Proceedings

2025 IEEE Rural Electric Power Conference

REPC 2025

29 April - 1 May 2025

Westminster, Colorado

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2025 IEEE Rural Electric Power Conference (REPC)

REPC 2025

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2025 IEEE RURAL ELECTRIC POWER CONFERENCE (REPC)

Target Audience

The 2025 IEEE Rural Electric Power Conference (REPC) is geared toward practicing utility engineers working for a rural electric cooperative, an investor-owned utility or a municipal electric utility. Consulting engineers specializing in electric utility power system planning, design or operations will also find the conference useful. Educators providing instruction in power systems or power electronics courses will also benefit from exposure to the advanced technologies and applications methods as presented as part of the conference forum.

Instructional Methodology and Learning Objectives

The 2025 IEEE Rural Electric Power Conference (REPC) consists of instructional methodology through technical paper presentations and learning sessions on the development and use of new technologies and innovative use of existing technologies to improve the overall efficiency of electrical generation, transmission and distribution delivery systems. This includes theoretical and practical applications of advanced technologies including computer hardware and software to promote increased efficiency and reliability in electric utility power systems. Presentations include a bound and/or digital copy of the Conference Proceedings and is handed out to audience participants at registration. Technical paper presentations include a variety of audio-visual presentation methods. Technical paper presentations are allotted 30 minutes each, with 20-25 minutes for the author's presentation and a minimum of 5 minutes allotted for questions from the audience of the author/presenter. Learning sessions are allotted 30 minutes each with question and answer throughout the presentation. Conference participants are seated classroom style in a large auditorium or meeting facility to permit taking notes and writing comments as author/presenters make audio/visual presentations on their technical papers. Several microphones are placed in strategic locations throughout the audience to encourage audience/participant feedback during the question-and-answer sessions that follow each presentation. Participants of the conference are also provided digital and/or paper conference evaluation forms to provide comments and feedback on hotel/meeting facilities and separate evaluation forms for the audience to rate the technical papers and to provide feedback needed to the IEEE Rural Electric Power Committee for possible improvements in future conferences and program/technical paper topics. The author(s) of the top papers as selected by the audience receive cash prize awards from the IEEE Rural Electric Power Committee. Several door prizes are also awarded from a random drawing of audience participants to encourage audience participants to stay until the final paper presentation is made on the afternoon of the second day of the technical paper presentations.

Conference participants will develop measurable new skills and add new tools to their repertoire of technical information that will allow them to become more proficient in planning, design and operations in an industry facing new technical, environmental and regulatory challenges in the future.

There are also exhibits set up during the conference by participating manufacturers and vendors to display the latest hardware and software technologies for audience participants to view during breaks and in the evenings. This venue also affords a great opportunity to network with peers and manufacturers/consultants.

2025 IEEE RURAL ELECTRIC POWER CONFERENCE
Westminster, CO
Schedule

Tuesday April 29, 2025

Date	Event	Location
8:00AM – 3:00PM	Exhibitor Setup	Legacy Ballroom (exhibit hall)
7:00AM – 6:00PM	Registration	Westminster Ballrooms Foyer
Committee Meetings		
1:00PM – 1:30PM	General Committee Meeting (intros and sub-committee updates)	Cotton Creek I & II
1:30PM – 2:30PM	Computer Applications Subcommittee	Cotton Creek I
1:30PM – 2:30PM	Guides and Standards Subcommittee	See Registration Desk
1:30PM – 2:30PM	NESC Subcommittee	See Registration Desk
1:30PM – 2:30PM	Power Quality and Efficient Electrical Use Subcommittee	Cotton Creek II
2:30PM – 4:00PM	General Committee Business Meeting	Cotton Creek I & II
4:00PM – 6:00PM	Exhibits/Happy Hour Reception	Legacy Ballroom (exhibit hall)

Wednesday April 30, 2025

Date	Event	Location
7:00AM – 8:00AM	Breakfast Buffet	Westminster Ballrooms I, II
7:00AM – 6:00PM	Registration	Westminster Ballrooms Foyer
8:00AM	Technical Session A Introduction – Clifton Oertli, P.E.	Westminster Ballrooms III, IV
8:00AM	A-1: “TCC Evaluation Method for Evaluating Arc Flash and Arc Blast Hazard at Low Voltages and First-Degree Burns”, Christopher L. Brooks, PE-Brooks Consulting	Westminster Ballrooms III, IV
8:30AM	LS-1: “Utilizing AMI Data for Operational Purposes”, Bruce Goss, PE - United Cooperative Services	Westminster Ballrooms III, IV
9:00AM	A-2: “Arc Flash: Not How or Why, but When to Complete an Assessment on an Electrical Distribution System”, Christopher Smart, PE - Finley Engineering Company	Westminster Ballrooms III, IV
9:30AM	Refreshment Break/Exhibits	Legacy Ballroom (exhibit hall)
10:00AM	A-3: “Aggregate Modeling of Behind-the Meter Solar Photovoltaic Systems and Defining Critical Penetration Thresholds for Distribution Fault Studies”, Jack Carnovale, University of Pittsburgh	
10:30AM	LS-2: “Distribution Automation – Not Your Grandpa’s Distribution System”, Scott Iverson, PE - Mountrail-Williams Electric Cooperative	Westminster Ballrooms III, IV
11:00AM	A-4: “The Value of Early Student Interventions in Building the Future Rural Energy Workforce”, Sean Kufel, PE - Power System Engineering	Westminster Ballrooms III, IV
11:30AM – 1:00PM	Lunch & Keynote Speaker: Mike Duffy	Westminster Ballrooms I, II

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Wednesday April 30, 2025 (continued)

Date	Event	Location
1:00PM	Technical Session B Introduction – Brian Lassiter	Westminster Ballrooms III, IV
	B-1: "Utility Distribution and Power Transformer Planning Practices Surveys and Proposed Planning Guidance Considering Future EV Adoptions", Justin McCann, PE - West Kentucky Rural Electric Cooperative Corporation	
1:30PM	LS-3: "The Fargo-Moorhead Flood Diversion Project Utility Relocations and Impacts", Troy Knutson, PE - Cass County Electric Cooperative	Westminster Ballrooms III, IV
2:00PM	Refreshment Break/Exhibits	Legacy Ballroom (exhibit hall)
2:30PM	B-2: "Identifying Road Speeds and Analyzing Trajectories: GPS-Based Response Time Insights for Electrical Grid Metrics", Weston Mueller, Powder River Energy Corporation	Westminster Ballrooms III, IV
3:00PM	B-3: "Proof of Concept: Utilizing Artificial Intelligence with Ground Level Imagery to Identify and Inventory Rural Electric Utility Overhead Infrastructure", Justin McCann, PE - West Kentucky Rural Electric Cooperative Corporation	Westminster Ballrooms III, IV
3:30PM	LS-4: "Retrofitting for Reliability: A Roadmap to Cost-Effective Wildlife Mitigation", Quentin Rogers – Powder River Energy Cooperative	Westminster Ballrooms III, IV
4:00PM – 6:00PM	Exhibits/Happy Hour Reception	Legacy Ballroom (exhibit hall)

Thursday May 1, 2025

Date	Event	Location
7:00AM – 12:00PM	Registration	Westminster Ballrooms Foyer
7:00AM – 8:00AM	Breakfast Buffet	Westminster Ballrooms I, II
8:00AM	Committee/Subcommittee Information Session – Clifton Oertli, PE	Westminster Ballrooms III, IV
8:30AM	Technical Session C Introduction – Jim Cross, P.E.	Westminster Ballrooms III, IV
8:30AM	C-1: "Using Artificial Intelligence to Improve Reliability and Operational Efficiency of Small-Scale Hydroelectric Distributed Generation", Arjun Bhattacharyya, University of Tennessee/Oak Ridge National Laboratory	Westminster Ballrooms III, IV
9:00AM	LS-5: "How Software and AI Bolster Grid Resilience" Jon Dumas - Southwire	Westminster Ballrooms III, IV

Thursday May 1, 2025 (continued)

Date	Event	Location
9:30AM	Refreshment Break/Exhibitors	Legacy Ballroom (exhibit hall)
10:00AM	C-2: “Synchrophasor-Based Islanding Detection for Distributed Generation Applications”, Timothy Clements, NEI	Westminster Ballrooms III, IV
10:30AM	C-3: “Lesson Learned through Operation and Maintenance of Distribution Electric Grid Connected Utility-Scale Renewable Energy Generation and Storage Projects”, Srikanth Madala, Bluestem Energy Solutions	Westminster Ballrooms III, IV
11:00AM	C-4: “Practical Considerations for Appropriate Arrester Selection”, Chaitali Naik, NEI	Westminster Ballrooms III, IV
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12:30PM	Plaque Presentation – Clifton Oertli, P.E.	Westminster Ballrooms III, IV
12:45PM	Invitation to 2026 – Tampa, FL March 31-April 2	Westminster Ballrooms III, IV
1:00PM	Door Prizes	Westminster Ballrooms III, IV
1:30PM	Adjourn	Westminster Ballrooms III, IV

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TCC Evaluation Method for Evaluating Arc Flash and Arc Blast Hazard at Low Voltages and First-Degree Burns

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***Abstract* - Traditionally, arc flash evaluations have had little to no methodologies for evaluation or literature below the Category 1 (CAT 1), which is 4 cal/cm^2, or even below 1.2 cal/cm^2, which is a second-degree burn. This lower level of the arc flash hazard has been treated as a survivable/curable range, since it is mainly a region of 250 VAC and 130 VDC and below. Historical arc flash research, calculation theory and PPE (Personal Protected Equipment) development has been on the highest levels of arc flash above 1.2 or 4 cal/cm^2. This excellent work in labs and theory has produced the recent IEEE 1584-2018 formulation for estimating arc flash levels. However, arc flash events lower than CAT 1 can still produce very damaging results to the human body, not necessarily to the PPE covered area of the body, but to those portions that may not always be covered, such as the bare skin of the face. Therefore, there is a vulnerability to serious damage to any bare skin sites.**

To address this concern the author has used the TCC (Time-Current-Coordination) arc flash evaluation method to provide a visual and tabular plotting of this vulnerability. The paper will address not only how a second-degree burn can occur at these low voltage levels but, for the first time in publication the plotting on TCCs will consider a first-degree burn as well. Also introduced will be the concept of a "minor arc blast" and its possible co-damaging to the skin, which can be far more damaging than the short-lived arc flash itself. The paper presents this TCC method/technique to examine the arc flash and arc blast at low voltages and provides a real field example of the damage it caused to an electrical worker from an actual event that had both an arc flash and a following minor arc blast.

***Index Terms* - Minor arc blast, low voltage arc blast, arc blast, low voltage arc flash, arc flash, human damage curve, IEEE1584, TCC arc flash evaluation.**

I. INTRODUCTION

There are three parts to the paper. The first part introduces the modelling of a first-degree arc flash burn using the previous arc flash modelling method of the Human Damage Curve with the TCC Arc Flash Coordination Method, which was introduced by this author in 2012 [1]. The second part of the paper will introduce a discussion of the Low Voltage (LV) arc flash hazards and the conceptual consideration of an actual Minor (or Low Voltage) Arc Blast, which will draw from the new TCC information provided in the first part of the paper. The third part will present a real LV arc flash and minor arc blast hazard event that caused harm to an electrical worker. The paper will include and conclude with some suggestions for mitigating this LV hazard.

A. Motivation

The motivation for the paper came from a real field event that had real harm. After reviewing the literature there is very little to no methodologies for arc flash evaluation below the CAT 1 (4 cal/cm^2) or even below 1.2 cal/cm^2, which is a second-degree burn. This lower level of the arc flash hazard has been treated as a survivable/curable range, since it is mainly a region of low voltage, 250 VAC and 130 VDC. In the ordinary North American home with 240V/120V service, temporary arcs occur without much fanfare but do strongly warn the user of the hazard of electricity. Such LV arcs in the open air that are below 250V, as published by Eblen & Short [2], have shown to self-extinguish in less than two cycles or about 33.3 milli-seconds (ms).

Since home fault levels are traditionally supplied by lower single-phase kVA transformers, say 5 to 50 kVA, and have lengthy secondaries, they do indeed extinguish rather quickly. But of course, there are larger homes that will have dedicated services well into large three-phase kVA, where fault levels will be higher. Historically much arc flash research, calculation theory, and PPE (Personal Protected Equipment) development have focused on the highest levels of arcing and arc flash in the industrial/commercial/utility sectors where hazards are more the concern at higher voltages. These higher voltages typically also pair with larger kVA transformers that have higher levels of fault current that can indeed cause second-degree burns starting at 1.2 cal/cm^2 and worse. This excellent work in labs and theory with higher voltages and currents has produced the recent IEEE 1584-2018 [3] formulation for estimating arc flash levels. However, arc flash events lower than 1.2 cal can still produce very damaging results to the human body.

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The normal arc flash evaluation and protection process assumes that once the arc flash is known for a work location, then the worker will initiate all the proper steps and PPE protection. But in LV work where the arc flash evaluations and protection processes have much less safety focus, the use of PPE to cover areas of the body, such as the bare skin of the face, neck, arms and hands, may be less concerning by both worker and management. Unfortunately, that LV mindset from home with generally lower kVA transformers does not translate well at work where typical transformer sizes have much higher kVAs. These higher kVAs will generate stronger arcs and greater arc flash hazard conditions.

In addressing this LV hazard at higher kVAs, the author has limited the review up to 500 kVA for both three-phase 208V/120V KVA and single phase 240V/120V. The effects and results discussed here will, however, only be greater at even higher kVAs. Even transformers at these modest levels have substantial fault currents that may start as a minor arc flash and suddenly progress to a full arc blast.

The other dependent component to any arc flash is the type and size of the current protection device ahead of it. Very fast current-limiting type fuses clear high currents as soon as their rating levels are crossed, but fuses and many molded case breakers have different TCCs that are skewed to allow even still higher current levels than rated to pass. These, as will be noted below, create vulnerabilities in their LV protection.

II. PART 1 – MODELLING THE FIRST-DEGREE ARC FLASH HAZARD

The reader is perhaps wondering, “why have much concern for an arc flash burn for a first-degree,” which is generally understood to be equivalent to a sunburn burn. One of this author’s clients, after an unfortunate LV arc flash event, asked how their workers could be even better protected. This begged the serious question - Does human harm have a lowest point of ‘No Care’? Survivable/curable is indeed an arbitrary low point for defining protectable human harm. So, this author with the support of his client, who chooses to remain anonymous, have developed new information and a process and methodology to begin to address mitigating LV arc flash hazards particularly under high fault current situations.

Even the use of the term first-degree burn is limited to a visual judgement of the surface of bare skin from a faded shade of pink to a bright red skin surface, just short of second-degree blistering. In reality, damage to the skin from radiation is cumulative and may in the beginning not even have a color change to the skin. The author in his research found that technical definitions of a first-degree burn are very limited. The best source that this author found was work done by Dr. Robert Roeder of Southwestern University and is detailed in Reference 4. Roeder was able to determine that for a fair skinned individual a first-degree burn, or sunburn, can occur at as low an incident energy level of 0.005 cal/cm^2.

This is a remarkable level considering a second-degree burn from the Stoll and Chianta research [5] occurs at about 1.2 cal/cm^2, or about 240 times greater than a first-degree.

Many times, a worker may have to get very close to wiring, in order to see and will require the flexibility with un-gloved hands to maneuver a testing device and their probes. The remainder of the worker’s body would normally be expected to be nearly completely covered with adequately electrically rated PPE clothing, such as wearing at least a buttoned-up long-sleeve shirt with a Category 1 (4 cal/cm^2) or greater protection level. Safety glasses and no rolled-up long sleeves should also be expected but, at the LV level, moments of “cheating” their removal in a hot environment could occur, thus providing even more vulnerability to bare skin.

And, of course, there will always be a gradient level of a first-degree burn from the 0.005 cal level to 1.2 cal. Such a gradient is subjective even from a review of different skin types that would have varying levels of melanin in them to degrade and even deflect the radiation from the sun or other sources. These low-cal numbers could of course be further researched only to find even more dependence on how the skin absorbs both visible and invisible levels of radiation. For our purposes, this level of incident energy (0.005 cal/cm^2) will be placed alongside the second-degree burn level (1.2 cal/cm^2) on a TCC to observe their impacts, as small as they both may be perceived.

Using this author’s methodology of the Human Damage Curve (HDC), Figure 1 of a TCC displays the HDCs for both the first- and second-degree burns to the bare skin. It also displays the thermal protection levels for CAT 1 (4 cal/cm^2) and CAT 2 (8 cal/cm^2) PPE. The TCC presentation provides a visual tool of when and where bare skin damage can occur as well as where the lower levels of PPE begin their protection. Note that CAT 1 and CAT 2 PPE levels are above and to the right of the HDC TCC for skin damage, indicating their implied expected protection of the skin from accidental electrical work.

For a quick description and understanding of the HDC curves in the TCC in Figure 1, the angled lower portions of the curves are the constant incident energy (cal/cm^2) portions that vary though the levels of current and time duration of an arc flash event. The vertical line portion of the curve represents the final escape or cessation of the arc flash event, meaning no further damage from the energy will continue in time beyond this point. The HDC for a PPE is representative of the level of its protection, as rated on the PPE clothing item. The area underneath the HDC would be the region where the cal energy is impressed on the clothing. If an arc or arc flash event were to proceed past an HDC then its protection will have failed. One purpose for it being on a TCC is to then find a fuse or breaker to halt the progression of an event before an HDC is reached. The paper in Reference 1 discussed this methodology in greater detail.

The other line on Figure 1, the dotted horizonal line, is the 3-cycle, or 0.05 ms, (60 hertz) level which will be used to demark the two-cycle level (plus one cycle for margin), which from research mentioned above is when an LV arc in the open air will self-extinguish. This two-cycle self-extinguishment level is also noted in the 2023 NESC code [6] in footnote 2 in

Table 410-1 for arcs up to 250V. The interaction between these HDCs and protection devices will be discussed below.

Two important points must be understood in this paper. 1) This discussion in no way addresses the CONTACT level of electrical harm. All proper protections for avoiding any contact at any voltage are assumed and expected by those working with or near electrical surfaces. 2) The burns to the body being addressed here are what are called proximity burns. They occur when a worker is too close to an event and the arc, light, radiation and explosive debris of the event damage the exposed skin which, in the context of this paper, would be basically the face, arms, neck, and even the hands. These areas of the body are generally the least likely to be covered when working LV.

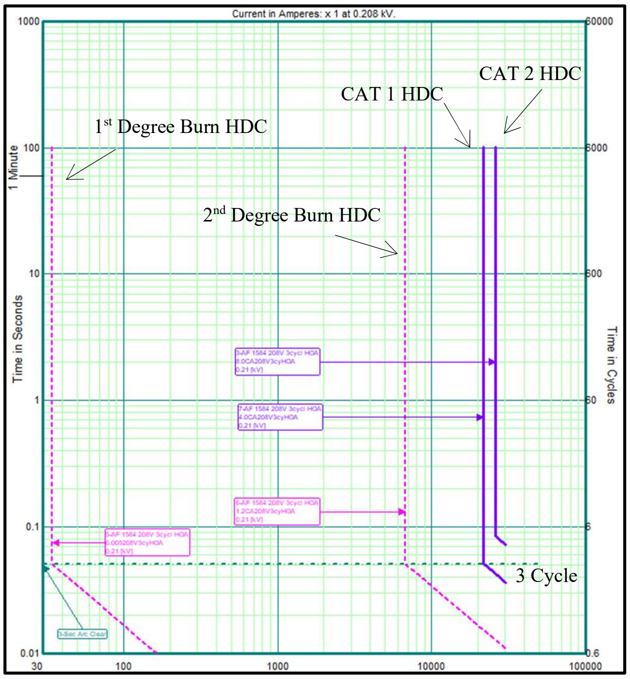

Fig. 1. HDC TCCs for first- & second-degree burn and PPE coverage for CAT 1 & 2.

A. Arc Flash vs Arc Blast

For this paper the duration of an LV arc flash in the open air as mentioned above is less than 33.3 ms. However, for voltage levels 480V/277V and above the arc can continue in the open air by turning the air into a conductive plasma and, depending on the situation, continue until cleared by any one or a combination of factors. An arc blast is differentiated from the arc flash as to being a secondary effect most likely started from a fault and/or arc flash that has progressed into consuming conductive material. The conductive material, such as copper, aluminum, or even steel, liquefies and vaporizes from high current into aerial plasma creating conductive arc paths. Unfortunately, the arc flash is of a lesser concern to the blasting mode of metal vaporization with its fast expansion of hot liquid metal, toxic smoke, harmful sound, and even more radiation of heat and light.

At the 480V/277V level and above much excellent research and publication has occurred. However, with the prevailing limited industry concern on arc flash below 250V, there has also been very little focus on how an LV arc flash progresses to an LV arc blast. A proper lab type understanding of the full spectrum of an LV arc blast is beyond the scope of this paper. This paper will only frame where theoretically such conditions could occur, of which an actual one is presented in the third part of this paper. Those conditions or factors for a LV or minor arc blast theorized here are when:

1) The source transformer or other supply has a very high fault current potential,
2) Certain breaker or fuse protection TCC allows ranges of high-current to pass, and
3) The unfortunate case where an event occurs in front of a worker with skin areas with inadequate PPE.

This theorization will use the TCC method of arc flash evaluation to model how such an event can progress to a minor arc blast. It must also be understood that because this paper uses the term of a minor, or LV, arc blast, it does not in any way minimize the hazard or potential harm to a human.

III. PART 2 – THE LV HAZARD USING TCC ANALYSIS

Like any other unfortunate event, it is when all the factors align at the wrong time in the wrong place. This is true for this discussion of LV harm. It will be addressed through the use of some tables and the TCC tool so there is visual clarity to it. These visual tools can also provide the possibility and opportunity of working to reduce or eliminate the harm associated with some of the factors mentioned above. Each factor will now be discussed.

A. Fault Currents

Before venturing into more details, an understanding of the difference between the bolted fault current and the minimum arcing current is needed. The IEEE 1584-2018 arc flash standard presents this concept and calculation of the minimum arcing current. The arcing current is the current of the fault that follows shortly after the initiating bolted fault. In this transition from the direct contact of the fault to the open air, the current now converts the air into a conductive plasma. The plasma has a much higher impedance compared to conducting at the initial contact event. This higher impedance therefore results in a lower current flow through the arc. The formulation in the IEEE standard calls this the minimum arcing current.

The plot in Figure 2 used the IEEE 1584 calculations to plot the minimum arcing current with its respective bolted fault currents for an arc flash event up to 3 cycles for an 208V HOA (Horizonal Open Air) electrical configuration event. These calculations used an example that produced a 1.2 cal/cm^2 level arc flash at 15 inches with an arc gap of 1 in. As again mentioned for an open-air LV event, the duration of an arc should only last about two cycles in the open air. This relationship between the bolted current and the minimum arcing current will calculate differently for different voltages and other event factors than seen in Figure 2.

Note from Figure 2 that the rough two-cycle open air cutoff for this example of a 208 V event is about 29,800 A and its minimum arc current level cutoff calculates at about 6,918 A. It then follows now to find where and at which transformer kVA sizes for 208V up to 250V could most likely have this sustained two-cycle arc.

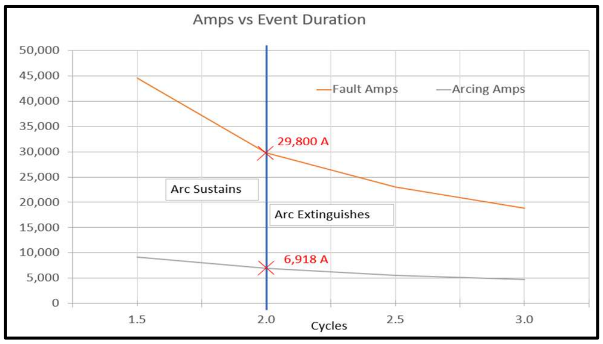

Fig. 2. Example plot of the calculated current levels of a 208V HOA event where the arc would exist and be extinguished.

Below Tables 1 & 2 calculate the estimated max fault levels for a range of kVAs. Table 1 addresses three-phase 208V/120V and Table 2 single phase 240V/120V. For brevity all transformers will use the same impedance of 3.2 %Z to find the max fault level. Since single-phase 208V transformers are not used, Table 2 will use 240V/120V, instead of 208V. The voltage difference for 240V/120V when calculated with IEEE 1584 did change the two-cycle level for the max current to about 25,400 A and the respective arc current level to be about 7,200 A. When applying these "two-cycle" fault/arcing levels to these sets of transformers we find the minimum kVA level where the two-cycle arcing events could possibly occur. For this set of three-phase transformers it would be around 350 kVA and for these set of single-phase transformers it would be around 225 kVA. These kVAs and higher are highlighted in the tables as italic bold-underlined.

And to provide a margin of one additional cycle for a three-cycle arc, the max fault current would be about 18,870 A for a three-phase transformer. This would now lower a possible arc sustaining event to as low as 225 kVA. For the single-phase case this three-cycle level is 16,450 A and would now lower a possible arc sustaining event here to 150 kVA. These are tagged in the tables with the italic font.

Changing the %Z or maximum available fault level would change the tables. However, these kVA levels provide a likely good starting point for an initial increase in concern for arc flash sustained arcing when working under these sizes.

A. Fuse or Breaker Protection TCCs

The next condition that can provide for a sustained arc flash or arc blast is the level of protection of the upstream fuse or breaker. There are mainly two types of fuses, expulsion and current limiting. These were briefly introduced above. The expulsion type is the most common because their TCC curve have their long-time current rated opening level usually at twice the posted number. This type also has a hockey stick portion of their TCC at high ampere levels approaching one cycle. Current limiting TCCs on the other hand are nearly vertical and open nearly always at the rated/posted current and have no hockey stick to the TCC.

Table 1. Three Phase 208V/120V Transformer.

kVA	Max A
50	4,340
75	6,510
100	8,681
150	13,021
167	14,497
225	*19,531*
250	*21,701*
300	*26,042*
350	***30,382***
450	***39,063***
500	***43,403***

Table 2. Single Phase 240V/120V Transformer.

kVA	Max A
25	3,255
37.5	4,883
50	6,510
75	9,766
100	13,021
150	*19,531*
167	*21,745*
225	***29,297***
250	***32,552***
333	***43,359***
500	***65,104***

An example one-line from the utility to a meter case is in Figure 3 and is modelled in the TCC in Figure 4. Figure 4 adds to Figure 1 the damage curve for a 300 kVA, 208V/120V three-phase 3.2 Z% transformer with its 25 A bayonet fuse on the high voltage side. Note from Table 1 that this 300 kVA transformer is in italic and just short of the two-cycle threshold of 29,800 A fault level, but is less than the three-cycle threshold which is at 18,870 A.

Figure 5 adds to Figure 4 the max fault current level of 26,042 A, and the minimum arcing current level at 6,278 A calculated above. The immediate concern that jumps out is that both fault levels are below the fuse level when looking at the time range up to 3-cycles, which means that the event will not clear before 3-cycles in the open air; but, under the wrong conditions, this initial arc could progress to a minor arc blast until the fuse clears the event. Note the burn vulnerability for bare skin for first- and second-degree burns, but not for body portions covered, will at least be CAT 1 PPE. Figures 4 and 5 both also show the transformer protection TCC of a Cooper 108C C08 Bayonet 25A rated fuse.

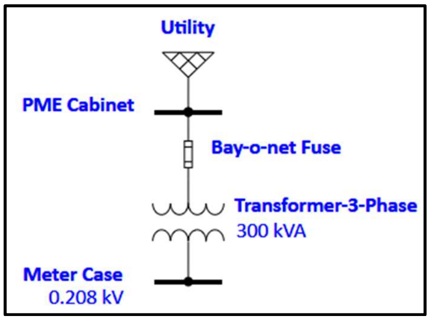

Fig. 3. One-line from the utility to a meter case.

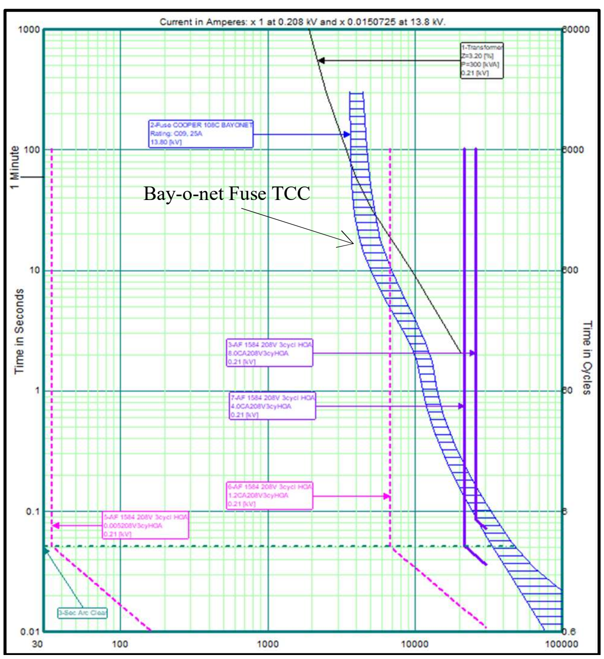

Fig. 4. Addition to Figure 1 a 300kVA transformer with a 25A fuse.

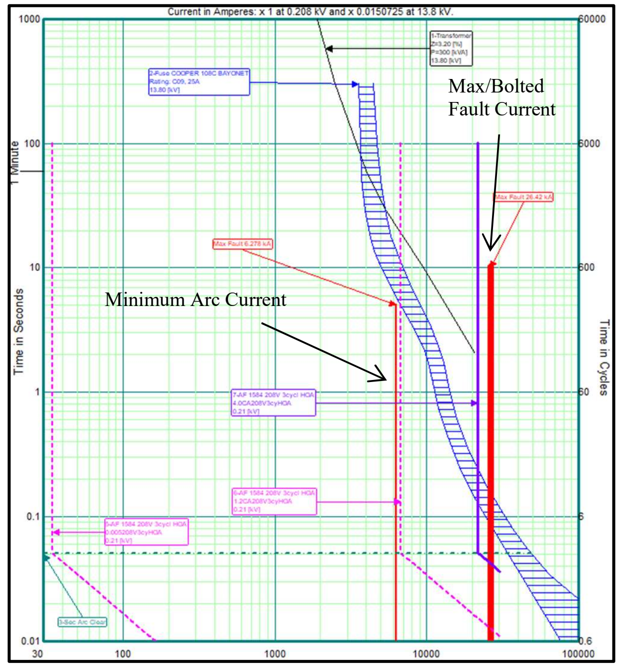

Fig. 5. Addition to Figure 4 the max fault and arcing current levels.

Figure 6 now shows a possible vulnerability range for a second-degree burn as a probabilistic gradient because it is above the 1.2 cal/cm^2 HDC curve. The darker the gradient shows the more likelihood of the burn. It starts at the inception of the arc flash event and continues to the 2- to 3-cycle boundary where at that time the arc could then self-extinguish. However, if during the 2 to 3-cycles the arcing conditions had started melting any exposed conductive metal, then that metal could transition into a vapor or exploding liquid hot metal that now transitions to a minor arc blast. The new vaporized metal will provide additional pathways for the arcing current. This then could at any moment also self-extinguish, or it could continue if arc vapor paths are still adequate and continue until the fuse clears it. Note this probability gradient goes no lower than the minimum arcing current level and goes no higher than a short piercing into the probability space between the minimum melt and total clear portions of the fuse TCC.

Figure 7 extends this concept to the first-degree burn possibility from the arc flash inception until the arc self-extinguishes or if, as mentioned, the arc transitions into a minor arc blast. It must be understood that this is a proposed concept and not provided here as a lab result. However, the actual event discussed in the third part of this paper will provide a reality check to how this could happen.

