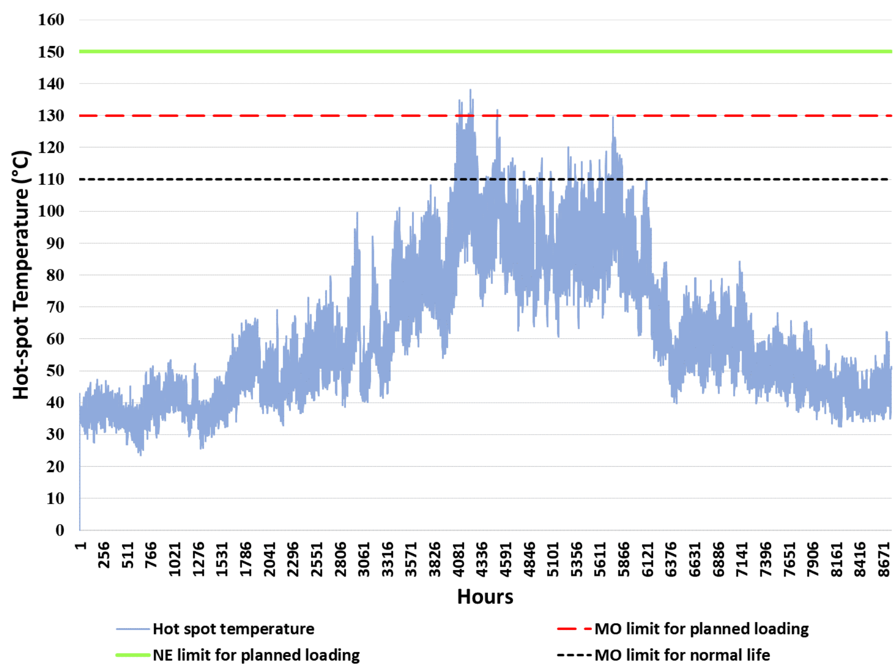

Figure 18. Hot spot temperature of 50 kVA unit BC140109 for year 2017.

Similarly, the Type 1 load profiles of five different units for each of 25, 50, 75 and 100 kVA rating are analyzed for the hot spot and top oil temperatures and the results are tabulated in Table 7. These temperatures are obtained using temperature rise formulae given in Section 3.2.2.

The suggested maximum hot spot and top oil temperatures with normal life and

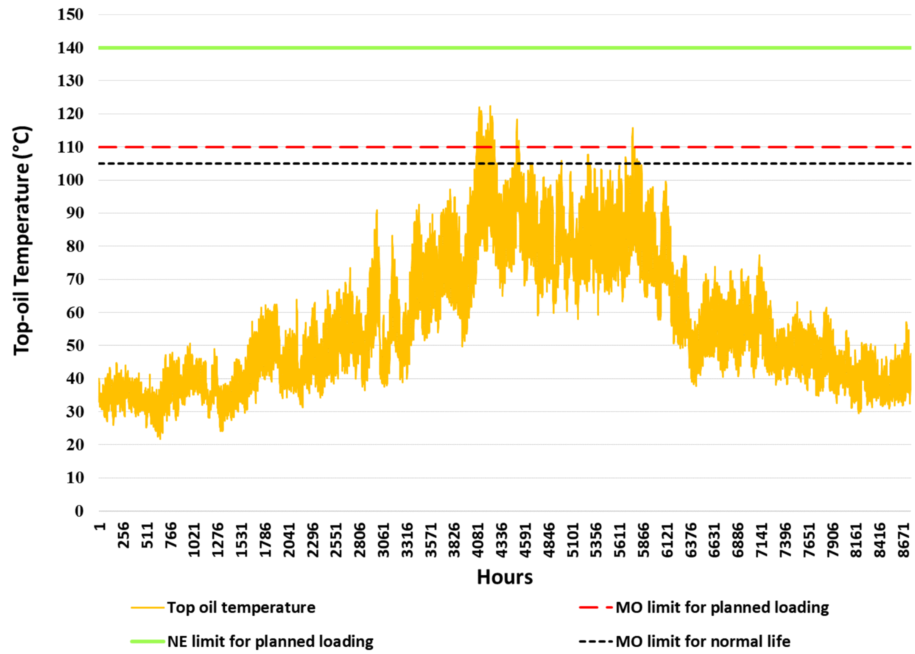

Figure 19. Top oil temperature of 50 kVA unit BC140109 for year 2017.

with planned loading beyond nameplate rating as per IEEE standards are indicated in Table 8.

