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Dynamic Loading Effect on Fault Current and Arc Flash for a Coordinated Substation

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ABSTRACT Due to load growth and various load types within the service territory, utilities need to enhance the utilization of substations. In any case, towards the coordinated substation design, the utilization of the transformers' most total capacity cannot be reduced just because there is a lack of proper coordination between transmission and distribution systems. The transmission and distribution systems' stability and safe operability must be investigated in a coordinated substation. The critical issues are the asymmetric fault currents on the high voltage and arc-related safety issues on the distribution switchgear at different dynamic loading scenarios. We found that when one 138 kV transmission line and two transformers are energized, with increased dynamic loading, from 40% and above, the substation, as a whole, gets gradually more stressed. Because of the highest amount of fault currents on the 138 kV bus, to avoid CT saturation, we need to consider that three transmission lines are connected, and all three transformers are running at 100% dynamic loading. At this value of dynamic loading, in the 13.2 kV switchgear, the incident energy is 2 cal/cm2, and the arc flash boundary is four feet, which ensures that all workers need to wear the proper arc-rated clothes to work on any de-energized cubicle of the switchgear.

INDEX TERMS Arc flash, distribution, dynamic loading, fault current, incident energy, transmission, X/R values.

I. INTRODUCTION

The utility provides power to the different types of customers-residential, commercial, and industrial. Consequently, their load requirement varies [1]. Also, each type of customer needs a different type of load at a different time, month, year, and it can change and grow at any time. Hence, to provide power reliably to all types of customers under the same substation, the correct analysis of planning, operation, and coordination of transmission and distribution networks requires an accurate representation of system loads' steady-state and dynamic characteristics [2]. However, the general perception is that utility uses a typical representation of static loads by the constant impedance/current/power load types, while dynamic loads are usually represented with the induction motor (IM) model [3], [4].

Utility considers a lumped load a single power-consuming device connected to the substation switchgear bus through a distribution cable [5]. Therefore, it develops a load model to perform the feasibility study and estimate long-lead equipment and budget sizes accordingly in the substation project's planning phase [6]. Throughout the substation planning, design framework where load types to the customer end are not generally considered, the transformer capacity utilization has been kept at low rates [7]. However, load modeling is not considered to understand that it is the customers' decision, and their data cannot be accurately obtained, hence reflected into the model because this data varies over time. Hence, the sizing of long-lead equipment cannot be done based on accurate load modeling for the substation design. However, distribution side load and type should be approached in a coordinated [8], [9] way with multiple transmission lines and high voltage power transformers. Nevertheless, using the system parameters of the utility would make the substation coordination with transmission and distribution systems more realistic [10].

In intelligent distribution networks, capacity utilization can be improved in some ways. Therefore, an optimization-based

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approach has been proposed and used for capacity management of transformers only considering the related costs of investment, maintenance, reliability, and losses [7].

In addition, the influence of demand response on increasing the transformer capacity utilization during contingencies has been investigated [11], [12]. These all modeling has been performed for the transformer of a substation only. However, no report has been reported yet where these approaches have been successfully applied in a real-world substation system. Therefore, a need for a coordinated substation design and implementation into a real-life project towards optimal power flow is warranted at different loading scenarios.

During the detail design phase of a substation project, proper integration hence optimizing transmission and distribution demand capability is investigated by selecting the various equipment and arrangement of those in the yard. So, in a real-life case, at best, a power flow study for the proposed substation is done to size the transformers by the utility during the planning phase.

In addition to that, generally, the symmetrical fault current is considered to develop the protection scheme for the substation. Except for some rare cases, the symmetrical fault current is lower than the asymmetrical current. In many cases, utility faces nuisance trips due to not considering the highest -asymmetric fault current. However, asymmetrical fault current needs to be considered [13]∼ [15]. Arcing initiates before the asymmetrical peak occurs, and arcing continues and finishes before the asymmetrical fault current becomes zero [16]. At the onset of the arcing, the asymmetrical current can be higher than the symmetrical peak of the fault current. Hence protection scheme must consider the asymmetric fault current. When the maximum fault and arc fault currents are coordinated, it results in CT requirement, which is very big and extremely difficult to find in the market and deploy into the project. Thus, substation sizing is severely affected when it is realized in the design phase. Consequently, the calculated Personal Protective Equipment (PPE) requirement may not be adequate to protect the personnel in the event of an arc flash in the medium voltage (MV) (15 kV class) switchgear.