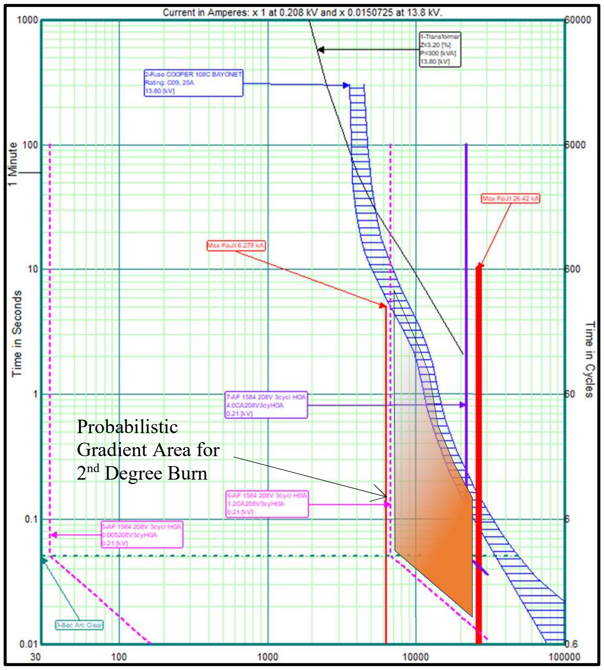

Fig. 6. Addition to Figure 5 the probabilistic gradient for second-degree burn for an arc flash progressing to a minor arc blast.

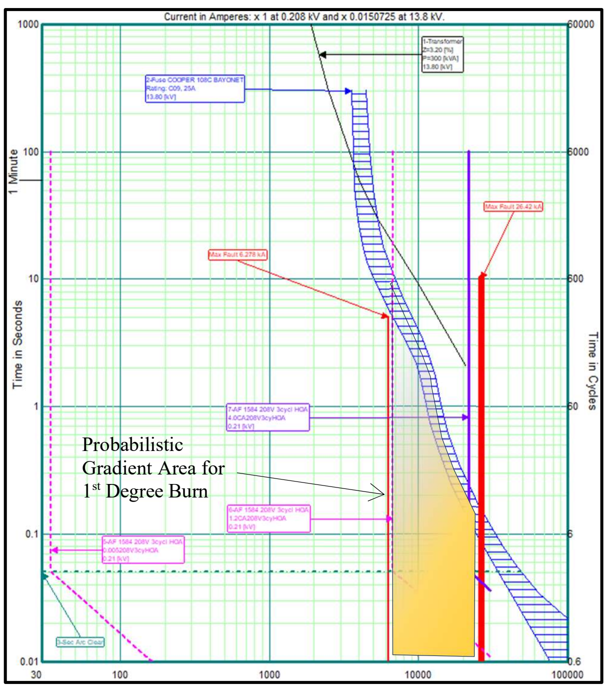

Fig. 7. Addition to Figure 5 the probabilistic gradient for a first-degree burn for an arc flash progressing to a minor arc blast.

Now extending this basic one-line in Figure 3 one more level from a meter case to service points where now a 1200A circuit breaker will provide the load protection after the meter. Figure 8 provides this extension to the one-line.

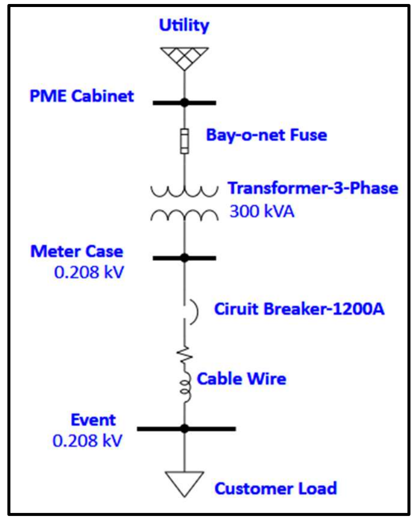

Fig. 8. One-line from the utility to an arc flash event.

Figures 9 and 10 add to Figures 6 and 7 respectively but with the addition of the TCC for a GE 1200 A LV breaker. Note now, that the probability areas for the first- and second-degree burns are much smaller, but are still real possibilities if an arc flash event were to start.

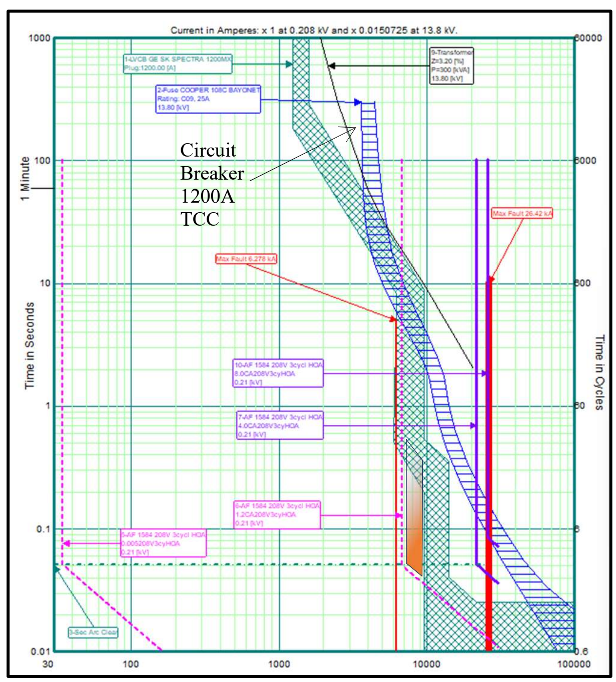

Fig. 9. TCC for probabilistic gradient for a second-degree burn after the 1200A breaker.

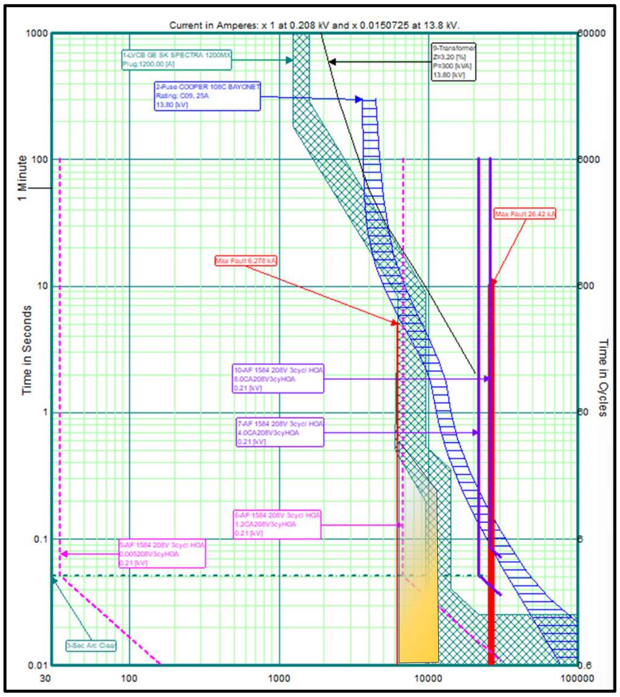

Fig. 10. TCC for probabilistic gradient for a first-degree burn after the 1200A breaker.

B. Workers Protection or an Avoidance Plan Factor

The discussion up to this point has provided some windows into a work site's protection as to how first- and/or second-degree burns could occur to any bare skin. This third factor has the most flexibility to address any vulnerabilities that are discovered. The first step could be to review the work site, which would include obtaining the transformer size and then calculate the bolted fault and the minimum arcing current levels. Then using a TCC, plot the currents and the protecting fuse or breaker. This will likely now show any vulnerabilities.

Next, after being aware of the vulnerabilities for such burns when working an LV site, reviewing PPE needs would be next. Since it is LV, a first reaction is to think that "since this is low voltage there really is little to no harm involved from arc flash and we are in a hurry." Not smart thinking. First, as mentioned, under these LV conditions if all other parts of the body are covered in CAT 1 or CAT 2 PPE or better, then those parts of the body are adequately protected. But since this is LV and workers typically must work close to install, check, and/or test such sites, working with a minimum amount of PPE would be helpful. Bare skin vulnerabilities are an issue. As it happens many times, it is an inadvertent move that starts the contact. If the transformer kVA is small, then maybe only a quick arc occurs and its gone. It might be so quick that any protecting breakers or fuses did not have to operate. However, if the size of the transformer is large, as pointed out above, an inadvertent contact could start with an arc and then rapidly transition into a minor arc blast when more server burns are much more a possibility.

As to what PPE should be worn over bare skin areas in developing a plan for the work site, it leans more on workers and management reviewing each site. Many options are available and start with hard hat or similar, long-sleeved shirt, good eye protection, and appropriate working gloves. Additional items could include face shields and neck coverings. The objective is to cover exposed areas of bare skin. However, it is a reality that sometimes one or more of these protection options could get in the way. This could occur if the ambient heat or cold at a site make it difficult to move or even see clearly the work at hand.

There are other options beyond PPE that could be considered, including: using other possible work sites to test or manage; other tool options that could minimize contact options; or working from a greater distance. If possible, and not the easiest, would be to temporarily change, or change out, an upstream protection device. Such a device would be set up to clear quicker than the primary device for the work site, such as a current limiting fuse or quicker breaker setting. The TCC plot would then be the tool to check for this option.

If after all those considerations there are still concerns, it would be up to management and the worker to fully consider the risk and nature of the task, situation, and location to decide on any reduction in PPE or of a protection option or procedure. The NESC provides for this in Rule 410A4+5, which is, however, never to be taken lightly and only with greatest of care, communication and consideration. Sometimes things can wait when safer conditions can be arranged or occur.

IV. PART 3 – AN LV HAZARD EVENT

The two previous parts of this paper set up the possibility of how a first- or second-degree burn could happen under low voltage situations. This part will now present the actual field situation where there were both an arc flash and minor arc blast involving an electrical worker. Be assured that the worker did walk away from the event and received a thorough medical checkout and is now back at work. The utility has respectfully asked not to be identified but was both agreeable and encouraging to have a paper written about the event so that it could help others to understand how such a type of situation could occur and how to both prepare for and hopefully avoid such a type of occurrence in the future.

The previous parts of this paper were used to both explain and model a LV possible event but also to define the exact situation that occurred in this real event. Figure 8 presented the one-line and Figures 9 and 10 the TCCs for the transformer, protection and HDC curves for where possible conditions could occur for first- and second-degree burns. Unfortunately, they actually occurred starting from an inadvertent shorting in the three-phase 208V/120V 1200 A customer distribution steel box. The inadvertent movement of a VOM probe initially shorted to one of the copper phase bars and then the event progressed to involve all three phases. An additional contributing site issue included some mislabeling of the LV circuits, which made the workers testing a more difficult effort.

The figures below show the actual aftermath of the event. Figure 11 shows the remainder of the copper or copper alloy

VOM test probe tips. One probe totally disintegrated and the other probe is partially gone. Figure 12 shows the damage and the clear loss of copper off the phase bus bars. For comparison, Figure 13 displays the same bus bars when new. The missing copper from both the probes and the bus bars indicate that there was a minor arc blast. Meaning that if, as previous stated by others, that there would be only two cycles or less of a flash and the air would then extinguish the arc and the event would be over, now cannot always be assumed to be true.

Instead, the arc started from the inadvertent contact, then within the two cycles or more the amperage was enough to begin the copper liquefication and vaporization. Next the current continued beyond the two cycles through the arcing using the copper vapor for new paths which were now strong enough to sustain the event. Thus, now theorizing here that the arcing in the copper vapor may have created even lower impendence current paths.

From the discussion above and a review of Figures 9 and 10, this event could now have gone on for a full half second or 30 cycles before the 1200 A breaker would have opened and stopped the event. Time and actual current levels could have varied even more than the theory in the TCCs. So, if the arcing current through the 1200 A breaker was not as calculated and if the second step in the TCC for the short time threshold was off, then the event could have continued up to as long as 10 seconds.

It was reported that where the worker had some exposed bare skin, he received a coverage of some black soot, and then when the soot was removed there was reddening of the skin underneath. There was also a small patch of his skin that received a second-degree burn. Some of the soot from the event can be clearly seen in Figure 11 on the probe where there is a soot shadow of where the workers hand was gripping and in Figure 12 on the fixture wall to the right of the damaged copper bars.

Fig. 11. Damaged meter leads.

Fig. 12. Damaged bus bars in 1200A CB cabinet.

Fig. 13. New bus bars for comparison for a 1200 A CB cabinet.

A. Mitigation

Mitigation is another topic that could generate a great deal of discussion and would vary for the many situations that electrical workers encounter even within the same day. The situation in this paper was for the work being done in a low voltage environment. This paper did not cover the dc aspect but much of the information developed and experienced here would have much carryover.

For simplicity and brevity some of the mitigating actions of the utility after this event included:

1) Changing the probe type to a twist lead type, no spring loaded or long bare portions will be used.
2) Working to create greater visibility when probing to a potential target under test.
3) Various PPE changes for open skin areas of the body.

The author mentioned above in the previous section some other possible mitigation and/or PPE choices and situational changes that could be included in a utility's safety operating procedures.

V. CONCLUSIONS

This paper has now put a brighter light on LV work with a couple of conclusions. One being that for higher LV fault current situations where there is the possibility of a minor arc blast, there must be more concern for the possibility of first- and second-degree burns. The paper provided the interaction of the use of the minimum arcing current, the HDCs for electrical burns, and protection devices that can be assembled within a TCC to determine these vulnerable situations.

This first conclusion should now encourage those looking to increase safety for their environments to determine at what level of kVA will this concept of an LV arc flash and a minor arc blast be of concern for their workers.

For the limited examples in this paper for the three-phase 208V/120V transformers it would be around 350 kVA and above; and, for the single-phase 240V/120V transformers, that level would be at about 225 kVA and higher. As mentioned, the author provides this paper to encourages all readers to examine their transformer sizes and determine where these greater hazard levels exist so as to improve safety maybe just one more level.

The other conclusion is that in LV work the "two-cycle rule" appears to be in serious jeopardy. The paper has pointed out a dependence on the fault level which then translates into the size and impendence of supplying transformers. It also points out the importance of the protecting fuse and/or breaker. A simple conclusion here would be to avoid, or at least be aware of, those devices that would be inadequate to address or clear the minimum arcing current for their transformers.

Electrical work always carries the need for good training and situational awareness. This paper was prompted by a utility that asked if the safety of their workers could be improved beyond the industry low threshold of survivable/curable of a second-degree burn. The author, from his experience and from the TCC methodology of the Human Damage Curve, allowed this paper to be developed and now provides a hopeful yes answer. But, above all, the hope is that this type of knowledge sharing will in the long run support better and safer environments for electrical workers.

ACKNOWLEDGMENTS

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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, 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.

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

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**		

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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.

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

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**		

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.

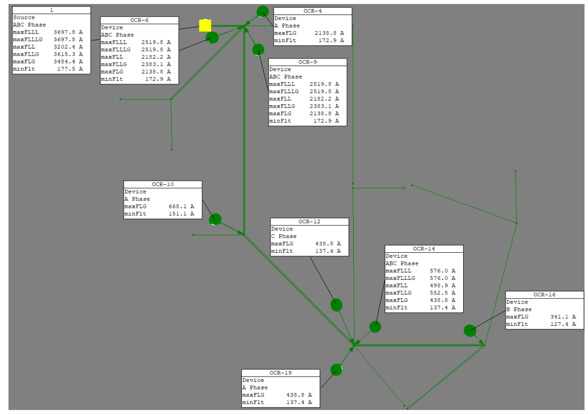
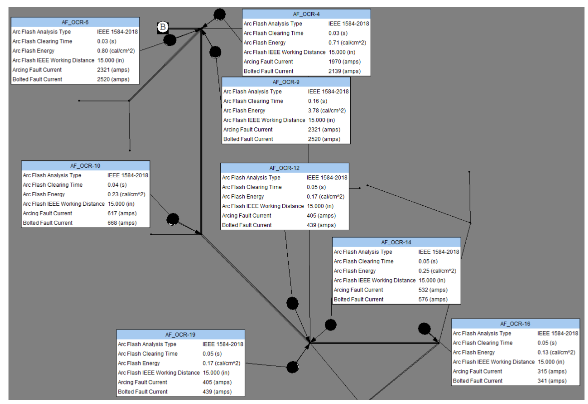


IMAGE 2: Arc flash calculations using the base point 7.5 MVA transformer.



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 downline 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.

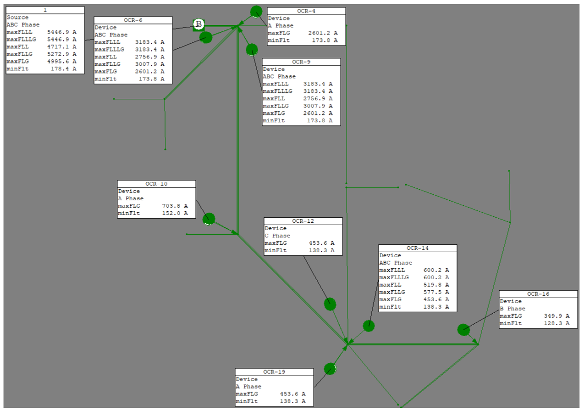
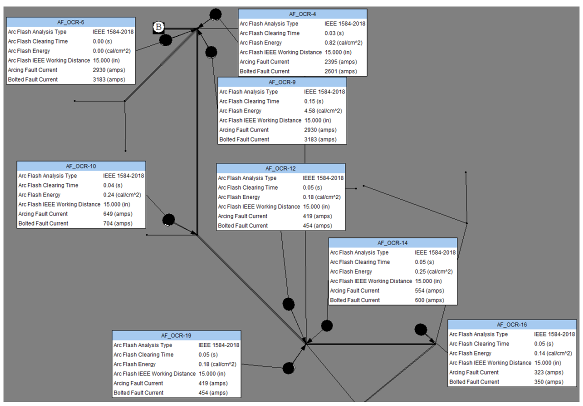


IMAGE 4: Arc flash calculations using the 12 MVA transformer.



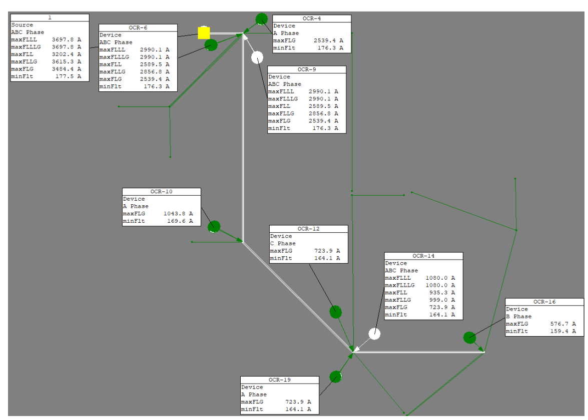
Although the increased fault current due to the transformer upgrade did not dramatically increase the arc flash calculations, there are a few changes that need to be noted. As you will see in Image 4, the arc flash clearing time and arc flash energy on OCR-6 are no longer calculated. This is due to the 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.

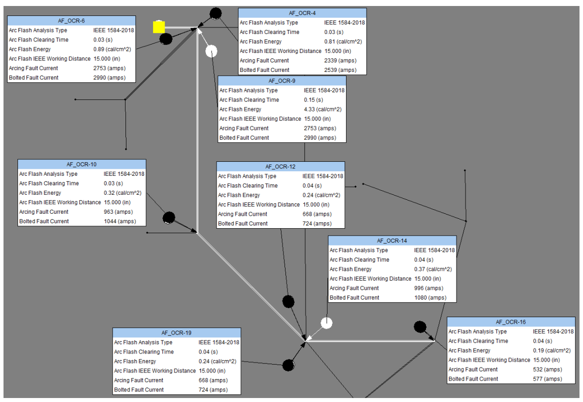
IMAGE 5: Fault current calculations with conductor upgrade from 1/0 ACSR to 795 ACSR



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

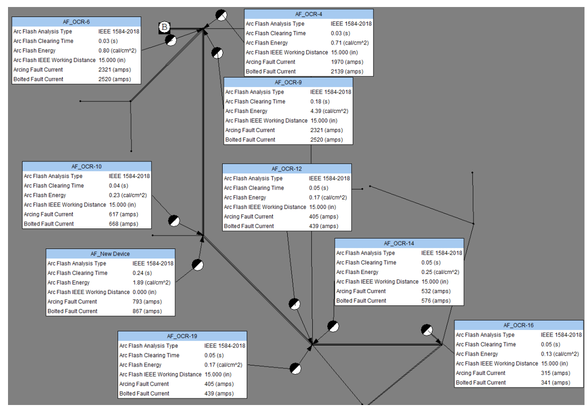
The reliability of an electric distribution system is an integral part of everyday operations. The most commonly used reliability index is the System Average Interruption Duration Index (SAIDI) [3]. To calculate SAIDI, the following formula is used:

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

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 20 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.

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Aggregate Modeling of Behind-the-Meter Solar Photovoltaic Systems and Defining Critical Penetration Thresholds for Distribution Fault Studies

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***Abstract*—The increasing adoption of behind-the-meter (BTM) solar photovoltaic (PV) systems in electric distribution networks has raised questions about their impact on fault analysis. Traditional fault studies often omit the contributions of distributed BTM PV generation, potentially introducing inaccuracies in fault current calculations and complicating protection coordination. This study investigates whether there exists a critical PV penetration threshold, defined as a percentage of total system load, beyond which BTM PV contributions significantly affect fault current levels. A range of PV penetrations is evaluated using both dynamic and static PV fault models, and composite load aggregation techniques are examined as a means to simplify model complexity. Detailed simulations using OpenDSS on the IEEE 8500 Node Test Feeder reveal that BTM PV has a minimal effect on primary-side fault currents, even at high penetration levels. As a result, strict modeling of BTM PV in distribution fault studies may not be necessary for most planning scenarios. Additionally, simple aggregation methods are shown to reduce model complexity and simulation time without compromising accuracy for static simulations. These findings can help utilities streamline fault study practices even as BTM solar deployment continues to grow.**

***Index Terms*—fault analysis, photovoltaic, behind-the-meter, dynamic simulation, distribution modeling, aggregate modeling.**

I. Introduction

The United States is witnessing a significant rise in solar photovoltaic (PV) installations, particularly residential behind-the-meter (BTM) systems. According to an NREL solar market study from 2024, the number of installed residential PV systems has grown at an annual rate of approximately 36% since 2005 following the passage of the investment tax credit. Distributed PV currently accounts for 3.9% of total U.S. generation capacity and 1.7% of total generation [1].

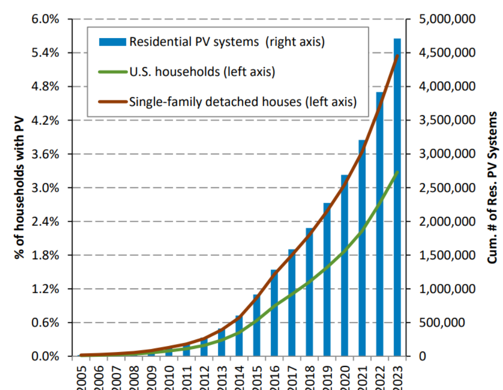

Fig. 1. U.S. Residential PV Penetration 2005–2023 [1]

As BTM solar adoption continues to grow, understanding its influence on power system operation has become increasingly relevant. Because these systems are installed behind the meter, utilities typically measure only the net power used for billing and do not record the individual output of PV installations. While distributed PV functions as a form of generation, its impact on system faults has been less widely studied, particularly at the distribution level. There has been concern that high PV penetration could influence fault current levels, potentially affecting protection coordination. However, there is no consensus in the industry on whether these effects are significant enough to warrant explicit modeling in fault studies.

Modeling BTM PV in fault studies presents unique challenges. As inverter-based resources (IBRs), PV systems exhibit

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highly nonlinear, current-limited fault responses regulated by fast control systems. These characteristics have led to a variety of modeling practices being used across the industry to model PV fault contributions [2]. Modern inverters must also adhere to the ride-through and control requirements specified by the *IEEE 1547 Standard for Interconnection and Interoperability of Distributed Energy Resources (DER)* [3]. Although simple approximations exist, such as modeling the IBR fault response as a constant positive sequence current source or as a current-limited power source [4], these methods often do not capture some of the critical dynamics of PV fault response.

To capture these complex dynamics, researchers have employed higher fidelity simulation methods including AI-based approaches [5], Simulink models [6], [7], and electromagnetic transient (EMT) simulations [8], [9]. Models, such as the WECC pvd1 [10] and the more recent EPRI der_a model [11], have gained traction as well. However, they often require extensive parameter sets (gains, filter values, impedances) that are not easily extracted from manufacturer datasheets. In response, EPRI developed OpenDER, an open-source DER model that adheres precisely to IEEE 1547 dynamic specifications [12]. They have also developed an OpenDSS dynamic PV model that adheres to the IEEE standard. With this built-in model and OpenDSS's dynamics mode [13], it is possible to configure and find dynamics solutions for large systems.

When evaluating the impact of BTM PV on fault studies, a critical consideration is that these systems are typically installed at the secondary level of distribution networks. Due to limited data availability and computational constraints, residential PV installations are often not explicitly modeled in large-scale distribution simulations. Instead, aggregation techniques are commonly used to simplify their representation. Machine learning methods such as clustering [14], binary tree approaches [15], and the use of advanced metering infrastructure (AMI) data [16] have been proposed for DER aggregation, but these techniques require large datasets that may not be accessible to all utilities. A more commonly used alternative is the composite load model [17]–[19], which aggregates downstream static, electronic, and motor loads, along with distributed generation, into a single bus connected through an equivalent line and transformer. This approach significantly reduces model complexity while retaining essential power flow characteristics. However, defining the appropriate equivalent feeder impedance remains a key challenge. Some default values exist [17], but alternative methods such as those proposed by Reiman et al. [20] offer parameter estimation techniques that improve accuracy.

Despite these advancements, many utilities still exclude BTM PV from power flow and fault studies. A 2021 NERC survey [2] reported that 62% of NERC members do not include residential DER in load flow studies, and 73% omit residential DER from dynamic (fault) studies, even though 40% of respondents observed widespread DER tripping during faults. This raises an important question: at what penetration level does BTM PV have a significant enough impact on fault currents to warrant explicit modeling? A 2022 NERC study [21] attempted to define a threshold for including PV in fault studies, recommending that all PV installations be modeled when fault current deviations exceed 5%. However, that study focused on transmission-level systems and large three-phase PV installations, leaving open questions regarding the significance of BTM PV contributions in distribution-level studies.

This paper seeks to clarify the role of BTM PV in fault studies by evaluating whether there exists a critical penetration threshold at which PV contributions to fault currents become significant. Using static and dynamic PV fault models, OpenDSS simulations are conducted on the IEEE 8500 Node Test Feeder [22] to assess fault current levels across various PV penetration scenarios. Additionally, the effectiveness of composite load aggregation is examined as a method for simplifying large-scale distribution system modeling. The results indicate that, even at high penetration levels, BTM PV has a negligible impact on primary-side fault currents. As such, strict modeling of BTM PV in fault studies may not be necessary for most planning scenarios. Furthermore, simple aggregation techniques are shown to effectively reduce model complexity and computation time without sacrificing accuracy for static simulations. These findings provide valuable insight for power system engineers seeking to optimize fault study methodologies in increasingly PV-rich distribution networks.

II. Modeling Techniques

This section details the various PV models and aggregation techniques employed in this study.

A. PV Models

The PV fault response exhibits several nonlinear characteristics–such as current limiting, positive sequence output only, and rapid tripping [23]–stemming from the fast control mechanisms inherent in PV inverters. Consequently, conventional generator fault models are inadequate for representing PV behavior during faults. In this paper, a current-limited generator model and a dynamic model will be considered to represent the BTM PV fault response.

1) Current-Limited Generator Model: One key feature of the PV inverter fault response is its current-limiting behavior. Unlike synchronous generators, which are typically modeled as voltage sources with a series transient reactance, grid-following PV inverters behave more like voltage-controlled current sources with a maximum current of approximately 1.2 to 1.5 per unit of their rated current [4]. While simplified fault calculations often approximate the PV as a fixed current injection, a more accurate representation considers the PV as a power injection constrained by a current limit. This will be the static model used in this study. Figure 2 illustrates the I-V relationship for this model, where the fault current is assumed to be limited to 1.2 per unit.

2) OpenDSS PV Dynamic Model: Due to the highly nonlinear behavior of PV fault characteristics, largely dictated by the guidelines of the *IEEE 1547 Standard for DER interconnection* [3], this study utilizes the dynamic PV model available in

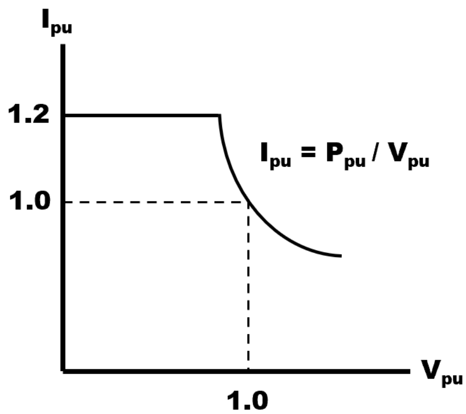

Fig. 2. Simple PV Model I-V Relationship

OpenDSS [13]. In dynamic studies, the PV is coupled with an inverter control object that can replicate the dynamic behaviors mandated by the IEEE standard. This model accurately emulates the tripping and current-limiting features of the PV fault response. It is implemented in OpenDSS via the *py-dss-interface* [24] library and executed through Python by accessing OpenDSS's dynamic solver. The model controller gains and parameters are tuned in this study to fit the response of the EPRI's OpenDER model [12], with notable adjustments being a current limit of 1.2 per unit and a trip voltage of 45% of rated voltage in accordance with IEEE 1547 Standard. This dynamic model is used to provide higher accuracy than the static model. It follows the generally accepted dynamic model for IBRs as proposed by Yazdani [25].

B. Composite Load Aggregate Model

For the aggregation aspect, a composite load model is employed to reduce system complexity. This model, which utilizes equivalent transformers and lines, can provide an accurate approximation of the system behavior at a reduced computational cost. Simply aggregating equivalent loading or generation without these elements can result in significant discrepancies in system losses. Therefore, the composite load model is a valuable tool for achieving simplified yet accurate aggregation.

In this approach, the composite load model represents a residential system using three components: a distribution network, a center-tapped transformer, and a triplex secondary line feeding a bus. At the bus, all static loads and total PV generation are aggregated into two static loads and two 120V PV generators, corresponding to each leg of the center-tapped system. The rated power for these elements is the sum of all power generated and consumed downstream of the aggregate bus. It is assumed that load power can be estimated from customer billing data, and PV generation can be derived from reported PV installations in practical applications.

For the center-tapped transformer, its per unit impedance is assumed to be uniform across all transformers in the system,

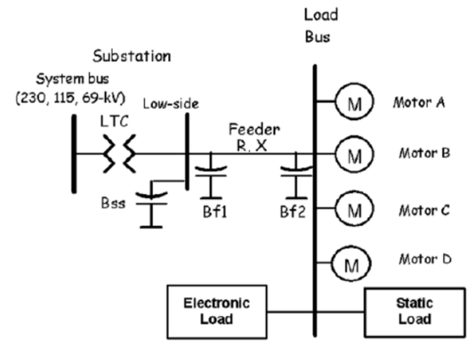

Fig. 3. Original Composite Load Model [17]

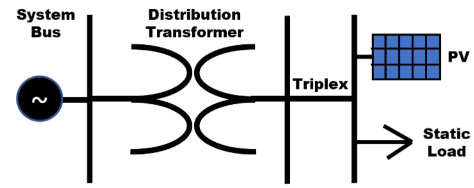

Fig. 4. Simple Composite Load Model with PV

with the transformer power adjusted to represent the aggregate of all downstream transformers. Realistically, a variety of transformer kVA sizes as well as impedances would be installed, however using averages for the composite load and PV model is considered adequate when aggregating. Similarly, triplex conductors will be of varying conductor sizes and lengths, however using justifiable averages for the composite model is considered adequate. Furthermore, to minimize these unknowns, and because many distribution systems utilize similar line sizes and configurations across multiple branches, the aggregate model reuses the most common downstream triplex line for representing the line component. The appropriate length of the triplex line in the composite model is determined by iteratively testing plausible length values until the aggregate model's power flow matches the bus current computed in the non-aggregated model.

