

Implementation of a Transformer Monitoring Solution Per IEEE C57.91-1995 Using an Automation Controller

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Implementation of a Transformer Monitoring Solution Per IEEE C57.91-1995 Using an Automation Controller

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Abstract—Distribution network operation periodically exceeds the loading capabilities of a substation power transformer. This can result in accelerated insulation aging and, in some cases, failure due to complete deterioration of the insulation. The solution described in this paper allows users to monitor critical substation transformer assets with a comprehensive transformer thermal model per IEEE C57.91-1995. An automation controller calculates the transformer loading capability rating. The substation operator may initiate control action based on a warning or alarm that the transformer is overloaded and in danger of excessive insulation aging or loss-of-life. The hottest-spot temperature of the transformer core is used as a basis for calculating the insulation aging acceleration factor and loss-of-life quantities. CenterPoint Energy intends to use this information to better manage their transformer assets and further utilize the power transformer near its actual thermal limits.

I. INTRODUCTION

CenterPoint Energy in Texas has distribution substations that deliver power to about 5 million customers. CenterPoint Energy is experiencing steady load growth, similar to other electric utilities across the United States. As the demand for electric power increases, the load on each distribution transformer also increases. Increased loads on distribution transformers can lead to additional mechanical wear and insulation deterioration of the transformer. Prolonged exposure to abnormal operating scenarios can also lead to transformer failures and distribution outages. Such failures may be prevented by using an effective real-time transformer monitoring solution for all distribution power transformers.

This paper outlines the need to monitor power transformers and discusses the methods used to monitor them. The paper presents the design and algorithm involved in implementing a transformer monitoring system using an automation controller. Laboratory tests were conducted for multiple operating scenarios, and the test results obtained are also presented.

II. NEED FOR POWER TRANSFORMER MONITORING

Large oil-immersed power transformers are the most expensive components of a transmission and distribution system and are considered the most valuable assets of an electric power utility system. System abnormalities, excessive loading, switching, and ambient conditions contribute to accelerated aging and can lead to the sudden failure of transformers [1]. Some of these failures can cause irreversible

damage to the transformer, thereby reducing its life. Power transformer failures can also lead to unplanned outages, which are not economical for the energy provider or the end user. A power failure causes multiple concerns for an electric utility, ranging from the replacement cost, the lead time to acquire a new transformer, the cost to schedule an outage and, in some cases, the environmental cleaning cost associated with an oil spill. As a result, it is imperative to continuously monitor these assets to ensure the effective and reliable operation of the electric power system.

III. TRANSFORMER LOADING CAPABILITY MONITORING METHODS

Protective relays are vital components required for fault detection and isolation of a transformer from a fault. In addition to these relays, other monitoring techniques are employed to adequately protect and monitor the transformer. Several transformer monitoring techniques have been developed for power transformer diagnosis [2]. The first technique is a time-based monitoring solution that involves performing various periodic offline tests to detect incipient problems. These offline tests can only be employed after a transformer outage or during scheduled maintenance. This method is expensive and labor intensive.

The present trend in the power industry is to move from time-based monitoring to a condition-based monitoring system. The condition-based technique can supply information about the transformer in real time and process the information to determine any corrective actions that may be needed to protect the transformer from overload. Condition-based monitoring contains a wide range of methods [3] [4] [5], including detecting partial discharges and insulation degradation, diagnosing winding deformations, monitoring dissolved gas evolution, and assessing the thermal condition of the transformer. The solution specified in this paper entails the use of an online monitoring solution based on assessing the thermal condition of the transformer.

The development of modern microprocessor-based relays with enhanced processing capacity enables relays to perform additional monitoring tasks while providing fault protection. With this enhancement, protective relays now can perform both protection and monitoring functionalities. The thermal model-based monitoring functions in protective relays are based on comparing the obtained transformer internal

temperatures and loss-of-life values with predefined limits. The relay is usually programmed to issue a warning if these limits are exceeded.

However, CenterPoint Energy needed a solution to provide a predictive loading assessment based on present loading conditions and ambient temperatures. In other words, it was essential to determine the loading capability of a transformer for the following two hours, providing the operator sufficient time to roll over loads and dispatch field personnel in case of an emergency. An automation controller was selected to perform these additional calculations.