The arc-related issues like incident energy, arc flash boundary are calculated once the substation is in operation as power system protection does not require considering the arc-related issues; instead, it considers the protection issues only. Therefore, very few papers give a little insight into the arc-related issue [17], [18] independently. Unfortunately, those findings are for the low voltage (LV) (∼600V and below) system design. There are many utilities whose voltage levels fall within this category. These days most distribution switchgears in the substation are rated 13.2 kV. To our best knowledge, this paper brought the issues of high voltage 138 kV by 13.8 kV substation design and 13.2 kV switchgear's highest possible fault current and arc-related incident energy together. The integrated approach between 138 kV (HV) transmission and 13.2 kV distribution lines for the design of this size substation was taken considering to serve the customers reliably and maintaining the safety of the workforce and public. Moreover, in the application-based substation design, different loading scenarios considering asymmetrical fault current and arc flash-related issues together make this paper unique.

The arcing current should be precisely estimated to predict the fault clearing time (FCT) accurately. The asymmetrical fault will change in the arcing current, incident energy, arc flash boundary (AFB) [19]. Arc flash on the main 13.2 kV distribution switchgear bus or breaker is a safety issue that can impact line and substation workers when working on a de-energized cubicle while the other nearby cubicles remain energized. Hence, the design needs to consider incident energy, arc flash boundary for the 13.2 kV switchgear to know the hazard risk category (HRC) and minimum personal protective equipment requirement [20]. The utility is the authority having jurisdiction (AHJ), has its strict safety policies, which are in many cases stricter than the established minimum requirements set by National Electric Safe Code (NESC), Occupational Safety and Health Administration (OSHA), and other safety agencies. Thus, the CT selection and protection scheme should consider the highest possible fault current. So, asymmetric fault current, coordination of 138 kV transmission and 13.8 kV distribution systems, and arc flash incident energy must be conceptualized in an integrated approach at the project's onset.

Most residential and commercial and a fraction of industrial loads are static loads since they are mainly resistive loads and have a very minimum dynamic response. However, this is not the case for the bulk of industrial loads, which depend on induction motors and non-linear loads like variable frequency drives (VFD), arc furnaces, Etc. These days, industrial customers use VFDs more than before, and their usage is increasing. Due to the unpredictable nature of the customers' dynamic load requirements and the different significant factors affecting the requirement, utility generally predicts voltage stability studies on the power flow-based static techniques. During the planning phase of a substation project, size the power transformer, switchgear.

This paper presents the critical issues required to address during the early stage of the 138 kV by 13.8 kV substation design to ensure reliable power supply to the customer and maintain the safety of the workforce. Towards optimal power flow through the substation, the effects of dynamic loading on the fault current (FC) on the HV and MV buses, and arc-related issues together. These approaches were applied to one of our projects to construct a 138 kV by 13.8 kV substation.

II. SUBSTATION LAYOUT

For the construction of the substation, we choose the breaker-and-a-half (BAAH) configuration. The justification was based on understanding load growth trends and reliably supplying the power to the customers.

Fig. 1 shows the BAAH bus configuration arrangements for the 138 kV by 13.8 kV substation. The rating of each

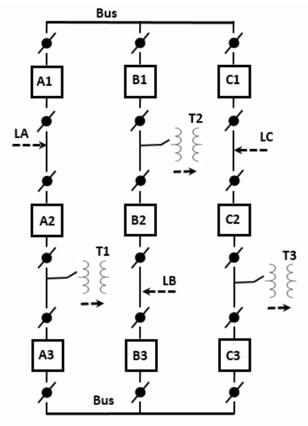

FIGURE 1. Breaker-and-a-half configuration for three 138 kV transmission lines.

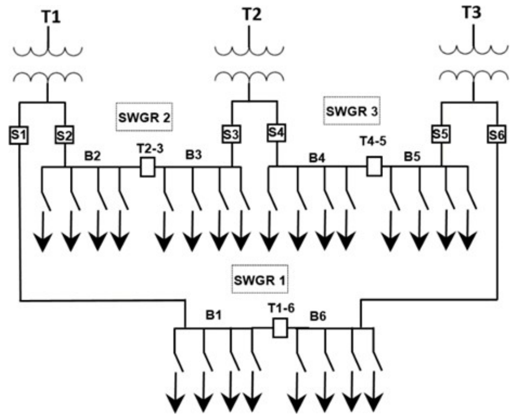

FIGURE 2. Ring configuration for 13.2 kV three distribution switchgear totaling 24 feeders.

TABLE 1. Transmission line parameters at substation end.