Temperatures reaching above maximum limits with planned loading beyond nameplate rating for 15 of 20 of these highly loaded units demonstrate that the mineral oil filled transformers are working under high risk of insulation failure. MO top oil temperatures exceeding 110°C could lead to permanent thermal breakdown of the molecular carbon structure and therefore reduce the breakdown voltage. By contrast, it is observed that these temperatures are well within the limits of the NE-based insulation system. Thus, replacement of such highly loaded units with equivalent size NE filled units with conventional loading (65°C AWR) could be a most suitable alternative. This design would increase the safety of transformer operation by reducing

Table 7. Temperature Rise Results for Type 1 Load Profiles

kVA Rating	Unit No.	Avg. Load (%)	Peak Load (%)	Top Oil Temp. (°C)	Hot spot Temp. (°C)
25	BB231163	40.0	165.6	93.6	116.0
	CF210421	38.4	177.0	89.7	115.1
	CF291011	51.2	165.6	103.1	128.3
	YG170604	43.5	188.9	98.4	124.9
	YG200208	45.6	188.1	85.0	114.1
50	AF060228	45.9	166.4	123.9	138.7
	BC140109	63.6	156.5	122.4	138.1
	YF121507	47.0	161.7	114.7	128.6
	ZB351611	40.4	165.1	117.1	130.8
	ZD270824	46.1	158.4	122.2	139.1
75	AB330208	49.2	163.2	124.0	144.6
	AG111605	47.5	170.4	134.1	160.4
	YF121505	39.2	145.6	108.7	124.5
	YF250212	56.8	162.8	122.6	142.8
	ZC320607	41.8	156.2	113.0	130.7
100	AE340352	60.5	198.4	173.7	198.4
	YE061620	41.0	142.8	117.9	130.6
	YE231414	42.4	147.9	126.1	141.3
	YH170507	50.7	150.8	128.9	144.4
	ZG030605	41.1	139.1	122.4	137.9

Table 8. IEEE C57.154, C57.91 Hot spot and Top Oil Temperature Limits

Fluid	Thermal Class		Top Oil Temp. (°C)		Hot spot Temp. (°C)	
	Liquid	Solid	Normal Life	Planned Load	Normal Life	Planned Load
MO	105	120	105	110	110	130
NE	130	140	130	140	130	150

the risk of overheating and fire. Further, per Equation (2.1) it extends the insulation life by 7.4 times that of the mineral oil units.

3.4.2 Sustainable Peak Loading of FR3 Filled Transformer for Type 2 Profiles

Transformers are not built only to match the temperature limits. There are other restrictions such as limitation of total losses which determine its construction. From the experience of transformer manufacturers and SRP engineers, the additional 20°C in temperature rise limits for NE filled transformers in the range of 15 kVA to 150 kVA may allow for approximately 35% to 50% of extra power with the same hardware. When this peak loading is set to match the capacity of the next nominal rating, it is called the "Sustainable Peak Loading" option as discussed in Section 2.3.2.

Sustainable peak loading of transformers is possible when the transformer top oil and hot spot temperatures are lower than the suggested limits for the paper immersed in the NE. For the load profiles of 25 kVA and 100 kVA mineral oil Type 2 units, the mathematical models are developed with next lower sizes of 15 kVA and 75 kVA FR3 filled units, respectively. The 15 kVA and 75 kVA FR3 filled transformer heat run test data at the rated load are obtained from Cargill Inc. [59]. These data are summarized in Table 9.