The internal temperatures and aging of a transformer are calculated based on the equations given in IEEE C57.91-1995 [6]. The convergence process provided in IEEE C57.91-1995 is modified to determine the loading capability for the next two hours.

IV. SYSTEM OVERVIEW

Fig. 1 illustrates the transformer monitoring solution for a typical medium-voltage substation with two distribution transformers. The system design involves the use of data acquisition (DAQ) modules for each distribution transformer. The DAQ modules are configured to obtain the necessary data for monitoring their individual distribution transformers. An automation controller is used to perform the calculations necessary for estimating the loading capability of the transformer for the next two hours without exceeding the aging and thermal limits.

The DAQ modules are placed in standard National Electrical Manufacturers Association (NEMA) 4X outdoor enclosures in the substation yard next to the distribution transformers. Resistance temperature detectors (RTDs) from

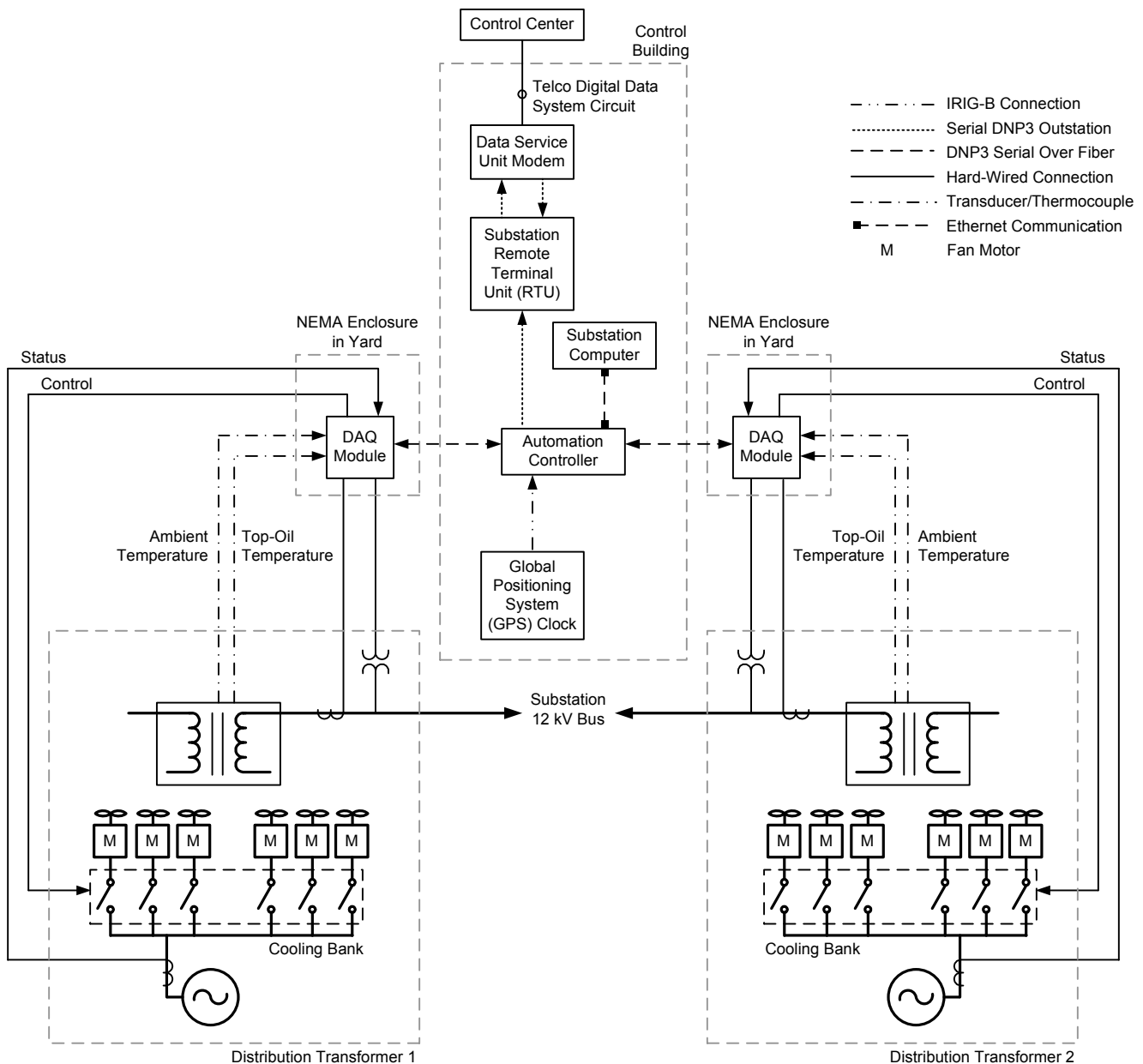


Fig. 1. Overall Transformer Monitoring System Architecture

the transformer and ambient temperature sensors are connected to the DAQ module analog input cards. These RTDs are used to measure the top-oil and ambient temperatures. In addition to these temperature analogs, the DAQ module receives the distribution transformer load current and voltage from the existing instrument transformers used in protection and metering circuits.

The DAQ modules are connected via a serial fiber-optic communications channel to the automation controller, which is located in the control building. The automation controller calculates the real-time transformer loading capability, insulation aging factor, and the hourly and daily loss-of-life values of the transformer. The substation computer is connected via an Ethernet local-area network (LAN) to the automation controller. The substation computer runs a custom human-machine interface (HMI) application that displays the real-time status of all the transformers in the substation (see Fig. 2). These data are transmitted to the utility control center via the modem connected to the substation RTU to provide remote monitoring capability for the power transformers at the substations. The automation controller is, furthermore, connected to a GPS-synchronized clock to provide time-synchronized measurements to the control center.

V. DETERMINATION OF LOADING CAPABILITY