Parameters	Line A (LA)	Line B (LB)	Line C (LC)
Line Length (mi)	1.5	3.5	4
Fault current MVA	3336.8	3269.3	3290.7
X/R	6.075	6.503	6.5

transformer is 18/24/30 MVA. Each 138 kV line is terminated to the nearby 138 kV primary side of the transformer by a gas circuit breaker, namely A1, A2, A3, Etc. (Fig. 1). Table 1 shows the parameters of the incoming lines like X/R values at the substation ends, fault current MVA ratings, length of each line. We used these to calculate power flow, asymmetric bolted fault current, and arc incident energy calculation.

Two parallel lines were pulled from each secondary of a power transformer. One line was terminated to a bus of one double-ended switchgear, and the other line was connected to a bus of another switchgear. From the secondary sides of the transformers to the switchgear buses, a ring configuration was used to ensure power delivery with the minimum requirement of one incoming transmission line and two transformers. Thus, six groups of feeder buses would be kept energized. Each bus of the switchgear has four distribution feeder lines connected through circuit breakers.

III. SYSTEM PLANNING AND DEVELOPMENT

Fig. 2 shows the connection diagram of the distribution network within the substation yard and control room. There are three 138 kV//13.8 kV transformers in the yard and three double-ended switchgears placed in the control room. The tie breakers are T1-6, T2-3, T4-5. One of the secondary sides of T1 is connected to bus B1 of SWGR 1 through circuit breaker S1, and the other is terminated to bus B2 of SWGR 2 through breaker S2. Similarly, secondaries of T2 and T3 are connected to different buses of two adjacent switchgears.

We distribute the total load uniformly among each main distribution feeder. In the planning phase, we used Electrical Transient and Analysis Program (ETAP) and took iterative approaches to reach an optimum solution for the substation design. We analyzed customers' loading data, parameters, the trend in the last couple of years. We found that Electrical Transient and Analysis Program would be the best fit and sufficient for this substation project. 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, and safety due to arc flash incident energy, arc flash boundary. This coordination must be done during the planning phase, not in the design phase. The main reason is that the sizing of long-lead equipment and limitations arising from the protection scheme and incident energy must be realized early in the design process to avoid more complexities and the substation's most total capabilities.

We need to ensure the most optimal power flow from the 138 kV transmission lines to the 13.2 kV distribution networks through the substation. In the iteration process, the steps followed are given in the flow chart (Fig. 3). Two out of three transformers can fulfill the maximum demand of our existing customers with one energized transmission line. Iteration considered the concept of a coordinated substation accounting for future load growth and maximum possible demand by the different types of customers and their different loading types. Maximum demand must be met using the minimum number of 138 kV transmission lines and 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, connecting more than one transmission line and the minimum number of energized transformers will cause the fault current (FC) on the 138 kV buses to increase. Hence the need to avoid high voltage side CT saturation is critical. The reason to consider two or three 138 kV transmission lines is that others will remain as a backup if any or two lines fail and get disconnected from the substation.

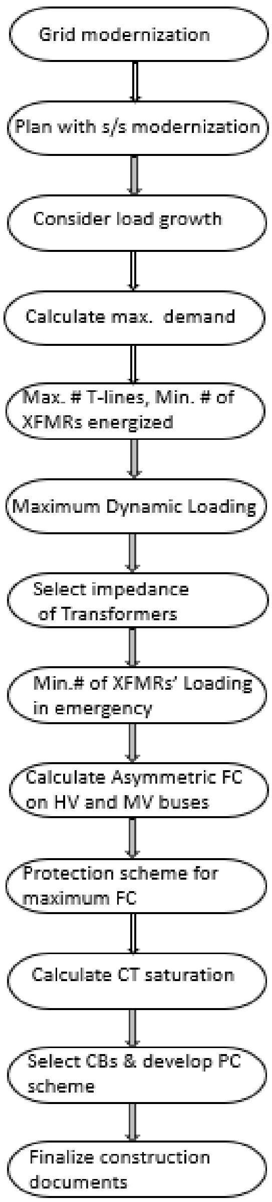

FIGURE 3. Flowchart to follow for a coordinated substation design to ensure optimal power flow between transmission lines and distribution networks.

Simultaneously, the protection scheme, hence safety, must consider the maximum fault current arising from the minimum number of transformers and transmission lines connected and the customers' worst dynamic loading scenarios. It is to be noted that this maximum demand also considers the emergency loading of the minimum number of transformers beyond each rated maximum capacity. The duration for this emergency loading of a transformer in the substation should be minimum. Hence, utility personnel must work safely and comfortably to 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.