III. Fault Study

To evaluate the impact of BTM PV on fault currents, fault studies were conducted using OpenDSS on multiple test cases based on the IEEE 8500 Node Test Feeder [22].

A. Test System

The test system utilized was the IEEE 8500 Node Test Feeder, which represents a typical radial distribution network with aggregated secondary nodes. For the purpose of conducting a fault study, regulator and capacitor controls were disabled.

B. PV Placement

To assess the impact of PV penetration on fault currents, PV units were randomly distributed to 120V nodes throughout the IEEE 8500 Node system, with penetration levels ranging from 1% to 35% of the original system load. The upper limit of 35% was imposed by solver constraints, as higher levels of distributed generation introduced excessive dynamic complexity, preventing the solver from achieving convergence. This remains reasonable, as 35% significantly exceeds typical distributed PV penetration levels [1].

At each penetration level, PV units were assigned to a corresponding percentage of all split-phase nodes. For example, a 25% penetration implies that 25% of the split-phase nodes include modeled BTM PV units. It also denotes that 25% of total load is supported by BTM PV generation. The PV units were rated between 5 kW and 10 kW depending on penetration level, reflecting typical residential BTM PV installations.

Additionally, PV was added in parallel with a static load having the same rated power and power factor, ensuring that the net loading remained constant across all cases. The penetration percentage is defined as

$$\%Penetration = \frac{P_{PV}}{P_{OriginalLoad} + P_{AddedLoad}}, \quad (1)$$

with the assumption that

$$P_{PV} = P_{AddedLoad}. \quad (2)$$

C. PV Model Configuration and Parameter Selection

Both dynamic and static models of the PV system were applied in various tests using OpenDSS. Tables I and II summarize the parameters for the OpenDSS current-limited generator and dynamic PV system models, respectively. The dynamic model was configured to closely replicate the response of the OpenDER model, which has been experimentally validated against real inverter behavior. Figure 5 shows a representative comparison of current waveforms from the OpenDER model and the OpenDSS dynamic PV model under varying voltage conditions. Although the OpenDSS model exhibits slightly more ringing during current transitions, both models ultimately converge to the same current levels during bolted faults, supporting the accuracy of the OpenDSS implementation.

TABLE I
STATIC PV GENERATOR OPENDSS PARAMETERS

Parameter	Value
kVA	P_{PV}
phases	1
kV	0.12
pf	1.0
Gen. Model	7
Ilimpu	1.2

D. Aggregate Systems

To construct equivalent aggregate circuits, five random aggregation points were selected throughout the network, leading to aggregates with diverse load and power characteristics.

TABLE II
DYNAMIC PV GENERATOR OPENDSS PARAMETERS

Parameter	Value
kVA	P_{PV}
kV	0.12
LimitCurrent	Yes
pf	1.0
Ilimpu	1.2
SafeVoltage (Trip)	45%
%R	0
%X	83.33
Pmpp	P_{PV}
irradiance	1
kVDC	0.6
Kp	0.1
PITol	0.01

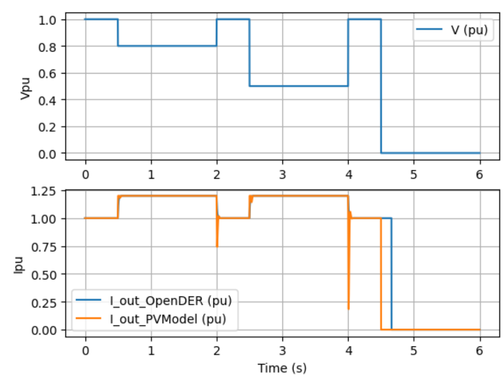

Fig. 5. Comparison of OpenDSS Dynamic PV Model to OpenDER Model

All aggregation followed the method described above and is illustrated in the flow chart in Figure 6.

Both the aggregated and non-aggregated versions of the modified IEEE 8500 Node Test Feeder were employed in this study. The primary objective of aggregation is to reduce computation time while preserving simulation accuracy. Figure 7 shows the aggregated and non-aggregated system.

E. Fault Current Comparisons

For this study, faults were introduced at every node on the distribution primary, and fault currents were measured for each system given varying PV penetrations. All faults on 240V line-to-line secondaries were deliberately excluded, as distribution planners typically set protective device trip settings on the distribution primary.

Both balanced and unbalanced bolted fault scenarios were considered, including grounded and ungrounded three-phase faults, line-to-line faults, and single line-to-ground faults. For each fault, a simulation was run, and the corresponding fault current was measured. Each fault was modeled as a 0.1mΩ resistor connected between faulted nodes.

An iterative power flow solution was leveraged to enable the static PV model to exhibit current-limited behavior. For the dynamic model, the same fault configuration was applied, but the OpenDSS dynamic solver was used. In all fault

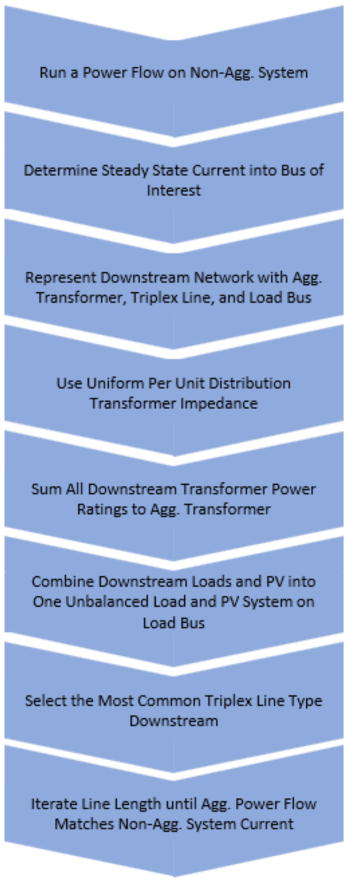

Fig. 6. Flow Chart of Simple Aggregation Method

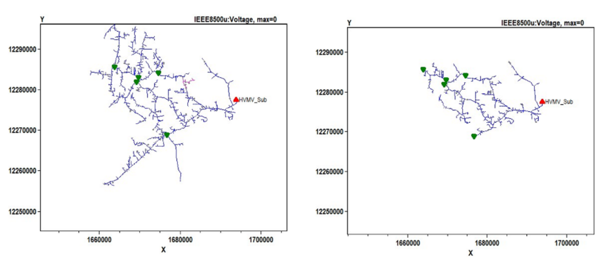

Fig. 7. Aggregation of the IEEE 8500 Node System

simulations, loads were modeled as constant admittances, in line with OpenDSS recommended practices [13].

Following the methodology in [21], fault currents on the same line were compared between different PV penetrations using the following percent difference equation.

$$\%Diff = \frac{|I_{f_{PV}} - I_{f_{NoPV}}|}{|I_{f_{NoPV}}|} \times 100\%. \tag{3}$$

The maximum percent difference between the fault currents measured would then be used to define a brightline threshold for PV modeling. A brightline threshold, as described in [21], defines the boundary of PV penetration above which BTM PV must be modeled to maintain appropriate fault current accuracy, regarding effects on coordination and protection studies. If the penetration of PV in a system is less than the brightline threshold, it is assumed PV contributions can be safely ignored.

Regarding differences in predicted fault currents, a technical report from NERC [26] outlines acceptable fault current variation margins. These are listed in Table III. Considering this report and the study in [21], a fault current exceeding a 5% difference from the base case is deemed statistically significant for this study. Thus, if a certain PV penetration exceeds the 5% difference margin from the base case, BTM PV must be explicitly modeled in fault studies for systems of the same or higher PV penetration.

TABLE III
NERC Fault Importance of Margins of Difference [26]

Current Difference	Priority	Description
Under 5%	Low	Acceptable, Could be Investigated
5-10%	Medium	Acceptable, Should be Investigated
10-15%	High	Should be Investigated
Over 15%	Very High	Must be Investigated

Similarly, to assess the accuracy across models, the percent differences between static and dynamic fault currents, as well as between aggregate and non-aggregate fault currents, were computed for each PV penetration level. Ideally, these differences should be significantly smaller than the percent differences of that PV penetration level compared to its base case.

In addition to comparing fault currents, the average solution time per iteration was recorded. This analysis evaluates the impact of extensive PV modeling on computation time and the benefits of aggregation in preserving accuracy while reducing solution times.

IV. Results

The following sections present the results of the fault current comparisons, using the dynamic model as the reference standard due to its higher fidelity and inclusion of tripping behavior.

A. PV Brightline Threshold

To evaluate the significance of BTM PV on fault current magnitude, results were analyzed across all major fault types using the dynamic model. As shown in Table IV, fault current deviations remained well below the 5% threshold for all penetration levels up to 35%. This confirms that BTM PV systems, due to their current-limited nature and rapid tripping behavior, do not contribute meaningfully to primary-side fault currents, even at penetration levels far exceeding current national averages.

In contrast, the results from the simpler static, current-limited model would support a brightline threshold around

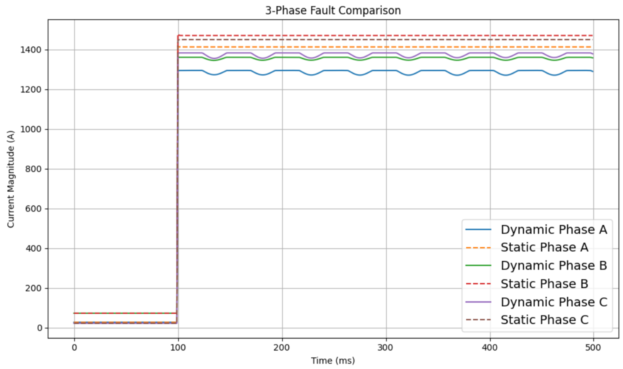

Fig. 8. Three Phase Fault Current Comparison for 25% BTM PV Penetration

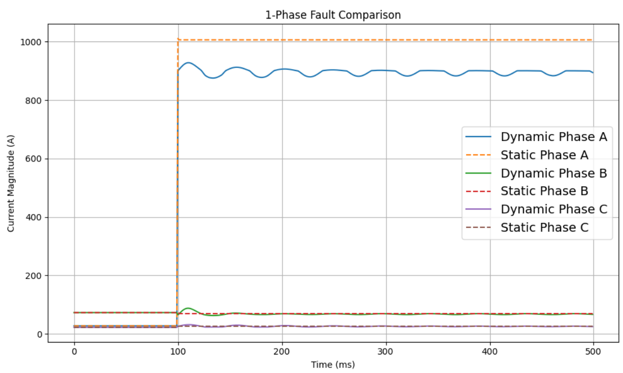

Fig. 9. Single Phase Fault Current Comparison for 25% BTM PV Penetration

15% penetration (Table V). Grounded faults in particular show higher sensitivity, which is expected given the grounded-wye transformer connections between distribution the primary and secondaries, which are common in residential interconnection. Note that results for PV penetrations of 30% and 35% are denoted *DNC* for *Did Not Converge*. The static model was unable to converge for the majority of faults in those scenarios due to overall system model complexity.

However, these results highlight a key shortcoming of static models: their inability to represent fault-induced tripping. Without accounting for dynamic ride-through and protection logic, static models tend to significantly overestimate PV fault contributions at higher penetrations. This reinforces the conclusion that, if PV must be modeled, a dynamic representation is preferred. Nevertheless, given the dynamic results, explicit modeling of BTM PV appears unnecessary for fault studies for systems up to at least 35% penetration.

TABLE IV
MAXIMUM FAULT CURRENT PERCENT DIFFERENCE FOR DYNAMIC MODEL

Percent PV	Fault Type					
	LLLG	***LLL***	***LLG***	***LL***	***LG***	***Max***
1%	0.48%	0.23%	0.48%	0.46%	0.48%	**0.48%**
3%	1.19%	0.69%	1.19%	0.75%	1.19%	**1.19%**
5%	1.26%	1.01%	1.19%	1.19%	1.19%	**1.26%**
10%	1.55%	0.99%	1.55%	1.21%	1.63%	**1.63%**
15%	1.34%	0.84%	1.34%	1.46%	1.46%	**1.46%**
20%	2.50%	2.72%	2.72%	2.72%	2.72%	**2.72%**
25%	2.92%	1.97%	2.92%	2.90%	2.95%	**2.95%**
30%	3.34%	1.81%	3.34%	4.06%	2.90%	**4.06%**
35%	3.69%	2.15%	3.69%	3.77%	3.33%	**3.77%**

TABLE V
MAXIMUM FAULT CURRENT PERCENT DIFFERENCE FOR STATIC MODEL

Percent PV	Fault Type					
	LLLG	***LLL***	***LLG***	***LL***	***LG***	***All***
1%	0.28%	0.20%	0.28%	0.28%	0.28%	**0.28%**
3%	0.95%	0.61%	0.95%	0.94%	0.97%	**0.97%**
5%	1.25%	1.16%	1.25%	1.11%	1.25%	**1.25%**
10%	2.92%	2.38%	3.10%	2.95%	2.51%	**3.10%**
15%	4.49%	3.53%	4.93%	4.54%	3.17%	**4.93%**
20%	8.06%	5.90%	8.38%	8.16%	7.21%	**8.38%**
25%	7.80%	6.64%	9.91%	8.47%	7.36%	**9.91%**
30%	*DNC*	*DNC*	*DNC*	*DNC*	*DNC*	***DNC***
35%	*DNC*	*DNC*	*DNC*	*DNC*	*DNC*	***DNC***

B. Dynamic, Static, and Aggregate Comparisons

When comparing fault current values across modeling approaches, the static aggregation method proved highly effective. As shown in Table VI, percent differences between non-aggregated and aggregated static models remained under 1% across all penetration levels in *(Stat to AggStat)*, in Table VI. This supports the use of simple composite load models for reducing system complexity without compromising accuracy in static studies.

For the dynamic models, aggregation remained accurate at lower penetration levels, but the percent difference increased with higher PV penetration in (*Dyn to AggDyn*), in Table VI. This suggests that while dynamic aggregation is feasible, it may require more sophisticated methods to capture nuanced inverter behavior, particularly when DER penetration is very high. Additionally, a baseline difference between dynamic and static models in *Dyn to Stat* is observed even at 0% penetration, likely due to solver discrepancies and inherent differences in solution methods.

Overall, the variation between dynamic and static model outputs is more pronounced than any change introduced by the presence of BTM PV, further reinforcing that static models should be carefully used for fault studies and that the influence of BTM PV on fault current is negligible.

The evaluation of solution time (Table VII) confirms that aggregation substantially reduces computational burden by more than 50% for both static and dynamic models. This supports the practical utility of aggregation not only for simplifying system representation but also for enabling faster fault studies without sacrificing accuracy in some applications.

In summary, the results of this study consistently indicate that explicit modeling of BTM PV is unnecessary for fault analysis at penetration levels up to 35% of system load.

TABLE VI
MAXIMUM PERCENT CURRENT DIFFERENCE FOR NON-AGGREGATE AND AGGREGATE SYSTEMS

PV Penetration	**Comparison**		
	Dyn to Stat	***Dyn to AggDyn***	***Stat to AggStat***
0%	2.31%	1.19%	0.15%
1%	2.69%	1.51%	0.14%
3%	3.33%	1.57%	0.14%
5%	4.05%	1.98%	0.15%
10%	5.17%	4.31%	0.13%
15%	6.77%	8.0%	0.13%
20%	11.32%	10.76%	0.19%
25%	13.22%	19.79%	0.2%
30%	—	5.95%	—
35%	—	7.73%	—

TABLE VII
AVERAGE TIME PER SOLUTION

Aggregation	**Faults Solved**	**Model**	
		Dynamic	***Static***
Non-Aggregate	27742	2.430 s	1.347 s
Aggregate	14179	0.857 s	0.358 s

While static models tend to overestimate PV contributions, dynamic simulations confirm that BTM PV units trip rapidly and inject negligible current during faults. Simple aggregation techniques can further streamline modeling efforts and reduce solution times, particularly in static studies. Together, these findings offer utilities a clear path toward simplifying fault study practices without compromising reliability or accuracy.

V. CONCLUSIONS

This study demonstrates that behind-the-meter (BTM) solar photovoltaic (PV) systems do not significantly impact primary-side fault currents, even at penetration levels up to 35% of total system load. Dynamic simulations on the IEEE 8500 Node Test Feeder confirm that the fault contributions from BTM PV are negligible due to their fast tripping behavior and current-limited inverter response. As a result, explicit modeling of BTM PV in distribution fault studies is not necessary for typical planning scenarios, removing a major source of complexity for utilities.

While static models tend to overestimate fault current contribution by ignoring tripping logic, dynamic models offer more accurate representations. However, the discrepancy between these models does not translate into meaningful differences in system fault behavior unless unrealistically high penetrations are assumed. Accordingly, modeling engineers should be cautious when using static PV approximations, particularly if evaluating systems where inverter tripping may occur.

In addition, this study finds that simple composite load aggregation techniques can reliably reproduce fault current behavior while substantially reducing simulation time. Static aggregation methods were highly effective, while dynamic aggregation showed increased error at high penetrations, suggesting a need for further refinement in dynamic aggregation strategies.

VI. LIMITATIONS AND FUTURE WORK

Although the findings presented are robust for the test system used, several limitations should be acknowledged. First, the use of a 5% threshold to define a significant fault current deviation is based on guidance from prior NERC work [21], [26], but the appropriate threshold may vary depending on system protection settings, load criticality, or operational standards. Future studies should explore how different fault sensitivity thresholds affect modeling decisions.

Additionally, this analysis was limited to the IEEE 8500 Node Test Feeder, which represents a typical large radial distribution system. However, factors such as network layout and voltage level can affect how PV interacts with faults. Future studies should validate these findings on a wider range of feeders, potentially considering differences between radial and meshed feeders.

Several simplifying assumptions were also made. Regulator and capacitor controls were disabled, and all loads were modeled as static admittances to isolate the effects of PV. Extending the study to include realistic dynamic load models, such as electronic and motor loads, would provide more comprehensive insight. Likewise, while the aggregation method performed well in simulation, practical deployment may be complicated by real-world variability in load behavior, unknown distribution transformer ratings, and incomplete PV reporting.

Another limitation is the assumption that all PV operates at full rated output, which represents a conservative worst-case scenario. In reality, PV output fluctuates throughout the day based on irradiance, shading, orientation, and system health. While fault studies typically focus on worst-case generation, time-series validation or sensitivity studies could add realism to future work.

Looking ahead, several research directions are recommended. Improved methods for dynamic aggregation, particularly for accurately representing inverter trip behavior and feeder impedance, should be developed. Experimental validation using utility fault data, or hardware-in-the-loop experiments, would further solidify the modeling assumptions used for BTM PV. Additionally, further work is needed to address the differences between dynamic and static fault models, particularly by incorporating logic into static models to better represent inverter tripping behavior.

In summary, as BTM PV adoption continues to accelerate, utilities and engineers must evaluate when and how these systems influence reliability studies. This work provides strong evidence that, under most conditions, BTM PV can be excluded from detailed fault modeling without compromising protection accuracy, streamlining the planning process while preserving system fidelity.

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The Value of Early Student Interventions in Building the Future Rural Energy Workforce

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***Abstract*— Finding engineering talent remains a major challenge in the energy sector in 2025, particularly for rural electric Cooperatives. According to the Energy Workforce Survey, turnover in utility companies in 2022 was at its highest in the 17-year history of the survey. While retirements stabilized in 2021 and 2022 for most of the energy sector, retirements at Cooperatives were forecast to surpass the rest of the field in 2023. As has been discussed at previous REPCs, power-focused education within EE bachelor's degree programs remains lacking in the United States, leaving Cooperatives to compete with larger utilities in more urban and suburban areas for a severely limited number of young engineers.**

While internships and cooperative education for college students can be a highly effective recruitment tool, students at that stage are committed to their field. If we are to build a skilled energy workforce capable of meeting the challenges of the energy transition and the grid of the future, we need to impress upon younger students the need for electric power engineers and the potential benefits of entering the field. In Southeast Ohio, Building Bridges to Careers (BB2C) has established a highly effective program of Community and Career Connected Learning, connecting community organizations, schools, and businesses in the region to bridge the gap between education and employment. PSE has been heavily involved in BB2C's activities for several years now, engaging with regional students as young as fourth grade in classroom visits, career days and career fairs, hands-on engineering activities, and job shadowing.

This paper will discuss the value of earlier student interventions in driving career pathway interest based on BB2C's research and program effectiveness in Southeast Ohio and will describe how electric Cooperative engineers can and should be engaging with schools in their regions to drive interest in electric power education and careers.

Keywords—workforce development, education, community

I. Introduction

The future of the energy workforce is a complicated topic, particularly for electric cooperatives. While the 2023 Energy Workforce Survey indicated that the Boomer generation represented just 15% of the workforce and that the gap had "largely been filled" [1], and while overall retirements stabilized in 2021 and 2022, cooperative retirements were expected to exceed the rest of the energy sector. Non-retirement turnover was higher for cooperatives in 2022 than in the rest of the industry as well—9% vs. 7%, according to NRECA [2]. Despite the closing of the industry workforce gap, rural electric cooperatives continue to face challenges in hiring and retaining young talent while competing with larger utilities in more urban and suburban areas.

The needs of the energy industry and its workforce are beginning to change quickly as well. The 2023 Survey was the second that gathered data on emerging technology jobs, and it showed significant growth in jobs related to renewable energy, advanced metering, advanced statistics and data models, machine learning and artificial intelligence applications, and electric vehicle fleet management and maintenance. These types of jobs are an inevitable part of the energy system of the future, even if some cooperatives may lag in their adoption. To meet the demands of this future system, the industry will need many of today's young students to be interested in filling these jobs. Unfortunately, many rural areas where cooperatives are located show a significant gap between interest and skills in advanced energy and local job market needs. This speaks to a need for all of us in the rural electric power industry to connect with younger students than we might have in the past, to ensure that they are aware of the needs and opportunities in an industry that is changing faster than it ever has before. While middle school and even elementary school students may not be thinking yet about their careers, this paper will argue that establishing and maintaining personal connections with local energy professionals throughout their school years will be key to building the future workforce that our industry needs.

II. The Skills Gap in Southeast Ohio

PSE's office in Marietta, Ohio has been involved in student outreach for the last seven years, largely though a local nonprofit called Building Bridges to Careers (BB2C). BB2C's mission is to connect students, educators, and businesses so that students can be aware of and prepared for jobs available in southeast Ohio, and so businesses can build the region's future workforce. As part of its work, BB2C both conducts and compiles research related to workforce development. One of the most striking findings from recent surveying and research is that there is a severe mismatch between student interest and aptitude and regional job growth in the energy and green economy sector; the latest data showed just one student interested in this field. Beyond this, the data showed that interest in other advanced STEM fields is higher than aptitude. All this points to the

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potential for a critical energy workforce shortage in the region, with both little interest and low aptitude scores. With one electric cooperative headquartered in the area and an investor-owned utility also having a significant presence, this is a significant concern.

III. BB2C's Impact on Student Engagement

BB2C is committed to helping students connect learning with real careers and real opportunities. Our programs go beyond the classroom, providing hands-on experiences that help students explore career paths, develop workplace skills, and build connections with industry professionals. Whether it's through internships, mentoring, career exploration, or real-world problem-solving, BB2C ensures that students are aware of opportunities and prepared to pursue them. Even if it means creating something new to provide access to those students and businesses that are in the gaps..

A. Making Learning Real: Career-Connected Learning & Workforce Development

BB2C's Community and Career Connected Learning (CCCL) framework helps students build meaningful relationships with professionals while gaining exposure to real career possibilities. Research shows that high school internships give students a clearer vision for their future and increase the likelihood of them staying and working in their communities [3]. Employers also report seeing growth in students' problem-solving, communication, and teamwork skills as a result of these experiences [4].

Our Career Pathway Specialist works one-on-one with students to help them identify their strengths, explore career options, and develop a personalized career plan. This guidance ensures that students take an active role in shaping their futures rather than passively entering the job market.

B. Learning by Doing: Real-World Problem Scenarios & Community Partnerships

We know that students learn best when they can apply their knowledge to real situations. That's why our Real-World Problem Scenarios (RWPS) program connects students with businesses to tackle real challenges faced by local companies. Instead of just learning theory, students work in teams, think critically, and present solutions to business leaders—giving them a firsthand experience of workplace problem-solving [5]. These experiences build confidence and develop the critical thinking and collaboration skills students will need in any career. These experiences also impact the educators involved in the program as they collaborate with the business partner to create the problem scenario aligned with their curricular standards. The career awareness of the teachers evolves right along with the students' awareness of local job options.

C. Connecting Students with Local Experts & Employers

Our Community and Business Advisory Council (CBAC) ensures that our programs align with the needs of local employers. Through this collaboration, students gain access to internships, mentorships, and career speaker events, helping them build professional networks and explore career pathways in real time [5]. In addition to the CBAC, BB2C works with multiple community partners to develop networking opportunities for educators and students that help them take advantage of social connections that already exist.

The Career Speaker Series brings over 100 industry professionals into classrooms, reaching more than 4,000 students across five school districts. These experts share their career journeys, offer advice, and answer student questions, helping to demystify the world of work [5].

Students also participate in Discover Days, where they get hands-on exposure to different career fields. Whether it's Discover Engineering Day, where students engage in STEM-based activities, or Discover Arts Day, where they work alongside local creatives, these events provide practical career insights and real-world learning experiences [5].

D. Why It Matters

Through these initiatives, BB2C effectively bridges the gap between education and employment, fostering a community-centered approach to workforce development that benefits both students, educators and local businesses.

We also emphasize the importance of place-based exposure—helping students recognize the career opportunities available in their own communities. Many young people in rural areas assume they have to leave home to find success, but BB2C works to change that mindset. By connecting students with local professionals, businesses, and real-world challenges, we show them that fulfilling careers exist nearby, often in industries they hadn't considered. These experiences not only build career confidence but also strengthen the local workforce pipeline, ensuring a sustainable future for both students and the region.

IV. Outreach Opportunities

Over the past seven years, PSE has had many opportunities to engage with local students through BB2C. These have ranged from predominantly speaking sessions like classroom visits and school career days to more hands-on activities like Discover Engineering Day, Y.E.S. Days (Young Engineers and Scientists), and Real-World Problem Solving. These events have allowed us to get in front of hundreds of students from school all over the region every year. Given what we've already stated about the energy workforce and the regional skills gap, we consider it critical to try to make students aware of the needs of the energy industry, the opportunity to have an active hand in the energy transition, and the demand that the industry will have for them if they pursue a career in electric power..

A. Reaching Students Before High School

PSE's outreach efforts started with events like Discover Engineering Day, which allowed us to talk with high school juniors and seniors; certainly a valuable opportunity, but we must also recognize that at that stage, many of those students are set (or close to set) on their educational paths. Opportunities like high school career days and career fairs that invite all high school classes present opportunities to influence students before they've chosen a career path or college major and are great chances to catch kids that may be interested in engineering but not sure what type to pursue. However, if we are to do our part to build a future workforce that can handle not just planning, design and operation of the power grid as we know it today but all of the work related to renewables, energy storage, electric vehicles, advanced grid control, and everything else needed for a successful energy transition, we need to be reaching many more students than are currently heading for college. BB2C has worked with schools and educators to provide us with opportunities to speak to students as young as fourth grade. While it may seem to some like kids at that age are too young to be thinking about their future careers, we would argue that basic knowledge of jobs in the region and personal connections with students as they progress through school are the value of these interactions.

Millennials and older generations did not have a great deal of exposure to the details of many jobs during our school years. Even today, at the ages of 11 or 12, most kids are probably only familiar with three or four jobs: whatever jobs their parents have, maybe the jobs their grandparents have, and "teacher." So, there is already value in giving even middle school students information about what various jobs are actually like. Even today though, it's even less likely that kids know anything about jobs related to electric power. One of the first things I ask of students I speak to is: "do you know anything about the electric power grid?" Unsurprisingly, most of them don't know anything about what it takes to deliver electricity to their homes and schools. Frankly, most people outside of the industry don't know either, and that's fine! That's how it's supposed to work. Electricity is a public good, and the people behind the scenes—i.e., us—are very good at keeping the system running! The average electric reliability in the United States is 99.95%, so chances are that most people don't think about grid operations except for those five hours per year when their power is out. There is high potential to open some young eyes to the jobs that our industry offers.

V. Tips For Engagement

The idea of creating enough material to fill a school class period may seem daunting at first, and not everyone will be immediately comfortable speaking to groups of children. The remainder of this paper will offer some tips and strategies for engaging with students, as well as a call to action.

A. Seek Community Support

PSE has been extremely fortunate to have a group like BB2C providing so much support and so many opportunities for student engagement. If a group like this exists in your area, connect with them! However, if you don't have this kind of facilitator, you can still seek opportunities to speak to students in your area. Start by contacting guidance counselors, science teachers and math teachers in your local schools. Many schools now have some form of career guidance classes, pre-engineering, or something similar; these classes may be open to hosting guest speakers. These contacts may also be able to tell you if there are career days or career fairs that you and your company can participate in. If your state Board or Department of Education requires something like Ohio's Business Advisory Councils, these are also excellent places to get connected to schools and educators. You can also connect with other businesses through local Chambers of Commerce to find out if and how they're involved with classrooms.

B. Keep it Simple

Even for high school students, your talk shouldn't be heavy on technical details. When I talk about what PSE actually does on a day-to-day basis, I keep it to the basics: we help utilities plan for how to upgrade their wires and substations. We design protection so that power doesn't get turned off to more people than necessary. We use computer models and digital maps. We design substations, renewables, and power lines. We do field staking. Unless someone asks for more details, this is as deep as you need to go, as much more technical information is likely to go over your audience's heads. I prefer to focus on the state and future of the industry, the urgency of our need for young engineers, and the impact we have on the communities we serve. It also helps to talk about your education and career path, how you got to where you are, and what makes your utility or company a great place to work. It can be difficult for students (even those who may have been hearing about local jobs for some time) to envision a path to a job in the energy industry, especially if they know very little about it. For older students getting ready for college, they're likely just as interested in the environments they can work in as they are the work they can be doing.

When talking to middle- or elementary school students, I find it helpful to involve some basic comparisons between their homes and daily lives and electric utility systems. How much bigger are 15 KV distribution cables than 120 V power cords? I have pieces of 1/0 and 750 MCM cable that always get a nice reaction. Do they know that the charging blocks for their phones and the power transformers at utility substations do the same basic job? Do they know that we protect the utility system the same way circuit breakers protect their houses (just with more expensive stuff)? These are the kinds of things that can get their attention and keep them focused on the rest of what you have to say.

C. Encourage Discussion

This may be a little more difficult for people still learning to be comfortable speaking to classrooms, but I believe it's important to encourage questions and discussion throughout a session. I've had some of my best classroom discussions come from seemingly random questions that occurred to a student. These can be especially enlightening if they're about the power grid or electricity in general. There will certainly be some teachers who ask students to hold questions until the end, and there will certainly be some classrooms that are simply quiet; still, I always open my presentations by inviting students to (politely, by raising their hands) interrupt me with questions at any time.

