Arc Flash: Not How or Why, but WHEN To Complete an Assessment on an Electrical Distribution System.

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Abstract: Arc flash risk assessment on an electrical distribution system is crucial to identify arc flash hazards in the workplace and determine mitigation measures to protect the safety of employees as well as the general public. The National Electric Safety Code (NESC) and the National Fire Protection Act Standard 70E (NFPA 70E) both have guidelines for when and how to complete arc flash risk assessment; however, there are other factors to consider as to when an arc flash assessment should be completed. This paper was completed to offer additional considerations for "when" an arc flash assessment should be completed on an electrical distribution system and how these additional considerations could affect the arc flash calculations.

I. Introduction

Employees who work on energized electrical equipment are exposed to arc flash hazards daily. Mitigation measures are required to prevent injury in the event of an arc flash which include (but not limited to) Personal Protection Equipment (PPE) and operational procedures. The NFPA 70E states that an arc flash risk assessment shall be performed to identify arc flash hazards, estimate the likelihood of injury, and determine protective measures [1]. Additionally, the NESC requires that the employer perform an assessment to determine potential exposure to an electric arc for employees who work on energized lines [2]. The arc flash risk assessment shall include calculations for arc flash energy based on three main components which are arcing fault current, device clearing time, and distance to the arc. It is recommended that the assessment be completed on the entire system where employees are exposed to arc flash hazards.

However, the question remains of how often an assessment needs to be completed and when is the best time to complete an assessment or even update an existing assessment. The NFPA 70E states that an assessment shall be updated when changes in the electrical distribution system occur that could affect the results of the analysis, and that the analysis should be reviewed for accuracy not to exceed 5 years. While this recommendation is a good rule of thumb, it is still ambiguous as to when is the best time to complete an assessment. The objective of this paper is to provide considerations as to when is the best time to complete an arc flash risk assessment.

II. Case I

One of the main components of calculating arc flash energy is the arcing fault current. If the arcing fault current at the source has changed, the results of a previous arc flash risk assessment could be greatly affected. Some examples that could cause the arcing fault current at the source to change include upgrades to the upline transmission line, upgrades to the substation transformer, or even changes to the operating voltage of the distribution system. Since this paper is focused on the electrical distribution system, Case I reviews the effect of the arcing fault current due to a substation transformer upgrade. Table 1 shows the substation source impedance and fault current that was used as the base to show the difference when upgrading a power transformer. On Table 1 below, the existing substation is fed from a 69 kV transmission line and has a base 7.5 MVA transformer with an 8.05% impedance operating at a 7.2/12.5 kV distribution voltage. Based on the high side impedances, the calculated fault current on the distribution load side is 3,697 amps three-phase and 3,484 amps single-phase.

Substation Transformer Load Side Fault Currents				
Transformer:				
High Side Voltage	69.0	kV		
Low Side Voltage	12.47	kV		
Impedance	8.05%	Percent		
Impedance at	7.5	MVA		
S_{base}	100.00	MVA		
Z_{base} for	69.00	kV=	47.610	Ohms
Z_{base} for	12.47	kV=	1.5550	Ohms
Source Impedance				
	R	+ j	**X**	
Z_1=	4.07637	+ j	7.79519	Ohms
Z_0=	7.64902	+ j	18.19178	Ohms
Source Impedance				
On	**100.00**	**MVA**	**Base**	
On	**69.0**	**kV**	**Base**	
	R	+ j	**X**	
Z_1=	0.08562	+ j	0.16373	P.U.
Z_0=	0.16066	+ j	0.38210	P.U.
Transformer Impedance on a 100 MVA Base				
Z_T=	0.0805	at	7.50	MVA
Z_T=	1.0733	at	100.00	MVA
Let				
R_T=	0.2	$* Z_T$		
X_T=	0.98	$* Z_T$		
	R	+ j	**X**	
Z_T=	0.21467	+ j	1.05187	P.U.
	(R_T)		(X_T)	
Total Impedance on Transformer Load Side (P.U.)				
(Source Z + Transformer Z)				
	R	+ j	**X**	
Z_1=	0.30029	+ j	1.21560	P.U.
Z_0=	0.37533	+ j	1.43397	P.U.
Available Fault Current on Transformer Load Side				
3-Phase	**3,697.61**	**AMPS**		
Single-Phase	**R**	+ j	**X**	
$Z_1 + Z_2 + Z_0$=	0.97590	+ j	3.86516	P.U.
Single-Phase	**3,484.23**	**AMPS**		