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.

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

We considered the asymmetric 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. 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 (nuisance) fault current. We showed 3-phase fault currents on the 138 kV and 13.2 buses of yard and switchgear, respectively, in Table 2.

TABLE 2. Effect of dynamic loading.

Loading Dynamic (%)	Transformer Primary Voltage (MVA)	Transformer Secondary Voltage (MVA)	% of VA drop in Transformer (Secondary Voltage as base)	Transformer Secondary Breaker Current (A)	3-ph FC on yard 138 kV Bus (kA)	3-ph FC on 13.2 kV SWGR Bus (kA)
0	20.1	19.4	12.67	927.5	13.96	11.466
20	22.3	21.3	13.1	1027	14.163	12.833
40	24.6	23.4	13.55	1132	14.329	14.199
60	27	25.5	14.04	1241	14.469	15.599
80	29.5	27.7	14.56	1357	14.586	16.976
100	32.1	30	15.13	1479	14.686	18.352

Optimizing the substation and the 138 kV transmission or the substation and the 13.2 kV distribution system independently does not assure an optimal strategy. On the contrary, it will produce a non-optimal system laden with operational and maintenance problems. At this point, we expect that the most considerable peak load through this substation would be around 60 MVA using two transformers during the peak season.

Table 2 shows the effect of dynamic loading when one (1) 138 kV energized transmission line connects to the substation. Two (2) transformers are energized, and a 2.5 MVA lump load is connected to each distribution circuit of a total of 24 circuits. Dynamic loading was increased by 20% steps.

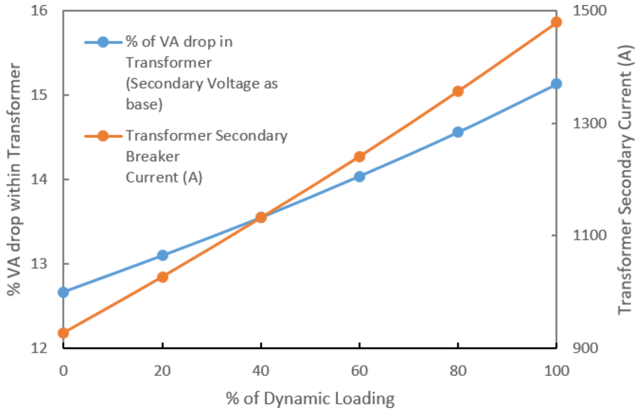

FIGURE 4. Effect of dynamic loading on percentage VA drop within power transformer and secondary current to account for power flow.

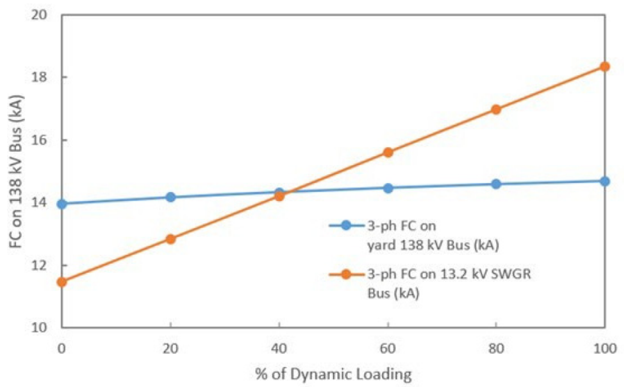

FIGURE 5. Effect of dynamic loading on asymmetric fault current on 138 kV and 13.2 kV bus.

It shows the percentage volt-ampere (VA) drop within the transformer and its secondary current and the asymmetric 3-phase fault currents on the yard 138 kV bus and 13.2 kV switchgear.

Fig. 4 shows that with increasing dynamic loading, the VA drop within the transformer and transformer secondary current increases. For example, from 0 to 40% of dynamic loading, the percentage change of VA drop is 2.2.

$$= \frac{(13.55 - 12.67)}{40\%} = 2.2$$

From 40% to 100%, it is 2.6.

The VA drop rate

$$\frac{(2.6 - 2.2) \times 100\%}{2.2} = 18.18\%$$

of 18.18% occurs from 40% and above due to increased dynamic loading. This higher VA drop causes the transformer to be overheated. The secondary currents change in these two categories are 5.11 A and 5.78 A in unit percentage. Thus with increased dynamic loading, from 40% and above, the substation, as a whole, gets gradually more stressed.