IEEE C57.91-1995 is used to determine the loading capability of mineral-oil-immersed distribution and power transformers [6]. This standard provides the technique to calculate and determine the temperatures and aging factors of a transformer. It also presents a convergence algorithm that is used to determine transformer loading capability at a particular instant.

For the CenterPoint Energy transformer monitoring solution, it was vital to determine the permissible additional load that could be applied to the transformer at the present loading condition for a period of two hours without exceeding the thermal limits (two-hour rating). In essence, this calculation gives the operator time to roll over loads and

allocate and dispatch field personnel in the event that any of the substation transformers trip or fail. In addition to the two-hour rating, the algorithm also computes the temperature and aging limits of the transformer reached at the end of the two-hour interval.

The highest temperature point (hottest spot) in the transformer is a major factor that influences the aging of a transformer. In addition, the insulation aging also depends on the amount of moisture and oxygen in the transformer oil. Modern oil preservation systems minimize the effect of moisture and oxygen present in the oil. They isolate the hottest-spot temperature as the only major time-based factor in determining the insulation aging.

IEEE C57.91-1995 offers two methods of calculating the hottest-spot temperature. One method uses the transformer bottom fluid temperature, which requires the heat-run test data to have parameters such as the bottom fluid temperature at rated load and the bottom fluid rise over ambient temperature at rated load. These additional parameters may not be available for most transformers that have been in service for 30 to 40 years. The second method uses the winding hottest-spot rise over ambient temperature and assumes that the oil temperature in the cooling ducts is the same as the oil temperature in the tank top oil for all operating conditions.

A. Thermal Model

IEEE C57.91-1995 assumes the hottest-spot temperature consists of three components: ambient temperature, top-oil rise over ambient temperature, and winding hottest-spot rise over top-oil temperature. The hottest-spot temperature is calculated as:

$$\theta_H = \theta_A + \Delta\theta_{TO} + \Delta\theta_H \quad (1)$$

where:

θ_H is the hottest-spot temperature.

θ_A is the ambient temperature.

$\Delta\theta_H$ is the hottest-spot rise over top-oil temperature.

$\Delta\theta_{TO}$ is the top-oil rise over ambient temperature.