D. Hands-On

Obviously not every event or session is conducive to a hands-on activity, but I would still encourage the use of demonstration items at minimum, whenever possible. Pieces of high-voltage wire and cable can make great conversation starters—just ask a group of middle school boys if they can bend 750 MCM cable. Utilities in particular will have all kinds of equipment on hand that can be brought to classrooms, from

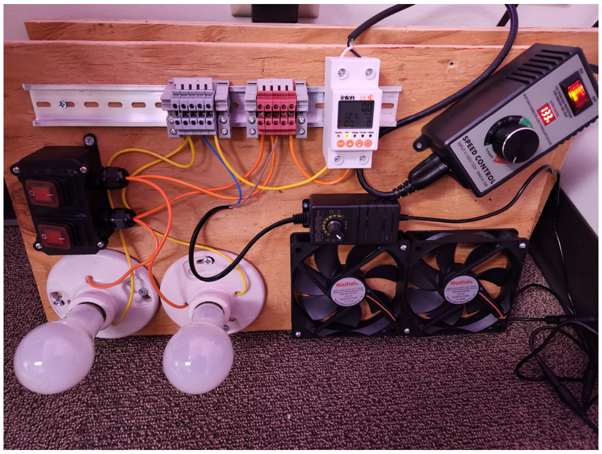

Fig. 1. Smart Circuit Breaker Demonstration Board

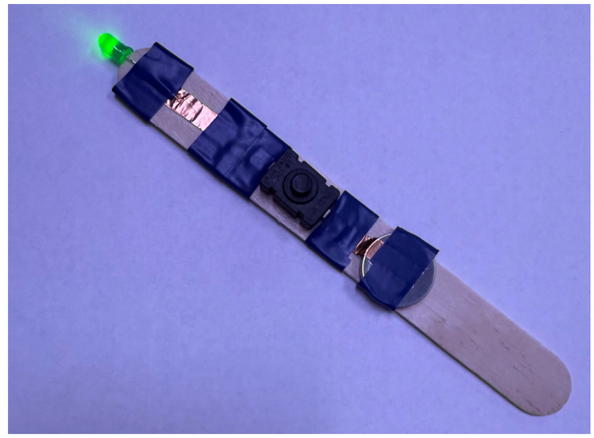

Fig. 2. Craft Stick Flashlight Project

insulators and cutouts to recloser controls and relays. Even if you don't have anything like this, you can build a very simple demonstration board with minimal cost and effort, such as the one shown in Fig. 1. This was built to demonstrate a smart home circuit breaker and required only some basic electrical parts.

For events where hands-on is the point (like our Discover Engineering Day), it's still most effective to keep it simple. We spent several years at Discover Engineering Day helping the students build basic circuits with breadboards, but the principles of a breadboard can be a bit difficult to teach in a 25-minute session, and didn't leave the students with anything they could take with them. In 2025, we changed course and had them build LED flashlights made from craft sticks, button batteries, pushbutton switches, conductive copper tape and multicolored electrical tape (see Fig. 2). This brought students a great deal of satisfaction when they finished the build successfully and gave them a working memento to take home; we even had some PSE stickers for a tiny bit of marketing. We were hearing about how effective this activity was from adults in the community weeks later.

E. Speak With Respect

While it is important to keep your material at a level that will enlighten and not confuse a young audience, it is also important to speak to them like adults. Encourage their questions, make sure they know that all questions are good questions, and even when you're simplifying your language, talk to them like they could be future colleagues. Especially with younger students, you may see them in future classrooms and at future events as they progress through school, and this is a huge opportunity to build and maintain connections. You may end up influencing their educational and career choices, and even if they seem distracted (as kids often do), if you make an impression and talk to them like equals, they *will* remember you.

VI. Call to Action

Thanks to state-level workforce development programs and local groups like BB2C, today's students have much greater exposure to the careers that they might pursue in their adulthood. This is very much a positive for our society. However, we in the electric power industry—and especially in rural power—simply must recognize that we have been a quiet and relatively unchanging industry for a long time. Kids don't see electricity as cutting-edge compared to many other fields; if we're going to build a future workforce that will help us solve the significant challenges we face with the energy transition, we absolutely need to get young people interested in electric power and make sure they understand that there is cutting-edge work to be done on the energy system of the future. We call on all our industry peers at the REPC and beyond to reach out in their communities in whatever way they can and bring awareness of our industry's needs to young people wherever they can. Driving even just a few students toward electrical engineering programs and careers in power will help us move the industry forward in the future, and your presence in their classrooms and lives is likely to be a positive influence in many more ways. Rural electric cooperatives are essential parts of the communities they serve, and your personal contribution can and will be an invaluable resource for the students of your community.

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Utility Distribution and Power Transformer Planning Practices Surveys and Proposed Planning Guidance Considering Future EV Adoptions

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***Abstract*— Transformers are important components of power grids and valuable assets of utilities. Good planning practices help utilities to properly size, rate, and fully utilize the capacity of transformers and prolong the life of transformers. Projected increasing adoption of electric vehicles and the charging demand may have significant impacts on transformers.**

Tennessee Valley Authority (TVA), Tennessee Valley Public Power Association (TVPPA), West Kentucky Rural Electric Cooperative Corporation (WKRECC), and University of Kentucky (UK) have performed a study looking at the impact of increasing EV adoption on transformers and proposing possible guidelines on transformer planning practices considering future EV adoptions.

We have prepared and conducted two surveys on transformer planning practices in 2023, one for distribution transformers and one for substation transformers, building upon (Electric Power Research Institute) EPRI's surveys. The survey questions include current practices for sizing, rating, and loading, replacement, overcurrent protection practices, Electric Vehicle (EV) and program affecting diversity, use of load and ambient temperature profiles when determining rating, use of advanced monitoring techniques for inspection and replacement, etc. The survey attendees are local power companies of TVA. The survey results will help utilities better understand the current transformer planning practices and develop sound guidelines considering future EV charging needs. This paper presents the aggregated survey results and proposed guidelines for transformer planning considering EV adoptions.

Keywords—Distribution transformer, electric vehicle, substation transformer, transforming planning, transformer sizing

I. Introduction

Sound transformer planning is important to meet future load growth including EV charging subject to engineering, regulatory and economic factors. TVA, TVPPA, WKRECC, and UK have performed a study looking at the impact of increasing EV adoption on transformers and proposing possible guidelines on transformer planning practices considering future EV adoptions.

To this end, we have prepared two surveys on transformer planning practices, one for distribution transformers and one for substation transformers, building upon EPRI's surveys [1][2]. The survey results help us to better understand the current transformer planning practices and develop proper guidelines concerning future EV charging needs. This paper presents the survey questions, analyzes the results, and proposes potential planning guidance considering future EV adoptions.

II. Transformer Planning Practices Surveys

The surveys ask the respondents to provide company name, office address, name of the person who completed the survey and contact information and the date. The survey questions are listed below.

A. Survey questions on distribution transformers

- What approach does your organization apply for sizing distribution transformers (e.g., planner's engineering judgment, internal sizing guidelines, software tool, etc.)?
- What factors do you consider when sizing distribution transformers, i.e., kVA? In particular, does your organization apply seasonal use, connected load, load profile, square footage, regional NESC load zones, asset-type specific ratings (e.g., pole-top vs. pad mount), etc.?
- Does your organization apply nameplate ratings provided by the transformer manufacturer and/or ratings developed internally? If the latter, please describe briefly on the approach used to determine the ratings (e.g., values provided in a standard, software, etc.). Do the ratings factor in voltage drop?
- Based on industry standards (e.g., IEEE C57.91), would you be willing to use weather information to develop a software tool to increase/decrease the rating of the transformers?
- Does your organization run distribution transformers until failure (i.e., reactive replacement) or proactively replace transformers based on measured loading and ratings or other criteria? If the latter, how is loading monitored, and what criteria are used to trigger a replacement?
- Do your current distribution transformer rating/sizing practices consider electric vehicle charging or programs affecting load diversity like demand response? If yes,

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please describe briefly. If not, is your organization considering any changes to your existing practices?

- What are your distribution transformer overcurrent protection practices: fuse standards for different transformer types/nameplate ratings, the overload required to melt the fuses, etc.?
- Can you provide more detailed information about distribution transformers, such as kVA, impedance, age, manufacture specifications, if requested?
- Are you willing to provide a detailed computer model for the electric system, if requested?

B. Survey questions on substation transformers

- What approach does your organization apply to sizing substation transformers (e.g., planner's engineering judgment, internal sizing guidelines, software tool, etc.)?
- What factors do you consider when sizing substation transformers, i.e., MVA? In particular, does your organization apply seasonal use, load profile, fault duty, projected loading, asset-type specific ratings (e.g., single phase, three-phase), etc.?
- What types of ratings does your organization currently apply for substation transformer banks of different cooling modes, e.g., ONAN, ONAF?
- Do you apply ratings specific to each transformer or generic ratings (e.g., based on the transformer nameplate)?
- Do you apply planned loading beyond nameplate ratings, long-term emergency ratings, short-term emergency ratings, etc.?
- Do you apply seasonal ratings, fixed ratings for the whole year, or something different (if so, please describe)?
- Does your organization use ratings provided by the transformer manufacturer, or do you specify the ratings internally? If the latter, which department (i.e., engineering or operation) in your organization or outside consultants determine the transformer ratings?
- What standard(s) does your organization follow when determining the ratings (IEEE Std. C57.91-2011, IEC 354, other) and what software does your organization utilize to determine the ratings (e.g., EPRI's PTLOAD, a vendor software (what), or in-house developed software)?
- What transformer aging and temperature limit(s) does your organization apply when determining your ratings? What is the motivation/origin of the limits applied?
- What load and ambient temperature profile(s) does your organization apply when determining the ratings? Are the profiles a single factor vs. 24-hour peak day vs. annual 8760 hours? Are these specific to each transformer or generic for all transformers? Where do you get the profiles?
- How frequently are transformer ratings updated and what drives the need for a reassessment, e.g., after winding refurbishment?
- Is your utility considering any changes to your existing transformer rating practices, considering growing Electric Vehicle adoption and transformer availability? If yes, please describe briefly.
- Can you provide more detailed information about substation transformers, such as MVA, impedance, age, manufacture specifications, if requested?

UK has developed the surveys using the Qualtrics platform. Then WKRECC, TVA and TVPPA helped to distribute the surveys to TVA's 150 Local Power Companies (LPC). The surveys were conducted from May 2023 to November 2023.

III. Distribution Transformer Planning Practices Survey Results

A. Overview on current planning practices on distribution transformers

Sixteen responses have been received for this survey. This section presents the results based on the responses.

Table I shows the overview of the current utility practices on distribution transformer sizing, loading, replacement, and preparedness for EVs.

Table I. Summary of the current utility practices on distribution transformer sizing and loading

Subject (Number of total responses)	Responses (Number of responses, percentage)
Sizing Guidelines (16)	• Engineering judgment (9, 56%) • Internal sizing guidelines (8, 50%) • Use of software tools (0, 0%) • Use of different methods for residential, commercial, and industrial customers (4, 25%)
Factors Considered in Sizing (16)	• Connected load data (14, 88%) • Load profile from similar, existing loads (6, 38%) • Estimated kW based on square footage, type of loads (5, 31%) • Load diversity factors (2, 13%) • Seasonal use (2, 13%) • Panel schedules and size (NESC ratings) (1, 6%) • AMI data when applicable (1, 6%) • Service main breaker size (1, 6%) • Use the same size whether pole- or pad-mounted (1, 6%) • Use different sizing for pole- or pad-mounted (2, 13%)
Rating and loading (15)	• Apply nameplate ratings (13, 87%) • Use IEEE tables for minimum impedance values (1, 7%) • Consider voltage drop with peak kW; Do not have exact impedances for every transformer in analysis software (Windmil) (1, 7%) • Employ an operational distribution transformer loading approach using the factory nameplate capacity as the boundary; Secondary service lengths/conductor size primarily dictate voltage drop considerations (1, 7%)
Transformer overcurrent protection (15)	• Use fuse standards (15, 100%) • Use CSP transformers and fuse conventional transformers (2, 13%) • Fuse rating at 150% of full load (1, 7%)

	• Fuse rating at 300% of full load (1, 7%)
Willingness to use weather information to develop a software tool to adjust rating (14)	• Yes (7, 50%) • No (5, 36%) • Possibly (2, 14%)
Replacement Approaches (15)	• Reactive replacement (i.e., run until failure) (5, 33%) • Both reactive and proactive replacement (10, 67%): Using loading data to identify overloaded transformers or transformers with out of tolerance voltage; using IR scan to identify problems; visually identify signs of damage (leaking oil, other defects/corrosion, etc.)
EVs & Program Affecting Diversity (15)	• Current practices do not consider EVs & programs like DR (14, 93%) • Current practices consider EVs (1, 7%) • Considering DR programs (1, 7%) • Thinking about EV charging (5, 33%)
Willingness to provide more detailed transformer information (14)	• Yes (13, 93%) • No (1, 17%)
Willingness to provide a detailed computer model for the electric system (16)	• Yes (8, 50%) • No (5, 31%) • Maybe (3, 19%)

B. Transformer sizing guidelines

Half of the respondents use engineering judgement for sizing transformers, and half of the respondents use some kind of internal sizing guidelines. No respondents mention the use of any software tools for transformer sizing.

Four utilities pointed out that they use different types of methods depending on general load types:

- Utility 1: For residential, they use rule of thumb method based on square footage and appliance type. Use some diversification if multiple homes are fed from the same transformer. For general power, they require a load sheet provided by the electrician listing all connected loads and approximate single-phase and three-phase totals.
- Utility 2: For residential, they use the size of the largest load in the house usually the heat pump, the length of the service and then do a flicker calculation. For commercial, they have the electrician fill out a load sheet and use percentages to allow for some diversity. For industrial, they use a load sheet when they can but a lot of these end up being sized to the panel.
- Utility 3: For residential, they use 15 kVA on single-wide trailers and small homes. They use 25 kVA on double-wide and medium size homes. On larger homes they will go with a 50 kVA. For commercial, they talk to the Manager and come up with the best estimate for peak load and size accordingly.
- Utility 4: For residential, they use distribution engineering judgment based on panel size (NESC ratings) and projected load. For commercial or industrial load, customers fill out a load sheet and the transformer is sized based on diversifying load. NESC stands for National Electrical Safety Code

One utility distinguishes between sizing single phase and three phase transformers, and its guidelines are stated as follows: "Single phase transformers are sized by Service Designers and aided by Support Engineering. It has designed internal tools used to size the transformer based on meter counts, if there is gas service to the address, and square footage.

Three phase transformers are sized by the Support Engineers. Members must fill out an issued load letter that outlines all connected kVA, building square footages, future EV installations, etc."

One utility said for pole-top its minimum size is 15 kVA and for pad mount the minimum size is 25 kVA.

One utility uses about 60% of connected load, and another utility assumes 50-70% of connected load usage.

One utility said it chooses the sizes that are typically in stock.

The following factors are considered in sizing transformers:

- Connected load data (14, 88%)
- Load profile from similar, existing loads (6, 38%)
- Estimated kW based on square footage, type of loads (5, 31%)
- Load diversity factors (2, 13%)
- Seasonal use (2, 13%)
- Panel schedules and size (NESC ratings) (1, 6%)
- AMI data when applicable (1, 6%)
- Service main breaker size (1, 6%)
- Use same sizing whether pole or mount (1, 6%)
- Use different sizing for pole or mount (2, 13%)

Generally, for residential customers, utilities commonly use building square footage and load type. For commercial and industrial, utilities commonly use connected load and load profile.

C. Transformer rating and loading.

Almost all utilities use nameplate ratings.

One utility uses IEEE tables for minimum impedance values on pole and pad mounted single phase transformers unless special cases arise where it needs nameplate accuracy.

One utility does take note of nameplate ratings but does not have the exact impedances for every transformer in its analysis software (Windmil). It does take voltage drop into account with peak kW if historical data is available.

One utility employs an operational distribution transformer loading approach using the factory nameplate capacity as the boundary. Transformer capacity ratings do not ordinarily factor into their deployment approach as secondary service lengths/conductor size primarily dictate their concerns for any voltage drop considerations.

One utility mentions that the voltage drop is monitored by smart meters.

D. Transformer replacement

About 33% of the utilities responded with 'run until failure' or reactive replacement without detailed comments.

Other utilities (67%) use a combination of reactive replacement and proactive replacement method. Some said they use the run-until-failure approach unless some issues arise.

Some utilities perform visual inspection and infrared (IR) scan to provide inputs for replacement decision. Some utilities use loading data from AMI or MDM (meter data management) that monitor transformer load to identify overloaded transformers, which will be candidates for replacement consideration. Some utilities use unacceptable voltage drops on transformers as a factor to trigger a replacement.

One utility's response offers valuable insights, which states "Yes, running distribution transformers to failure ensures our customers enjoy these assets to the fullest. However, and to clarify, we use AMI and other institutional data/analysis to monitor transformer loading to identify overloaded units that when meeting specified overload limits, may be replaced. General limits require replacement when peak capacity limits exceed 100% in summer and 130% in winter."

E. *Distribution transformer overcurrent protection practices*

All utilities use fuse standards, with ratings based on the transformer size. One utility specifically mentioned that it uses D fuses for transformer protection.

Two utilities pointed out that they use CSP (completely self-protected) transformers and fuse conventional transformers. One of them indicated that "Most of our single-phase transformers are CSP. We do use some conventional transformers close to our substations. Those are fuse based on kVA size. Our three-phase banks are fused depending on the transformer configuration and kVA rating."

One utility indicated it uses "standard riser fuses for pad mount transformers" and does not mention pole transformers. One utility indicated that "employ fuse standards for both overhead pole mounted and underground pad mounted types that consider transformer capacity, cold load pick-up needs, and the like." Other utilities do not specifically differentiate between pole and pad mounted transformers. So, it seems that utilities do not make such differentiation.

Some utilities provided the overloads that will melt the fuses as follows:

- fuse rating at 150% of the full load of transformers.
- open in 5 minutes when the load is approximately three times full load.

F. *EVs & Program Affecting Diversity*

Most respondents' current planning practices do not consider EVs or other programs affecting load diversity such as demand response (DR). One utility is considering DR program. Several utilities begin wondering and learning what impacts EVs may have on their systems but have not actually taken concrete actions yet.

One utility said it sees well below 25% penetration of level 2 EV chargers for new residential services.

One utility said starting approximately a year ago it began requesting whether EV chargers would be present/future projected on all three phase load letters. If its member decides to add EV chargers, then the utility will take the approach to upsize the transformer accordingly.

G. *Interests in developing a dynamic rating tool using weather information*

This survey asks respondents whether they are interested in using weather information to develop a software tool to increase/decrease the rating of transformers based on industry standards such as IEEE C57.91.

Half of the utilities are interested in such a software tool for dynamically adjusting transformer ratings using weather information.

36% of the respondents either said 'no' without explanation or said they did not see a need for their service area. One utility said its service area climate is pretty predictable year by year.

One utility that said 'no' and provided a detailed explanation: "Despite any consideration for weather (presumably to harvest additional unit capacity), utilities must ensure that requisite transformer capacity is always available to meet their customers "demand" needs... especially, during weather extremes (heat & cold) that often result in placing peak demand on this equipment."

A few members simply said 'maybe' without detailed comments.

H. *Wiliness to provide transformer specific information*

Most respondents are willing to provide transformer data including kVA, impedance, age, and manufacturing specifications. Some mentioned that a mutually agreed Non-Disclosure Agreement (NDA) is needed.

Some data such as transformer impedance data may not be readily available. To get some data, field inspection is needed. One respondent mentioned that they have a database that houses transformer test results if tests are performed and that otherwise they use IEEE tables for minimum impedance values on pole and pad mounted single phase transformers. One member mentioned they have the impedance for some of their transformers but do not start recording the data until the arc flash analysis becomes a requirement.

I. *Wiliness to provide a detailed computer circuit model*

Half of the respondents are willing to provide a detailed computer model for their electric system. 30% of respondents said they are not willing to provide such models. Several members said whether they can provide the model depends on who is requesting the model, why the model is needed, and how the model is used. One member mentioned an NDA would be needed. One member mentioned that a Windmil model could be provided, and the model, however, does not include distribution transformers.

IV. Substation Transformer Planning Practices Survey Results

A. *Overview on current planning practices on substation transformers*

Fourteen responses have been received. This section presents the results based on the responses.

Table II shows the overview of the current utility practices on substation transformer sizing, loading, replacement, and preparedness for EVs.

Table II. Summary of the current utility practices on substation transformer sizing and loading

Subject (Number of total responses)	Responses (Number of responses, percentage)
Sizing Guidelines (14)	• Engineering judgment (8, 53%) • Engineering consultant (5, 33%) • Internal guidelines (5, 33%) • Software (3, 20%)
Factors Considered in Sizing (14)	• Current load, projected load (12, 86%) • Load profile (1, 7%) • Seasonal use (2, 14%) • Basic insulation level, available fault current (2, 14%) • Back-feed scenario, redundancy, system reliability (3, 21%) • Standard sizes (2, 14%) • Flexibility in unit deployment across the system with a high degree of interchangeability (1, 7%) • Trucking requirements (1, 7%)
Rating and loading (14)	• Use nameplate rating (13, 93%) • Use outside consultant to determine rating (1, 7%) • Use fixed rating for the entire year, i.e., no seasonal rating (14, 100%) • Use mixed cooling modes (10, 71%) • Use ONAN/ONAF/ONFAF with three rating levels (8, 57%)
Loading beyond nameplate ratings, long-term/short-term emergency ratings (14)	• Not exceeding nameplate rating (10, 71%) • Exceeding nameplate rating (4, 29%). This is used only when left without option and rarely. This normally would initiate immediate remediation, consideration of building new substations, etc.
Use of load and ambient temperature profiles when determining ratings (12)	• Unsure (1, 8%) • No (5, 42%) • Yes (6, 50%) Information considered: • One day peak usually in summer, monitored by SCADA or metering system • Use 65 degrees Celsius rise rating with both stages of fans based on IEEE Std. • Practice is either generic across all transformers or specific to each transformer • Manufacturer use of ambient temperature at 30 degrees Celsius • IEEE Std. C57.91-2011, C57.12.00
How frequently ratings are updated (11)	• Never update (7, 64%) • May update (4, 36%) Factors that drive the need for a reassessment of rating, upgrade, or replacement include: • Results from Oil test, DOBLE test • Winding refurbishments, rebuilt unit • Any abnormalities identified through monitoring and testing
Consider changing current practices due to EV (13)	• No (12, 92%) • Yes (1, 8%)
Willingness to provide more detailed transformer information (14)	• Yes (11, 79%) • No (2, 14%) • Maybe (1, 7%)

B. *Approach and factors considered for sizing substation transformers*

There are fifteen responses to this question.

Utilities use Engineering judgment, engineering consultant firm, internal guidelines, and software for sizing transformers. No specific mentioning about single phase or three phase transformers. Two members said their substation transformers are three phase with LTC.

One utility said, “we use a standard 25MVA base transformer unless special conditions require some other sizes.”

One utility said, “Our fleet standardization philosophy, institutional methodology, engineering judgement, but most importantly utilization of system planning tools developed around Customer need: current, requested and forecasted using Cyme electric modeling software, SCADA data, etc.”

Another utility responded, “Substation transformer sizing is based on our Construction Work Plans and Long-Range Plans. Planning engineers evaluate current loading levels, estimated load growth curves, and any known incoming loads to evaluate size of new substation transformers. We also take into account any back-feed opportunities the new substation may provide and size up as appropriate.”

Another utility said, “we settled on the standard size some years ago because it gave us great flexibility in backfeed and redundancy scenarios.”

Another utility said, “Substation transformers are 3-phase with LTC. Size is based on the largest MVA available to meet trucking requirements, maximum continuous current ratings in relation to bus sizing, and limited magnitude of available fault current for equipment.”

A utility said, “I use billing data from TVA to see peak times then use that time to apply customer interval data to the load allocation model.”

Another utility said, “Our MVA standardization philosophy ensures the greatest flexibility in unit deployment across our system with a high degree of interchangeability (think common physical sizes & component ratings) and levelized equipment performance (think common BIL's, ampacity, AFC's and such).” Note BIL refers to the basic insulation level, the maximum impulse voltage that insulation will withstand. AFC stands for available fault current, the maximum fault current during a fault.

The following factors are considered when sizing substation transformers:

- seasonal use, current load, projected load, load profile.
- standard sizes.
- basic insulation level, available fault current.
- back-feed scenario, redundancy consideration, system reliability.
- using standardization philosophy to ensure flexibility in unit deployment across the system with a high degree of interchangeability.
- trucking requirements.

C. *Rating and loading, cooling modes*

This section summarizes Survey Q3, Q4, Q6, and Q7.

There are fourteen responses to each of these questions. Thirteen utilities use nameplate ratings, and one utility uses outside consultants to determine the transformer ratings.

One utility said, "We have 3 standard sizes based on historical decisions."

One utility said "We use the nameplate rating. We typically have two power transformers in each substation, because of how our system is built. When the load gets too high for one transformer to carry, we put in another substation."

Regarding cooling modes, some utilities use ONAN, some use ONAF, some use ONAN/ ONAF/ONAF. 'O' indicates that the internal cooling medium is oil. 'A' indicates that the external colling medium is air. 'N' means natural convection. 'F' means forced circulation.

Ten utilities said they have mixed cooling modes. Among these, eight utilities said they are using ONAN/ONAF/ONAF, i.e., two stages of forced air cooling; for these transformers, they have three rating levels.

One utility said "Most of our transformers have three rating levels. Base - stage 1 fans - stage 2 fans (ONAN/ONAF/ONAF)."

One said "25kV base is 36MVA, no forced oil. 13kV base is 25MVA, no forced oil." Another utility said, "New substation units are generally rated with an ONAN/ONAF/ONAF capacity ratings."

Regarding the application for seasonal ratings or fixed ratings for the entire year (Survey Q6), 14 responses were received. All utilities have fixed ratings for the entire year. Some utilities indicate that they look at winter or/and summer peak load of the year to make sure the nameplate rating can carry the load.

Most utilities replied concisely "fixed ratings." One utility said, "I do apply different load mixes for different seasons with a load model for each peak winter/summer season." Another utility said, "Fixed transformer ratings for the whole year are considered as our operational constraints/boundaries for their operation." Another utility said, "We look at loading for the different seasons and the largest peak demand triggers discussions."

D. *Loading beyond nameplate ratings, long-term/short-term emergency ratings*

Fourteen responses were received. Ten utilities said they do not exceed nameplate ratings. Four utilities said yes.

For the utilities that said they do not exceed nameplate ratings, some insightful responses are shown as follows:

- Not typically. We normally stay below 55deg C top end rating.
- We do not overload maximum KVA with contingency planning.
- No. We plan our system around an already deployed first contingency capacity allowing us to efficiently address the potential for transformer overloading, event management, and system preventive maintenance needs.

For those utilities that said they do exceed nameplate ratings, some responses are excerpted as follows:

- If we had to, we would go past the nameplate rating in the winter but would start immediate remediation.
- Possibly short-term emergency ratings but only when left with no other options.
- Yes, through our protective overcurrent settings. In a few rare situations, we have bumped that up, but our Planning Engineers seek out new substations when loading approaches a setpoint.

E. *Standards and software used when determining ratings*

Fourteen responses were received for this survey question. The responses are:

- Seven utilities use IEEE standards C57.91-2011, C57.12.00.
- One utility said standards are determined by outside consultants.
- One utility use Milsoft Windmil software.
- Four utilities do not use any standards and software.
- Two utilities are unsure.

No utilities mentioned IEC 354, EPRI's PTLOAD software, and in-house developed software.

Excerpted responses are shown as follows:

- Our engineering firm gets involved when we are nearing nameplate capacity. Not sure what software they use.
- Our first and foremost standards are the collection of the IEEE/PES Transformer standards starting with IEEE Std C57.12.00.

F. *Transformer aging and temperature limits applied when determining ratings*

Fourteen responses were received for this survey question. Three utilities use 55 degrees Celsius rise in winding temperature.

Excerpted responses are shown as follows:

- None. We do take oil samples and perform DOBLE testing as a preventive maintenance. However, we do not use this information to adjust ratings.
- We test the oil and make sure the temperature (ambient + loading) of the transformer is below the rating.
- We try to stay with 55 deg nameplate rating as max. Most of our units run until either a failure or oil samples/inspection deem the unit unusable.
- Temperature limits are guided by IEEE Std C57.12.00 Clauses 4.1.2.1/5.11.1.1/Others and aging consideration, if ever needed, would be interpreted by IEEE Std C57.91 using individual unit certified test report temperature test data supplemented with field loading details from SCADA, equipment & environmental temperature sensing devices and the like.
- Consultant engineer specifications. We also take the test annually.

G. *Use of load and ambient temperature profiles when determining ratings*

There are twelve responses to this question.

One utility said it is unsure about the answer.

Five utilities said they do not use these profiles to determine transformer ratings. Ratings come from the manufacturer, i.e., nameplate ratings. Among these, one utility said it uses peak system loading for summer and winter to determine if operating within the limits of the nameplate rating.

Six utilities said they use some sort of information for rating:

- One day peak usually in summer.
- Use 65 degrees Celsius rise rating with both stages of fans based on IEEE Std. practice is generic across all transformers.
- Manufacturer specified rating at ambient temperature at 30 deg C; 24-hr peak day; Specific to each transformer; Get profiles from meter data.
- 24-hour peak, monitored by SCADA.

H. *How frequently transformer ratings are updated*

This survey asks about "How frequently are transformer ratings updated and what drives the need for a reassessment, e.g., after winding refurbishment?"

There are eleven responses to this question.

Seven utilities (64%) said they never update transformer rating. Among these, excerpted responses are shown as follows:

- Ratings are never updated. Oil test and DOBLE test provide us with indication when maintenance/replacement are approaching.
- We do not update ratings. Transformer sizes are upgraded if a larger standard size is appropriate and requested by the Planning Engineer.
- Transformer ratings for deployed assets are generally not updated or adjusted, ever. Where winding refurbishments are concerned, we treat them like new equipment and bound their capacity limit by the prescribed/specified nameplate rating confirmed by the manufacturer/vendor through factory testing.

Four utilities (36%) indicate that they may update ratings. Among these, excerpted responses are shown below:

- We use the nameplate rating unless the oil test or some other factor suggests we derate.
- No specific timeframe.
- Unfrequently, only after rebuilds, new installations, etc.
- Transformers are monitored monthly and tested yearly for any abnormalities. Ratings would not be updated unless there was an issue identified that needed further investigation.

Factors that drive the need for a reassessment include:

- Results from Oil test, DOBLE test.
- Winding refurbishments.
- Transformers are monitored monthly and tested yearly for any abnormalities.

I. *Considering changing current practices due to EV adoption*

There are thirteen responses to this question. Twelve utilities said no changes are considered. Most of them do not provide much detail. A few indicated that they feel there will be little EV penetration in their territory. Only when EV becomes more prevalent will they reconsider their practices.

Only one utility said yes but was not sure where to start.

J. *Willingness to provide transformer specific information*

There are fourteen responses to this question. Most respondents (79%) are willing to provide transformer data including kVA, impedance, age, and manufacturing specifications. Two utilities (14%) said no. One utility mentioned that a mutually agreed NDA is needed.

V. Recommendations on Distribution Transformer Planning

This section presents recommendations on distribution transformer planning including sizing, loading, and replacement.

A. *Distribution transformer sizing*

Engineering judgment plays a critical role in current practices. Engineers' expertise may be lost due to retirement or job change. It is recommended that these engineering judgments be thoroughly documented together with any existing internal sizing guidelines to create methodical guidance for sizing transformers.

The following factors may be considered in sizing distribution transformers:

- Connected load data
- Load profile from similar, existing loads
- Estimated kW based on square footage, type of loads
- Load diversity factors
- Seasonal use
- Panel schedules and size (NESC ratings)
- AMI data when applicable
- Service main breaker size
- Specific requirements for pole- or pad-mounted transformers

Load profiles if available provide valuable input for sizing. AMI will provide more availability of typical load profiles for distribution transformers including residential transformers. For commercial and industrial customers, one may consider connected load and load profile. For residential customers, one may consider building square footage and load type, if load profile is not available.

B. *Distribution transformer loading*

The transformer nameplate ratings should be used as the basis for loading. When resources are available, it is recommended utilities perform the following analysis to determine loading for individual transformers:

- Consider ambient temperature profile and obtain adjusted transformer rating for loading based on IEEE C57.91-2011. Especially in winter when the temperature is low, the transformer loading capacity would be higher; in summer when the temperature is high, the transformer loading capacity would be lower. A simplified method for deciding transformer loading when ambient temperature changes is provided in the IEEE C57.91 standard as shown in Table III. Loading according to this table will give approximately the same life expectancy as if transformers were operated at nameplate rating and standard ambient temperature over the same period. It is recommended that a 5 °C margin be used to accommodate temperature measurement inaccuracy, where each degree beyond the 5 degrees is applied to the table.