For the sustainable peak loading of FR3 filled transformer, hot spot and winding temperature rise, loss of life, and electrical losses are calculated from transformer rated data and SRP load profiles. The results are tabulated in Table 10. It is observed that that 15 kVA and 75 kVA nominal rated NE filled units (65°C AWR) can serve loads of 25 kVA and 100 kVA MO filled units respectively without exceeding temperature limits in addition to giving insulation life extension benefit of about 5 times that of a

MO unit. It is also observed that there is a substantial savings in the total energy dissipation over the course of the year because of lower no load losses of smaller sized units being more significant than load losses during higher load operation. Thus, for the transformers with lower average loading, typically below 30% and peak loading of 150%, as observed in the above two cases, sustainable peak loading is possible without additional loss of life.

The following are the advantages of sustainable peak loading:

1. Lower initial investment for transformer purchasing,
2. Improved efficiency of the system, and
3. Equal or lower loss of life.

Table 9. Summary of Temperature Rise Test Results for 15 and 75 kVA NE Filled Transformers (at transformer rated kVA) [59]

Transformer Rating	**15 kVA**	**75 kVA**
Top oil rise over ambient (°C)	34.1	48.2
Copper to oil gradient (°C)	11.4	9.9
Top oil time constant (hours)	5.3	5.8
No load loss (W)	47	141
Load loss (W)	208	646

3.5 Conclusion

The development of a transformer mathematical model from the heat run test results provides a technical basis for analyzing FR3 filled transformers. The yearlong load profiles of SRP distribution transformers showed two trends: 1) transformers with

Table 10. Comparison of Results for Type 2 Mineral Oil Units with Sustainable Peak Loaded FR3 Units

Parameter	**Unit YH340952**		**Unit AG201314**	
	With MO	**With NE**	**With MO**	**With NE**
kVA Rating	**25**	**15**	**100**	**75**
Avg. load (%)	9.7	16.1	20.9	27.9
Peak. load (%)	72.2	120.3	143.7	191.5
Top oil Temp. (°C)	58.9	63.3	69.4	77.0
Hot spot Temp. (°C)	62.9	72.3	83.5	105.4
Insulation Life (years)	16.5	94.9	3.0	16.8
No load Loss (W)	69	47	194	141
Avg. load Loss / Year (W)	4.9	9.5	54.6	73.5
Energy Dissipated / Year (kWh)	647.5	495.2	2177.9	1878.6

high average and peak loading, and 2) transformers with low average and peak loading. These load profiles are then analyzed for oil temperatures, hot spot temperatures, loss of life and electrical losses using a spreadsheet program.

A new way of sizing ester filled transformers based both on average and peak load, instead of only peak load, called “Sustainable Peak Loading” showed smaller size transformers can handle the same yearly peak loads while keeping superior insulation lifespan. It is additionally possible to have a reduction in total energy dissipation over the year. This proposed approach fits for units having a low yearly average demand.

Transformer units, which already have high average loads, are not suitable for such an approach. However, the use of natural ester filled units in such cases, keeping the same nominal rating, showed longer estimated life expectation.

Chapter 4

COST BENEFIT ANALYSIS

An economic analysis of the FR3 filled transformer quantifies its benefits, helping utilities to assess the profitability of the projected investment. This chapter discusses the methodology adapted to calculate the benefits of increased transformer life from its increased insulation life. The life extension benefits of conventional load design are evaluated by performing a net present value (NPV) cost benefit analysis. Benefits of sustainable peak loading are analyzed by comparing its electrical losses and initial cost to the mineral oil filled unit.