TABLE 1: Starting point for substation transformer low side fault current

To show how a simple transformer upgrade can change the downline fault current on the distribution system, Table 2 displays how by only changing the substation transformer size from a 7.5 MVA to a 12 MVA, while holding everything else constant, the calculated fault current increased by 1,749.02

amps to 5,446.63 amps three-phase while the single-phase fault current increases by 1,511.09 amps to 4,995.32 amps.

Substation Transformer Load Side Fault Currents				
Transformer:				
High Side Voltage	69.0	kV		
Low Side Voltage	12.47	kV		
Impedance	8.05%	Percent		
Impedance at	12	MVA		
S_{base}	100.00	MVA		
Z_{base} for	69.00	kV=	47.610	Ohms
Z_{base} for	12.47	kV=	1.5550	Ohms
Source Impedance				
	R	+ j	**X**	
Z_1=	4.07637	+ j	7.79519	Ohms
Z_0=	7.64902	+ j	18.19178	Ohms
Source Impedance				
On	**100.00**	**MVA**	**Base**	
On	**69.0**	**kV**	**Base**	
	R	+ j	**X**	
Z_1=	0.08562	+ j	0.16373	P.U.
Z_0=	0.16066	+ j	0.38210	P.U.
Transformer Impedance on a 100 MVA Base				
Z_T=	0.0805	at	12.0	MVA
Z_T=	0.6708	at	100.00	MVA
Let				
R_T=	0.2	* Z_T		
X_T=	0.98	* Z_T		
	R	+ j	**X**	
Z_T=	0.13417	+ j	0.65742	P.U.
	(R_T)		(X_T)	
Total Impedance on Transformer Load Side (P.U.) (Source Z + Transformer Z)				
	R	+ j	**X**	
Z_1=	0.21979	+ j	0.82115	P.U.
Z_0=	0.29483	+ j	1.03952	P.U.
Available Fault Current on Transformer Load Side				
3-Phase	**5,446.63**	**AMPS**		
Single-Phase	**R**	+ j	**X**	
$Z_1 + Z_2 + Z_0$=	0.73440	+ j	2.68181	P.U.
Single-Phase	**4,995.32**	**AMPS**		

TABLE 2: Update to substation transformer low side fault current due to transformer upgrade

Analysis was run using Milsoft's Windmil software to show how this change in fault current can affect the arc flash calculations on the distribution system. Image 1 shows the downline fault current at the existing overcurrent protection device locations used in the base model with the initial source impedance using the 7.5 MVA transformer. Image 2 shows the corresponding arc flash calculations at each location.

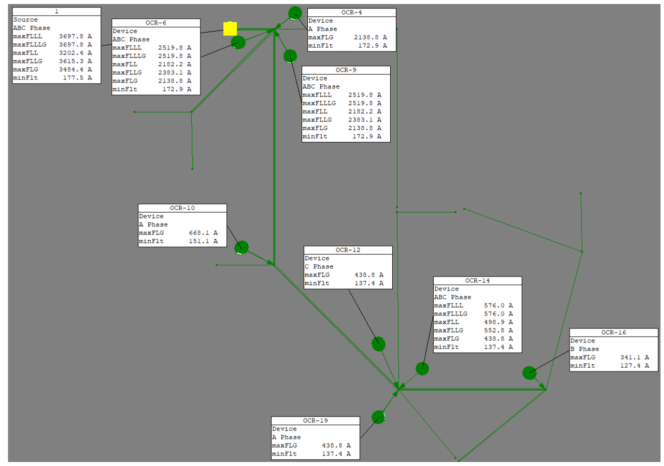

IMAGE 1: Fault current calculations using the base point 7.5 MVA transformer.

