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Emergency Loading of a Transformer in a Coordinated Substation at Different Dynamic Loading Conditions

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ABSTRACT Utility encounters situations like when one out of two power transformers in the substation requires maintenance and only one transformer remains in operation. To meet the load requirements of a maximum number of customers, if not all, the only transformer needs to be overloaded. Due to various load types within the service territory, utilities need to understand the customers' maximum dynamic loading amount to overload a transformer in an emergency. We propose the iteration process with real-world substation data, which considers the concept of a coordinated substation for optimal power flow. We found to what extent the only 138 kV//13.8 kV, 30/40/50 MVA transformer can be safely overloaded beyond its nameplate's maximum rating for a minimum time. Within that time, the utility personnel can work on the substation yard and switchgear room safely and comfortably to bring back the other transformer in operation. We found from the perspective of power flow that with increased dynamic loading, transformer secondary current increases. Therefore, under the maximum dynamic loading condition, we should calculate the asymmetric fault current on the 13.2 kV switchgear bus to select the suitable CTs and develop a protection scheme accordingly.

INDEX TERMS Emergency loading, high voltage transformer, coordinated substation, dynamic loading, fault current, incident energy, arc flash boundary.

I. INTRODUCTION

The utility provides power to residential, commercial, and industrial customers. Also, each type of customer needs a different type of load over time. These different types of load demand can change and grow at any time [1]. Power system professionals are conducting more research to understand the existing load types and the loading characteristics to accommodate smart grid technologies such as distributed generators (DGs), electric vehicles (EVs), and demand-side management (DSM). The correct distribution networks analysis ensures reliable power supply to the different customers through the respective substation. Hence, a detailed understanding of the steady-state and dynamic loading types under the respective substation is warranted [2], [3]. The general perception is that utility uses a typical representation of static loads by the constant power load types, while dynamic loads are usually represented with the induction motor (IM) model [4]–[6]. It is felt like load models, and their parameters currently used by utilities and system operators for power system analysis are generally not in the public domain [4]. Industry always accepts any research efforts when only it can be implemented to their whole existing system in an integrated way without sacrificing the safety of its workforce and reliability of power to the customers it serves. Generally, utility serves customers like- industrial, commercial, residential, airports, hospitals, care facilities, Etc. During the COVID pandemic, the need to provide power without failure is hugely higher than at any other time.

Utility considers a lumped load as the collective power demand at the substation. It is regarded as a single power absorbing device connected to the substation switchgear bus through a distribution cable [7], [8]. In an application-based case, the utility develops a load model to perform the feasibility study and estimates all long-lead equipment and budget sizes accordingly in the planning phase of a substation project [9]–[12]. The first requirement of a substation design is to avoid a total shutdown of the substation. In a situation where we have two transformers in a substation, for any reason, to conduct maintenance work on any equipment like transformer due to failure or fault somewhere out on the line, one transformer might need to be de-energized (clear) for few hours. So, it is crucial to decide the best suitable substation bus scheme. The maintenance and operational flexibility, and reliability of the substation dramatically depend upon the bus scheme.

This ring bus configuration has good operational flexibility and high reliability. When a fault occurs, it is isolated by tripping a breaker on both sides of the circuit. Only the faulted circuit is isolated by tripping two breakers while all the other circuits remain in service. The main disadvantage of a ring bus system is that when a fault occurs, the ring is split, which results in two isolated sections. Due to the different transmission line parameters, each of these two sections may not have the proper combination of source and load. This issue is more critical when a substation has two transformers, and one of them is out of service for maintenance, and only one remains energized to supply power to the customers reliably.

Simultaneously, the only energized transformer needs to be overloaded beyond its maximum rated capacity to meet all customers' demands for few hours. It is expected that within few hours, utility personnel can bring the other transformer in service to share the load to supply power reliably. As utility personnel works in the substation and switchgear room to energize the second transformer within the minimum time, their safety needs to be ensured. Unlike the transformer, the utility does not maintain the second distribution switchgear in a substation to allocate for the same distribution networks. Hence, utility personnel needs to work on any energized distribution switchgear in the substation. So, the design must ensure that arc-rated incident energy (IE) and arc flash boundary (AFB) are the minima. It is noteworthy that arc-flash protection is typically based on the incident energy level on the working person's head and torso at the working distance and not the incident energy on the hands or arms [13].