Fig. 5 shows the fault current on the 138 kV bus increases a little with increasing dynamic loading, while on the 13.2 kV switchgear bus, the asymmetric fault current increases significantly. This point is noteworthy from the operational and maintenance perspective. On 138 kV bus, fault current change per unit of percentage dynamic loading increment is 0.92 A, 0.60 A, respectively, between 0 to 40% and 40% to 100% dynamic loading. On the 13.2 kV switchgear bus, these values are 6.83, 10.38 A. We conclude that the switchgears' downstream dynamic loading has no considerable effect on the 138 kV bus as the transformer electrically isolates the secondary from the primary. However, again 13.2 kV distribution system gets more stressed from 40% onwards of dynamic loading.

When a maintenance issue arises in a switchgear's feeder circuit, the only cubicle associated with that circuit needs to be isolated to conduct operational and maintenance work. Working on that cubicle needs to be done safely. The other nearby cubicles are assigned for other distribution circuits. All nearby circuits and hence, cubicles need not be isolated to ensure a reliable power supply to the customer. The increased asymmetric fault current on the switchgear bus with increasing dynamic loading must change the arc flash boundary. Higher asymmetric fault current means higher arcing fault current, hence higher incident energy and arc flash boundary.

TABLE 3. Effect of dynamic loading on incident energy and AFB.

Dynamic Loading (%)	Transformer Secondary Breaker Current (A)	Bolted FC on 13.2 kV SWGR Bus (kA)	Incident Energy at 36" (cal/cm^2)	Arc Flash Boundary (AFB) (ft)
0	927.5	9.963	1.138	2.9
20	1027	11.328	1.286	3.13
40	1132	12.693	1.433	3.36
60	1241	14.093	1.582	3.58
80	1357	15.468	1.728	3.78
100	1479	16.843	1.873	3.98

Table 3 shows the effect of dynamic loading on the arc flash incident energy and arc flash boundary (AFB). As the dynamic loading amount in the distribution circuits increases, transformer secondary current, incident energy, and arc flash boundary (AFB) increase due to arc fault current. At increased dynamic loading, the transformer output current 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 reached its maximum loading capability, as shown in the second column of Table 3. In Fig.5, as the dynamic loading increases, both the incident energy and arc flash boundary increase. Because the utility has no control over the customers over VFD-operated motor usage, it must implement all safety measures in its transmission, substation, and distribution networks. To maintain the strict

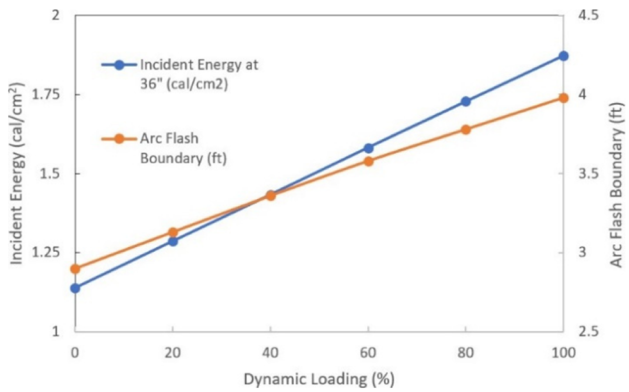

FIGURE 6. Effect of dynamic loading on arc flash incident energy and arc flash boundary of the 13.2 kV switchgear.

safety practice for its personnel, the incident energy, and arc flash boundary need to keep a minimum.

Arc flash boundary is calculated at incident energy $\sim$1.2 cal/cm^2. At this value of incident energy, the arc flash boundary is around three ft. This three ft spacing is the width of each cubicle of the 15 kV switchgear. Our focus is not to allow incident energy far more than 1.2 cal/cm^2 within three ft distance from the cubicle's conducting bar. Therefore, it falls under the zero (0) hazard risk category. The arc-rated PPE is not required. It is to ensure that standard safety measures are in place with sufficient knowledge and awareness. It appears that at $\sim$20% of dynamic loading, incident energy and arc flash boundary are within that range.

It is noteworthy that at 40% of dynamic loading, the asymmetric fault currents (when drawn on the same scale) on 138 kV bus and 13.2 kV switchgear bus have almost the same values. Interestingly, as shown in Fig. 6, at this 40% dynamic loading case, the incident energy, and arc flash boundary are 1.43 cal/cm^2 and 3.36 ft, respectively. Therefore, its arc-rated hazard risk category is two (2), and the PPE requirement is 8 cal/cm^2 [21].