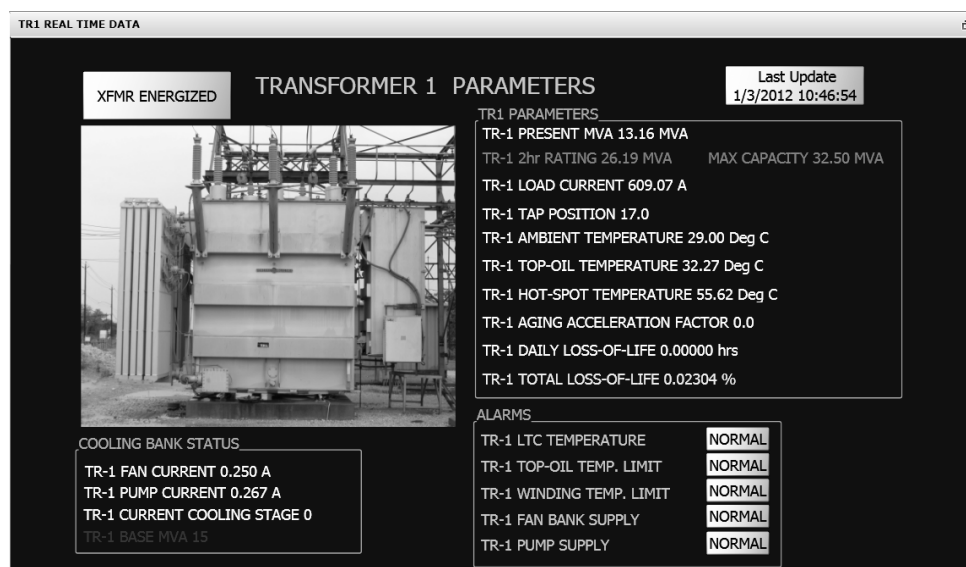


Fig. 2. Transformer Monitor Local HMI Screen

The top-oil and ambient temperatures are obtained as measured values from the DAQ module. IEEE C57.91-1995 provides equations to determine the change in the $\Delta\theta_H$ and $\Delta\theta_{TO}$ temperatures. The hottest-spot temperature determines the transformer accelerated aging factor, F_{AA} . F_{AA} , in turn, adds up over a period of time to the equivalent aging factor, F_{EQA} , and the daily and total loss-of-life values. The equations for obtaining the change in temperatures follow.

The top-oil rise over ambient temperature is given by the following two equations [6]:

$$\Delta\theta_{TO} = (\Delta\theta_{TO,U} - \Delta\theta_{TO,i}) \cdot (1 - e^{-\frac{\Delta t}{\tau_{TO}}}) + \Delta\theta_{TO,i} \quad (2)$$

$$\Delta\theta_{TO,U} = \left(\frac{K^2 \cdot RATL + 1}{RATL + 1} \right)^{EXPn} \cdot \Delta\theta_{TO,R} \quad (3)$$

where:

$\Delta\theta_{TO,U}$ is the ultimate top-oil rise over ambient temperature in degrees Celsius.

$\Delta\theta_{TO,R}$ is the top-oil rise over ambient temperature at rated load in degrees Celsius.

$\Delta\theta_{TO,i}$ is the initial top-oil rise over ambient temperature in degrees Celsius.

RATL is the ratio of load loss at rated load to no-load loss.

K is the ratio of present load to the rated load.

EXPn is an empirically derived exponent used to calculate the variation of $\Delta\theta_{TO,U}$ with changes in load.

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

Δt is the duration of load in hours.

Equation (2) is the solution for the first order differential equation shown by (4).

$$\tau_{TO} \cdot \frac{d\Delta\theta_{TO}}{dt} = -\Delta\theta_{TO} + \Delta\theta_{TO,U}, \Delta\theta_{TO}(0) = \Delta\theta_{TO,i} \quad (4)$$

Using a forward Euler's approximation of (4), the equation to calculate the change in top-oil temperature from a previous time interval is determined [7]. The time interval is chosen to be two hours. Similar approximations are applied in determining the hottest-spot temperature. With the calculated hottest-spot temperature, the F_{AA} value for transformers with 55°C average winding rise is determined using (5).

$$F_{AA} = e^{\left[\frac{15000}{368} \frac{15000}{\theta_H + 273} \right]} \quad (5)$$

With the temperature and aging factors calculated, the automation controller can determine the loading capability of the transformer.

B. Convergence Algorithm

A convergence algorithm to determine the precise loading capability of the transformer without exceeding the temperature and aging limits is programmed in the automation

controller. The flow chart depicting the convergence algorithm is shown in Fig. 3.