The arcing current should be precisely estimated to accurately predict the protective devices' response time to clear a fault current. At the point of the fault, the arcing current may contain a dc component. The asymmetrical fault will cause to increase in the arcing current, and accordingly, incident energy, arc flash boundary (AFB) [14], [15]. Arc flash on main distribution switchgear or breaker (<15 kV voltage class) is a safety issue that can impact utility workers while working on a de-energized cubicle while nearby other distribution cubicles are energized. Incident energy, arc flash boundary needs to be considered in the medium-voltage switchgear cubicles to know the hazard risk category (HRC) requirements and minimum personal protective equipment (PPE) required to ensure the safety of personnel [16]. The utility is the authority having jurisdiction (AHJ), has its strict safety policy, which is in many cases stricter than the established minimum requirement set by National Electric Safe Code (NESC) [17], Standard for Electrical Safety in the Workplace [18], Occupational Safety and Health Administration (OSHA), and other local safety standards.

Transient voltage stability studies and voltage collapse are dynamic phenomena [19]. Voltage stability studies are usually limited to power flow-based static techniques [20]. Most residential, care facilities and, commercial loads could be modeled as static loads since they are mainly resistive loads (heating, light) and are considered linear since they have no dynamic responses. However, industrial and hospital loads, like induction motors driven by variable frequency drives (VFD), are non-linear loads.

It is apparent that various models on dynamic loading have been suggested, as shown in different pieces of literature. However, there is a vast lack of papers in applying dynamic loading in a substation project. This paper suggests how the overloading of one (1) 30/40/50 MVA load in a substation can be affected by the customer sides' dynamic loading. The key affected issues have been addressed while changing the dynamic loading amount in 20% steps: transformer secondary current, 3-ph fault currents, arc flash incident energy, and arc flash boundary. To our best knowledge, this is the first paper that brought the issues of high voltage 138 kV by 13.8 kV ring configured substation design and switchgear's asymmetric fault current and arc flash incident energy together. Irrespective of the total size of the utilities, almost all the utilities have this size substation. Therefore, there is a massive interest among the utility communities.

Table 1 shows the acronyms and their definitions used throughout this paper.

II. SYSTEM PLANNING

For the construction of the substation, we choose the ring configuration in the 138 kV yard. The justification was based on the understanding of load growth trends and reliably supplying power to the customers.

Fig. 1 shows the ring bus configuration arrangements of the 138 kV//13.8 kV substation. There are three 138 kV incoming lines- L1, L2, L3. The rating of each transformer is 30/40/50 MVA, on-load-tap-changer (OLTC). Each 138 kV line is terminated to the nearby 138 kV primary side of the transformer by a gas circuit breaker, B1, B2, B3, Etc. The parameters of the incoming lines like X/R values are given in Table 2.

One line is pulled from each secondary of a transformer. Each lime is terminated to a double-ended switchgear bus through the main distribution breaker (S1 or S2). The rating of S1/S2 or switchgear bus is 3000A. Each bus of the switchgear has six distribution feeder lines connected through circuit breakers.

When one out of the two transformers needs maintenance service or de-energize for any reason, the other transformer will meet the load while the tie (T1-2) between the switchgear buses is closed. However, if the total demand at any time of the

TABLE 1. Acronyms and Definitions

Acronym	Definition
A/G	Above Ground
AFB	Arc Flash Boundary
AHJ	Authority Having Jurisdiction
CT	Current Transformer
DG	Distributed Generation
DSM	Demand-Side Management
ETAP	Electrical Transient Analysis Program
EV	Electric Vehicle
FCT	Fault Clearing Time
HRC	Hazard Risk Category
IM	Induction Motor
IE	Incident Energy
LTC	Load Tap Changing
MVA	Mega Volt-Ampere
NERC	North American Electric Reliability Corporation
NESC	National Electric Safety Code
OLTC	On-Load-Tap-Changer
OSHA	Occupational Safety and Health Administration
PPE	Personal Protective Equipment
VCB	Vertical Conductors in a Box
VFD	Variable Frequency Drive