4.1 Estimation of the Transformer Life Extension from its Insulation Life Extension

An estimation methodology has been applied to convert the reduction of degradation rate of paper insulation in NE into transformer life extension. The typical MO transformer lifespan defined in [1] is 180,000 hours or 20.55 years. This equals to transformer failure rate of 4.87% per year calculated as follows:

$$Percentage\ transformer\ failures\ per\ year = \frac{100}{20.55} = 4.87\% \tag{4.1}$$

Thus, from the total fleet of transformers, 4.87% of transformers fail and need replacement every year. But, not all transformer replacements are due to transformer failures. After consultation with SRP planning engineers, three reasons for the replacement of a transformer unit are considered for the analysis: 1) random causes, 2) increase in load demand, and 3) failure of a transformer unit as listed in Table 11.

Table 11. Improved Replacement Rate Estimation

Transformer Replacement Motivation	**Percentage of Cases (%)**	**NE Impact on Failure**	**Rate of Replacement with MO**	**Rate of Replacement with NE**
Formula	**p**	**q**	**p(4.87%)**	**p(1-q)(4.87%)**
Random	5%	0%	0.24%	0.24%
Increase in demand	15%	50%	0.73%	0.37%
Transformer failure	80%	See Table 12	3.89% (‘x’)	2.48% (From Table 12)
Total	**100%**	**-**	**4.87%**	**3.09%**

From the SRP transformer failure cases in the last 20 years, it is observed that 5% of the transformers are replaced due to random aspects, such as a repositioning of the unit or a car crash. There would be no impact by the use of FR3 filled transformers on number of transformer replacements for such occurrences. Thus, the rate of replacement of MO and NE filled transformer units due to random causes remains same and is five percent of 4.87% which is 0.24% replacements per year.

The second reason for replacing a transformer is an increase of load demand, which has been observed in 15% of the cases. As the use of NE liquids does increase the peak loading capacity, it has been estimated that only 50% of these transformers would require replacement since the increased load requirement could be carried by the increased thermal capability of the NE fluid. Thus, fifteen percent of 4.87% that is 0.73% of the replacements are due to increased load demand with MO unit. Replacements with NE filled units are seven and a half percent of 4.87% that is only 0.37%.

The third reason of replacement is the failure of the transformer unit itself. In

Section 2.3.1, it was shown that natural ester filled transformers can improve the insulation life by 7.4 times that of the mineral oil unit. However, end-of-life of insulation is one possible failure mode. There are various other reasons for the failure of a transformer. According to CIGRE Technical Brochure 642 [60], from a population of 964 major failures, the failure modes can be classified as shown in Figure 20.

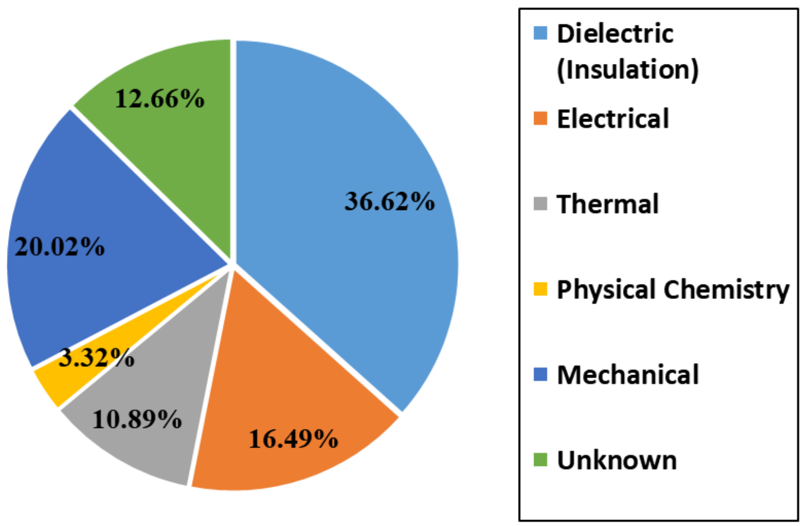

Figure 20. Transformer failure modes [60]

Table 12 calculates the beneficial impact of using NE fluid in reducing the degradation rate for each transformer failure mode. A consensus between SRP, Cargill Inc. and ASU was reached regarding the NE impact (in %) on the transformer failure modes and the reduction in transformer degradation rate with NE. This facilitated the calculation of the rate of transformer failure with NE from the rate of transformer failure with MO.