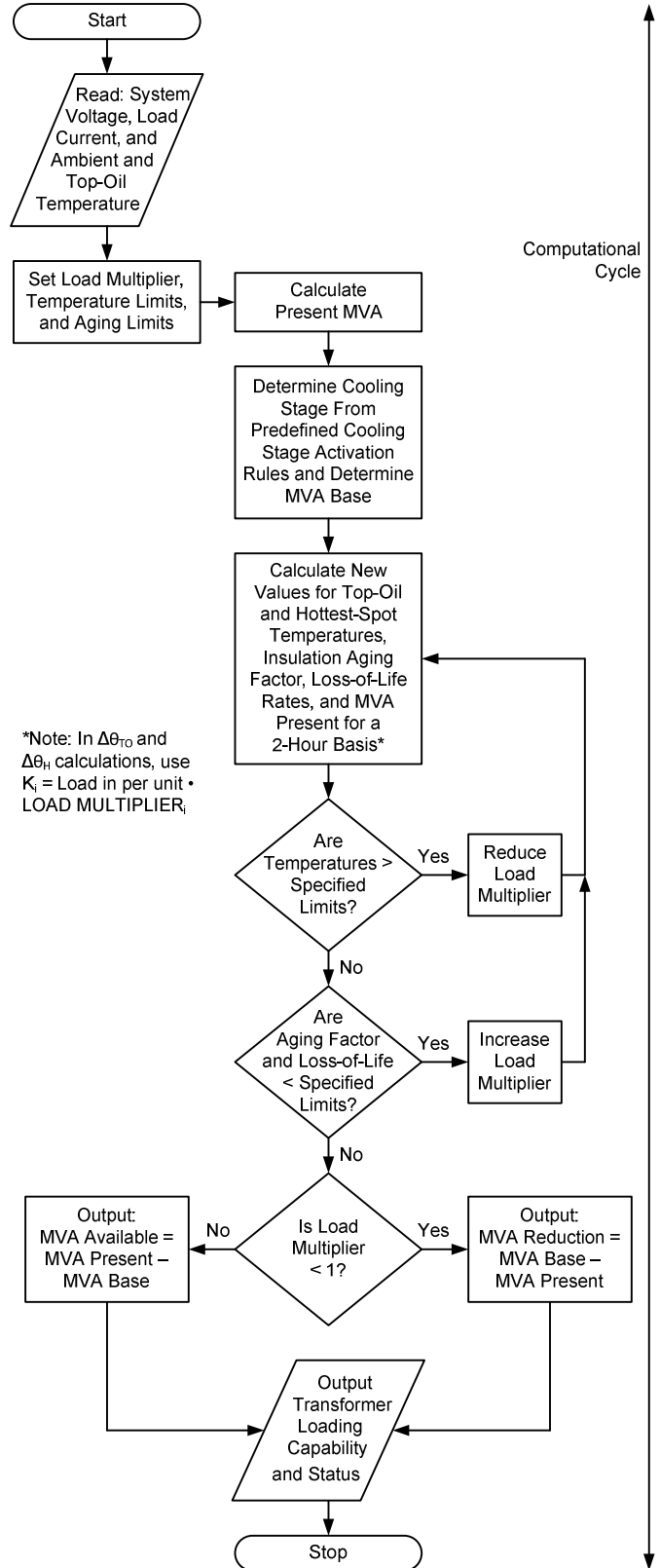


Fig. 3. Convergence Algorithm

For every computational cycle, the automation controller gathers analog data from the DAQ modules. The limits for temperatures and aging factors are set at the start of the cycle. A load multiplier is used to vary the value of K to determine the new temperatures and aging values as follows:

$$K_i = \text{Load in per unit} \cdot \text{LOAD MULTIPLIER}_i \quad (6)$$

where:

i is the iterative variable.

The algorithm starts the convergence process by setting the load multiplier to 1 and determining the present MVA on the transformer. The base MVA is set based on the active transformer cooling stage. The active cooling stage is determined by predefined activation rules, such as those shown in Table I. The cooling stage selection is validated by current detection of cooling bank loads by the DAQ modules.