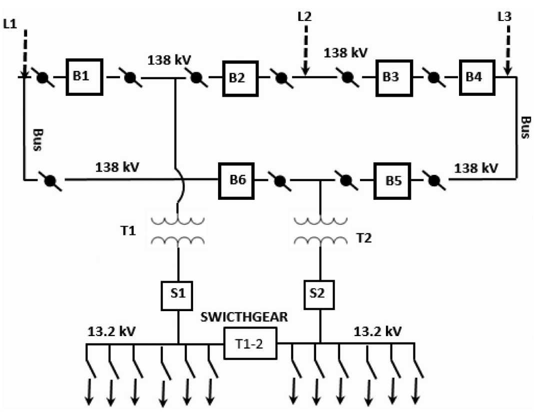

FIG. 1. Ring configuration of the yard for three 138 kV lines and two main 13.2 kV distribution buses in the substation.

TABLE 2. Transmission Line Parameters at Substation End

Parameter	Line 1 (L1)	Line 2 (L2)	Line 3 (L3)
Line Length (mi)	2.75	4.67	4.45
Fault Current (MVA)	6633	4843	4411
X/R value	6.368	6.663	9.58

year exceeds each transformer's highest capacity (50 MVA), overloading would be required. Therefore, we distribute the total load uniformly among each main distribution feeder.

III. SYSTEM COORDINATION AND ANALYSIS

In the planning phase of the substation project', we used Electrical Transient and Analysis Program (ETAP) and took iterative approaches to reach an optimum solution. The critical concept toward this substation planning is that the 13.2 kV distribution system must be coordinated and optimized with the 138 kV transmission systems for maximum power flow, protection scheme for maximum fault current, and safety due to arc flash incident energy and boundary. The main reason is that the sizing of long-lead equipment and limitations arising from the protection scheme and incident energy must be realized to avoid more complexities and the substation's most total capabilities. It is more practical to think of when we have only one transformer to meet the demand to more than the maximum capacity of the transformer.

The steps to follow to the order in the iteration process are given in the flow chart (Fig. 2). Two transformers can fulfill the maximum demand of our existing customers with one energized transmission line. Iteration considered the concept of a coordinated substation for optimal power flow from the transmission lines to the distribution circuits to understand future load growth and maximum possible demand, typically on a hot summer day. Maximum demand

must be met using the minimum number of energized transformers in the substation yard. The number of 138 kV transmission lines connected to the 138 kV bus would not affect the maximum demand. However, more than one number of transmission lines will cause the fault current on the 138 kV bus to increase. Simultaneously, the protection scheme, hence safety, must consider the maximum fault current arising from a single transformer and more than one transmission line connected and the customers' worst dynamic loading scenarios. It is to be noted that this maximum demand also considers the emergency loading of a transformer beyond its rated maximum capacity. The duration for this emergency loading of a transformer in the substation should be minimum. Hence, utility personnel must be capable of working safely and comfortably. Utility personnel can bring other equipment in service to overcome the emergency scenario. Accordingly, in the design stage, details of equipment like percentage impedance, winding and oil properties of the transformer, current rating, and rated interrupting time of the primary and secondary circuit breakers, the maximum current capacity of switchgear bus, CT burden, CT wire size were calculated.

The number of 138 kV transmission lines connected to the only transformer should be more than one. It can be two or three. Under different dynamic loading conditions, it is obvious to iterate the whole substation system and the maximum number of transmission lines connected to the substation. It will ensure that the highest amount of fault current is considered for equipment selection and protection purposes so that the emergency loading of a transformer does not create any protection and safety issues. The design must verify that incident energy, the configuration of electrodes of the switchgear for arc fault, the FCT (fault clearing time) against equipment availability in the market. The FCT was kept six