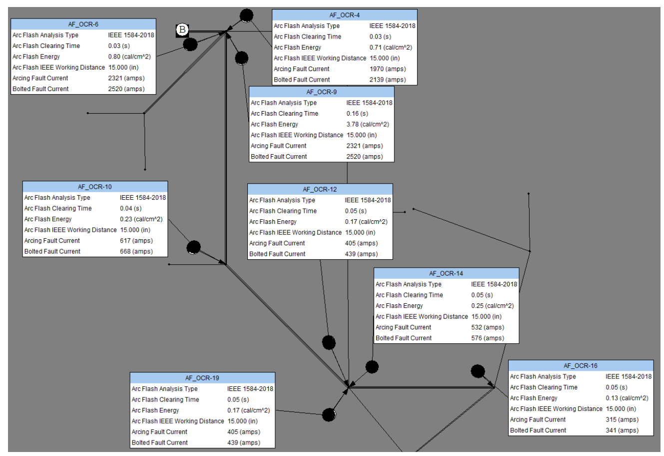

IMAGE 2: Arc flash calculations using the base point 7.5 MVA transformer.

The arc flash calculations using the base model indicate that arc flash energy is low with the exception of OCR-9 which has an arc flash energy of 3.78 cal/cm^2. What this means is that at any point on the line between OCR-9 and the next dowline device, the worst-case arc flash energy is 3.78 cal/cm^2. Since all calculations are below 4 cal/cm^2, this system is classified as a 4-cal system and requires PPE to have an Arc Thermal Protection Value (ATPV) of 4.

The base model was updated using the updated source impedance from Table 2 and the fault current and arc flash analysis was re-run. Image 3 shows the updated downline fault current and Image 4 shows the corresponding arc flash calculations.

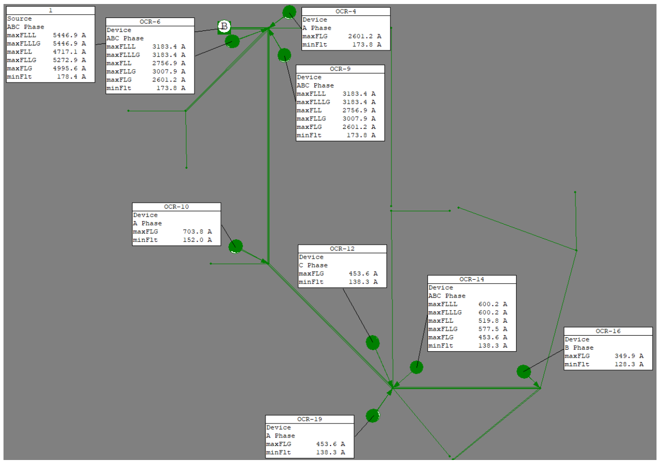

IMAGE 3: Fault current calculations using the 12 MVA transformer.

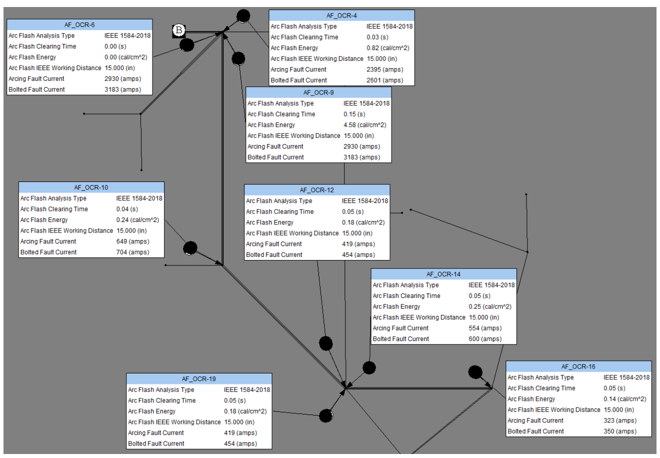

IMAGE 4: Arc flash calculations using the 12 MVA transformer.