More accurate thermal analysis can be performed based on IEEE C57.91-2011 clause 7 [3]. When loading current contains harmonics, such analysis can be performed based on IEEE Std C57.110-2018 [4].

- When transformer impedance is available, calculate the voltage drop on the transformer with peak kW to check whether the voltage drop is within limits.
- Dynamic rating may be determined if a real time monitoring system is in place. In such a system, the conditions of a transformer (temperature, oil gas pressure, etc.) and ambient conditions (temperature, wind, etc.) are monitored. IEEE C57.91-2011 may be used to calculate the maximum loading while keeping temperature rise and other indices within limits.

Table III. Loading on the basis of temperatures (average ambient other than 30 °C and average winding rise less than limiting values) (for quick approximation)
(ambient temperature range -30 °C to 50 °C) [IEEE C57.91 table 3]

Type of cooling	% of kVA rating	
	Decrease load for each °C higher temperature	**Increase load for each °C lower temperature**
Self-cooled—ONAN	1.5	1.0
Water-cooled—ONWF	1.5	1.0
Forced-air-cooled—ONAN/ONAF, ONAN/ONAF/ONAF	1.0	0.75
Forced-oil, -air, -water-cooled—OFAF, OFWF, ODWF, and ONAN/OFAF/OFAF	1.0	0.75

C. Distribution transformer replacement

A combination of reactive (i.e., run until failure) and proactive replacement is recommended. While it is desirable for a transformer to run until failure for economic considerations, proactive measures may be taken to identify incipient problems, correct them, and increase the transformer's longevity.

When resources are available, the following practices are recommended:

- Using loading data obtained from the metering system to identify overloaded transformers or transformers without tolerance voltage. These transformers will be treated as replacement candidates for further analysis.
- Using IR scan to identify problems.
- Visually identify signs of damage (leaking oil, other defects/corrosion, etc.).
- Using forecasted load to identify potential overloaded transformers, which will be treated as replacement candidates.

D. Distribution transformer sizing and loading considering future electric vehicle (EV) adoptions

1) Overall distribution transformer sizing procedure with EV charging

To properly size a transformer considering future EV impacts, a reasonably accurate forecast of EV charging demand to be supplied by the transformer is needed. This EV charging can be considered together with other types of loads.

To get a good estimate of future EV adoption, utilities can refer to publicly available EV forecasts for the service area if available and the national average forecast otherwise. The utilities can use local EV registration information obtained from local vehicle registration offices for verification and further tuning the forecast. Normally 5, 10, 15, 20-year forecasts may be considered. As an example, Table IV shows the US cumulative EV projections for three scenarios: low, medium and high adoption scenarios, obtained from [5].

Table IV. U.S. cumulative EV projections for low, medium, and high scenarios [Grid Integration Tech Team, 2019]

Year	EV fleet size (low)		EV fleet size (medium)		EV fleet size (high)	
	Number in Millions	Market share (%)	Number in Millions	Market share (%)	Number in Millions	Market share (%)
2027	1.5	0.6	10	4	29	12
2030	2.1	0.8	14	5	40	15
2040	5.1	1.7	44	15	113	38
2050	8	2.5	85	26	170	53

Table V lists the average value of relevant quantities estimated from National Household Travel Survey.

Table V. U.S. average driving statistics

Count of vehicles per household	1.858
Count of persons per household	2.754
Count of vehicles per person	0.675
Annual miles per vehicle	9579
Annual miles per driver	17782

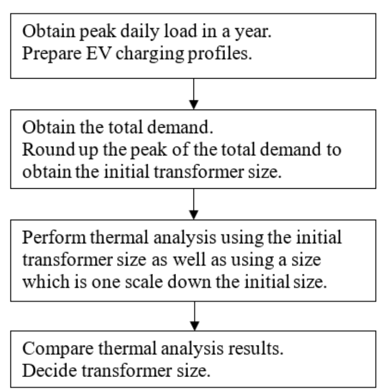

Fig. 1. Transformer sizing procedure

Based on the EV adoption prediction, the number of households a transformer is planned to serve, and the number of vehicles each household has, we can estimate the number of EVs a transformer is going to power.

In addition, it is necessary to know the EV charging profile, which depends on several factors including daily driving distances, EV charger type, charging power, time of charge, and charging energy. Charging behaviors are of random nature, and the above factors are usually intertwined. The total EV charging profiles for a transformer will be the sum of each individual EV's charging profile. Typical charging profiles can be used.

Fig. 1 shows the transformer sizing flowchart considering EV charging profiles. The last step decides whether to choose the initial size or the one-scale downsize. The smaller size that does not cause overloading will be chosen as the required size. However, utilities can choose the one with overloading if the hottest spot temperature and the aging acceleration factor are acceptable.

2) Distribution transformer loading considering EV charging

Detailed transformer loading analysis can be performed based on IEEE Std C57.91-2011 and C57.110-2018 [3][4][5]. Again, obtaining accurate EV charging profiles may be challenging, so typical, selected profiles can be used for studying transformer thermal dynamics.

If utilities do not have the necessary resources to perform the above analysis, the nameplate ratings may be directly used.

3) Relevant study results based on WKRECC system

This section reports the findings related to transformer upgrading and planning based on the EV impact study that UK performed based on WKRECC system. Most of the transformer overloading occurred on transformers with rating 7 kVA, 10 kVA, 15 kVA and 25 kVA. Considering potential prevalence of future EV charging rate of 10-20 kW per EV, to avoid overloading for even charging a single EV, it may be advisable to simply upgrade all transformers of 5, 7 and 10 kVA to a larger rating. It may not be economically feasible to upgrade all 15 and 25 kVA if they account for a significant portion of the assets. So, it may be desirable to use charging controllers to limit the EV charging rate for consumers served by these transformers.

In addition, to avoid transformer overloading for transformers serving multiple consumers, appropriate time-of-use schemes to incentivize consumers to charge their EVs at different times and spread their EV charging as much as possible would be helpful.

For new installations, it may be judicious to consider using only 25 kVA or 50 kVA or above transformers depending on the number of households the transformer is going to serve.

VI. Recommendations on Substation Transformer Planning

This section presents recommendations on substation transformer sizing and loading.

A. Substation transformer sizing

Engineering judgment plays a critical role in current practices. Engineers' expertise may be lost due to retirement or job change. It is recommended that these engineering judgments be thoroughly documented together with any existing internal sizing guidelines to create methodical guidance for sizing transformers. Utilities may also seek advice from outside engineering consulting firms.

The following factors may be considered when sizing substation transformers:

- seasonal use, current load, projected load, load profile.
- standard sizes.
- basic insulation level, available fault current.
- back-feed scenario, redundancy consideration, system reliability.
- using standardization philosophy to ensure flexibility in unit deployment across the system with a high degree of interchangeability.
- trucking requirements.

B. Substation transformer loading

It is recommended that the nameplate ratings be used as the basis for loading. While it is common to use fixed ratings for the entire year, the following factors may be taken into consideration:

- Use of IEEE standards C57.91-2011, C57.12.00, Std C57.110-2018.
- Use of 24-hour peak load monitored by SCADA and ambient temperature when available.
- Use of software, e.g., Milsoft Windmil.
- Use different loading levels for different cooling modes, e.g., ONAN, ONAF, ONAN/ONAF/ONAF. Multiple stages of forced air cooling may be considered for specific applications requiring different loading levels.
- Examining winter or/summer peak load to make sure the nameplate rating can carry the load.
- If loading beyond nameplate ratings is used to meet load, when necessary, immediate remediation and proper protective overcurrent settings should be considered.
- Use of outside consulting.

It is common not to update transformer rating. The following factors may be considered when updating is required:

- Oil test and DOBLE test results provide information about maintenance/replacement.
- Oil test or some other factors may suggest derating consideration.
- When winding refurbishments are made, the new rating will be confirmed by the manufacturer through factory testing.
- Monitor and test transformers regularly, say monthly or yearly, to identify abnormalities that warranty further investigation.

C. Substation transformer sizing and loading considering EV charging

1) EV charging profile for substation transformer

When performing transformer sizing and loading analysis based on Std C57.110-2018, EV charging profiles are needed. In contrast to distribution transformers, EV charging profiles for substation transformers are different from individual profiles of residential households, but aggregate EV charging profiles of all the EVs of residential households served by the feeder. The aggregate EV charging profiles may be less random and more predictable.

Based on the EV adoption prediction, the total number of households a substation transformer (i.e., the feeder) is planned to serve and the number of vehicles per household, we can estimate the total number of EVs a transformer will power.

EV charging profiles over a day can be estimated using NREL EVI-PRO [5][7]. Fig. 3 depicts a sample EV charging profile for 1000 EVs for charging strategy of delayed finish by departure at home and workplace. Fig. 3 shows a charging profile for charging strategy of immediate charging as soon as possible.

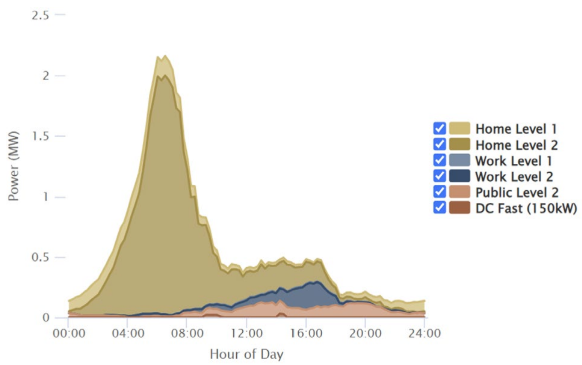

Fig. 2. Sample EV charging profile, Home: delayed-finish by departure, work: delayed-finish by departure.

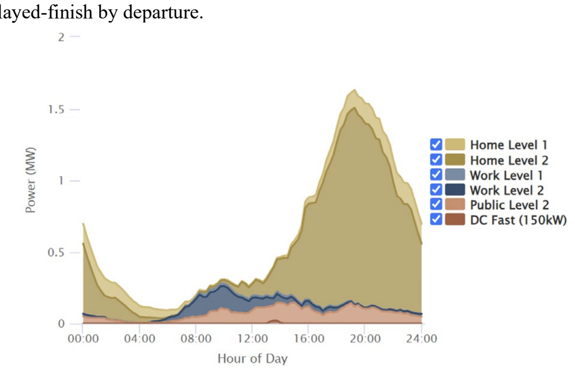

Fig. 3. Sample EV charging profile, Home: immediate, work: immediate.

2) Substation transformer sizing and loading procedure considering EV charging

The procedure as shown in Fig. 1 is still applicable to substation transformer sizing, except the estimated aggregate EV charging profiles will be added to the existing load profiles to calculate the total load profiles seen by the substation transformer. Substation transformer thermal dynamics study considering different EV charging scenarios can be performed similarly to that shown for distribution transformers in the previous section.

VII. Conclusion

This paper summarizes the current practices for distribution and substation transformer planning based on the surveys performed for TVA LPCs. These practices provide valuable insights and best practices for transformer planning. Most utilities do not consider future EV charging needs in their planning. This report provides recommendations on transformer planning by considering additional EV charging in the future.

UK performed an EV impact study using WKRECC system, and studies indicate that there are likely no anticipated problems for the primary components (circuits, transformers) and feeder protection systems to meet the forecasted EV charging demand for decades to come [8]. Therefore, current practices utilities used for substation transformer planning may be adequate to meet EV charging needs for the foreseeable future. Utilities can focus their efforts on dealing with future EV charging needs in their distribution transformer planning process.

Acknowledgment

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Identifying Road Speeds and Analyzing Trajectories: GPS-Based Response Time Insights for Electrical Grid Metrics

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***Abstract*—Calculating travel time to outages from different starting locations is essential for evaluating impacts of staffing levels on a utility's grid outage metrics. Many roads traveled by utility responders are private and/or do not have speed limits, reducing accuracy when determining routes and travel time to outages. This paper demonstrates methods for utilizing OpenStreetMaps (OSM) [1] road data with historical GPS information to analyze changes to the Customer Average Interruption Duration Index (CAIDI) when initial responses to outages come from a different location. By analyzing increases and decreases in first responder response time, we can understand the impacts of handling outages from different shops on CAIDI. The following analysis establishes practices for utilities to develop a model for estimating travel time from different locations and determining impacts on CAIDI through a case study in Northeast Wyoming.**

***Index Terms*—GPS, OpenStreetMap, Outage Management, Grid Metrics, CAIDI**

I. INTRODUCTION

Utilities must respond quickly and efficiently across vast tapestries of the United States and commonly in isolated areas with minimal populations. Finding lineman to live in remote areas can be difficult and reduced staffing may cause impacts on grid metrics. Powder River Energy Corporation (PRECorp), a utility cooperative with approximately 10,400 miles of distribution line serving a territory of 15,952 square miles in Northeast Wyoming, experienced such issues with one of their shops located in Wright, WY. Understanding impacts of handling on-call from an alternative shop in Gillette, WY was necessary to decide how to approach staffing rates. Handling outages during normal business hours was not concerning, as lineman from other PRECorp shops would be stationed in the area for typical maintenance and utility services. On-call would present increased response times of outages as lineman not based in Wright, WY would travel from their associated shop to the Wright outage. As the nearest shop (Gillette, WY) is approximately 40 miles (41 minutes) from the Wright shop, impacts to CAIDI during on-call can be substantial and vary depending on the location of the outage. To respond to an outage, lineman typically utilize a mixture of public and private roadways for navigating to the predicted location. PRECorp's territory encompasses extensive Oil & Gas operations, which contribute to a vast network of private roads. These roads vary significantly in navigability, and many lack available speed data. In the analysis, GPS data collected from PRECorp vehicles was merged with OpenStreetMap roads to create a routable model with the ability to estimate travel time between given locations. Historical outage data for the Wright service area was then combined with Milsoft Utility Solution's Windmil connectivity models and PRECorp GIS data to define outage areas. GPS information during the outage was used to identify first responders to outage areas and the paths in which they took. Finally, alternative routes from the Gillette service area were calculated to estimate the change in response times by first responders. These changes were used to recalculate CAIDI, enabling executive staff to evaluate the impacts and feasibility of handling on-call for Wright from the Gillette shop.

II. DATA

A. GPS Data

PRECorp began storing GPS data for their fleet in 2012 with records included speed, direction, timestamps, active status, and vehicle identification. The frequency of data collection typically ranged from 10 to 30 seconds. Cases existed where GPS data was unavailable such as:

- The vehicle radio which collects GPS data was inactive
- Gaps in network coverage prevented vehicle radios from reporting data

Upon switching a vehicle radio off, the GPS collection software generates a final GPS point with the active status set to false. This information was used to identify sequences of GPS points and a unique route id was created for each sequence.

B. Road Information

Road information with a 'highway' tag was obtained from OSM for PRECorp's service territory and used to create a graph model using the OSMnx [2] and NetworkX [3] python packages through the following steps:

- Create an area envelope of PRECorp's service territory with a 15-mile buffer added to ensure all relevant roads are included.

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- Download OSM data for the area using OSMnx, with the 'highway' tag as a filter (non-simplified, retaining non-connected graphs, truncating roads by the envelope edge).
- Convert the returning data's geometry to the appropriate GIS projection used by PRECorp.

The resulting data is represented as an OSMnx object, which adds geospatial functionality to the NetworkX graph model. As roads can have substantial lengths, those greater than 300 feet were divided into smaller segments using python's shapely [4] package. This allowed the ability to regionalize average speed when merging with GPS data and added granularity of changing road conditions to the model.

During the division of road segments, the validity of connectivity was retained by updating edges and nodes to connect with new segments in the sequence in which they were split. GPS data with a speed greater than 10 miles per hour was then joined to the nearest road segment (up to 100 feet away) using the PostGIS [5] extension's spatial functions in a PostgreSQL database and median speed for each road segment was calculated. Using GPS data with speeds greater than 10 miles per hour prevents the inclusion of cases where a driver purposefully drove at a lower speed than a roadway allows (e.g., "driving lines" in search of issues, repositioning vehicles for maintenance). In some cases, speed information for road segments was unavailable due to a lack of data. In these scenarios, the following methods were used to populate missing information (in order):

- Speed limit listed in OSM data.
- Median calculated speed from upstream and downstream segments so long as the road classification did not change, up to four segments away.
- A default of 15 miles per hour for remaining segments with missing speed information.

With the average speed for each road segment calculated, main public and private roads are easily identified as shown in Fig. 1. The graph model was converted to a table of graph edges and uploaded to PostgreSQL to leverage the PostGIS extension's Dijkstra functions for calculating routes and travel time.

C. *Outages*

PRECorp utilizes National Information Solutions Cooperative's (NISC) Outage Management System (OMS) with Milsoft Utility Solution's Windmil software, uploading connectivity models into OMS on a frequent basis. Models are stored in NISC managed databases and the active model for each analyzed outage was downloaded for identifying the outage location and affected downstream infrastructure. Additional outage details such as CAIDI, the substation upstream of the outage, meters out, the time of the outage, and the time of restoration were also obtained from OMS. As outage data provides GIS information, an 1/8 mile buffer was created for the upstream protective device of an outage, all infrastructure downstream of the protective device, and the location of the substation serving power for each outage. Generating an

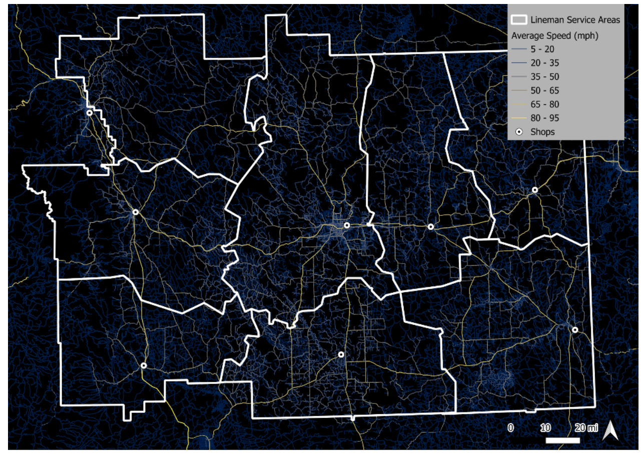

Fig. 1. Map of Average Road Speeds for PRECorp's Service Territory.

outage area allows the ability to identify when a PRECorp employee arrives at the location, which was defined as staying within the area for a minimum of 5 minutes in this analysis. A total of 379 outages from 2018 through 2024 occurred during on-call hours for the Wright service area, however not all were analyzed for the following reasons:

- 16 outages did not have a lineman responder (resolved autonomously or through SCADA).
- 55 outages' had first responders starting their route outside of the Wright Service Area (other shops responding to an outage due to staffing issues).
- 18 responses started inside an outage (GPS did not start recording due to network coverage or other radio issues).

An outage was considered as on-call if it occurred on Saturday, Sunday, or between 4:00 PM and 7:00 AM on weekdays.

III. Route Analysis

A. *First Responders Identification*

As GPS data includes vehicle identification information, we can identify those specifically entering outage areas. For each outage, GPS data with timestamps was analyzed using python's MovingPandas [6] library. MovingPandas provides functionality to convert a set of GPS points into trajectories, where a trajectory is defined as different starting and stopping points along a route. Using these methods provides the ability to identify starting and stopping points for PRECorp vehicles. A trajectory was split into multiple trajectories when:

- There was a 10-minute gap between two GPS points.
- GPS points remained within a 330 foot area for 5 minutes (within 1-2 poles).

Following the application of these operations on GPS data, the first responder was identified as the first vehicle to end their trajectory in an outage area. With first responders identified, the response route was recalculated using the Gillette shop as a alternative starting point. Rather than recalculating the time taken to reach an outage, the time from the Gillette shop to reach any location along the original route was used as

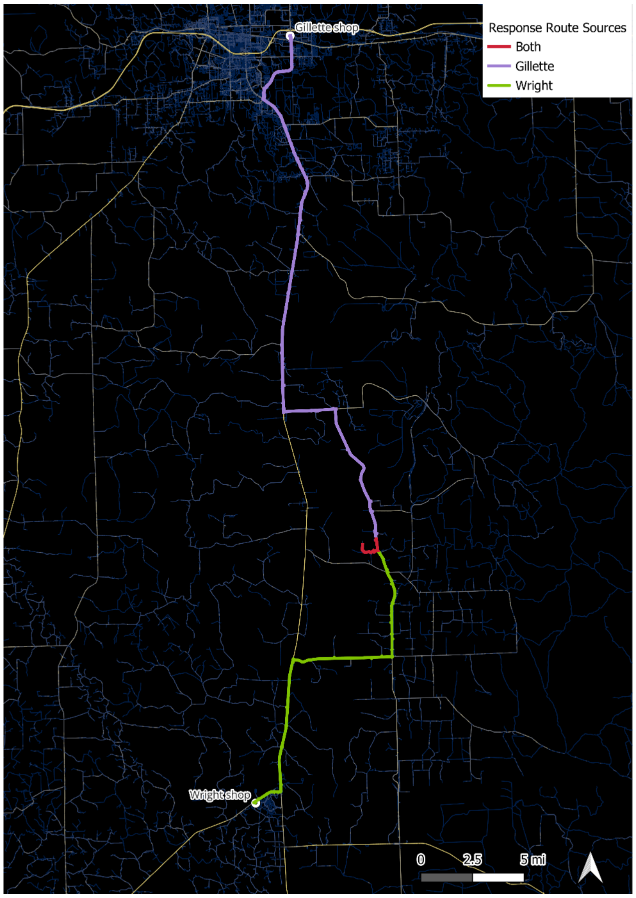

Fig. 2. Comparison of Response Routes from Gillette and Wright to an Outage Area.

shown in Fig. 2. This approach isolates travel time associated with traveling from Gillette and preserves impacts on travel time occurring downstream of where the two routes meet (e.g. non-optimal routes due to locked gates or switching operations). After determining the locations where these routes converge, we calculated the original route's response time to the converge point and assessed the difference from its original starting point to isolate travel time attributed to a lineman living in Wright.

B. *Effect of Travel Time*

Responding from the Gillette shop typically added 35 minutes, however given the vast area that the Wright Shop responds to, A more accurate representation of impact on response times can be estimated by evaluating the changes by substation (see Fig. 3). Analyzing the data in such a way establishes that impacts of outages are not always similar, such as the Hartzog substation being less impacted by an alternative route than the Wright substation.

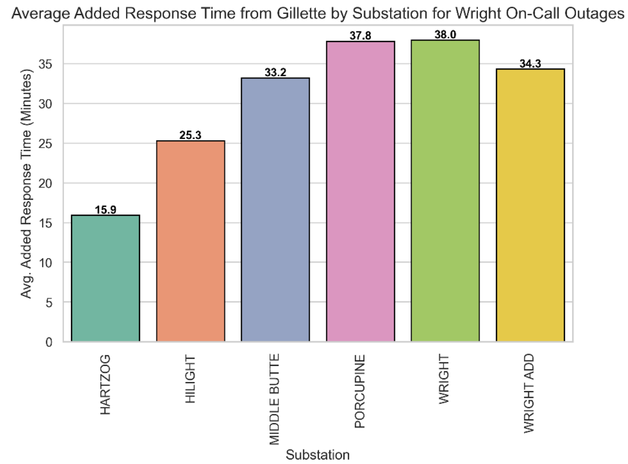

Fig. 3. Average added response time from PRECorp's Gillette shop to outages by substation.

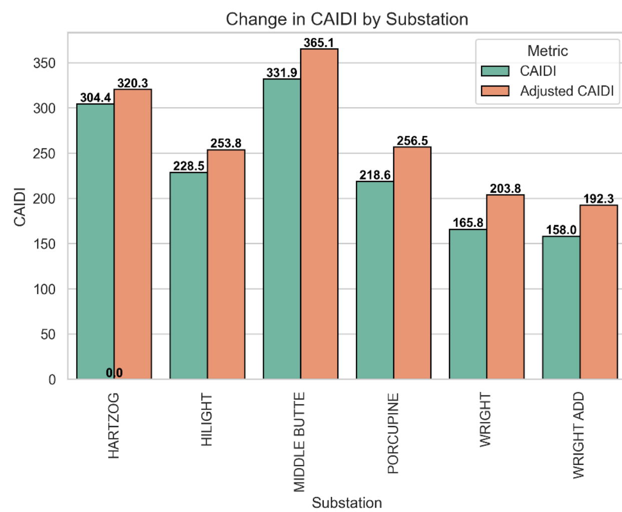

Fig. 4. Adjustments to CAIDI when factoring in added response time from PRECorp's Gillette shop.

IV. Impacts on Grid Metrics

Following the identification of added response time to analyzed outages, we can understand how metrics are impacted by comparing CAIDI with and without the added response time by adding the Gillette shop effect:

$$\text{Adjusted CAIDI} = \text{CAIDI} + \text{MAG} \tag{1}$$

where MAG is the Minutes Added from Gillette responses. Comparing the different metrics for analyzed outages, the Hartzog substation shows to be the least impacted, with CAIDI rising from 304.4 to 320.3 while the Wright substation shows the greatest increase with CAIDI rising from 165.8 to 203.8 as shown in Fig. 4. Reviewing the effects as a percentage change in Fig. 5, we find a large degree in differences between substations, with a 5.2% increase in CAIDI for the Hartzog

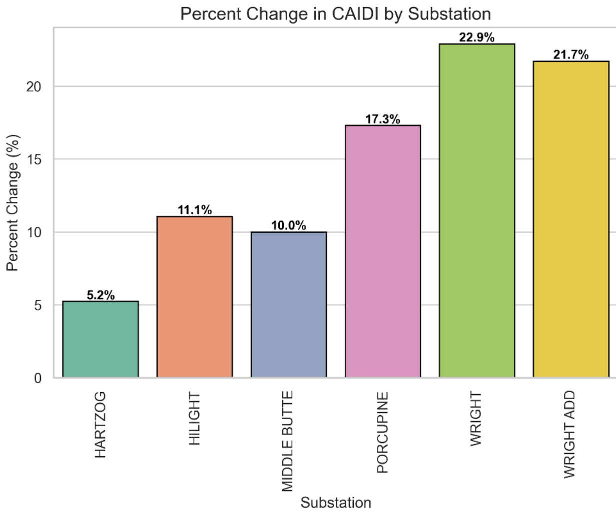

Fig. 5. Percent Changes in CAIDI when factoring in added response time from PRECorp's Gillette shop.

substation and a 22.9% increase for the Wright substation.

V. Conclusion

The integration of GPS and OpenStreetMap data provides a valuable framework for analyzing the impact of response times on key grid metrics. In PRECorp's Wright staffing scenario, we quantified changes in CAIDI when on-call outages were handled by the Gillette shop, typically leading to longer response times. Future analysis could expand to evaluate response times from additional shops, particularly those with the potential for faster dispatch than the Gillette crew. Additionally, the development of a routable model presents new opportunities for estimating travel costs for construction and optimizing service order completion times.

Acknowledgment

Map data copyrighted OpenStreetMap contributors and available from https://www.openstreetmap.org

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Proof of Concept: Utilizing Artificial Intelligence with Ground Level Imagery to Identify and Inventory Rural Electric Utility Overhead Infrastructure

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***Abstract* — The evolution of Artificial intelligence (AI) continues to positively impact utility asset management, creating value-add solutions that were not feasible until now. The case study presented in this white paper was used to define and prove out an automated, cost-effective data collection and asset database population methodology. By building on this case study, utilities can streamline the identification of third-party attachments, pole features, and design discrepancies.**

This pilot project integrated West Kentucky Rural Electric Cooperative Corporation (West Kentucky) assets with AI technology provided by Mesa Associates, Inc. (Mesa), to remotely generate asset management level information for the utility. Through the Tennessee Valley Public Power Association, Inc. (TVPPA) R&D program, the pilot explored the feasibility of using AI tools to gather and analyze distribution structure data. The pilot successfully identified and geo-located Rural Utilities Service (RUS) 1728F-804 C1 and C2 pole top assemblies on distribution poles, achieving a classification accuracy rate greater than 98%. The results demonstrate the viability of AI for improving asset management in a variety of utility settings.

Keywords—Distribution system, pole inventory, artificial intelligence, image processing, pole assessment, pole attachment

I. Introduction

The rural electric industry is reaching the end of a nearly 100-year life cycle, and it is time to address the aging infrastructure, new generation of consumers, and advancement of technology that is changing the landscape of energy production and distribution in the 21st century. Now is the time for utilities to address their steadily increasing capital and operating budgets and determine how to best manage their human and capital investments. Managing assets is a key component of addressing the aging infrastructure that is prevalent throughout the industry. Maintaining an accurate system database is necessary to identify concerns and determine the proper solutions.

Also, today's electric utilities are facing significant challenges that will require a diverse portfolio of both new and existing energy solutions that must include consideration of emerging technologies, existing infrastructure maintenance, environmental requirements, and regulatory mandates. These are all components necessary to create the utility of the future. Emerging analytics and AI tools enable the utility to tackle these challenges efficiently, especially once the foundation is laid with accurate asset information.

With the impact of aging and new challenges being considered, this joint effort between West Kentucky and Mesa was designed to prove-out an easy-to-use and affordable method of identifying and categorizing existing distribution poles. The generated data was intended to be useable in populating and/or checking asset management databases at a price point that matched well with the asset's total installed cost (TIC). Specifically, the AI solution provided geo-locating with acceptable accuracy and identified the structure type based on previously defined RUS guidelines.

In general, utilizing modern AI tools presents a comprehensive strategy to address asset management challenges by integrating legacy knowledge with cutting-edge tools and balancing asset monitoring costs with TIC. By extension, utilities can leverage AI technologies to economically manage large volumes of data, complete image inspections, create/update/maintain asset management databases, enabling better system modeling, improved decision-making and reduced asset management costs.

II. Approach

As with most complex projects and programs, success on R&D activities begins with precise scope definition. To that end, West Kentucky, TVPPA, and Mesa worked together to

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define scope that would accomplish project goals at minimal cost and schedule. Therefore, the study was focused on 5,000 poles within the West Kentucky service territory and limited the RUS classification to two pole types.

The premise was to use using Google ™ Street View images as inputs to an AI engine that utilizes analytic/programmatic tools to automatically detect the asset location and that utilizes machine learning to detect asset design-type. At a slightly more technical level, by using the remotely collected street view data and applying analytics and a neural network, we created a model supported by vector triangulation to confirm both outputs needed for a successful Pilot.

Google ™ Street View images available via Google Maps cannot be used in an automated manner as this violates the terms of service. A paid account was configured to use the Google Maps API[4] to enable programmatic access to the necessary street view imagery. Street view images are available from the API at multiple resolution or zoom levels, and it is these images that can be used to sufficiently locate and classify poles. Using the highest zoom level imagery for the pole detections would drive up costs beyond acceptable ROI levels. To optimize the use of low-resolution free images and high-resolution paid images, AI tools were built and deployed for preliminary examination of low-resolution images with an output designed to then select high-resolution images for final inspection. This multistep approach allowed the Pilot to meet speed, accuracy, and cost constraints simultaneously, rather than failing on one or more of the constraints.

III. PILOT

At the summary level, actual piloting activities included initial data collection, iterative software selection-configuration-testing, and final end-user output evaluation. The first two items (data collection and software iteration) were encapsulated in six project-level steps:

A. Identifying Streetview Locations

B. Initial Panorama Image Request

C. Pole Localization/Mapping

D. Detailed Image Collection

E. Image Classification

F. Structure Classification

The final end-user output evaluation was separate from these six project steps. The evaluation included an ad hoc test just before the final presentation. In a very real sense, this verified both capability and usability for multiple end-users in a final "test" of the pilot results.