It is estimated that the NE fluid improves the dielectric (paper insulation) failure

Table 12. Estimated Transformer Failure Rate for Failure Modes

Failure Modes	**Percent of Failure**	**NE Impact on Failure**	**Reduced Degrad-dation Rate**	**Rate of Failure with MO**	**Rate of Failure with NE**
Formula	**y**	**a**	**b**	**c = xy**	**c(1-a)+ac/b**
Dielectric	36.62%	85%	7.4	1.43%	0.38%
Electrical	16.49%	0%	0	0.64%	0.64%
Thermal	10.89%	100%	4	0.42%	0.11%
Physical Chemistry	3.32%	75%	2	0.13%	0.08%
Mechanical	20.02%	0%	0	0.78%	0.78%
Unknown	12.66%	0%	0	0.49%	0.49%
Total	**100%**	**-**	**-**	**3.89%**	**2.48%**

Note: x is from Table 11.

by 7.4 times in 85% of the failure cases. The remaining 15% of dielectric failures may be due lightning or partial discharge which are unavoidable even with NE fluids. The electrical modes of failure include short circuit, open circuit, and poor electrical contact. Use of NE fluid will not change failures due to these reasons. Thermal failure mode includes hot spot and overheating of transformer. It is assumed that NE fluid improves the thermal performance of transformer by four times in 100% of the cases. Physical chemistry of insulating fluid affects the transformer life. Contamination by moisture and sludge precipitate causes breakdown of the transformer. Natural esters have better chemical properties than mineral oil fluids and hence it is estimated that NE fluids can improve the degradation rate by 2 times in 75% of cases. In the remaining 25% cases, corrosion of transformer tanks can cause its failure which is unavoidable even with the use of NE fluids. Also, there is no improvement in the mechanical failures like bending, loosing, vibration, and displacement of transformer components with use of NE fluids. NE fluids do not improve failures due to unknown failure modes. In summary, NE fluids improve the failure rate due to dielectric, thermal, and physical failure modes. Thus the failure rate with MO is eighty percent of 4.87% which is 3.89% while that with NE fluid is 2.48% as calculated by the formulae included in Table 12.

The improved replacement rates due to all the three reasons are summarized in Table 11. The final failure rate percentages are 4.87% for mineral oil filled units and 3.09% for natural ester filled units. This shows the life expectancy of the transformers is increased by a factor of 1.58 times (4.87% / 3.09%) by using natural ester filled units. This is equivalent to the 32.38 years of estimated life for a natural ester filled transformer while that for mineral oil filled transformer is 20.55 years. The financial benefits are calculated using these values of transformer lifetime.

4.2 Net Present Value Analysis of Conventional Load Design for Type 1 Load Profiles

The net present value or discounted cash flow method [61] takes into account the time value of money. It measures the profit by subtracting the present value of cash outflows from the present value of cash inflows over a period of time. NPV can be calculated by considering different time horizons. In this analysis, NPV is first calculated by considering the time horizon as the lifetime of the FR3 transformer. NPV is also calculated by considering the time horizon as perpetuity in which the cash flows for mineral oil and FR3 units are assumed continuous until their respective end-of-life periods.

The net present value is calculated using following formula:

$$Net\ Present\ Value = \sum_{t=0}^{N} \frac{R}{(1+d)^t} \tag{4.2}$$

where,

t is the time of cash flow from 0 to N years,

d is the discount rate, that is, the return that could be earned per unit of time on an investment with similar risk, and

R is the net cash flow which is the difference between cash inflow and outflow.