Although the increased fault current due to the transformer upgrade did not dramatically increase the arc flash calculations, there are a few changes that need to be noted. As you will see in Image 4, the arc flash clearing time and arc flash energy on OCR-6 are no longer calculated. This is due to the arcing fault current exceeding the rated value of the hydraulic recloser, which in this case is a 70-amp type E OCR. With the increased fault current, this device will most likely need to be upgraded as well to a device that is rated for this fault current level. A new device at this location will have different settings which affect the arc flash clearing time and thus the calculated arc flash energy. The second thing that needs to be noted is the calculated arc flash energy on OCR-9. In the base model, the system was classified as a 4-cal system. However, as seen in Image 4, the updated arc energy is now 4.98 cal/cm^2 which means the system is now classified as an 8-cal system which requires PPE to now have an ATPV of 8.

This proves that for **Case I**, a simple substation transformer upgrade can have a direct **effect** on the required ATPV of PPE for the system. Upgrades to substation equipment that affects the downline fault current on the electric distribution system is one consideration as to when an arc flash assessment should be performed.

III. Case II

It was shown in Case I how changes at the substation level can affect the downline fault current as well as the downline arc flash calculations. However, changes to the distribution system itself can also impact the fault current and arc flash calculations too. Case II reviews the effect of arcing fault current from a distribution system improvement. Conductor size has an impact on the flow of arcing fault current on a distribution system. Smaller conductors tend to have a greater resistance than larger conductors which limits the flow of current from the source to the end of the line. For example, a standard 1/0 ACSR conductor has a current carrying capacity of 230 amps and a resistance of 1.12 ohms/mile. Conversely, a standard 795 ACSR conductor has a current carrying capacity of 900 amps and a resistance of 0.13 ohms/mile. The base model used in this study has a conductor size of 1/0 ACSR from the source to the end of the feeder. As shown in Image 1, the maximum single-phase line to ground fault current drops from 3,484 amps at the source to 341 amps at OCR-16 which is a 90% decrease in available fault current. To show how a distribution system improvement affects fault current, the model was updated by replacing the 1/0 ACSR conductor with 795 ACSR conductor. As shown in Image 5, increasing the conductor size increases the available fault current at the end of the line. With the larger conductor in place, the maximum single-phase line to ground fault current only decreases by 83% from the source to OCR-16.

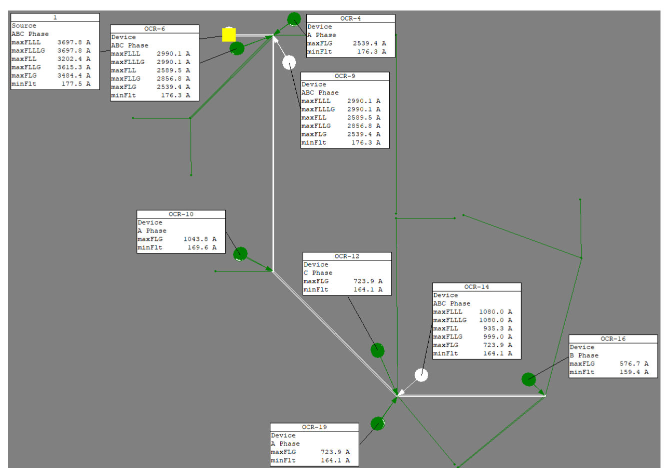

IMAGE 5: Fault current calculations with conductor upgrade from 1/0 ACSR to 795 ACSR

The available fault current at the source did not change but by increasing the conductor size, the available fault current at the end of the line also increased.