A. Identifying Streetview Locations

A web-based application was built that allows the user to click points along a path to define the road that they would like to have images processed along. This web application outputs a CSV of points that define the path. This CSV is read in by the processing application which takes a user input of the desired spacing between points that are generated. The distance between panoramas available in Google Street View vary in spacing, and a user input variable is specified below the minimum spacing typically seen. For this evaluation a value of 20ft was used providing a list of GPS points along the user specified path at intervals of 20ft. This list of points was then used to query the Google Street View API (Street View API Link) to determine the panorama ID of the closest panorama to the specified point location. The panorama ID is a unique identifier for an image capture at a single location. As the user specified spacing value of 20ft is less than the actual spacing there are typically several duplicated panorama IDs in the list, and the duplicates are removed for the next step. After the initial list of IDs is generated, another API call is made to request the metadata for each panorama ID. (Metadata) This response contains useful information including the latitude, longitude, heading, tilt, roll, and date of the image. The full panorama height and width in pixels, as well as copyright information is also returned. This metadata is used to filter out non-Google car images as some images are uploaded by marketing firms, and other individuals/companies and this pilot is only using images from the Google Street View car for consistency reasons.

B. Initial Panorama Image Request

After the list of panorama IDs is filtered, images are requested via the Google Tile API. Google has two different methods of requesting Street View images. One method is using the Street View Static API. More information regarding the Street View Static API can be found at (Documentation).

Using this method, a request is made by supplying the panorama ID, field of view, heading, pitch, and api key. The other method of retrieving an image us using the Tile API (Tile API). The Tile API allows a user to request a Tile which is a 512px x 512px image.

Fig. 1. Street View image of detected distribution poles. Source: From the Owner, Photo by: Google.

For this initial image a Zoom Level of 1 was used, and so two tiles were required to show the entire field of view (360°). These images could then be stitched together (as shown above) for viewing the 360° panorama. A YOLO-NAS [1] object detection model was trained to detect poles and accepts a single image as an input. This model was trained on 2,575 training images and 144 test images. For this step each tile is sent individually to the object detection algorithm and processed. The resulting images after object detection inference can be stitched together as shown below.

Tiles can be requested at zoom levels ranging from 1 to 5. An overview of the Zoom Levels and Approximate Field of View is shown below.

TABLE I. ZOOM LEVELS AND APPROXIMATE FIELD OF VIEW

Zoom Level	Approx-imate Field of View	Tiles per Panorama ID	Cost per Panorama ID
0	360°	1	$0.002
1	180°	2	$0.004
2	90°	8	$0.02
3	45°	32	$0.06
4	22.5°	128	$0.26
5	11.25°	512	$1.02

A data file containing the detections for each image, its GPS location, and the x/y pixel values for each detection are stored for future use.

C. *Pole Localization/Mapping*

For each Image there may be multiple detections, and a single pole may be detected in 7 or more images. For this reason, it is necessary to distinguish between these poles so that we can ensure we are not over counting the number of poles for inventory reasons. A basic methodology was used to triangulate the poles and assign an ID to each pole for tracking purposes. From the x/y pixel detections, the relative angle of the pole from the car's orientation was determined. This angle along with the recorded heading of the car was used to determine the absolute angle of the detected pole from the car's location. Rays were then extended from the car in this direction and overlapping or crossing rays were determined to be a potential pole location. A user configurable parameter was used for the length of this ray, as well as for the number of crossings needed to count as a pole. A manual radius was also set to be used in the calculation to account for slight position differences between the crossing locations. A visual is shown below which depicts the car locations, and the detection rays.

This methodology should be expanded, and alternative methods explored to provide a more robust solution for identifying and tracking the location of the detected poles. For the purposes of this pilot, it was determined that this was an acceptable solution to locating the poles.

Fig. 2. Satellite image of detected distribution pole rays. Source: From the Owner, Photo by: Google

D. *Detailed Image Collection*

The Zoom Level 1 images collected in Step 2 are acceptable for detecting and localizing poles, but they do not contain the level of detail required to determine a classification of the pole. This project was intended to determine the accuracy of a classification of each pole within the nine groupings shown in the table below.

TABLE II. POLE CLASSIFICATION

Vision Model Class	Description
A	Standard, Pin Top
B	Staggered
C	Vertical
D	Cross Arm, Pin Top
E	Cross Arm, Neutral on Cross Arm
F	Double Cross Arm, Pin Top
G	Double Cross Arm, Neutral on Cross Arm
H	Double Cross Arm, Neutral on Pole
J	Junction

To assist in classifying the detected areas, more detailed images needed to be collected. The x/y pixel detections were used along with the orientation information for each panorama ID to calculate the appropriate pitch and field of view to obtain the highest quality images available from the Street View API. For reference, the image below is taken from the same panorama location as the image shown above in Step 2.

Fig. 3. Street View image of a distribution pole. Source: From the Owner, Photo by: Google.

Several of these more detailed images were collected based on the locations determined from the detections in the lower-level zoom images.

E. Image Classification

Approximately 8,500 detailed images were downloaded and manually labeled for training classification models. Of the total, approximately 8,000 images were identified as a pole, and 6,800 images were manually classified as being visually like a C1 or C2 structure based on RUS 1728F-804. The total number of images for each class is shown in the table below.

A review of sample primary assemblies, modeled in a 3D space using AutoDesk Inventor with discrete material components by West Kentucky, was completed to evaluate the feasibility of creating synthetic images which could be used as model training content. The synthetic image datasets were systemically created using a readily available software named Blender. While the synthetic images were deemed to be useful in a longer project development roadmap, they were ultimately excluded from this pilot project to reduce content variability and thus improve model testing control.

TABLE III. IMAGE CLASSES

Image Class	Number of Images
A	182
B	900
C	584
D	2443
F	2238
G/H	499

The classes of G and H were combined, and the class of E was removed based on a lack of data from the manual classifications.

Several machine learning classification models were trained on the dataset and the accuracy of the results are listed below.

TABLE IV. CLASSIFICATION MODELS

Model	Accuracy
Resnet 18	84.8% after 20 Epochs
Resnet 34	86.0% after 20 Epochs
Resnet 101	84.9% after 20 Epochs
Resnet 152	85.3% after 20 Epochs
Vision Transformer (Vit B 16)	71.7% after 20 Epochs

Resnet 34 and 101 [2] both provide reasonably accurate results while also maintaining a relatively fast inference time. If the quantity of training images were higher, it is believed that more complex architectures like the Vision Transformer [3] and Resnet 152 would increase in accuracy more with additional training.

F. Structure Classification

To assist in a more robust classification of each structure, multiple images from different angles are classified and the results of the multiple classifications are combined into a result for the structure. For this current evaluation, up to 5 images for each pole will be classified and combined into the structure classification.

A three-mile portion of the road along HWY-94 was chosen for an evaluation and 82 poles were identified which fell into the scope of this project. The 82, 3-Phase C1/C2 assemblies were classified using the developed AI system and compared to a human classification. The results showed that 82 of 82 poles were correctly classified by the AI system. Additionally, a 5-mile portion of road along Highway 381 was also chosen for evaluation. 60 C1/C2 poles were identified, and these were also classified by a human and using the AI system. These 60 poles were also determined to match. In total, 142 structure classifications were evaluated and all the classifications were determined to match the human classifications.

IV. Results

Although development/testing results have been discussed throughout this whitepaper, the most significant test of the tools occurred on July 23, 2024 when the Mesa team was travelling to West Kentucky to present the results of the project. While the Mesa team was travelling, West Kentucky sent two kmz files defining two different pole routes for evaluation. This data was processed quickly by the processing pipeline that had been configured and the results for these two routes were presented at the meeting the following day.

The software as Piloted was used to ingest the selected network's images, identify Distribution poles, calculate the GIS information for each, and classify each RUS structure. The results are shown in the table below.

TABLE V. Route results

Item	Quantity
Miles of Highway	8
Number of Poles Found	142
Number of Poles Actual	TBD
Approximate GIS Accuracy	+/- 5 feet in each axis
RUS Category Accuracy	100%*

*Compared to manual inspections

These results are impressive, especially considering a Pilot does not get the benefit of extended field testing and incremental improvements.

V. Future Considerations

A. *Automation*

By simply automating the tools that were built and confirmed in this Pilot, a Utility could have access to a nearly autonomous system of building or checking their associated asset management database. Alternatively, a hybrid system can be envisioned where technical personnel use the Pilot tools to semi-automatically deliver information in CSV files that can be manually imported into an asset management database or compared to CSV files from an existing database to identify inaccurate records.

B. *Joint Use*

Joint Use monitoring could be improved by upgrading the tools described in this white paper or by augmenting the tools as noted in the *Image Collection Modes* section below. The addition of joint use detection doesn't have to be an all or nothing (perfection) approach. An automated tool could use information from past inspections and "as designed" to flag obvious inconsistencies. And with the addition of measurement tools, other obvious defects could be detected. This would guide follow-on inspections for assets where they were not readily confirmed as passing or failing.

C. *Image Specifications*

The initial detections for this project were completed on two, 512px X 512px images and this quality sufficed for the initial pole object detections. The detection model accuracy could likely be improved by using higher resolution images. The processing time and overhead would increase. The classification model(s) used 640px X 640px images as an input and these images were taken from 30 – 150 feet away, but most fell into the 60 – 100 feet range. For future development, the required range, field of view, and resolution would need to be considered.

For an image where ½ of the image width shows a crossarm we can calculate a pixel width, based on an assumed length of 8 feet for the crossarm. The output of this calculation is 7.6 mm/pixel, which is acceptable for classifying images. However, labels on transformers were most often not readable. Future use cases involving label reading, material defect detection, etc., will require images with a smaller pixel width.

D. *Image Collection Modes*

Images captured by drones, automobiles, and offroad vehicles will typically provide even higher-level resolution and more real-time information. When combined with the capabilities discussed in this white paper, utilities can benefit from both fast/inexpensive asset database setup/verification and slower/costlier, but more real-time, long-term monitoring capability. And as noted earlier, these higher resolution images can be used for anomaly detection and more detailed classifications (e.g., joint use).

E. *Technology Integration*

As AI tools evolve and vendors continue working on their island in this emerging market, simple integrations between the islands can be used to create larger masses of capability. For the Pilot discussed here, the addition of image inspection tools focused on anomaly detection could be very valuable. Combining this with higher resolution images (see Image Specifications and/or Image Collection Modes sections) could lead to trend insights built on historical datasets. For example, a cross-arm out of level a small amount may not get noticed by a casual inspection but might be readily highlighted by automation tools that detect that its slope changed dramatically in the past 60-days.

F. *Technology Integration*

West Kentucky and Mesa envision a path to build on the success of this AI pole inventory pilot project. Future collaborative work to incorporate vehicle cameras for image gathering, comprehensive training datasets from synthetic images, and new features options such as pole attachment identification as described above is under consideration and in the early planning stages. It is appropriate to note that any ongoing roadmap development would include cooperative business case justifications to evaluate the given development value stack.

VI. Conclusion

This Pilot was identified due to the Utility's need to establish and maintain an accurate and up-to-date inventory of assets, including specific asset types. Historically, this need is impeded by time consuming and costly data collection activities that require additional bandwidth and larger budgets than may be available. The Pilot showed that a low cost, quick access, and highly accurate solution is available to Utilities, preserving bandwidth and budget significantly more than competing solutions.

As presented in this whitepaper, the associated Pilot was well planned, well defined, and generated exceptional results. The Pilot showed that a new AI capability can aid Utilities in building initial asset management databases, checking existing asset management databases, and establishing a foundation for new tools and capabilities just entering the market.

AUTHOR BIOGRAPHIES

Justin McCann, **PE** Vice President of Engineering for West Kentucky Rural Electric Cooperative Corporation in Mayfield, KY. He obtained his Bachelor in Business Education from Southern Illinois University, Carbondale, (M'2003) and Bachelor in Electrical Engineering from The University of Memphis (M'2006). Justin has 20 years of engineering and leadership experience, including over 15 years in the electric utility industry, developing comprehensive system and financial planning and design projects. He previously served as Vice President of Engineering for Today's Power, a subsidiary of the Electric Cooperative of Arkansas, where his work included projects to develop utility-scale solar and battery energy storage, as well as planning and testing electric vehicle charging infrastructure. McCann also worked as a principal and managing member for Fisher Arnold and Midsouth Utility Consultants. He is a registered professional engineer in several states. Justin McCann is a member of the Institute of Electrical and Electronics Engineers ('06), National Rural Electric Cooperative Association's Transmission and Distribution Engineering Committee, EPRI Distribution Sector Council, Chairman of the Tennessee Valley Public Power Association's Research and Development Committee, and several other regional boards and committees.

Wayne Ferguson, PE, has more than 16 years' experience in the engineering and software development industries. He currently functions in Mesa's Machine Learning Engineer role by developing solutions in cloud computer vision applications and delivering calculations/models for Industrial Customers using Python, Pandas, Numpy, PyTorch, Sci-kit Learn for predictions, and anomaly detections. His career spans work in Engineering Services (Mesa), Gas Turbine thermal modeling (Southern Company), Gas Turbine and Combined Cycle fleet performance testing (Southern Company), and custom data acquisition applications in accordance with ASME Performance testing (McHale & Associates). In addition to being a Certified Professional Engineer, he has his MBA and is currently pursuing his Master's in Computer Science at Georgia Tech.

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Appendices

Appendix-A: 1728F-804 Configurations (Typical)

Table T101 – Configuration and Classification Matrix

Grouping	Assembly ID	Vision Model Class	Assembly Number
Cross Arms	Single 8' Cross Arm	D	C1.11, C1.11L C1.11P, C1.12 C1.12L, C1.12P C1.13, C1.13L C1.13P
	Single 10' Cross Arm	E	C1.41, C1.41L C1.41P
	Double Cross Arm	F	C2.21, C2.21L C2.21P, C2.24 C2.24P, C2.25 C2.25P, C2.51 C2.51L, C2.51P C2.52, C2.52L C2.52P
	Junction	J	C1.81G
Standard 1'-9" Spacing		A	C1.1N, C1.1NP C1.2N, C1.2NP C1.3N, C1.3NP C2.1N, C2.1NP C2.2N, C2.2NP C2.3N, C2.3NP C2.3NG
Staggered 2' Spacing		B	C1.4N, C1.4NP C1.5N, C1.5NP C1.6N, C1.6NP C2.4N, C2.4NP C2.5N, C2.5NP C2.6N, C2.6NP
Vertical 4' Spacing		C	C1.7N, C1.7NP C1.8N, C1.8NP C1.9N, C1.9NP C2.7N, C2.7NP C2.8N, C2.8NP C2.9N, C2.9NP

Appendix-B: Configuration Examples (Typical)

Image B101-Classification A, Standard Pin Top

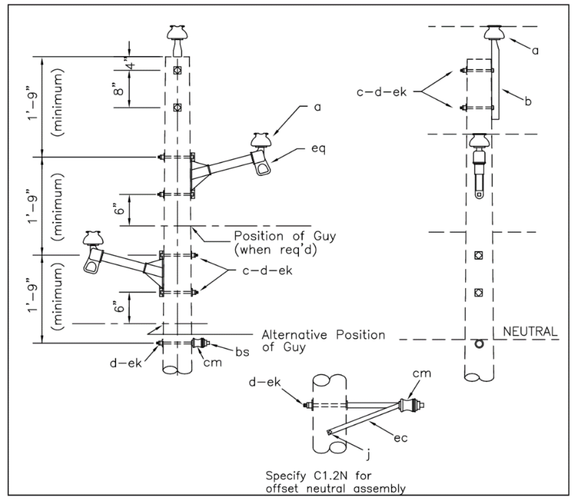
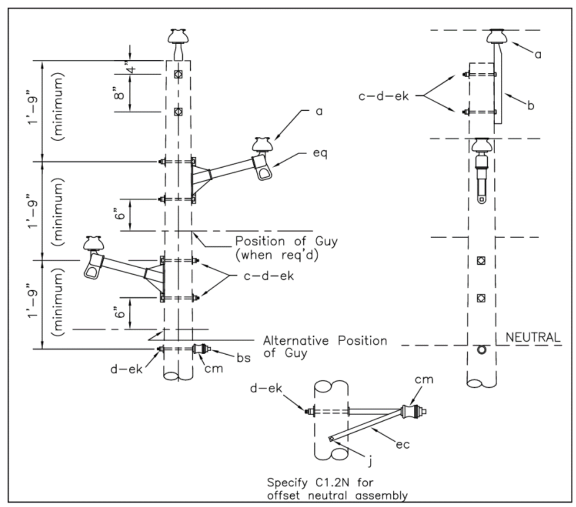


Image B101-Classification B, Staggered



Using Artificial Intelligence to Improve Reliability and Operational Efficiency of Small-Scale Hydroelectric Distributed Generation

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***Abstract*—Reliability and resilience are critical concerns for distributed generation (DG) at the rural electric level. The integration of renewable energy sources, such as small-scale hydroelectric distributed generators (hydro DGs), introduces operational challenges, particularly regarding aging infrastructure and grid stability. Artificial Intelligence (AI)-driven Machine Learning (ML) models and applications of Large Language Models (LLMs) offer promising solutions for optimizing DG operations and enhancing resilience. This paper explores AI-based models for improving efficiency, fault resolution, and outage mitigation in small-scale hydro DGs. Furthermore, it highlights the development of a centralized, AI-powered information portal for rural electric cooperatives and municipalities. The research evaluates hydro DG plant models and discusses the applicability of AI-powered question-answering tools for real-time operations, focusing on statistical data, load flow, voltage regulation, and generation power. The findings demonstrate AI's potential to transform DG management to ensure greater stability and resilience in rural electric grids.**

Index Terms*—Distributed Generation, Reliability, Resilience, Artificial Intelligence, Machine Learning, Large Language Models, Hydro DG, Rural Electric Utilities.

I. INTRODUCTION

The global energy landscape is undergoing a significant transformation, shifting from centralized power generation toward a more decentralized, distributed model. This evolution is driven by increasing concerns regarding environmental sustainability, energy security, and the need for greater grid resilience. Distributed generation (DG) systems, particularly small-scale hydroelectric power plants, are emerging as a crucial component in this transition as they offer reliable renewable energy solutions for rural and remote communities.

However, integrating DG into the existing energy infrastructure presents a range of technical and operational challenges. Traditional bulk power systems, particularly in the United States, rely on aging frequency-regulating infrastructure that was not originally designed to accommodate bidirectional power flows associated with DG. These challenges create vulnerabilities in grid stability, necessitating innovative solutions to ensure seamless integration and optimal performance of DG resources.

Artificial Intelligence and machine learning algorithms have revolutionized industries by enabling intelligent automation, predictive analytics, and data-driven decision-making. In the context of DG operations, AI-driven models offer the potential to improve reliability, efficiency, and fault detection and thereby mitigate risks associated with equipment failures and power outages. By leveraging AI-powered algorithms, utilities can optimize power dispatch, enhance real-time monitoring, and predict equipment failures before they occur. Furthermore, LLMs provide an additional layer of operational support, offering insights, recommendations, and troubleshooting assistance for grid operators.

This paper explores the application of AI-based methodologies in enhancing the reliability and resilience of DG systems; particular focus is given to small-scale hydroelectric distributed generators (hydro DGs). The research highlights the development of a centralized AI information portal aimed at supporting rural electric cooperatives and municipalities. This study presents a framework for improving the efficiency and sustainability of distributed renewable energy systems via advanced data analytics, real-time monitoring, and AI-assisted fault resolution. Ultimately, the integration of AI into DG operations has the potential to transform rural energy management, ensuring greater accessibility to reliable and clean power sources.

II. HOW THE GRID IS EVOLVING

Since the advent of modern power system interconnections, operational and planning frameworks have been designed based on the assumptions of dispatchable, high-inertia, and centralized generation resources. However, as the energy sector continues to evolve to meet modern electricity demands, significant transformations in the grid infrastructure have emerged. The increasing penetration of renewable energy sources is among the most prominent changes. This change has been driven by technological advancements, policy interventions, and financial incentives, all of which have contributed to a decline in deployment costs. Over the past two decades, electrical grids have witnessed substantial growth in variable, nonsynchronous, and decentralized generation sources, which have fundamentally altered conventional power system dynamics [1].

The integration of renewable energy introduces uncertainties in forecasting and system stability, demanding unique reliability considerations for different renewable generation technologies at their respective interconnection points. For instance, the ability to provide frequency support and fault ride-through capabilities is contingent upon advanced inverter control strategies, as standardized by IEEE 1547-2018 [2].

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Additionally, the spread of microprocessor-based technologies has significantly enhanced data acquisition, communication, and real-time control within modern power networks. Although the definition of a *smart grid* varies, smart grids are broadly characterized by the integration of advanced sensing, communication, and control mechanisms aimed at improving grid reliability and efficiency [3].

The transition towards a smart grid architecture is partially a response to the increasing share of renewable generation. However, this transition is also evident across transmission, distribution, and end-user levels, where digitalization has led to the deployment of sophisticated networked control devices. The evolution of the generation profile is primarily distinguished by changes in dispatchability, system inertia, and decentralization, as depicted in Fig. 1. Concurrently, the advancement of digital grid technologies is exemplified by the widespread implementation of wide-area measurement systems that use synchrophasor technology and advanced metering infrastructure supported by smart meters. These developments are pivotal in enhancing the observability, controllability, and resilience of modern power systems in response to an increasingly dynamic energy landscape [4].

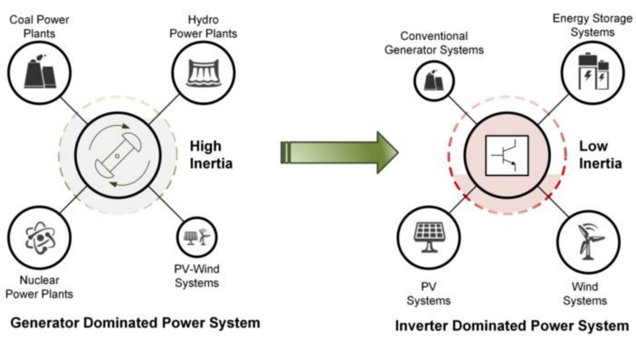

Fig. 1: Evolution of the grid toward inverter-based renewable energy sources [5].

III. DISTRIBUTED GENERATION AND RURAL ELECTRIC INFRASTRUCTURE

A. Role of Small-Scale Hydro DGs

Small-scale hydroelectric power generation, often referred to as micro or mini hydropower, plays a pivotal role in supplying reliable and sustainable energy to rural and isolated communities. These systems harness the kinetic energy of flowing water to generate electricity, offering a renewable alternative to fossil fuels. One of the primary advantages of small-scale hydro DGs is their ability to operate independently of centralized power grids; this ability makes these systems ideal for remote areas where grid extension is economically or technically unfeasible. Moreover, the environmental footprint of these small-scale systems is typically lower compared with that of large-scale hydroelectric projects because small-scale systems often use run-of-river designs that minimize ecological disruption. The implementation of small-scale hydroelectric systems not only provides essential electricity for lighting, heating, and communication but also fosters economic development by powering local industries and improving overall quality of life. Additionally, by reducing reliance on imported fuels, these systems enhance energy security and contribute to the reduction of greenhouse gas emissions. Engaging local communities in the planning and operation of hydro DGs further ensures that the benefits are equitably distributed and that the projects are tailored to meet specific local needs [6].

B. Challenges in Rural Grid Operations

The integration of distributed generation into rural electric infrastructure presents several challenges that must be addressed to ensure grid reliability and efficiency. One significant issue is voltage regulation. Traditional rural distribution networks were designed for unidirectional power flow, which delivers electricity from centralized plants to consumers. The introduction of DG, especially variable renewable energy sources such as solar and wind, can cause fluctuations in voltage levels, leading to power quality issues. For instance, when local generation exceeds demand, reverse power flow can occur, potentially causing overvoltage conditions and complicating the operation of voltage-control devices [7].

Another challenge is the protection of the electrical network. The presence of multiple generation sources can alter fault currents and disrupt the coordination of protection schemes, making it difficult to detect and isolate faults effectively. This complexity necessitates the development of advanced protection strategies that can adapt to varying power flows and ensure rapid fault detection and isolation [8].

Additionally, the intermittent nature of renewable energy sources introduces uncertainty in power supply. Solar and wind generation are weather-dependent, leading to variability that can challenge grid stability, especially in systems with high penetration levels of these resources. This intermittency requires the implementation of robust forecasting methods and the integration of energy storage solutions to balance supply and demand effectively [9].

Furthermore, many rural electric utilities operate with aging infrastructure and may lack the financial resources and technical expertise necessary to upgrade their systems to accommodate DG. Upgrading grid infrastructure to handle bidirectional power flows, implementing advanced monitoring and control systems, and training personnel are essential steps, but these steps can be resource-intensive. Collaborative efforts, including policy support, funding mechanisms, and technical assistance, are crucial to overcoming these barriers and ensuring the successful integration of DG into rural electric grids [10].

IV. ENHANCING RELIABILITY AND RESILIENCE BY USING AI

The integration of AI into DG systems offers transformative potential for enhancing grid reliability and resilience. By leveraging advanced machine learning algorithms and data analytics, AI facilitates predictive maintenance, fault detection, and optimized energy management, thereby addressing the complexities introduced by decentralized renewable energy sources.

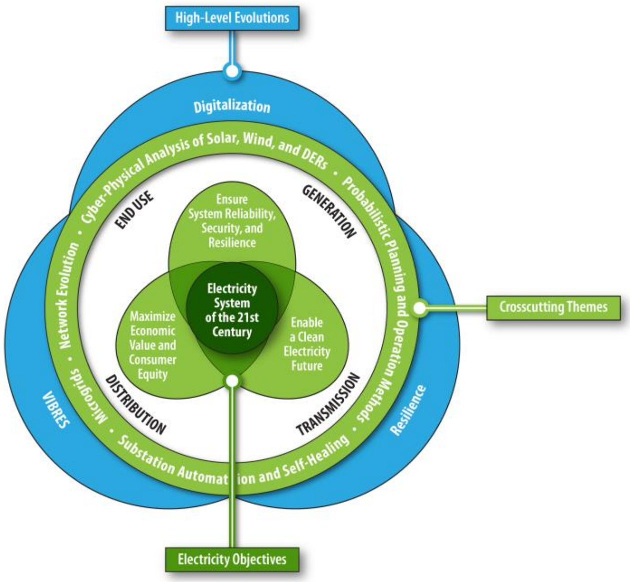

Fig. 2: Goals and themes of the evolving electrical grid [4]. Source: Idaho National Laboratory

A. *AI-Based Grid Optimization*

AI-driven grid optimization employs ML models to analyze vast datasets, enabling precise forecasting of energy demand and generation. Techniques such as neural networks and support vector machines process historical and real-time data to predict consumption patterns and renewable output; these techniques facilitate efficient energy dispatch and reduce operational costs. For instance, AI algorithms can dynamically adjust voltage controls and reactive power compensation to maintain grid stability amidst fluctuating inputs from renewable sources. The implementation of AI in grid optimization not only enhances operational efficiency but also supports the seamless integration of DG into existing power networks [11].

An application is the use of reinforcement learning (RL) for day-ahead grid planning and real-time energy dispatch. A study titled “Reinforcement Learning Based Power Grid Day-Ahead Planning and AI-Assisted Control” introduced an RL-based model that learns optimal control policies for power grid operations [12]. The RL agent was trained using historical grid data to forecast energy demand and generation capacity, dynamically adjusting power flow based on real-time conditions.

The observations from the study were as follows:

- The RL-based control system enhanced grid stability, particularly in cases of fluctuating renewable energy inputs
- Operational costs were reduced by optimizing energy dispatch, effectively balancing supply and demand
- The AI model performed better than traditional static optimization methods by continuously adapting to real-world grid uncertainties

This example demonstrates how AI-driven optimization methods can make power systems more resilient, efficient, and cost-effective, enabling better integration of renewables without compromising stability.

B. *Fault Prediction and Preventive Maintenance*

AI applications in fault prediction and preventive maintenance play a crucial role in minimizing system downtime and enhancing reliability. ML models analyze historical operational data to identify patterns indicative of potential equipment failures. Early fault detection allows operators to schedule maintenance proactively and thereby reduce unexpected outages.

In a study [13], a generative AI approach was applied to analyze continuous point-on-wave measurements. The authors identified abnormal voltage fluctuations associated with potential transformer and grid faults. The study reported a 30% reduction in unplanned outages, showcasing the effectiveness of AI in improving predictive maintenance strategies. By employing AI in fault detection, rural utilities can optimize maintenance schedules, enhance grid reliability, and extend equipment lifespan.

C. *AI-Assisted Decision-Making*

AI-driven decision support systems, which analyze vast datasets and provide real-time recommendations to grid operators, have been instrumental in improving operational efficiency. LLMs process diverse data sources, including weather forecasts, power demand trends, and equipment performance metrics, to generate actionable insights for optimizing power dispatch.

One practical implementation of AI in decision-making is illustrated in the referenced literature [14]. An AI-powered grid resilience model was developed to predict and mitigate the effects of extreme weather events on distributed energy resources. The model used ML algorithms to analyze historical weather patterns, infrastructure vulnerability data, and real-time meteorological inputs to anticipate potential disruptions. By leveraging AI-driven simulations, the system was able to identify high-risk grid components, enabling utilities to reinforce infrastructure in advance. Furthermore, the study demonstrated that AI-assisted grid hardening reduced system vulnerability by 40% by implementing adaptive resource allocation strategies and real-time contingency planning. This proactive approach allowed grid operators to optimize energy distribution, minimize outage durations, and enhance overall grid resilience against climate-induced disruptions.

V. AI-POWERED HYDROELECTRIC POWER PLANT RELIABILITY ANALYSIS

A. Hydropower Component Mapping and NERC GADS Cause Codes

A key aspect of hydroelectric power plant reliability analysis is understanding component-level failure modes and their effect on overall system performance. The North American Electric Reliability Corporation (NERC) Generating Availability Data System (GADS) provides a structured approach to tracking and analyzing failure events in power generation facilities.

1. Hydropower Taxonomy and Failure Mode Definition

Hydroelectric power plant components are classified into major categories, such as turbines, generators, transformers, control systems, and balance-of-plant components, to ensure a comprehensive reliability assessment. Each category is further divided into specific failure modes, including mechanical, electrical, structural, and instrumentation failures.2. AI-Assisted Mapping to NERC GADS Cause Codes

AI is leveraged to create an automatic mapping table to link hydroelectric power components with corresponding NERC GADS cause codes. This structured approach enhances failure classification and enables predictive failure mode analysis. AI-driven algorithms refine this mapping via historical data validation and expert consultation.

B. Understanding the Physics of Hydroelectric Power Operations

AI models are trained to analyze the physics of hydroelectric power plant operations to improve predictive maintenance. This step focuses on identifying correlations between different components and understanding the cascading effects of failures.

1. Balance of Plant and Switchyard to Grid Correlations

By examining power flow dynamics, voltage fluctuations, and component interactions, AI models can determine how failures in one system affect other systems. For example, turbine malfunctions may affect generator efficiency, and transformer failures may lead to grid instability.

2. AI-Based Predictive Analytics for Failure Correlation

Using neural networks and deep learning models, AI systems identify patterns in operational data to predict potential failures. These models are trained on historical performance data and real-time sensor readings to enable proactive maintenance interventions.

C. Synthetic Data for AI Model Training

One of the challenges in AI-driven reliability analysis will be the limited availability of failure data. To overcome this, synthetic data will be generated to train AI models effectively.

1. Development of Synthetic Operational Data

By simulating different operational conditions and failure scenarios, AI-generated synthetic datasets will replicate real-world conditions. These datasets will include parameters such as component health, vibration analysis, and power output fluctuations.

2. Enhancing AI Model Accuracy with Synthetic Data

Synthetic data will be integrated into AI training pipelines to improve model robustness. By diversifying training datasets, AI models will better generalize predictions and identify rare failure events.

D. ChatHydro: AI-Enabled Decision Support System

ChatHydro will be a state-of-the-art, AI-powered decision support tool specifically designed for hydroelectric power plant operators. The system will leverage advanced natural language processing (NLP) and ML algorithms to provide real-time insights, improving decision-making and operational efficiency. By integrating ChatHydro with real-time monitoring systems, hydroelectric power operators will be able to access critical operational data, assess failure risks, and proactively perform corrective actions.