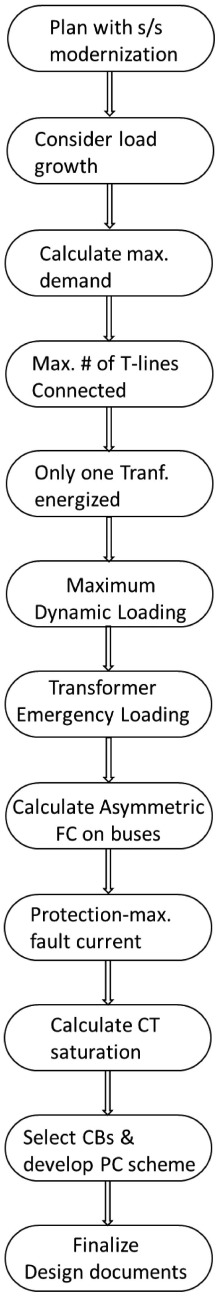

FIG. 2. Flowchart to follow for emergency loading of 138 kV//13.2 kV transformer for optimal power flow between transmission lines and distribution networks.

cycles by the protection schemes for this substation design. Primary protective relaying systems typically operate in one to one-and-a-half cycles, and the opening time of the most reliable 145 kV class breakers is three cycles. So faults are typically cleared in four to five cycles.

Moreover, the NERC requirement is fault clearing time (FCT) of six cycles for a breaker failure scheme. To be connected to the national power grid, the utility must adhere to all applicable codes, standards set by federal, state bodies to maintain the highest safety and reliability. So, we must assume

TABLE 3. Dynamic Loading of a Single Transformer (4 MVA Load)

Dynamic Loading (%)	Trans. Second. Current (A)	3-ph Asymm. FC on 138 kV Bus (kA)	3-ph Asymm. FC on SWGR Bus (kA)	3-ph Bolted FC on SWGR Bus (kA)	AFB (ft)	IE at 36" (cal/cm^2)
0	2024	28.04	11.39	9.88	3.07	1.23
20	2053	28.28	14.08	12.56	3.99	1.58
40	2084	28.44	16.81	15.3	4.95	1.95
60	2119	28.56	19.52	18	5.91	2.32
80	2157	28.64	22.22	20.7	6.89	2.69
100	2199	28.71	24.91	23.4	7.87	3.07

conservative protection operating times when considering the stability and reliability limits for planning purposes.

We considered the half-cycle asymmetric bolted fault currents for 138 kV and 13.2 kV buses for the protection scheme. This high fault current easily saturates a CT if not correctly analyzed the performance of different CTs and their wire resistances to the respective relay panels. This CT saturation by the asymmetric fault current, under different dynamic loading scenarios, mainly controls the size and selection of the main bus circuit breaker. This asymmetric peak occurs at around 8.33 ms. Hence, a very controlled CT selection design and its circuitry are mandated to protect the substation equipment from asymmetric fault current. This protection scheme ensures the worst case to protect the damage of equipment from any possible fault current. We showed 3-phase fault currents on the 138 kV and 13.2 buses of yard and switchgear, respectively, in Table 3.

The maximum rating of each transformer is 50 MVA, and there is a total of 12 distribution feeders in the switchgear. When equally distributed, ∼4 MVA load needs to be connected to each feeder. When two (2) 138 kV transmission lines are connected, and one transformer is energized, the variation of transformer secondary current, 3-phase asymmetric fault currents of 138 kV and 13.2 kV buses, arc flash boundary, and incident energy 3 ft away are shown in Table 3. At increased dynamic loading, the secondary current of the only transformer will be higher. VFD remains connected to the circuit to control the speed of the motor when the load changes. As VFD's circuitry requires additional currents, the line current will be higher when dynamic loading increases. The motor runs at full speed, and full load via a VFD; the power absorbed through the transformer secondary will be higher than any other starter form. Hence, the current drawn due to dynamic loading gradually increases and reaches its maximum loading capability, as shown in Table 3. Because the utility has no control over the customers for their VFD-operated motor usage, it must implement all safety measures in its distribution, substation, and transmission networks.