IV. EFFECT OF 138 kV TRANSMISSION LINES

One or two or three energized 138 kV transmission lines connected to this substation can provide a total of 90 MVA. When a total of 90 MVA loads are equally distributed among 24 feeders, each distribution feeder will provide a 3.75 MVA load. Three transformers will meet this requirement. Effect of the number of energized transmission lines connected to this substation on the fault currents on 138 kV yard bus, 13.2 kV switchgear bus is shown in a tabular form at 100% dynamic loading. Table 4 also shows the incident energy and arc flash boundary of the switchgear under the same condition. The third and fifth columns show the magnitudes of $\frac{I_F}{I_P} \cdot \frac{Z_B+R_S}{Z_{BS}+R_S}\left(\frac{X}{R}+1\right)$ (Z_{AH}, Z_{AL} for 138 kV, 13.2 kV sides, respectively) to verify whether these values are less or more than 20. Respective 138 kV bus or 13.2 kV switchgear bus CTs will not be saturated if these values are less than 20. (I_F, I_P, Z_B, Z_{BS}, R_S are the bus fault current, primary current rating, actual burden, standard burden, internal resistance of the selected CT, respectively). W The asymmetric fault currents on both 138 kV yard bus and 13.2 kV switchgear buses increase with more connected transmission lines to the substation, as shown in Fig. 7. When all three transmission lines are connected, the 138 kV bus fault current is $\sim$42 kA. The CT characteristics and the size, length, and routing of the CT wire to connect to the respective relay panel were calculated to ensure that CT is not saturated under this worst fault case, i.e., meet the requirement that the expression is less than 20.

TABLE 4. Effect of connected transmission lines.

Connected energized T-lines (#)	3-ph Asymmetric FC on yard 138 kV Bus (kA)	CT Saturation Checking on 138 kV Bus (Z_{AH})	3-ph Asymmetric FC on 13.2 kV SWGR Bus (kA)	CT Saturation Checking on 13.2 kV Bus (Z_{AL})	Incident Energy at 36" (cal/cm^2)	Arc Flash Boundary (ft)
1	15.049	7.10	18.37	14.42	1.875	3.98
2	28.727	13.55	18.74	14.70	1.904	4.02
3	42.115	19.86	18.87	14.81	1.914	4.04

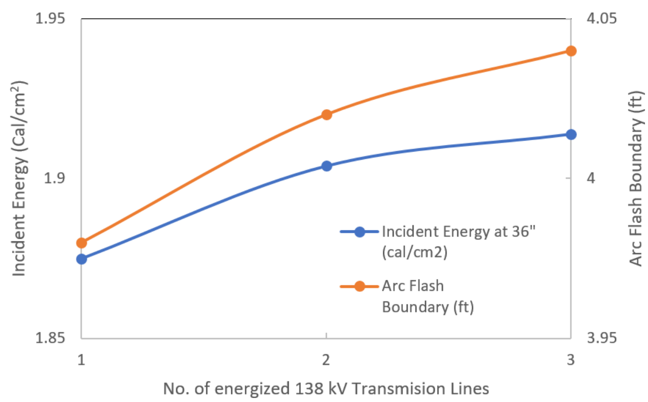

FIGURE 7. Effect of connected energized transmission lines on the fault currents of 138 kV yard and 13.2 switchgear buses.

Running the substation with all three energized 138 kV transmission lines and transformers are common. Depending on the substation's location and the intended service territory, the use of two (2) transmission lines at any given time can be standard as well. The third transmission line's addition causes a linear increment of fault currents on 138kV and 13.2kV buses, incident energy, and ac flash boundary from the switchgear. In any case, the protection scheme must consider the highest amount of fault current. Fault currents on the 13.2 kV buses increased by a small amount when more energized transmission lines are connected. Under any conditions, the selected CT will not saturate, as shown in the fifth column of Table 3, where the value of $Z_{AH} < 20$. So, for the switchgear, the next consideration must be the incident energy and arc flash boundary. Incident energy increases with increasing fault current. At 100% dynamic loading, with two or three 138 kV lines connected to the substation, the arc flash boundary is more than 3 ft, the limited approach boundary. The fault clearing time (FCT) was kept six cycles for the protection scheme. It is to ensure that NERC (North American Electric Reliability Corporation) requirements are met. In all three conditions, incident energies are more than 1.5 cal/cm^2. This incident energy falls under the flash protection boundary category for which FCT needs to be six cycles or faster [22]. The protection scheme considers six cycles (0.1s) to clear the more than 1.5 cal/cm^2, and AFB is above three ft. This application can be significant for the industrial customer or if the substation is solely dedicated to the industrial purpose, where many VFD-operated motors run, which will increase. Arc flash boundary (AFB) also gets larger with the addition of transmission lines shown in Fig.8. Always having connected two transmission lines is a prevalent practice in the industry. Generally, the third line is connected when an additional exit is required to supply power cost-effectively to the nearby areas. In that case, the system design requires considering a very high fault current (∼42 kA) on the 138 kV bus, and the arc flash boundary in the switchgear is ∼3.4 ft under the condition of 100% dynamic loading when all three transformers, transmission lines are energized. In addition, the arc flash warning label posted on the panel's front door must indicate the type of PPE required to work on the de-energized cubicle.