Since the available fault current has a major impact in the arc flash calculations, a distribution system improvement for a conductor upgrade will have an impact on the arc flash calculations as well. Using the base model, it was established that the system was a 4-cal system because the highest arc flash energy is 3.78 cal/cm^2 at OCR-9, as seen in Image 2. With the 1/0 ACSR conductor changed to 795 ACSR, the arc flash calculations were updated due to the updated available fault current. As shown in Image 6, the arc flash energy at each device location increased with the largest increase being on the devices towards the end of the line.

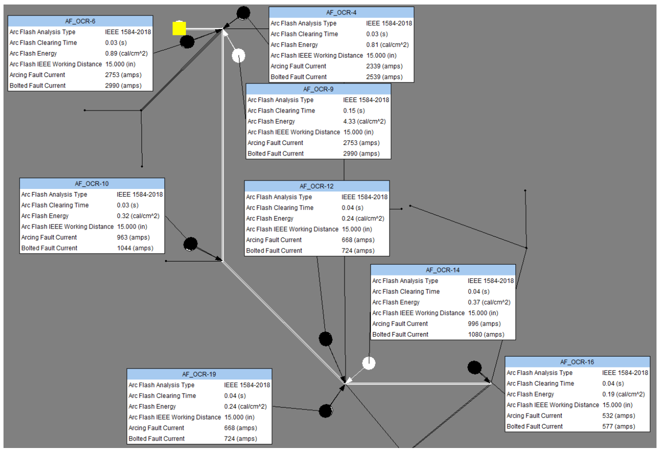

IMAGE 6: Arc Flash calculations after the 795 ACSR conductor upgrade

However, the biggest impact is once again seen at OCR-9 with the arc flash energy increasing from 3.78 cal/cm^2 to 4.33 cal/cm^2. As was the same in Case I, the conductor upgrade has moved the system from a 4-cal system to an 8-cal system.

This proves that for **Case II**, a distribution system improvement can have a direct effect on the required ATPV of PPE for the system. Upgrades to the distribution system that affect the downline fault current, such as a conductor size increase, is another consideration as to when an arc flash assessment should be completed.

IV. Case III

The reliability of an electric distribution system is an integral part of everyday operations. The most commonly used reliability index is the System Average Interruption Duration Index (SAIDI) [3]. To calculate SAIDI, the following formula is used:

$$SAIDI = \frac{Number\ of\ customers\ per\ outage\ x\ Duration\ of\ outage}{Total\ number\ of\ customers\ served}$$

To improve reliability, the goal to reduce the SAIDI number and the easiest way to reduce the SAIDI number is to reduce the number of consumers per outage. The easiest way to reduce the number of consumers per outage is through sectionalizing by installing additional protection devices on the circuit.

When looking at the base model shown in Image 1, there is a lot of exposure between OCR-9 and OCR-14. One solution to sectionalize the circuit and reduce the number of consumers per outage would be to install a new device half-way between these two existing devices. However, when installing a new device, coordination needs to be reviewed to ensure proper sequence of device operation. In Image 7 below, the base model was updated with New Device between OCR-9 and OCR-14. The New Device was installed as an electronic recloser, and settings were developed to coordinate with the device's downline from it. However, to allow for these New Device settings, the existing settings in OCR-9 needed to be updated to slow the device down so that the New Device has a chance to operate and clear an outage before OCR-9.

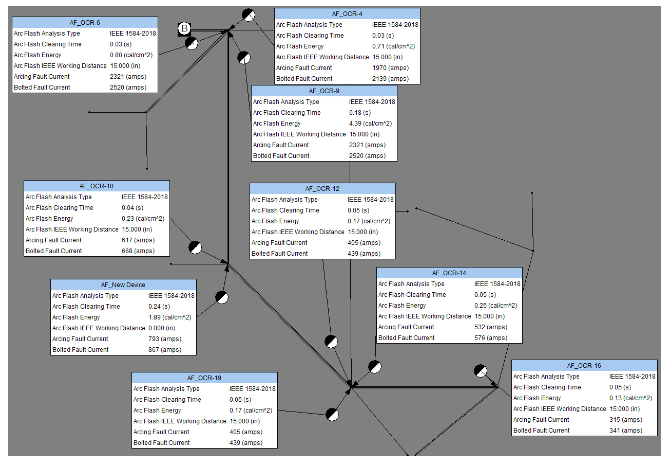

IMAGE 7: Arc Flash calculations with the New Device installed in the circuit

Recall in Image 2 how the base model showed the highest arc flash energy was 3.78 cal/cm^2 thus classifying the system as a 4-cal system. With the New Device installed and the settings updated for OCR-9, Image 7 shows the updated arc flash energy increased to 4.39 cal/cm^2 which once again moves the system from a 4-cal system to an 8-cal system.