1. AI-Driven Question–Answer Interface

ChatHydro will function as an interactive AI assistant capable of interpreting and responding to queries related to hydroelectric power plant operations. Using a LLM, the system will be able to process natural language inputs and provide precise, data-driven responses. Operators will have the ability to query the system for the following information:

- The expected effect of specific component failures, such as turbine malfunction or transformer overheating
- Optimization strategies for improving power output under different hydrologic conditions
- Predictive failure analysis based on historical trends and real-time sensor inputs

By automating responses to routine and complex operational queries, ChatHydro will reduce the cognitive load on plant operators and enable them to more quickly make informed decisions.

2. Integration with Real-Time Monitoring Systems

ChatHydro will be integrated with hydroelectric power plant supervisory control and data acquisition (SCADA) systems to maximize its utility. This integration will allow the AI model to process and analyze real-time operational data, including the following:

- Turbine efficiency metrics and load conditions
- Generator performance data and potential fault indicators
- Voltage fluctuations and grid stability parameters
- Environmental conditions affecting hydropower production

ChatHydro will offer predictive insights and recommendations via real-time monitoring and analysis. For example, if the system detects an anomaly in turbine vibration data, it will alert operators about the potential for mechanical failure and suggest preventive maintenance actions before critical failures occur.

3. Enhancing Reliability through AI-Powered Diagnostics

ChatHydro will also serve as a diagnostic tool capable of detecting patterns in operational data and identifying probable causes of system inefficiencies. By continuously learning from historical data, the AI model will refine its predictions and improve reliability assessments over time. Key benefits of this feature will include the following:

- Automated fault detection and classification
- Risk-based prioritization of maintenance tasks
- Reduced downtime via proactive issue resolution

As the model evolves, it will integrate feedback from operators and reliability engineers to enhance its accuracy and applicability in diverse hydroelectric power plant settings.

4. Future Developments and Adaptations

Although the initial deployment of ChatHydro will focus on predictive analytics and real-time diagnostics, future enhancements will incorporate additional capabilities, including the following:

- AI-driven anomaly detection using advanced deep learning techniques
- Integration with weather forecasting models to predict water flow variations
- Automated generation scheduling based on demand-response signals

As its functionality expands, ChatHydro will play a crucial role in modernizing hydroelectric power plant operations and ensuring a more resilient, data-driven approach to plant management.

E. Proposed Work and Future Enhancements

The AI-powered hydroelectric power plant reliability framework will undergo continuous improvements through research and real-world validation.

1. Validation with Expert Consultation

The system will be validated using real-world failure data and expert feedback to ensure AI model accuracy. Collaboration with hydroelectric power engineers will refine AI-driven failure mode identification.

2. Expansion of AI-Driven Predictive Maintenance

Future enhancements will include expanding AI models to incorporate weather forecasting, hydrologic cycle predictions, and adaptive control algorithms for optimizing hydroelectric power generation.

VI. CONCLUSION

The integration of AI into DG is revolutionizing reliability and resilience in rural electric utilities. This paper discusses AI's transformative role in optimizing grid operations, predictive maintenance, and real-time decision support.

AI-driven models, such as ML models and LLMs, enhance DG efficiency by forecasting demand, managing congestion, and predicting equipment failures. RL has proven effective in reducing operational costs and stabilizing energy distribution, and AI-powered fault detection minimizes unplanned outages. Decision support tools such as *ChatHydro* enable real-time insights, enhancing operational awareness and response times.

AI in hydroelectric power plant management improves reliability via failure mode analysis, predictive maintenance, and synthetic data generation. ChatHydro's NLP capabilities further bridge human expertise with data-driven decision-making.

Despite challenges such as data privacy and cybersecurity, AI's potential in DG operations is undeniable. Future research should refine AI models, improve interoperability, and develop advanced predictive maintenance algorithms. By embracing AI, rural utilities can enhance system reliability, improve efficiency, and support a smarter, more resilient power grid.

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Synchrophasor-Based Islanding Detection for Distributed Generation Applications

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***Abstract*— A Rural Electric Cooperative (CO-OP) is a medium sized utility based in Colorado with a 69kV sub-transmission used primarily to feed their industrial members. The CO-OP is adding 180 MW of natural gas combustion turbine generation onto this sub-transmission network. The network is wholly owned by the CO-OP and is fed from multiple sources of which they own. Multiple sources, switching configurations, and ring buses feeding these sources make breaker status impractical for islanding detection. There exist scenarios outside the sub-transmission system that can lead to an islanded system. If the load and generation are closely matched, then local-islanding detection is not viable to detect an island. The CO-OP will use synchrophasor-based islanding detection in conjunction with over and under-frequency to detect an island.**

***Keywords*— Islanding, Distributed Generation, Synchrophasor**

I. Introduction

A. Summary

The CO-OP is adding a natural gas combustion turbine facility (Plant) consisting of six 47.8 MVA generators to their 69 kV sub-transmission system. Islanding on the 69 kV CO-OP system could occur from faults or human errors in switching operations at various locations. If the generation and load are closely matched, then local measurement-based islanding detection such as over and under-frequency protection schemes may be inadequate to detect the island [1]. Synchropashor-based islanding detection is a suitable way to determine if an island has occurred regardless of the generation to load ratio. The implementation of this scheme requires Phasor Measurement Units (PMUs) strategically placed at the generation source and at a remote location. PMUs accurately synchronize and time-stamp measurements across a large network. The scheme also requires a SCADA data concentrator to compare the synchrophasors from the PMUs to determine if an island has occurred

A study was conducted to determine the parameters for the implementation of synchrophasor-based islanding detection in this system. This study was conducted using the Western Electricity Coordinating Council (WECC) 2025 Heavy Summer and 2025 Light Winter PSLF models. These models were modified to include the new generation on the 69 kV system, and the loads of the system were modified to be more accurate to what CO-OP is expecting to see during that time.

There are few instances where the load and generation are closely matched on this system. The load and generation are closely matched in the Heavy Summer 2025 Model on the Substation B side (Loop B) of the 69 kV system with PV generation online at Substation B's T1 and T3. If Substation B were to be separated from Substation A during a period of generation from the Plant and the PV facilities, then an island would be difficult to detect using local measurement-based islanding detection at Switchyard D. Another instance of relatively matched Load and Generation occurs when only one unit is online during light winter conditions on the Substation C Loop (Loop C) and an island is formed at the Substation C T3 Transformer. Synchrophasor-based islanding detection is an adequate method to detect these islands and trip off the generation to prevent voltages falling out of sync and resulting in a fault when the tie to the grid is re-established.

Over and under frequency protection theoretically can detect most of the islands that can occur in this network. Roughly 90% of the islanding cases reviewed result in frequency changes that will be detected by the over or under frequency protection. However, the roughly 10% of islands that cannot be detected by the over and under frequency elements, require the use of synchrophasor-based islanding detection. The loading in this system is changing, and the

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number of cases where load and generation closely match may also change.

B. Subtranmission System

The CO-OP's sub-transmission system is a complex network of loads and sources. The simplified model used in this study can be seen in *Figure 1.* There are multiple ways to feed the loads tied to this system which is wholly owned by the CO-OP. The Plant's combustion turbine facility is well embedded in the system, which means it can be islanded by upstream faults or human errors. The Plant facility is tied into the sub-transmission system at the 69kV Switchyard (Switchyard D). Switchyard D feeds into two 69kV loops: Loop C and Loop B. These loops have multiple loads on them, and they can be tied together at several points to include Switchyard D. However, they are normally not tied together.

Substation C is a sub-transmission/distribution substation that is fed from a single 115 kV line from Substation A and is wholly owned by the CO-OP. The 115 kV side of Substation C is a ring bus that has two 115 kV lines, one distribution transformer (115/13.2 kV T1), and one autotransformer (115/69 kV T3). One of the 115 kV lines dead-ends and does not go anywhere. The other line is Substation C's feed from Substation A. The transformers each have low-side mains that feed a bus with multiple feeders. T1 has around 18 MW of load and T3 has about 22 MW of load on average throughout the year. The 22 MW on T3 represents the load on Loop C.

Substation B is a sub-transmission/distribution substation that is fed by two 115 kV lines from Substation A and is wholly owned by the CO-OP. The 115 kV side of Substation B is a ring bus that has two 115 kV lines, three distribution transformers (115/13.2 kV T1, T2, & T4), and one autotransformer (115/69 kV T3). The transformers each have a low-side mains that feed a bus with multiple feeders. The distribution buses have ties to each other. The distribution buses have around 61 MW of load and T3 has about 11 MW of load on average throughout the year. The 11 MW on T3 represents the load on Loop B. There is a PV Solar farm tied into T1 that has around 4 MW of output capacity during the summer. There is another PV Solar farm tied to T3 that has around 5 MW of output capacity during the summer months.

Substation A is a 230/115/69 kV substation with a 230 kV ring bus that feeds two 230/115 kV autotransformers, T1 and T2. The 230 kV bus is owned by a Bulk Electric Provider, and CO-OP owns everything downstream of the 230kV transformer disconnect switches. On the 115 kV ring bus, there are three 115 kV lines, two 115 kV lines that feed Substation B and one that feeds Substation C, and one 115/69 kV autotransformer, T3, that also feeds into the 69 kV system. The 230 kV ring bus is considered to be the Bulk Electric System (BES), and thus there must be continuity to the 230 kV bus from Switchyard D to avoid an island.

TABLE 1. GENERATOR NAMEPLATE DATA

Generator Nameplate Data	
Apparent Power (MVA)	47.8
Real Power (MW)	31.4
Voltage (kV)	13.8
Power Factor	0.85
Xd	2.626
X'd	0.2647
X"d	0.1825
X2	0.1825
X0	0.098

C. Natural Gas Combustion Turbine Facility (Plant)

There are six natural gas combustion turbines that will be introduced to the sub-transmission system. The nameplate data for each turbine can be seen in Table 1.

Each generator will feed into a 13.8/69 kV, 28.8/38.4/48 MVA GSU transformer which will then feed into Switchyard D. Switchyard D's Switching Diagram can be seen in Appendix A.

The generators are manufactured by GE, who also supplied the modeling parameters. *Figure 2* illustrates Switchyard D's west bus and *Figure 3* illustrates Switchyard D's east bus.

D. Western Electricity Coordinating Counsel Models

WECC is a regional entity that governs the Bulk Electric System in the Western Interconnection [2]. The sub-transmission system lives within the Western Interconnection. WECC provides PSLF models for this system, which contains nearly every major bus, transformer, generation, and load in the Western Interconnection. The PSLF models used in this study were the PSLF 2025 Heavy Summer and 2025 Light Winter models.

In these models, every bus and transformer are modeled at Substation B. The loads and PV generation for Substation B are modeled on each respective bus. The loads in each model are projected for what is expected on the grid during each time frame. Substation C is modeled as a 115 kV bus with a load attached directly to the 115 kV bus. The model was modified to show the 13.2 kV and 69 kV transformers, buses, and loads.

The updates outlined in this section were incorporated to the WECC provided static model .epc files for both summer and winter conditions. The .epc files for both summer and winter models can be requested from WECC. The .epc modifications entailed: adding the generators, transformers and buses for the Plant. Additional modifications to the loads at Substation C and Substation B and adding the T1 and T3 transformers and buses at Substation C.

The dynamic model modifications were made on the .dyd file which can also be requested from WECC. The .dyd file was modified to have the generator, exciter, and governor models attached to each generating unit at the Plant. Meters were also attached to the Switchyard D Buses to measure real and reactive power and voltage angle. A voltage angle meter was attached to the Substation E. This is the remote bus that the BES PMU will be stationed at. Substation E is wholly owned by the CO-OP and cannot be part of an island from Switchyard D.

The loading on each bus was modified based on the CO-OP's preference based on their historical data and future projections. The modified model depicting Substation A to Substation C and Substation B can be seen in Figure 1. T3 at Substation A is modeled as a 115 kV load. Substation C's T1 and T3 have been added to the model for better accuracy.

Figure 2 shows the configuration the Switchyard D West Bus that feeds into Loop C. Figure 3 shows the configuration of the Switchyard D East Bus that feeds into Loop B.

The summer and winter models are identical in terms of configuration and vary with respect to PV generation and loading. The winter model has the PV generation at Substation B T1 and T3 out of service.

E. Assumptions and Constraints

Loading at Substation C was modified to be larger than the WECC provided model based on historical data from CO-OP's 2024 loading for both summer and winter models. The loading for Substation C and Substation B can be seen in Table 2.

The 69 kV system is a complex network and has been simplified to loads on the 69 kV buses at both Substation C and Substation B. Simplifications and assumptions were necessary for the model and are listed below:

- Building the entire network would result in minimal differences that would not change the overall accuracy in this report.
- There are many cases that could occur, but it is not practical to run every single scenario.
    - The cases outlined later in the report have been identified as most likely scenarios that could theoretically cause significant islanding conditions.
    - The cases that were examined included islands where the load and generation are evenly matched and a few where they are not.
- Nearby generation will not curtail based on the additional generation.
    - There is a generation facility adjacent to Substation A (~500m). This generation was not modified during the iterations of this study.
- PV generation at Substation B is taken out of service for the light winter model.
    - This decision was made by WECC. There is PV generation that occurs at Substation B during the winter months, but its impact is negligible.
- Most faults are expected to clear within 5 cycles.
    - Transformer differentials, bus differentials, line differentials and zone 1 step distance faults should operate within 5 cycles.
    - Zone 2 step distance elements are set in the 69 kV feeders at Substation B and Substation C. These zone 2 faults are assumed to clear within 10 cycles.
- Since the PSLF model has the 69 kV loads attached to the buses at Substation C and Substation B, a 10 cycle 115 kV backup (BU) fault was used to simulate the zone 2 fault.
    - This allows for the Plant generators to still feed the 69 kV load, but to form an island.
- The loading is modeled as constant throughout each simulation.
- PSLF does not allow for transformer faults, faults on adjacent buses are sufficient

Switchyard D has a tie that connects the two buses. This means that Units 1 through 6 can be tied together to feed either or both loops. However, due to line capacity, the CO-OP will not put more than 2 units worth of generation onto Loop B or more than 4 units onto the Loop C. If line capacities change and more units are available to each loop, then the study should be re-examined.

II. Dynamic Scenarios

There were two different types of scenarios analyzed: islands and non-islands. Each scenario follows the same timeline. From t=0s to t=1s, the system is intact and there are no faults. At t=1s, a fault is applied for either 5 or 10 cycles, and then the faulted element is taken out of service. The simulation continues until t=10s with the generators in service and the faulted element out of service. Measurements of voltage angles at Switchyard D and at Substation E are

TABLE 2. MODIFICATIONS TO WECC LOADS

Modifications to WECC Loads	2024 Summer WECC (MW)	2024 Summer Modified (MW)	2025 Winter WECC (MW)	2025 Winter Modified (MW)
Substation C T1	N/A	18.2	N/A	17.1
Substation C T3	N/A	22.2	N/A	35.1
Substation C 115 kV	22.3	N/A	30.1	N/A
Substation B T1	18.3	18.3	17.1	17.1
Substation B T2	33.5	33.5	31.4	31.4
Substation B T3	11.3	11.3	15.0	15.0
Substation B T4	9.1	9.1	8.6	8.6

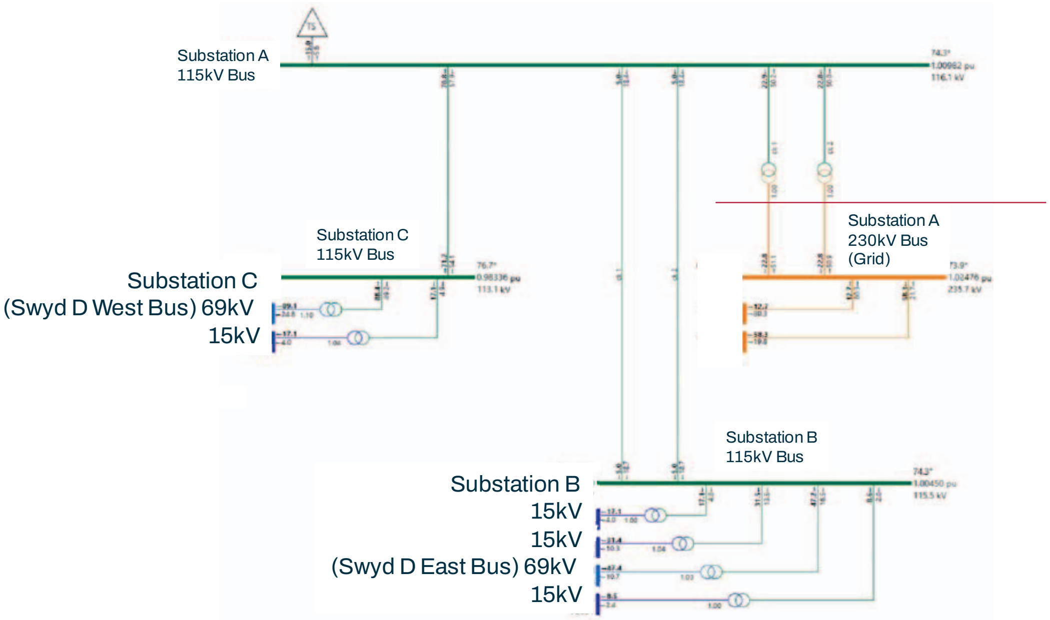


Fig. 1. WECC Light Winter Model

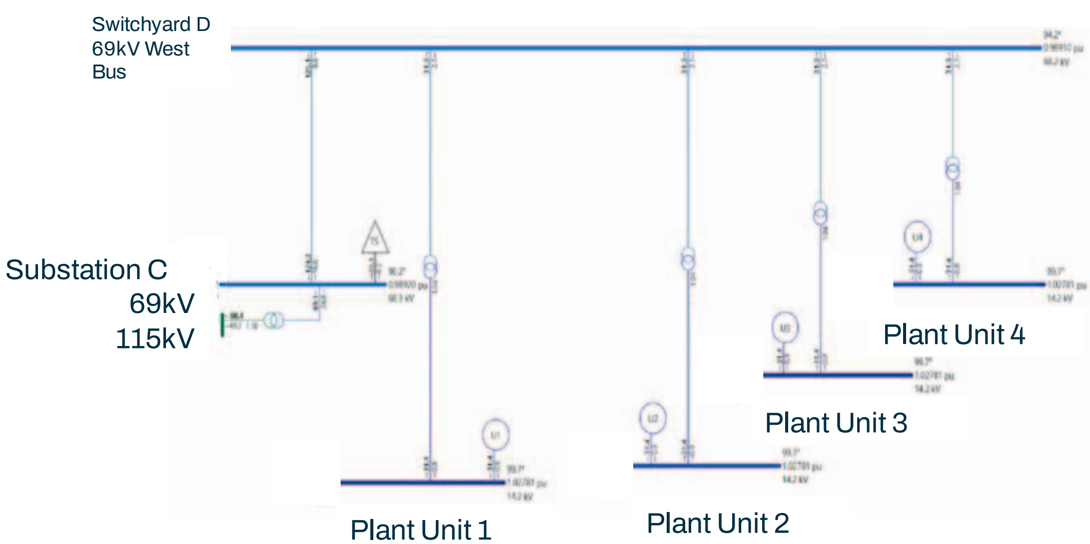


Fig. 2. WECC 2025 Light Winter Model of Switchyard D – Loop C – West Bus

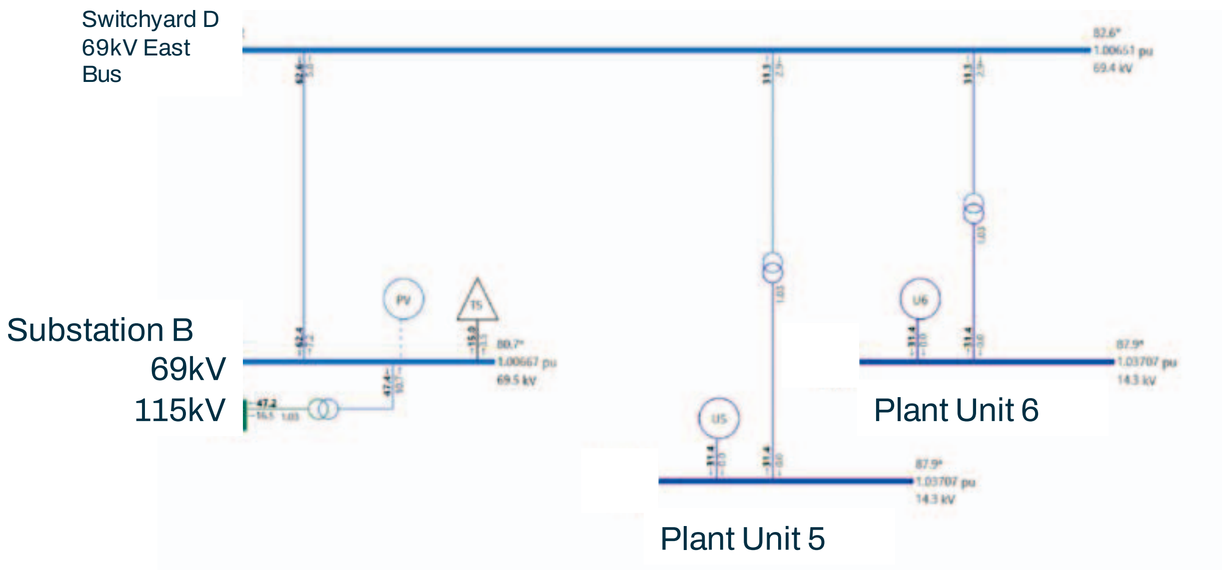


Fig. 3. WECC 2025 Light Winter Model of Switchyard D – Loop B – East Bus

exported. Frequency, real, and reactive power at both buses of Switchyard D are also exported for analyzing. In practice, the PMUs will be located on each bus at Switchyard D at Substation E.

III. Over and Under Frequency Settings

Over and Under Frequency (81O and 81U), are the Plant's and CO-OP's local islanding detection methods. A large deviation in frequency from the nominal frequency of 60 Hz can indicate that the loading on the generators has changed. The change in the frequency usually indicates that there is no longer a connection to the grid from the generators and an island has formed. If the generators are producing more power than the load of the island, then the frequency will increase. Conversely, if the load of the island is greater than the generation, then the frequency decreases. These changes in frequency when the load and generation are not closely matched, result in a change of 2Hz or more within the island. However, when the load and generation are closely matched, then the frequency may not drastically change. 81O and 81U elements may not detect an island during an event where the load and generation are closely matched. The bands for 81O and 81U should not be set too tight, since there are normal disturbances on the system which cause frequency changes such as faults or large load changes.

The over and under frequency settings used in Plant's relays are shown in Table 3. The frequency settings are set such that a deviation of +/- 1.2 Hz will initiate a trip if not cleared within 300 cycles. This means that if the frequency for any one generator's voltage is greater than 61.2 Hz or less than 58.8 Hz for longer than 5 seconds, then the generator breaker will trip.

The CO-OP's 50BF relays on the line breakers have the 81O/81U settings shown in Table 4. There are two bands of settings: a fast trip and a slow trip. The slow trip is set to be just outside Plant's settings, and they are set to +/-1.5 Hz with a 360 cycle delay; they serve as a backup to the Plant's 81O/81U settings. The fast settings are set to trip for an island within 2 seconds of the island forming. The fast settings are set at +/-2Hz with a 30 cycle delay. As shown later in the report, during most island scenarios, the frequency shifts far more than 2 Hz during an islanded condition.

IV. Island Scenarios

There are two main categories of islands with regards to this system: islands where the load and generation are closely matched and islands where the load and generation are not closely matched. "Closely matched" means that the load and generation is within 10 MW of each other. In the model, there are two scenarios that have been identified where the load and generation are closely matched, and the 81O/81U elements fail to detect the island. The first island scenario that will be examined in-depth will be an island where load and generation are not closely matched.

Table 3. Plant 81 Settings

Plant 81 Settings		
Menu	Description	Value
81U FREQUENCY	#2 PICKUP	58.8Hz
81U FREQUENCY	#2 DELAY	300 cycles
81O FREQUENCY	#4 PICKUP	61.2Hz
81O FREQUENCY	#4 DELAY	300 cycles

Table 4. CO-OP 81 Settings

CO-OP 81 Settings		
Menu	Description	Value
81 FREQUENCY	#1 PICKUP	58.5Hz
81 FREQUENCY	#1 DELAY	360 cycles
81 FREQUENCY	#2 PICKUP	58.0Hz
81 FREQUENCY	#2 DELAY	30 cycles
81 FREQUENCY	#3 PICKUP	61.5Hz
81 FREQUENCY	#3 DELAY	360 cycles
81 FREQUENCY	#4 PICKUP	62.0Hz
1 FREQUENCY	#4 DELAY	30 cycles

Most of the islands that can form in the system will result in the generation being much larger than the load. Thus, 81O/81U should be sufficient for most of the island cases. The first scenario examined is representative of most islanding cases. The second scenario is an island formed at the Substation C T3 transformer specifically during winter loading with only 1 unit in service. This scenario will not be cleared by 81O/81U elements and will require synchrophasor-based islanding detection. The final scenario that would require synchrophasor-based islanding detection is an island forming between Substation A and Substation B with both Units 5 and 6 feeding into the Loop B.

Table 5 shows all the islanded scenarios that will be examined throughout this paper. These are not all the cases that were examined as part of this study, but they have been selected to show the average and edge case scenarios.

The first scenario in the following section was chosen because it is representative of most islands that the system could occur, where the load and generation are not closely matched. The scenario is a fault on the Substation A-C 115 kV line with all four units in service. The Substation C-Substation A 115 kV line fault is unlikely to occur, and has not occurred within the last 5 years, but it represents what would happen if a fault were to occur anywhere from the BES to the Loop C side of Switchyard D. The second scenario is also unlikely, as CO-OP is planning to run either all or none of the generators at any one time. However, it is the island where the load and generation are the closest in magnitude with the future loading at Substation C. The Substation B-Substation A 115 kV line fault was chosen because it has the smallest frequency change. The two latter cases prove the need for synchrophasor-based islanding detection in this scheme.

TABLE 5. ISLAND SCENARIOS

Island Scenarios			
Scenario	Tripping Element	Generation/Load of Island (MW)	Time to Trip from Formation of Island
Substation C-Substation A 115 kV Line Fault	81O	125.6/52.2	0.75 seconds
Substation C T3 Fault (Winter)	data concentrator (Synchrophasor)	31.4/35.1	0.50 seconds
Substation B-Substation A 115 kV Line Fault with 1 line Out of Service (Winter)	data concentrator (Synchrophasor)	62.8/72.1	0.50 seconds

A. *Substation C-Substation A 115kV Line Fault*

There is a single 115 kV line that ties the 115 kV buses at Substation A and Substation C together. If this line were to have a fault, the generators at Plant would feed the fault. The 115 kV breakers at both Substation A and Substation C would trip (line differential with no taps). This would leave Loop C and Substation C distribution load unintentionally islanded. Units 1, 2, 3, and 4 would be feeding the 69 kV load on the Loop C and the distribution load through Substation C's T1 distribution transformer. Refer to Figure 1 to see the line connecting the Substation A 115 kV bus and the Substation C 115 kV bus.

The plot in Figure 4 shows the frequency of the Switchyard D West Bus. Per Table 4, the 50BF relay for the line breaker will pick up the over-frequency event at time t=1.25s. The relay will then trip the breaker by time t=1.75s.

Figure 5 shows the frequency of the Switchyard D East Bus during an island on the other. The Switchyard D East Bus

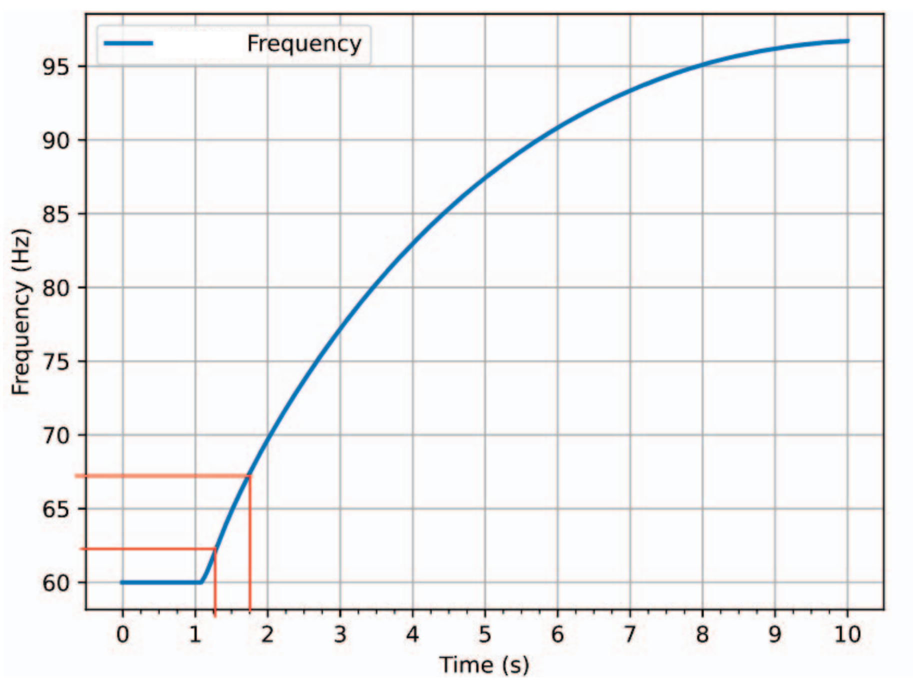


Fig. 4. Switchyard D West Bus Frequency for Island at Substation C – Substation A with 4 Units Online (Summer)

feeding the Substation B Loop is not islanded. Thus, there is not much disturbance to the frequency since it is tied to the grid. 81O/81U elements would not initiate for faults on the other bus.

The generation on the island is much greater than the load, which is why the frequency increases on the West Bus. Figure 6 shows the power being supplied at Switchyard D West Bus during the duration of the simulation.

The power being supplied by these generators was being absorbed by the surrounding network, then at the time the island formed, the load dropped off. This causes the over-frequency event. The winter model yields nearly identical results. Due to the mismatch of load and generation, local islanding detection is sufficient for detecting the island and tripping the Plant.