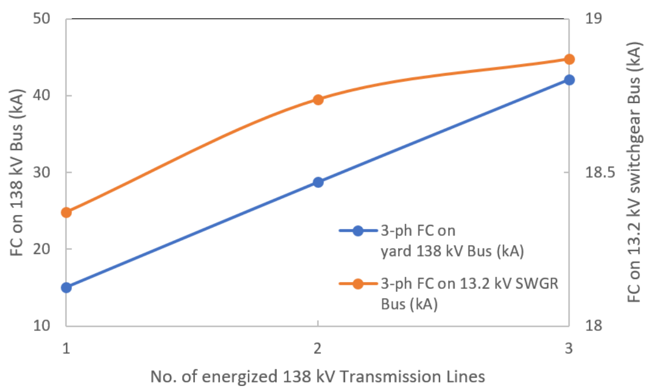

FIGURE 8. Effect of energized 138 kV transmission lines on incident energy and arc flash boundary of the 13.2 kV switchgear bus.

For 138 kV line and bus protection during an asymmetric fault, avoiding CT saturation helps to size the CT. To fulfill the condition [23]

$$20 \geq \left|\frac{X}{R} + \mathbf{1}\right| \times I_F \times Z_B$$

IF is the maximum fault current in per unit of CT
= CT primary current divided by the turns ratio
ZB is CT secondary burden in per unit (p.u.) of standard burden
X and R is the primary system reactance and resistance up to the point of fault
X/R = 6.503 (LC) (Table 2)

When all three energized transmission lines connect to the substation and three transformers are running at their maximum capacity, the line LA's fault current was 42.115 kA (Table 2). Therefore, the chosen CTs' ratios for 138 kV and 13.2 kV buses were 2000:5, 3000:5 respectively. In addition, the selected CT's internal resistance, CT wire from CT to the relay panel located in the control room, wire routing were investigated and analyzed to ensure that the actual CT burden remains below 1/8 p.u.

When we energize the substation by three transmission lines and meet the load by three transformers, the 138 kV bus CTs' will not saturate.

$$Z_{AH} = \left(\frac{X}{R} + 1\right) \times I_F \times Z_B = 19.86 < 20$$

Asymmetric fault circuit current on the 13.2 kV switchgear bus is 14.27 kA at 100% dynamic loading. This case,

$$Z_{AL} = \left(\frac{X}{R} + 1\right) \times I_F \times Z_B = 14.81 < 20$$

In any case, it ensures that the DC component in the first half cycle would not cause any CT saturation during an asymmetric fault.

V. TRANSFORMER MAXIMUM LOADING

This substation can be loaded to a maximum of up to 90 MVA while energizing all three transformers, and all three energized transmission lines are connected to the yard.

Asymmetric fault currents on both the 138 kV and 13.2 kV buses increase with increasing dynamic loading, as shown in Table 7 and graphically in Fig. 9. Fault current on 138 kV bus goes up to ∼42 kA and 13.2 kV switchgear bus up to ∼19 kA. In both cases, the protection system must consider this maximum amount of current. However, these values of fault currents, both the 138 kV and 13.2 kV bus CTs will not saturate as the values of Z_{AH} and Z_{AL} remain below 20 even at 100% dynamic loading, as shown in Table 4 and 5.

TABLE 5. Effect of dynamic loading when all 3 transformers connected to transmission lines.

Dynamic Loading (%)	3-ph FC on yard 138 kV Bus (kA)	CT Saturation Checking on 138 kV Bus (Z_{AH})	3-ph FC on 13.2 kV SWGR Bus (kA)	Incident Energy at 36" (cal/cm^2)	Arc Flash Boundary (ft)
0	41.025	19.350	12.001	1.182	2.97
20	41.33	19.494	13.363	1.329	3.2
40	41.581	19.613	14.749	1.477	3.42
60	41.788	19.710	16.123	1.624	3.64
80	41.964	19.793	17.497	1.769	3.84
100	42.115	19.864	18.87	1.914	4.04

The most striking point is that, for any utility whose system has higher X/R values, the criteria to avoid saturation due to asymmetric fault current may not meet unless they can control it by selecting the appropriate CT wire size, length, and CT type. Hence, to reduce the asymmetric bolted fault current level on the 138 kV bus, more than two energized transmission lines cannot be connected to the substation buses at any time.