As dynamic loading (%) increases, transformer secondary current also increases, and at 100% of dynamic loading, it

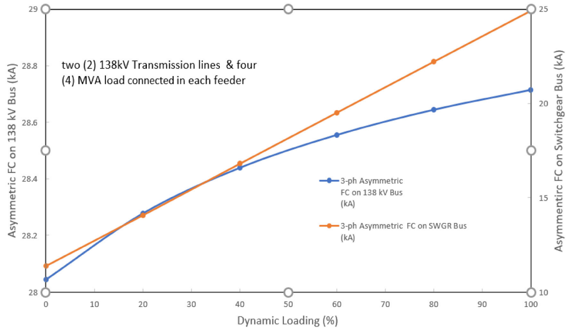

FIG. 3. Variation of asymmetric fault currents on 138 kV and 13.2 kV switchgear buses at different dynamic loading (%) when 4 MVA lump load is connected to each feeder.

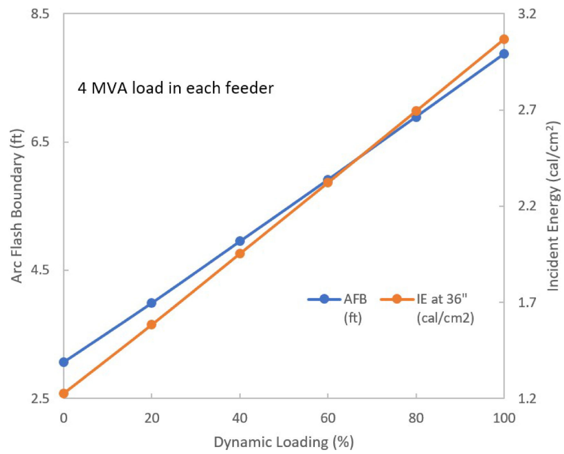

FIG. 4. Variation of arc flash boundary and incident energy against dynamic loading when 4 MVA load is connected to each feeder.

remains within the limit of the 13.2 kV bus current rating, which is designed to be 3000A. Correspondingly, asymmetric and bolted fault current on the switchgear bus increases, as shown in Fig. 3.

A VCB (vertical conductor in a metal box) electrode configuration of the selected switchgear is used to calculate the bolted fault current for arc flash incident energy and boundary. The slope of fault current on 13.2 kV switchgear bus remains the same at different dynamic loading (%), whereas the same on 138 kV bus slowly decreases. The high voltage power transformer with numerous coils on both primary and secondary sides remains between the 138 kV and 13.2 kV systems. The increasing tendency is seen for arc flash boundary and incident energy as the dynamic loading increases (Fig. 4).

When 4 MVA lump load is connected to each distribution feeder circuit with the increased amount of dynamic loading, the arc flash boundary from the switchgear 13.2 kV bus increases. For example, at 40% of dynamic loading, the arc flash boundary is 4.95 ft. At this boundary, the incident energy is 1.2 cal/cm^2, whereas, at a 3 ft (36″) distance from the arc source, the incident energy is 1.95 cal/cm^2. Our focus is, if

TABLE 4. Dynamic Loading of a Single Transformer (5.75 MVA Load)

Dynamic Loading (%)	Trans. Second. Output (MVA)	Trans. Second. Current (A)	3-ph Asymm. FC on SWGR Bus (kA)	3-ph Bolted FC on SWGR Bus (kA)	AFB (ft)	IE at 36" (cal/cm^2)
0	58.8	2783	11.39	9.88	3.07	1.23
20	60.3	2872	15.29	13.77	4.41	1.75
40	62.1	2975	19.18	17.66	5.79	2.28
60	64.1	*3095*	23.06	21.54	7.19	2.81
80	66.4	*3240*	26.99	25.42	8.62	3.35
100	69.2	*3419*	30.8	29.28	10.1	3.89

possible, not to allow incident energy to be more than 1.2 cal/cm^2 within a 3 ft distance from the nearby cubicle of the same switchgear. It falls under the zero (0) hazard risk category (HRC). The arc-rated PPE is not required. It is to ensure that standard safety measures are in place with sufficient knowledge and awareness.