TABLE I
COOLING STAGE ACTIVATION RULES

Criteria	Threshold	Cooling
Top-Oil Temperature	75°C	Cooling Stage 1 Activation
	85°C	Cooling Stage 2 Activation
Hottest-Spot Temperature	100°C	Cooling Stage 1 Activation
	120°C	Cooling Stage 2 Activation
Load Current	1.00 pu	Cooling Stage 1 Activation
	1.20 pu	Cooling Stage 2 Activation

With all the set points and parameters determined, the algorithm begins the convergence loop. In every loop, the load multiplier is changed to vary K . For every new load multiplier, the algorithm determines the temperatures and aging factors reached at the end of two hours. At the end of the convergence loop, the algorithm fine-tunes the load multiplier value to reflect the actual load that can be impressed on the transformer without exceeding the temperature and aging limits.

VI. TEST RESULTS

The CenterPoint Energy transformer monitoring solution was tested in a laboratory using multiple operating scenarios. Some of these scenarios included a single transformer four-day test run (Case Study 1) with an example distribution transformer load profile from IEEE C57.91-1995 and a two-transformer substation contingency test involving a single

substation transformer failure (Case Study 2). The transformer data and the heat-run data of the transformer under test are shown in Table II and Table III, respectively.

TABLE II
TRANSFORMER DATA

Parameter	Value
Capacity	15/20/25 MVA at 55°C
High-Voltage Winding	67 kV
Low-Voltage Winding	12.47 kV
Impedance	7.79%

TABLE III
HEAT-RUN DATA

Parameter	Value		
Transformer Life	180,000 hours		
Cooling Stage	OA ⁽¹⁾	FA ⁽²⁾	FOA ⁽³⁾
Top-Oil Rise Over Ambient Temperature at Rated Load, °C	47.6	39.3	39.6
Hottest-Spot Rise Over Top-Oil Temperature at Rated Load, °C	17.4	25.7	25.4
Winding Exponent, EXPn	0.8	0.8	0.9
Oil Exponent, EXPm	0.8	0.8	1.0
Top-Oil Time Constant at Rated Load With Initial Top-Oil Rise of 0°C, $\tau_{TO,R}$, Hours	9.322	8.133	6.715
Winding Time Constant, Hours	0.1		

⁽¹⁾ Oil Air (OA) Stage 1 Cooling

⁽²⁾ Forced Air (FA) Stage 2 Cooling

⁽³⁾ Forced Oil-Air (FOA) Stage 3 Cooling

The test setup consisted of a secondary injection of three-phase currents and voltages with a test set. This test set output was varied to simulate actual distribution transformer loading patterns. The inputs from an RTD simulator were used to represent the inputs obtained from an ambient temperature probe. These laboratory tests used the calculated top-oil temperature to determine the hottest-spot temperature. In field implementation, the top-oil temperature is a measured value obtained from an RTD probe placed in a thermal well inside the transformer core. In the laboratory, the analog inputs from the test set and the RTD simulator were connected to the DAQ modules.

A. Case Study 1: Four-Day Load Profile

The single transformer four-day test run involved determining the response of the transformer monitoring solution for an example load profile from IEEE C57.91-1995. A constant ambient temperature of 34.5°C was maintained during the test, and the base MVA of the unit was set to 15 MVA (i.e., the transformer was run without additional cooling). Fig. 4 shows the results obtained at the end of the test period. From these results, it is evident that the predicted two-hour rating is dependent on the transformer load and the top-oil and hottest-spot temperatures. In other words, as the temperatures and present load on the transformer approach the limit, the algorithm determines if load reduction is required depending on the cooling stages. In this test simulation, the transformer was run without any additional cooling; hence the algorithm predicts the amount of load that should be removed to prevent the transformer from aging more rapidly.

B. Case Study 2: Contingency Run

A contingency situation for a two-transformer substation involving the failure of one of the distribution transformers was simulated, and the response of the convergence algorithm is shown in Fig. 5. A typical load profile from a CenterPoint Energy substation with two distribution transformers was selected. The time duration of the test was chosen to include the peak load and the highest ambient temperature. During the time of the test, the ambient temperature was varied to illustrate its impact on the two-hour rating.