The cash outflow is the time value of the sum of the initial cost and the installation cost of the transformer. The cash inflow is the time value of the salvage cost of transformer calculated using initial cost, installation cost and salvage value. The time value of the money is considered by using the inflation rate ($i\%$). Following are the steps used for the NPV calculation:

1. Calculate the inflation factor and the discount factor using the inflation rate and the discount rate for each time period as follows:

$$Inflation\ Factor(IF) = \frac{1}{(1+i)^t} \tag{4.3}$$

$$Discount\ Factor(DF) = \frac{1}{(1+d)^t} \tag{4.4}$$

2. Calculate cash inflow considering first cost (FC), salvage value (SV) and inflation factor as shown below:

$$Cash\ Inflow = (FC - \frac{(FC - SV)^t}{N})IF \tag{4.5}$$

where,

first cost (FC) is the sum of the purchase cost and the installation cost of the transformer.

3. Calculate cash outflow considering the first cost and the inflation factor as follows:

$$Cash\ Outflow = (FC)(IF) \tag{4.6}$$

4. Calculate R by subtracting cash inflow from the cash outflow.

$$R = Cash\ outflow - Cash\ inflow \tag{4.7}$$

5. Calculate the net present value using R and the DF as follows:

$$Net\ Present\ Value = \sum_{t=0}^{N} R(DF) \tag{4.8}$$

Table 13 summarizes asset and financial parameters used for the analysis.

Table 13. Asset and Financial Parameters

Parameter	**Value**
Salvage Value (as % of initial cost)	20%
Installation Cost/ Transformer ($US)	850
Discount Rate (%)	5.91
Inflation Rate (%)	1.18

The extension of life expectation of the NE transformers from Section 4.1 can be applied for the calculation of a NPV for conventional load design for Type-1 load profiles. The difference between the net present values for the FR3 filled transformer

Table 14. Net Present Value (NPV) Savings

Transformer Rating (kVA)	**Transformer Cost ($US)**		**NPV Savings ($US) Per Transformer When Horizon is**	
	MO	**NE**	**Perpetuity**	**Transformer Life**
25	2,333	2,726	862	378
50	3,293	3,759	1,144	513
75	4,175	4,651	1,459	718
100	5,537	6,123	1,853	900
167	8,267	9,111	2,603	1,212

and the mineral oil unit gives the NPV savings for each size. Using the asset and financial parameters, the NPV savings for each transformer size is calculated with the cost averaging for different manufacturers for MO and NE filled units. Two cases of NPV savings are presented in Table 14 since financial analysis can be viewed by different timeframes. NPV in perpetuity is defined as continuously over time while NPV in transformer life horizon is limited to the life expectancy of the NE transformer. Results summarized in Table 14 show that regardless of higher initial cost of NE transformers, positive NPV savings are achieved in each size irrespective of the timeframe considered. NPV calculated with the timeframe of transformer life horizon is more likely the best representation of savings as it considers the lifetime of NE filled units. The analysis shows that the conventional load design of FR3 filled transformer for Type 1 load profiles is a profitable investment.

4.3 Cost Benefits of Sustainable Peak Loading for Type 2 Load Profiles

Transformers are some of the most significant investments utilities make. Minimizing the investment and increasing the utilization of the assets is an important driver for any company. However, eventual overloading periods may result in an increase of the total dissipated losses. Conversely, using a larger transformer just to handle peak loads adds higher no load losses to the network, which is a constant cost.

Finding the right balance is not only dependent on the cost, but also on the financial strategy of each company. While some may prioritize the long term advantage of reducing the total losses, others may prefer to minimize the initial investment. The situation where the best option is very clear is when the yearly average loading of the transformers is low. For values in the range of 20%-30%, the reduction of the no load losses is expected to compensate for the increase of the load losses during the peak period.