Up to 100% of dynamic loading, arc flash boundary is less than 8 ft, and the maximum incident energy at 3 ft distance is 3.068 cal/cm^2. It falls under HRC 2, for which the incident energy range is 1.2 ∼ 8 cal/cm^2, and the minimum PPE rating is 8 cal/cm^2 clothing. In HRC 2, the additional PPE requirement compared to HRC 1 is arc-rated flash suit hood, long sleeve shirt, pants, jacket, insulating gloves, ear canal inserts of noise reduction rating 25 dB or higher. For HRC 4, the incident energy level range is 8 ∼ 40 cal/cm^2, and the minimum PPE rating is 40 cal/cm^2 clothes. These requirements make personnel work at a slow pace. Thus it will take more time to complete the work. For example, if a switchgear's cubicle door on an energized feeder is open, 40 cal/cm^2 (HRC 4) clothing is required for all individuals in the vicinity. Therefore, a very high probability that this time required would be more than the standard required time.

In the utility industry, it is considered that a single transformer can be overloaded up to 140% of its rated maximum capacity for a few (typically four) hours. Therefore, this maintenance work would not require more than four (4) hours. The expectation is that personnel can work comfortably with due attention to complete the work within a minimum amount of time. The management takes safety measures with comfortable dressing. It is strongly preferred that minimum arc-rated PPE is worn to ensure a comfortable work environment. To overload up to 140% of the rating, the only transformer should be loaded to 70 (=50×1.4) MVA. If equally distributed among the feeders, each feeder circuit should be loaded at 5.75 (≈70/12) MVA.

As shown in Table 4 and Fig. 5 , when each feeder is connected to a 5.75 MVA load, transformer secondary currents and fault currents on switchgear buses increase with increasing dynamic loading. Beyond 40% of dynamic loading, transformer secondary current is more than 3000A. From 60%

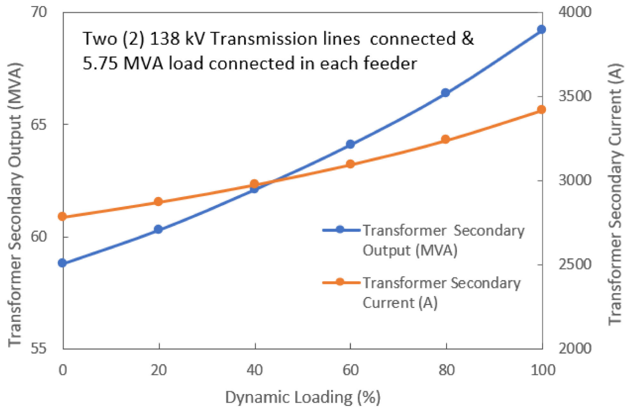

FIG. 5. **Variation of transformer secondary output (MVA) and secondary currents against dynamic loading when two (2) transmission lines are connected to the substation and 5.75 MVA load is connected to each feeder.**

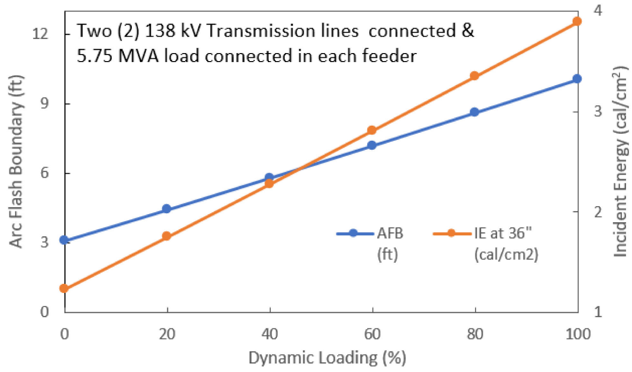

FIG. 7. **Variation of arc flash boundary and incident energy against dynamic loading when 5.75 MVA load is connected to each feeder.**

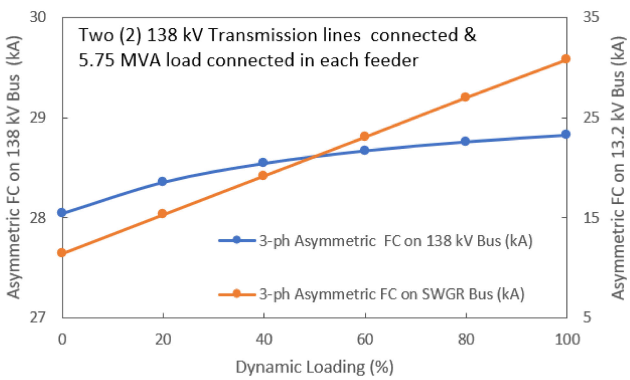

FIG. 6. **Variation of asymmetric fault currents on 138 kV and 13.2 kV switchgear buses at different dynamic loading (%) when two (2) transmission lines are connected to the substation and 5.75 MVA load is connected to each feeder.**