In Fig. 10, it is evident that incident energy remains below the 2 cal/cm^2 at different dynamic loading scenarios. At this incident energy level, the hazard risk category is two, and the arc-rated PPE requirement is above the minimum. At 100% dynamic loading, the arc flash protection boundary is slightly

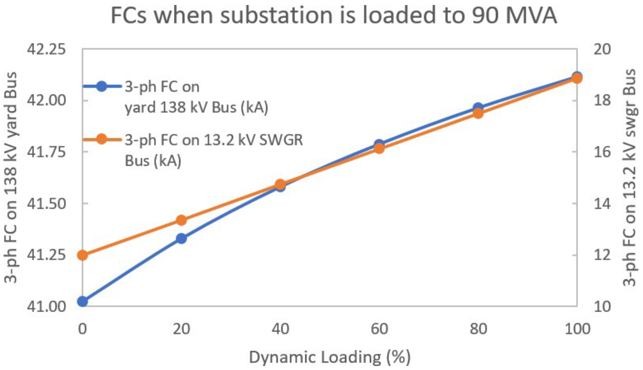

FIGURE 9. Effect of dynamic loading on faults currents when energized transmission lines are connected to three transformers.

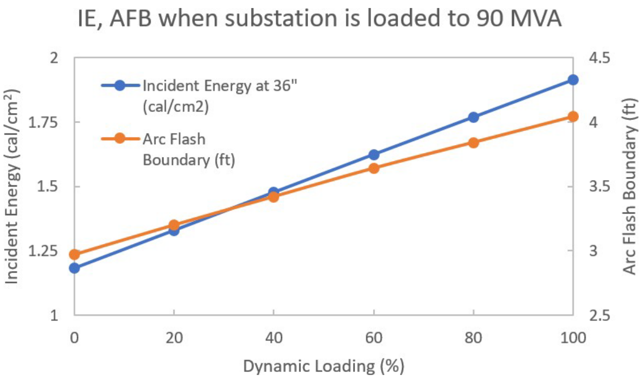

FIGURE 10. Effect of dynamic loading on incident energy and AFB when energized transmission lines are connected to three transformers.

more than four ft. The lower the boundary limit is, the better it is. In our case, the cubicle width is three ft. So, while working on the de-energized cell, appropriate arc flash-rated PPE must be worn to mitigate the risk. Equipment selection and hence sizing should consider this scenario.

VI. CONCLUSION

This paper discussed the critical issues required addressing during the early stage of the 138 kV by 13.8 kV substation design. The critical issues are the asymmetrical fault current, CT saturation, arc flash incident energy, and arc flash boundary. We found that the asymmetrical fault current increases with more energized 138 kV transmission lines connected to the substation. To consider the highest amount of asymmetric fault current and select an appropriate CT that will not saturate, we considered that three transmission lines are connected, and all three energized transformers are running at 100% dynamic loading. This scenario would be a case when the substation solely serves industrial customers. 100% dynamic loading can happen when the industrial customers are going through their peak production. The daily duration can be for several hours only. However, when the substation serves a combination of residential, commercial, and industrial customers, dynamic loading would be less than 100%. Under the same condition, incident energy and AFB on the switchgear bus are less than 2 cal/cm^2 and 4 ft, respectively. When one 138 kV transmission line and two 138 kV by 13.8 kV transformers are energized, with increased dynamic loading, from 40% and above, the substation system gets gradually more stressed. It happens because the transformer's internal loss increases faster from 40% and above dynamic loading. At the 13.2 kV switchgear at this dynamic loading, the incident energy is more than 1.2 cal/cm^2, and the arc flash boundary is just above three ft. Therefore, to work on any de-energized cubicle while other nearby cubicles are energized would not jeopardize safety due to arc-related incidents when HRC 2 PPE is used. These understandings should be realized in the concept or planning phase of the substation design process.

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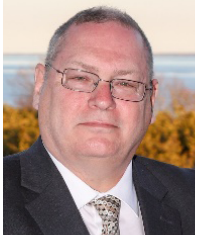

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