In Table 15, cost benefits for the two real cases discussed in Section 3.4.2 with sustainable peak loading for Type 2 load profiles are presented. Despite the one year demand curve showing a peak value that crosses the rated capacity of the chosen transformer, the average loading is about 20% (refer to Table 10). The typical evaluation of the losses capitalization takes different values for each of the losses, for taking in consideration the loading variation. For this table, a weighted cost datum for total losses of \$6.38/W is used. The calculated "Total Cost" gives just a partial view of the total cost of ownership, including the initial cost of the transformer and the capitalized losses. It is observed that the sustainable peak loading option can have significant cost savings due to lower initial costs and lower no load losses.

This design could also offer insulation life extension benefits in addition to lower

Table 15. Cost Savings With Sustainable Peak Loading

Parameter	Unit YH340952		Unit AG201314	
	With MO	With NE	With MO	With NE
kVA Rating	**25**	**15**	**100**	**75**
Total Cost of Losses ($US)	472	361	1,586	1,368
Transformer Cost ($US)	2,333	1,635	5,537	4,651
Total Cost ($US)	2,805	1,996	7,123	6,019
Savings ($US)	**809**		**1,104**	
% Savings	**28.8%**		**15.5%**	

initial costs and electrical losses (as observed in this case from Table 10). The NPV analysis as per Section 4.2 can be applied to quantify life extension benefits. However, for a conservative analysis, the life extension benefits are excluded and cost savings only due to the other advantages are presented.

4.4 Conclusion

A practical estimate of transformer life extension of 1.5x for NE filled units is obtained from the theoretical insulation life extension benefit of 7.4x. This life extension benefit of 1.5x is applied to transformers having Type 1 load profiles. The savings in the net present value of NE filled units with conventional load design for such profiles show that the investment in NE filled units is beneficial for SRP.

Sustainable peak load design for Type 2 load profiles can save upto 30% in the total ownership cost of the transformer.

Chapter 5

CONCLUSIONS AND FUTURE WORK

5.1 Conclusions

Literature analyzing the properties and testing of FR3 brand natural ester filled distribution transformers was reviewed. It was found that FR3 fluid has better physical, chemical and thermal characteristics making them an alternative to conventional mineral oil. Experimental as well as in-service testing of FR3 filled units and satisfactory performance feedback from surveyed utilities show that FR3 fluid is a reliable technology. The per unit insulation life curve for FR3 filled transformers showed that cellulose paper insulation in FR3 fluid can have life extension up to 7.4 times that of the mineral oil. In other words, FR3 filled transformers, having a high thermal class of solid and liquid insulation, can operate at temperatures up to 20°C higher than mineral oil equivalents; thus, holding additional loading capacity without losing life expectancy. While many of the early adopters switched to natural esters because of fire safety and environmental advantages, today many utilities are focusing on the thermal advantages and higher thermal class of the insulating fluid and insulation system to gain cost and operational benefits. Based on different temperature rise limits, FR3 filled transformers can be implemented with three different loading designs: 1) conventional loading, 2) compact loading, and 3) sustainable peak loading. Suitability of a design depends on the nature of the load profile and cost saving priorities of the utility.

From the detailed study of the SRP distribution transformer load profiles in this work, following conclusions can be drawn:

- The SRP load profiles can be categorized into two types: 1) Type 1 load profiles with high average and peak loads, and 2) Type 2 load profiles with low average and peak loads.
- The data-driven thermal mathematical models are developed for SRP transformers from the yearly load profiles and ambient temperature data of the city of Phoenix. The most suitable FR3 filled transformer designs are suggested based on these models.
- For the Type 1 load profiles, FR3 filled transformers having the same nominal rating as that of the MO unit, called conventional load design, showed 7.4 times longer life expectation. Commercial benefits of this design calculated using net present value method showed savings up to US$1200 per transformer unit.
- A new way of sizing ester filled transformers based both on average and peak load, instead of only peak load, called "Sustainable Peak Load Design" showed smaller size transformers can handle the same yearly peak loads while keeping superior insulation lifespan for the Type 2 load profiles. The total ownership cost savings for such designs are up to 30%.
- In Figure 21, a flow diagram is shown that helps provide guidance to the utility to decide which design capability might be most advantageous. In some cases more than one of these can apply. When the peak loading limit of a natural ester filled transformer is matched with its peak capacity, the thermal capability of the ester fluid handles the overload. Thus, a utility can gain a huge benefit by using a small size natural ester filled unit instead of a large size mineral oil unit.
- This research has analyzed various scenarios and designs to conclude that FR3

natural ester fluid is beneficial irrespective of the load profile. The benefit gained depends on the priorities and needs of the utility.