and above dynamic loading, the transformer secondary currents are above the rated capacity of the 13.2 kV switchgear bus. It is shown in the italic and shaded areas in Table 4. At 40% of dynamic loading, the transformer's secondary output is 62.1 MVA, and its secondary voltage level will be 12.05 kV. It is 124% of the rated maximum 50 MVA capacity of the transformer. At this 40% of dynamic loading, the asymmetric fault currents on 138 and 13.2 kV buses are 28.54 and 19.18 kA, respectively.

In an emergency, when one (1) out of two (2) transformers (sitting on the substation yard) is out of service, and only one transformer is running, then in the central control room, the LTC setting of the transformer is changed from automatic to manual. It is done to allow utility personnel to work safely and comfortably in the yard to bring back the first transformer into operation. The reason is that when personnel works on the transformer in the yard, the automatic LTC operation of the second transformer would bring the voltage (i.e., 12.05 kV for 40% dynamic loading) level to be nominal (13.2 kV) and pose a relatively higher safety hazard. In the manual setting of the LTC operation of the second transformer, depending on the load requirement and voltage level on the secondary, we may or may not change the tap as long as the staff work on the first transformer. We may maintain a reduced voltage level in the secondary of the second transformer. In that case, the secondary cables will carry a relatively higher current. These cables pulled on the minimum 16' high above-ground (A/G) cable tray to the switchgear room create reduced safety hazards than the relatively higher voltage level (due to automatic LTC operation) in the secondary bushing of the transformer. So, to ensure the stringent safety measures and maintenance flexibilities for our staff, in the substation design, we size the transformer based on the load types and requirements without considering the impact of LTC operation. However, we ensure that the OLTC arrangement is in the transformer. The OLTC setting would be automatic when running two transformers in parallel or only one transformer while ensuring that no personnel is working in the yard.

When 4 MVA load was connected in each feeder circuit, at 40% of dynamic loading, the fault currents were 28.44 and 16.81 kA, respectively, and the transformer secondary output was 45.9 MVA, which is 92% of the rated maximum capacity. A significant increase in fault current on the switchgear bus is noticed in comparison to the situation when the transformer is required to run at 124% of its rated maximum capacity at 40% of dynamic loading.

Up to 60% of dynamic loading, AFB is less than 8 ft, as shown in Table 4 and Fig. 7. 80% and above of dynamic loading, AFB is more than 8 ft. It falls under the HRC of 2, for which clothes will be heavier, thicker, and requires ear canal inserts. Wearing heavier, thicker PPE would slow down the maintenance work. It needs more time to complete work. Hence, to finish the maintenance work on the other de-energized transformer and hence energized switchgear, we must understand the customers' dynamic loading as a whole. If the customer's dynamic loading is within 40%, then utility workers would wear HRC 2 clothes and smoothly conduct the maintenance activity to finish this job within less time

TABLE 5. Dynamic Loading of a Single Transformer (5 MVA Load)

Dynamic Loading (%)	Trans. Second. Output (MVA)	Trans. Second. Current (A)	3-ph Asymm. FC on SWGR Bus (kA)	3-ph Bolted FC on SWGR Bus (kA)	AFB (ft)	IE at 36" (cal/cm^2)
0	53.1	2467	28.04	11.39	3.07	1.28
20	54.2	2527	28.32	14.75	4.22	1.68
40	55.4	2594	28.5	18.17	5.43	2.14
60	56.8	2670	28.62	21.54	6.64	2.6
80	58.4	2758	28.71	24.91	7.87	3.07
100	60.1	2861	28.78	28.28	9.12	3.54

than wearing PPE of HRC 2 category. This observation is that the dynamic loading of the customers would be higher than 40%, then the energized loads connected to each feeder would be less than 5.75 MVA. It means that the output of the only energized transformer needs to be less than 62.1 MVA. That is, the transformer would run less than 124% of its rated maximum capacity.