When specific set points for the temperatures or the load current were reached, the algorithm automatically changed the base MVA based on the cooling stage selection rules shown in Table I. The test started at 09:35, with both the substation transformers being healthy. During this period, the temperatures and load were within the limits specified for Cooling Stage 1 (OA). At about 10:35, a substation event

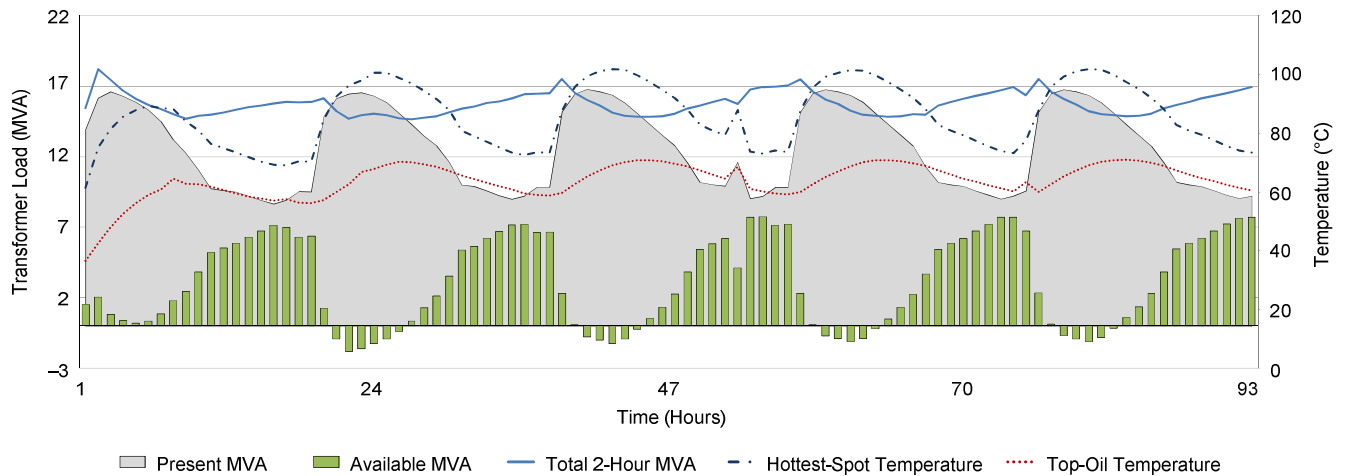


Fig. 4. Results of Four-Day Test Run

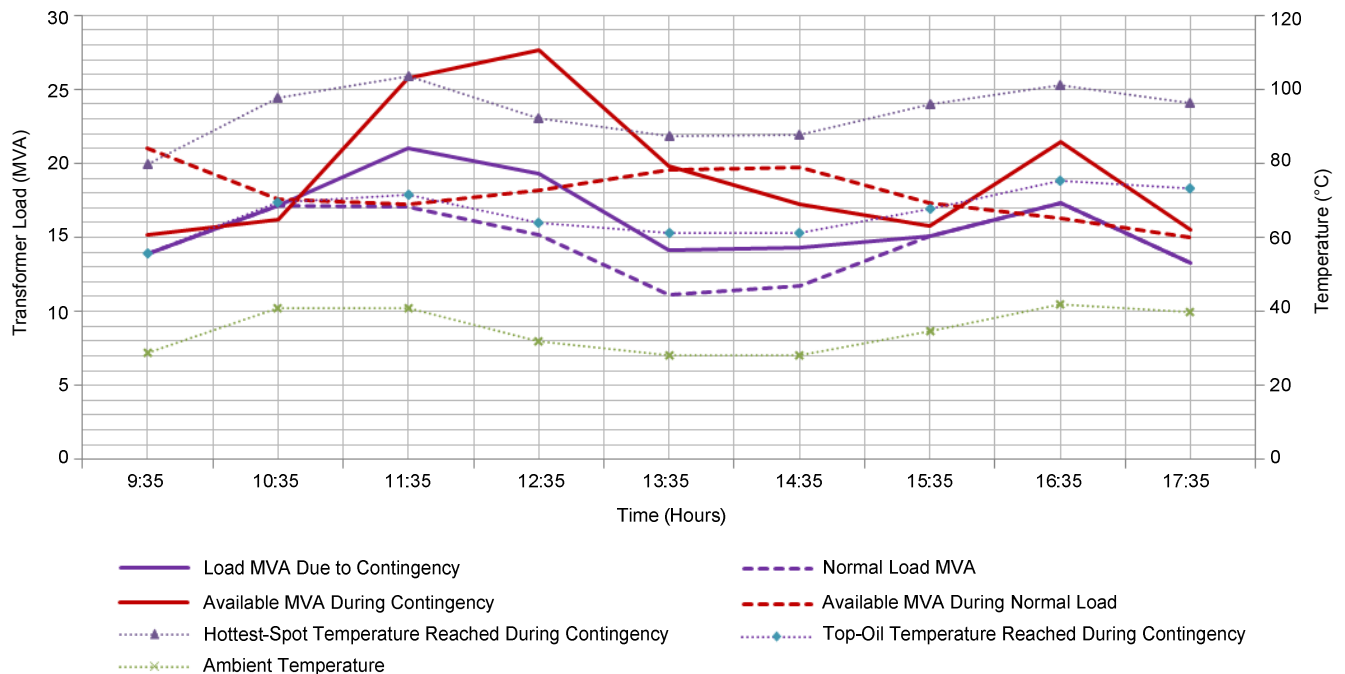


Fig. 5. Contingency Run

caused one of the transformers to fail. At that time, the entire load for that substation was transferred to the transformer under test. For the next five hours, the additional load impressed on the in-service transformer caused the transformer to activate Cooling Stage 2 (FA). Fig. 5 shows the predicted two-hour rating and the top-oil and hottest-spot temperatures during this contingency. Similar tests were run to simulate the normal (noncontingency) load on the transformer. Fig. 5 also illustrates the algorithm responses obtained during the noncontingency situation. It is significant to note the algorithm responses between 13:35 and 15:35. The loadable MVA during contingency is observed to be less than the loadable MVA under normal operating conditions. This is because the transformer is burdened for an extended time interval under contingency and, as a result, its temperatures increase. The time constant for the top-oil temperature is approximately six to nine hours, and consequently, it takes time for the temperatures to cool down, during which time the loading capability of the transformer is reduced.

VII. CONCLUSION

CenterPoint Energy is presently using a time-based method to monitor its distribution transformers. The shortcomings of this method are that the load profile data used to determine the transformer loading capability are based on a typical CenterPoint Energy example load profile and not the actual load profile, the ambient temperatures are not the actual values, and the inspection and analysis are performed on a yearly basis. With the real-time monitoring solution, CenterPoint Energy can detect transformer loading capability