This case is a different example of how updates to the distribution system affect the arc flash calculations. Although adding the New Device and updating the settings on OCR-9 didn't change the fault current on the system, the clearing time on OCR-9 was increased which in turn increased the arc flash energy.

This proves that for **Case III**, sectionalizing and coordination on the system can have a direct effect on the ATPV of PPE for the system. One major component of arc flash calculation is device clearing time and sectionalizing and coordination has a major impact on the clearing times. Completing sectionalizing and coordination studies is one more consideration as to when an arc flash assessment should be completed.

V. Conclusion

The NFPA 70E suggests that an arc flash assessment should be completed when changes to the electric distribution system occur that could affect the results of the assessment, and that the assessment should be reviewed for accuracy not to exceed 5 years. However, there are many things to consider when determining when the best time is to complete an arc flash assessment.

A major component of arc flash calculations is the arcing fault current. Upgrading a substation transformer can have a major impact on the arcing fault current of the electric distribution system. As shown in Case I, upgrading the substation transformer increased the downline arcing fault current on the system which in turn updated the arc flash energy calculations moving the system from a 4-cal system to an 8-cal system. When considering completing an arc flash assessment, review your substation transformer capacities and determine if upgrades will be needed that will affect downline available fault currents.

Distribution system improvements can also contribute to a change in the downline arcing fault current. As shown in Case II, reconductoring a line from 1/0 ACSR to 795 ACSR can increase the downline fault current thus changing the arc flash energy at the device location which also moved the system from a 4-cal to an 8-cal system. Consider any planned distribution system improvements and their effect on the downline arcing fault current before deciding when to complete or update an arc flash assessment.

Reliability is critical to an electric distribution system. A good way to improve the SAIDI of the system is completing a sectionalizing and coordination study. As shown in Case III, clearing times of protection devices play a major role in the arc flash energies at each device. If a plan is in place to improve reliability by sectionalizing the system, consider completing the arc flash assessment after the system sectionalizing is complete and the device clearing times are updated. This will provide a more accurate are flash assessment of the system and could prevent having to complete the assessment twice, once before and once after the system sectionalizing is updated.

There are many considerations as to when is best to complete an arc flash assessment and this paper was completed to offer additional considerations for “when” an arc flash assessment should be completed on an electrical distribution system.

References

[1] NFPA 70E Article 130.5 Arc Flash Risk Assessment
[2] NESC Section 41 Supply and communications system – Rules for employees 410(A)(3)
[3] IEEE 1366-2022

Chris Smart is an accomplished professional engineer with over 19 years of experience in consulting engineering for electric utilities, mainly focused on distribution system planning including analysis using many types of engineering software and engineering principals. He has performed forecasting, detailed load flow and voltage drop analysis for construction work plans and long-range plans. He also completes arc flash studies, motor start analysis, short circuit analysis, sectionalizing and coordination analysis, power optimization, and feasibility studies. Chris has completed distribution and substation system planning for over 20 electric utility cooperatives, municipals, and investor-owned utilities.

Chris has a B.S. in Electrical Engineering from the University of Texas, San Antonio, is a registered P.E. in Arkansas, Iowa, Illinois, Kansas, Missouri, New Mexico, Oklahoma, and Texas, and is in the process of adding licenses in other states. Chris is a member of the Institute of Electrical and Electronic Engineers (IEEE), National Society of Professional Engineers (NSPE), and Texas Society of Professional Engineers (TSPE).