If the dynamic loading of the customers served through the substation is more than 60%, then the maximum output from the transformer needs to be lower. Table 5 shows the changes of transformer output, secondary current, fault currents, AFB, and incident energy when 5 MVA load is connected to each feeder circuit under the condition of two transmission lines and only one transformer is energized and connected to the circuits.

Table 5 shows that even at 100% of dynamic loading, the transformer secondary current remains within the limit of the switchgears' bus rating of 3000A. 100% dynamic loading cannot be a real scenario for the customers of a substation unless it is solely designated to an industrial facility. At 80% of dynamic loading, AFB is less than 8′, and incident energy is just above 3 cal/cm^2, for which arc-rated PPE requirement is HRC 2 type. At this loading amount, transformer secondary output is 58.4 MVA, i.e., 117% of the transformer's rated maximum capacity. To what extent the only transformer can be loaded will depend on the customers' dynamic loading amount. The asymmetric fault current on the switchgear bus is relatively higher, and its value is ~25kA. This fault current does not saturate the 3000:5 CT. Even when a substation solely serves the industrial customers within its service territory, the dynamic loading, on average, cannot be more than 80%. The current drawn due to dynamic loading gradually increases and reaches its maximum loading capability. It needs to be considered to select and size the secondary cables or cable bus from the transformer secondary to both switchgear buses. Asymmetric fault currents, incident energy, and arc flash boundary increase with increasing dynamic loading. Because the utility has no control over the customers' VFD-operated motor usage, it must implement all safety measures in its substation while working on any de-energized switchgear cubicle while other nearby cubicles are energized.

IV. CONCLUSION

This paper has proposed an application-based approach during an emergency in a highly utilized substation system when one (1) power transformer and two (2) 138 kV transmission lines are energized and connected to the substation. The loss of one transformer and overloading of the remaining only transformer in the substation requires an in-depth understanding of the customer's loading types, maximum rated capacity of the bus of the only switchgear, asymmetric fault currents on the 13.2 kV bus, arc flash incident energy, and arc flash boundary to ensure the workforce's safety and comfortability.

When two (2) 138 kV transmission lines are connected to the only 30/40/50 MVA, 138 kV//13.8 kV transformer to meet the demands in an emergency, the substation design must consider the maximum dynamic loading of the customers. We found from the perspective of power flow that with increased dynamic loading, transformer secondary current increases. Therefore, under the maximum dynamic loading condition, the asymmetric fault current on the 13.2 kV switchgear bus should be calculated to select the suitable CTs, and a protection scheme must be developed based on that.

The flowchart given in Fig. 2 should be followed to optimize the loading scenarios and two 138 kV transmission lines and 12 distribution circuits coming out from only switchgear. When a 5.75 MVA load is connected to each feeder at 40% of dynamic loading, the only transformer's secondary output can be as high as 62.1 MVA. It means that the only transformer can be overloaded up to 124% of its rated (50 MVA) maximum capacity. The switchgear bus rating controls it. The striking observation is that going beyond this amount will put the only switchgear at the risk of failure.

Moreover, at this 40% of dynamic loading, the asymmetric fault current is around 18 kA on the switchgear bus. At this value of asymmetric fault current, CT will not saturate and work smoothly. In addition to that, the arc flash boundary will be relatively lower, and utility personnel will need to wear HRC 2 type PPE to work on any de-energized cubicle of the switchgear. However, it will allow them to work more comfortably and faster than working while wearing HRC 4 or 40 cal/cm^2 PPE suits.

Whenever the total dynamic loading amount is relatively higher among the customers of substation service territory, then the transformer output needs to bring down by prioritizing the customers it needs to serve. When 5 MVA load is connected to each feeder, the 30/40/50 MVA transformer output can be as high as 58.4 MVA, and the dynamic loading amount it can handle is 80%. So, we can overload the only transformer up to 117% of its rated maximum capacity. To maintain the strict safety practice for its personnel, the incident energy and arc flash boundary need to keep a minimum.

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