abnormalities and selectively schedule maintenance. In addition to providing CenterPoint Energy with an accurate estimate of the loading capability of its transformers, this solution will also help CenterPoint Energy better allocate its maintenance crew. CenterPoint Energy intends to use this custom-developed solution to better manage its substation assets by considerably increasing the mean time between maintenance, avoiding unexpected outages due to transformer failures, and, more importantly, reducing the risk of exposing the transformer to abnormal operating conditions.

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IX. BIOGRAPHIES

Walter A. Castillo received his B.S. in 2006 from Louisiana State University. He worked at PPG Aerospace in Huntsville, Alabama, as a process engineer for less than a year. In 2006, he joined CenterPoint Energy and is presently a lead engineer in the substation protection and automation group. He is a registered professional engineer in the state of Texas.

Rekha T. Jagaduri received her B.S. in 2003 from Madras University in India and her M.S. (magna cum laude) in power systems from Tennessee Technological University. She worked as a power system engineer in the protection and control division for the EPC Company in Knoxville, Tennessee. Rekha has utility company and research experience. She was involved in electric power engineering protection and control design, solution development, and detailed engineering design. In 2008, Rekha joined Schweitzer Engineering Laboratories, Inc. She has led large industrial projects, is a member of IEEE, and has authored various technical papers. She is a registered professional engineer in the state of Texas.

Prasanna K. Muralimanohar received his B.S. in 2008 from Anna University in India and his M.S. in electric power systems from Rensselaer Polytechnic Institute in 2009. His research encompassed power system modeling and analysis. Prasanna worked as a junior protection engineer at United Electric Systems in Allentown, Pennsylvania, where he was involved in performing protection settings analysis for industrial protection schemes. In 2010, he joined Schweitzer Engineering Laboratories, Inc. as a protection engineer.