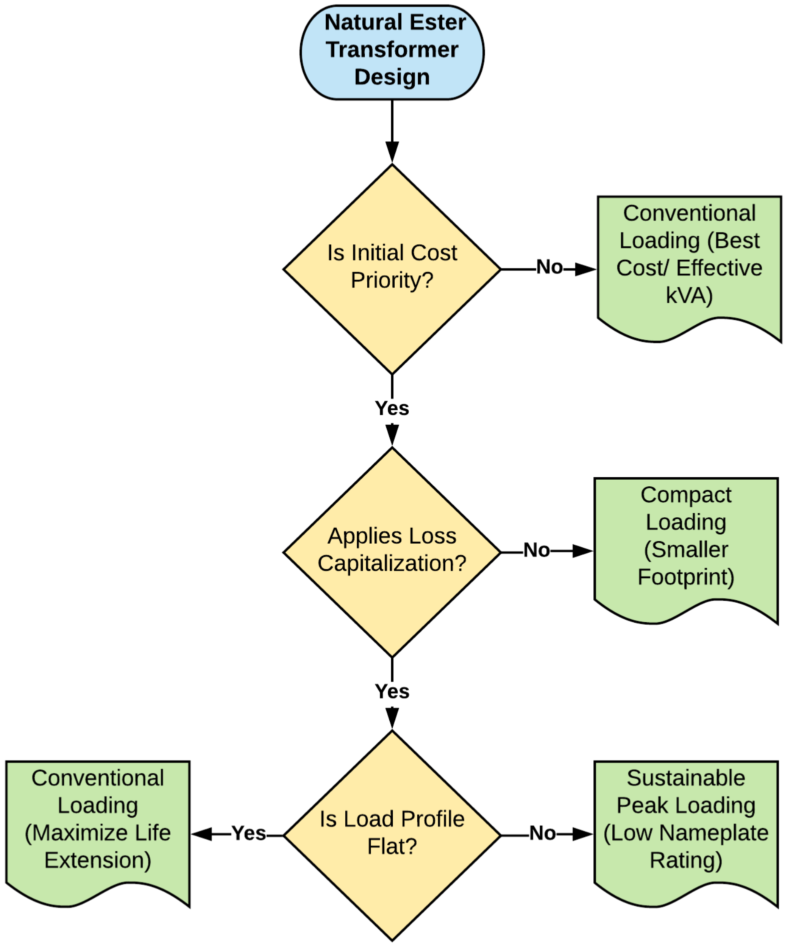

Figure 21. Guidance flow diagram for NE transformer design

5.2 Future Work

Thermal characteristics of the natural ester fluid are considered as the basis for the evaluation of the suitability of natural ester filled transformers to the SRP load profiles. The assessment can be improved further as follows:

- Thermal models of a sample of SRP transformers were developed. In order to estimate the suitability of FR3 filled units and the associated savings for the entire transformer fleet, it is necessary to analyze more transformer load profiles from different SRP distribution areas.
- Redesigning of the distribution system may be needed under downsizing of transformer units with FR3 fluid for Type 2 load profiles. This could involve modifications in protection system and installation of new secondary cables to ensure voltage regulation. Feasibility and costs associated with them needs to be studied in detail.
- Effects of high temperature operation of transformers on transformer bushings, gaskets, pressure relief valve, tap changer, insulation leads should be analyzed.
- Cost benefits using net present value method are presented in the analysis. Commercial evaluation could be extended by applying other methods such as internal rate of return, payback period, and benefit to cost ratio.

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