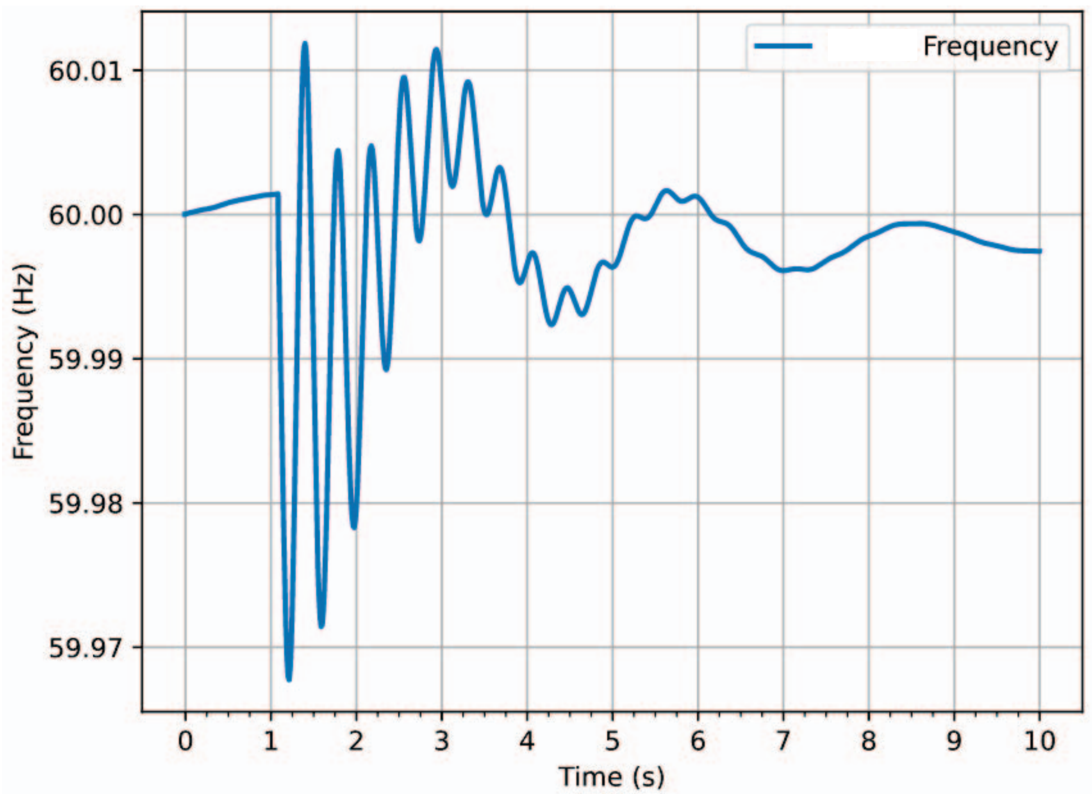


Fig. 5. Switchyard D West Bus Frequency for Island at Substation C 115 kV Bus with 4 Units Online (Summer)

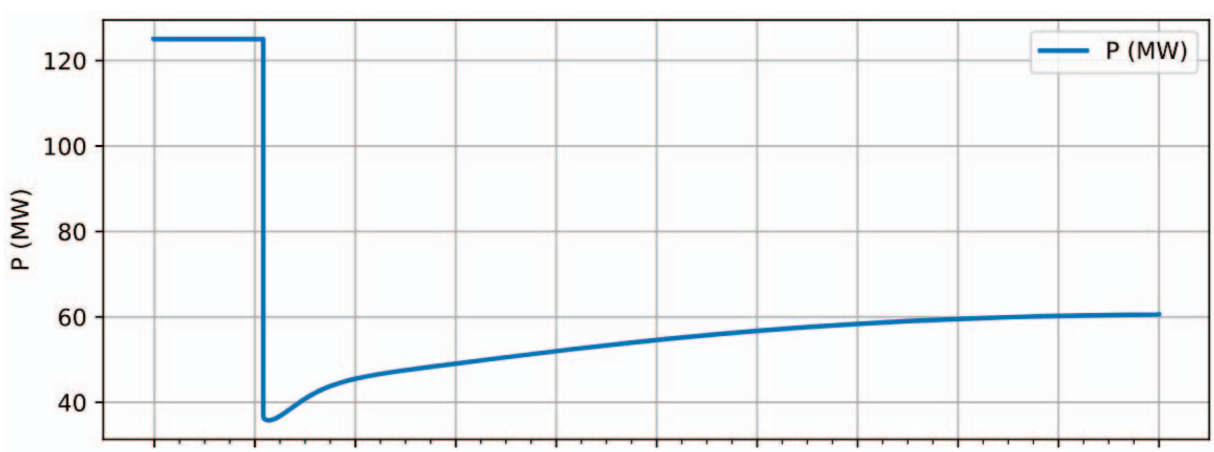


Fig. 6. Switchyard D West Bus Power Output for Island at Substation C 115 kV Bus with 4 Units Online (Summer)

B. Substation C T3 Fault or Out of Service with 1 Unit Online (Winter)

A fault on the Substation C T3 transformer would cause the Switchyard D West Bus and Loop C to become an island. Additionally, operator error on either the low-side main breaker of T3 or the line breaker at Substation C would cause an island; if an operator mis-identifies a control switch and operates a different breaker than intended, an island could form. Either of these scenarios allow for Switchyard D West Bus to feed the load on Loop C. Refer to Figure 2 to see T3 for Substation C. If only one unit is in service, then the winter loading in Loop C is close to the output of a single generator at Switchyard D.

At time t=1s, a fault was applied to the Substation C 115 kV bus for 5 cycles, then T3 was taken out of service. This simulates a fault occurring on the transformer (since a fault cannot be applied directly to a transformer in PSLF). After T3 was taken out of service, the model ran until t=10s.

The frequency at the Switchyard D West Bus can be seen in Figure 7. The load is slightly larger than the output of the generator, so the frequency slows down slightly.

This frequency change would be picked up by the 81O element on Plant's relaying, but the timer would expire with the frequency being in an acceptable range, so the breaker would never trip. This island would be out of sync from the grid and would lead to catastrophic consequences if/when the tie to the grid was re-established. Thus, synchrophasor-based islanding detection is needed for this instance. There is also the possibility of operator error taking Substation C's T3 out of service. There are control switches in the control building at Substation C that could lead to either the low-side main or line breaker to be opened unintentionally. This would create an island without a fault and allow for the Plant to feed an island on Loop C. The frequency for the operator error scenario can be seen in Figure 8.

T3 at Substation C was set out of service at time t=1s. The ending frequency of Figure 8 is nearly identical to Figure 7. Islanding can occur from both faults and human error, and thus it must be accounted for in the synchrophasor-based islanding detection.

The basis for synchrophasor-based islanding detection is to compare the positive sequence voltage angle at each Switchyard D bus and compare it to a remote bus that is not part of the island. Figure 9 shows the angular voltage difference between the islanded bus at Switchyard D and Substation E. Substation E is a remote bus that cannot be part of an island from Switchyard D. Substation E is owned by CO-OP. There is a standing difference between Switchyard D and Substation E during normal operation, which varies from 10 to 30 degrees.

During non-island conditions (t=0 to1s), the difference in voltage angle is around 10 degrees. As the island is formed, and the frequency shifts slightly at Switchyard D West bus, the voltage angle difference between the two buses begins to drift. This difference is how Switchyard D will detect an island and trip. The comparison of the voltage angles will be performed by the data concentrator at Switchyard D as can be seen in [3].

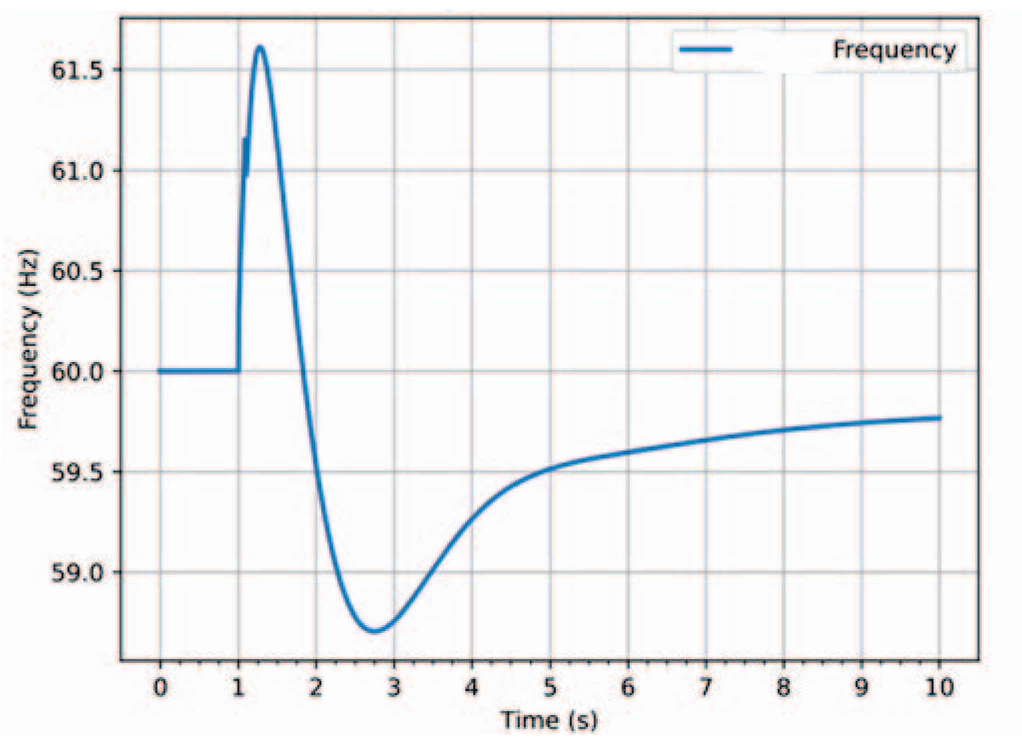


Fig. 7. Switchyard D West Bus Frequency for Island at Substation C T3 with 1 Unit Online (Winter)

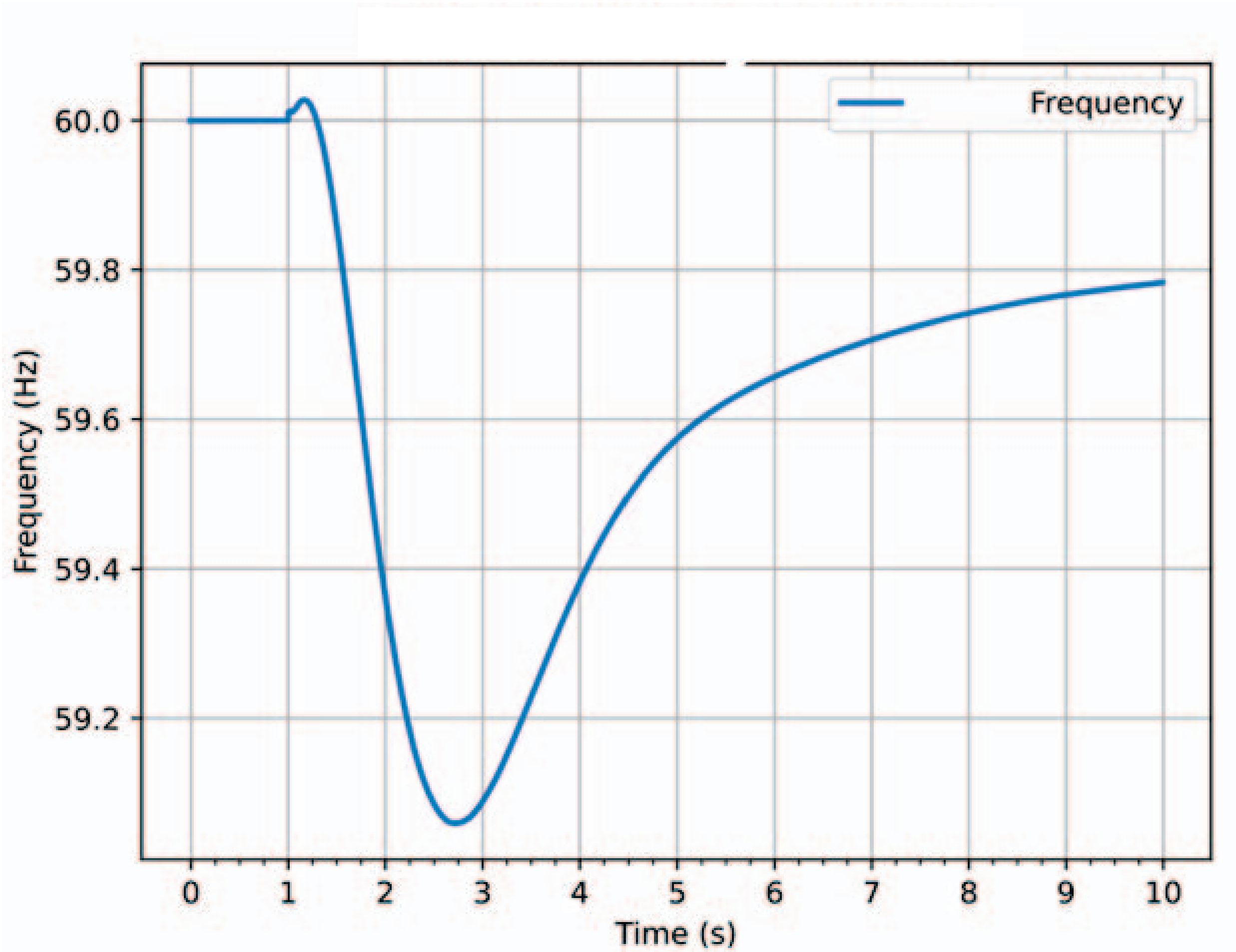


Fig. 8. Switchyard D West Bus Frequency for Island at Substation C T3 with 1 Unit Online (Winter) (Operator Error)

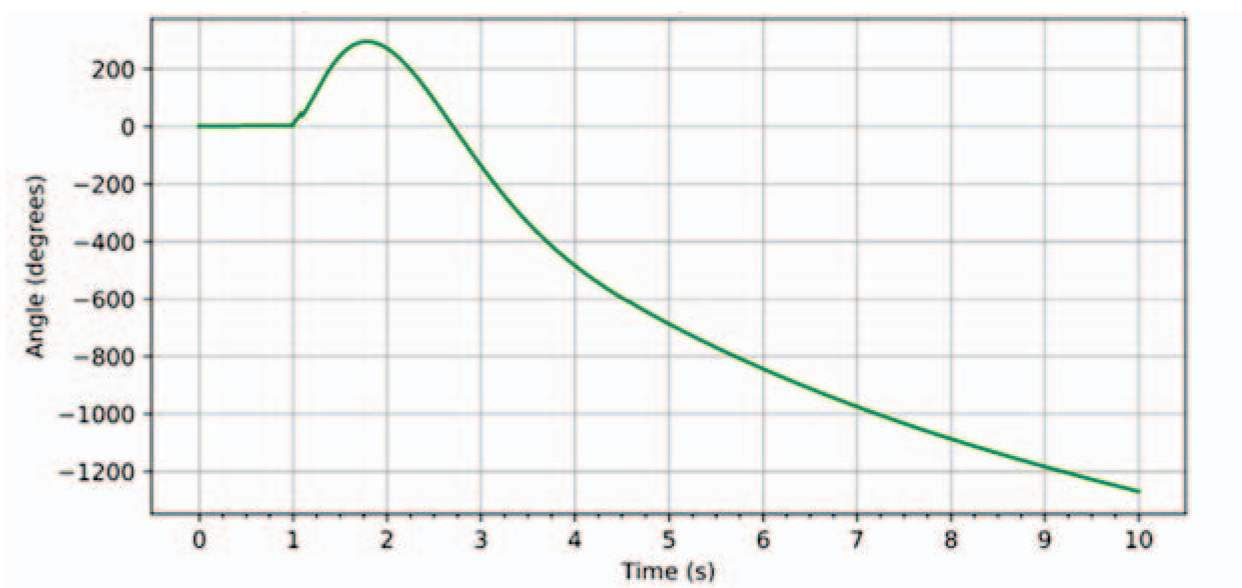


Fig. 9. Voltage Angle Difference Between Switchyard D and Substation E During an Island at Substation C T3 with 1 Unit in Service

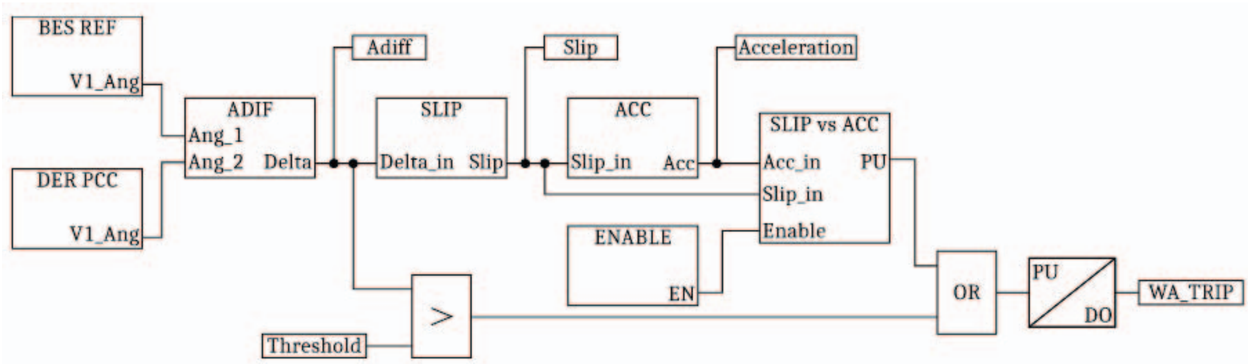


Fig. 10. RTAC Synchrophasor-Based Islanding Detection Logic

In the block diagram, "BES REF" is Substation E and "DER PCC" is Switchyard D. The positive sequence voltages are provided from the PMUs at each site. The PMU data from Substation E is provided via fiber to Switchyard D. The PMU data at Switchyard D is provided via serial connection from the PMUs to the data concentrator. There are PMUs on each line breaker at Switchyard D, which allows the data concentrator to perform the logic in Figure 10 for the East and West Bus.

During initial implementation, the slip and acceleration trip logic will not be implemented as the parameters cannot be determined at this time. However, all the islanded scenarios have an angular difference greater than 100 degrees. Thus, the threshold logic will suffice in conjunction with 81O/81U elements for islanding detection.

When the data concentrator detects that the angle difference is greater than 100 degrees for either bus, it will trip the respective bus lockout. This is to allow for breaker fail schemes and the tripping of the feeder breakers at Switchyard D. Per [1], an unintentional island must be tripped within 2 seconds of the island forming, which the data concentrator will be able to do based on its threshold settings.

C. *Substation B-Substation A 115 kV Line Fault with 2 Units in Service (Winter)*

During Winter loading and PV generation offline, Substation B's distribution (13.2 kV) and sub-transmission (69 kV) loads are closely matched to 2 units' worth of generation. If a fault were to occur on the 115 kV line between Substation B and Substation A while the other line is out of service, Substation B would not have continuity to the grid. Thus, if the Plant is generating onto Loop B, an island would be formed. During this line fault, if the Plant had both units online generating into the Loop B, the island would not be detected from 81O/81U elements (see Fig. 11 Appendix B). The frequency change would not be enough for Switchyard D to know that an island has formed. However, the angular difference between Switchyard D and Substation E is sufficient to detect an island (see Fig. 12 Appendix B).

Although this scenario is unlikely since there are two lines that go from Substation B to Substation A, the case is important because it proves that synchrophasor-based islanding detection will work even when the load and generation are nearly matched. This case has a frequency shift that would not be detected by 81O/81U elements at all, but the data concentrator would detect that the island has formed. There are non-island scenarios where the frequency shift due to a fault would initiate the 81O/81U elements, but the frequency returns to an acceptable range, preventing a trip. The angular difference between Switchyard D and Substation E in these non-island cases never surpasses 80 degrees.

V. NON-ISLAND SCNEARIOS

Synchrophasor-based islanding detection can detect an island effectively as noted in the previous section. However, this detection method should only trip for islands, and not for other faults within the system. When there are faults within the system, the frequency does change. The change is sinusoidal and dampens so long as its connection to the grid is maintained. Consequentially, the difference in voltage angle between Switchyard D and Substation E increases during these faults. It is important that the data concentrator can distinguish the difference between a disturbance to the system and an island. The following sub-sections will examine angular differences during faults not leading to an island, and why the threshold value of 100 degrees is adequate for this system. The first scenario that will be examined is a fault on a Substation B distribution transformer with all 6 units online. This case was chosen because there are 4 transformers on the Substation B 115 kV ring bus, and thus, it can illustrate the systems response for any of the distribution transformers. It also has one of the largest frequency shifts that does not result in an island, which proves that the frequency settings at Switchyard D should not be set tighter than what they are. The final non-islanding scenario proves that the data concentrator at Switchyard D will see an island on one of the buses and not the other. This is critical to ensuring that the generators are not tripping from nuisance faults (not leading to an island).

A. *Substation B T1 Fault with 6 Units in Service (Summer)*

This case was modeled using the same timeline as the scenarios in the previous sections. From time t=0s to time t=1s, the system was operating with no disturbances and all units were online. At time t=1s, a 5 cycle fault was applied to the Substation B T1 13.2 kV bus. After the fault, the T1 transformer was taken out of service and the model was ran until t=10s. The frequency of the Switchyard D East bus that feeds Loop B (see Fig. 13 Appendix C).

The Plant 81O/81U relays would initiate, but the timer would expire for this instance and the frequency shift would not be picked up by CO-OP's 81O/81U settings. Thus, 81O/81U would not trip for this event. As the frequency changes at Switchyard D, the voltage angle difference between Switchyard D and Substation E also changes. Figure 14 in Appendix C shows angular difference for this scenario.

The voltage angle difference between these two buses exceeds 70 degrees but does not exceed the 100 degree trip threshold that the data concentrator has. The result in this case would be no trip at the Switchyard D. This is the desired outcome because downstream relaying (87T) would clear the fault, and an island would not be formed. The generators would continue to supply power to the system and would be tied to the grid. The 100 degree threshold is satisfactory.

B. Substation B T3 Fault (Winter)

The next scenario is Substation B's T3 fault, which results in an island forming on Loop B; Units 5 and 6 will only be feeding the load on the Substation B 69 kV system. During this time, the data concentrator and 81O/81U elements will detect an island and will trip the line breaker feeding into Loop B. In this event, Loop C will not be islanded. The data concentrator will be performing the logic in Figure 10 for both Buses. There are PMUs on each line breaker at Switchyard D which the data concentrator will be measuring against Substation E for islanding detection. The frequency of the East Bus after a T3 fault can be seen in Figure 15 in Appendix D.

The 81O element in the 50BF would be able to detect this island and trip. The data concentrator would also detect the island as the angular difference between Substation E and Switchyard D surpasses the 100 degree threshold as seen in Figure 16 in Appendix D.

This angular difference would be detected within the first second of the island forming. The data concentrator would trip the breakers on the East Bus before the timer on the 81O element expires. In this event, the West Bus generators would feed the fault through Substation A. There would be a disturbance to the Loop C as adjacent loading would shift the frequency. The frequency disturbance on the West Bus can be seen in Figure 17 in Appendix D.

The fault initially causes the frequency to shift but eventually dampers back to the nominal value (60 Hz). The 81O/81U elements on the West Bus of Switchyard D would not initiate because the frequency never surpasses the thresholds set in the relays. Figure 18 in Appendix D confirms that the data concentrator's logic on the Substation C Loop side of Switchyard D would not mis-interpret the fault on Substation B T3 as an island.

The voltage angle on the West bus never surpasses the 100 degree threshold required for the data concentrator to trip the bus lockout. The data concentrator can perform both comparisons at the same time and will be able to distinguish between an island and a fault and trip the correct bus lockout.

VI. Conclusion

Unintentional islanding can have major consequences if not addressed in a timely manner. When distributed generation is well embedded in a network that has multiple disconnects prior to the connection to the Bulk Electric System, breaker status may not be feasible for islanding detection. If local loading and generation are not evenly matched, then over and under frequency elements may suffice for islanding detection. However, when loading and generation are closely matched, then synchrophasor-based islanding detection can be implemented to detect an island. To implement this detection method, modeling must be performed to determine the maximum angular difference between a grid reference point and the distributed generation bus; PMUs must be in place at the distributed generation and a bus that cannot be part of the island; a data concentrator must have communications with the PMUs; and the data concentrator needs to be able to perform the angular difference calculations to determine if an island has been formed.

VII. References

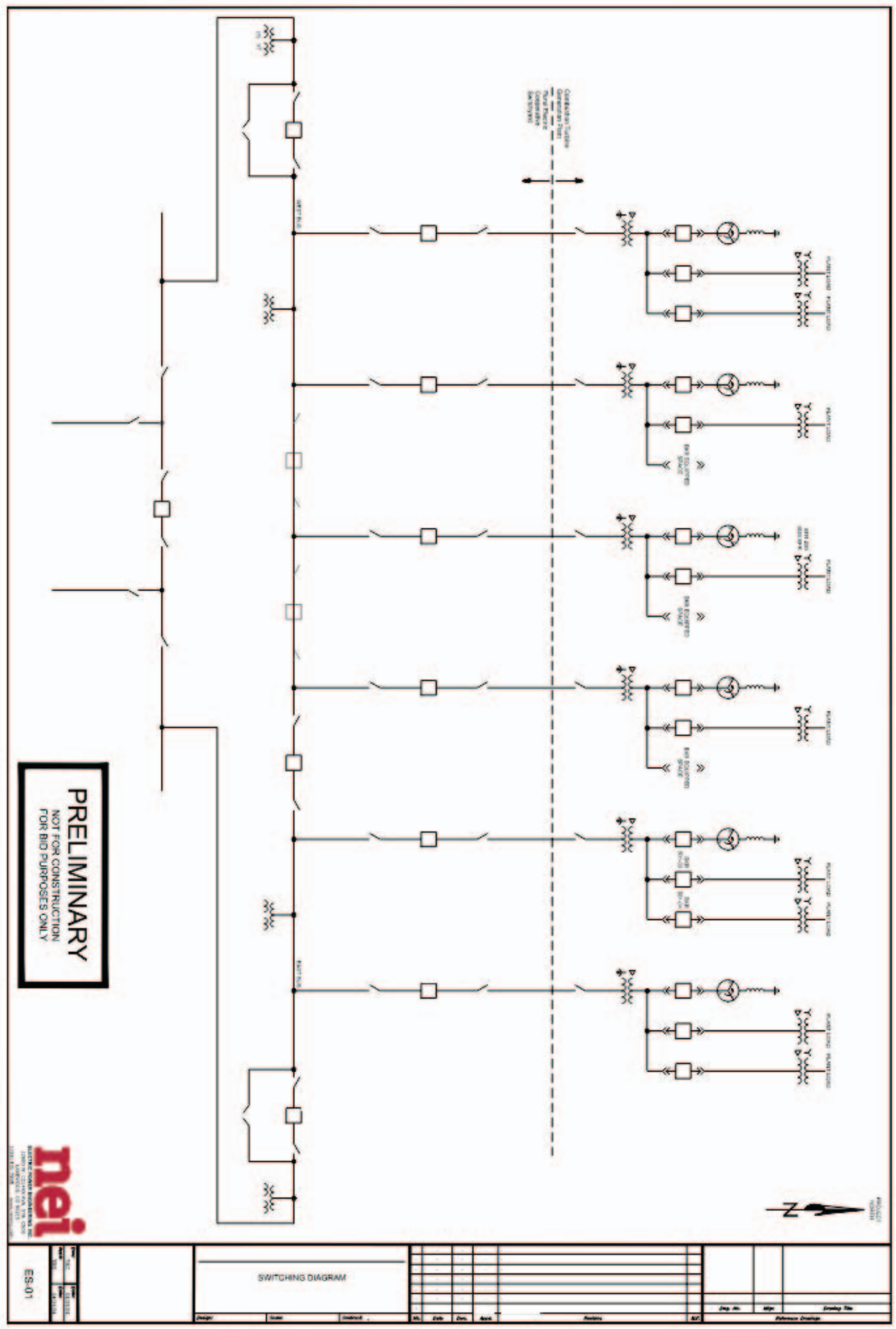
[1] IEEE Standard for Interconnecting Distributed Resources with Electric Power Systems, IEEE Std 1547-2018, 2003.

[2] Western Electricity Coordinating Council. "About WECC." Available: https://www.wecc.org/about/about-wecc. (Accessed: Feb. 23, 2025).

[3] Subbarayan, J., Watson, J., & Cockerham, B. "Implementing Synchrophasor-Based Anti-Islanding Protection for DERs With Multiple Grid Interconnects Using an SEL RTAC and SEL-735 Meters." SEL Application Guide, Volume V, AG2022-01, 2022

Appendix A

Switchyard D Switching Diagram



APPENDIX B

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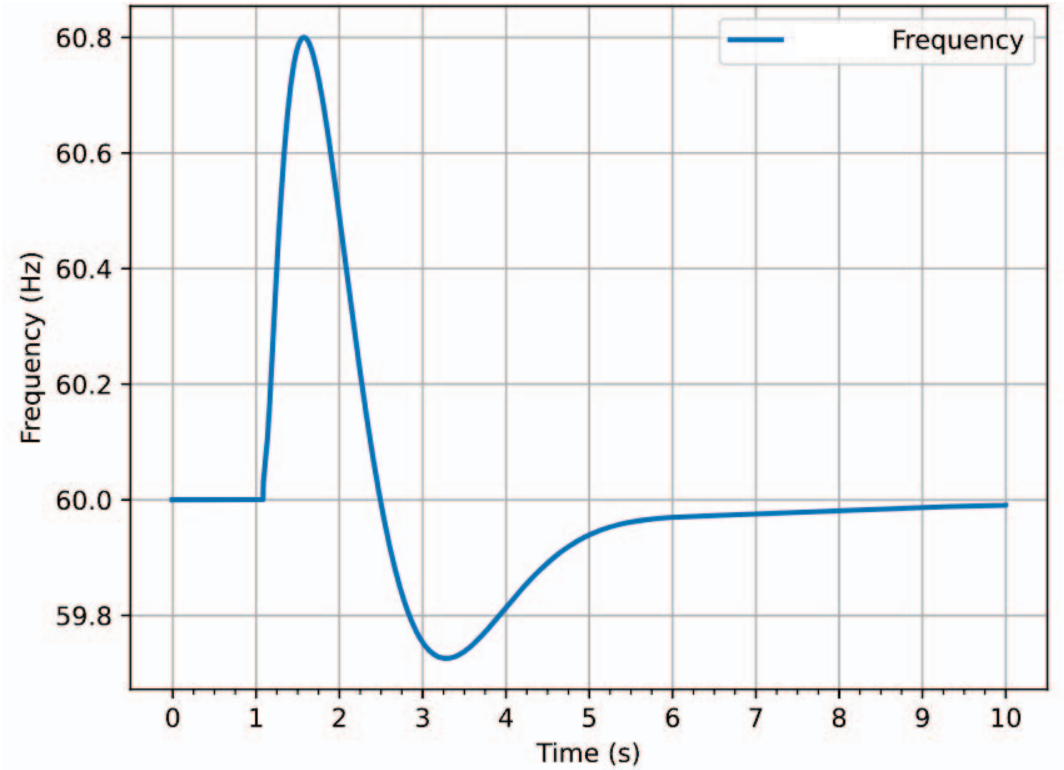

Fig. 11. Switchyard D East Bus Frequency for Island at Substation B 115 kV Bus with 2 Units Online (Winter)

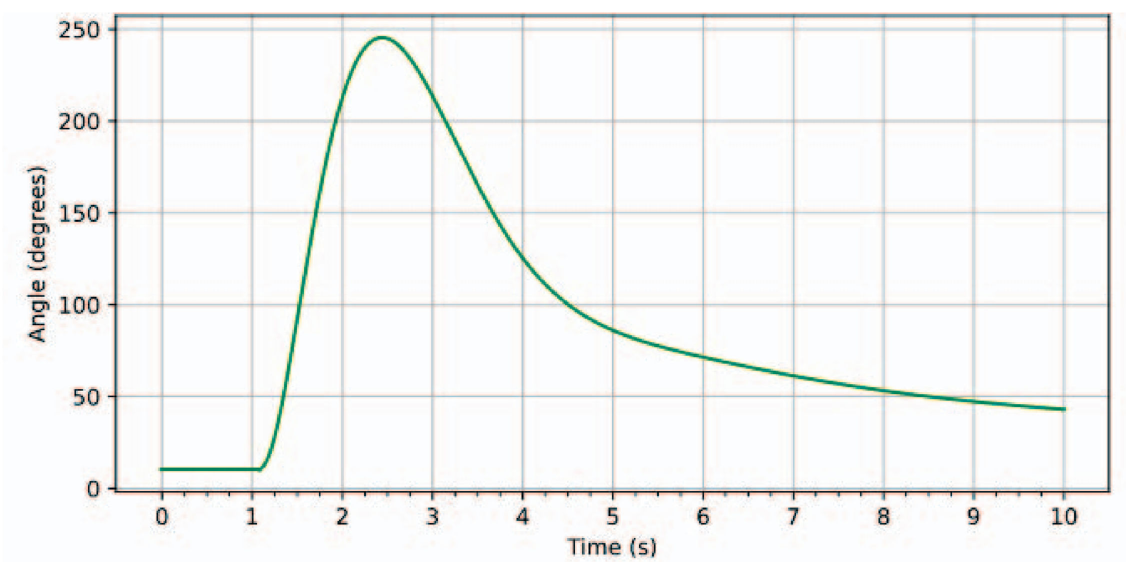

Fig. 12. Voltage Angle Difference Between Switchyard D East Bus and Substation E During an Island at Substation B 115 kV Bus with 2 Units in Service

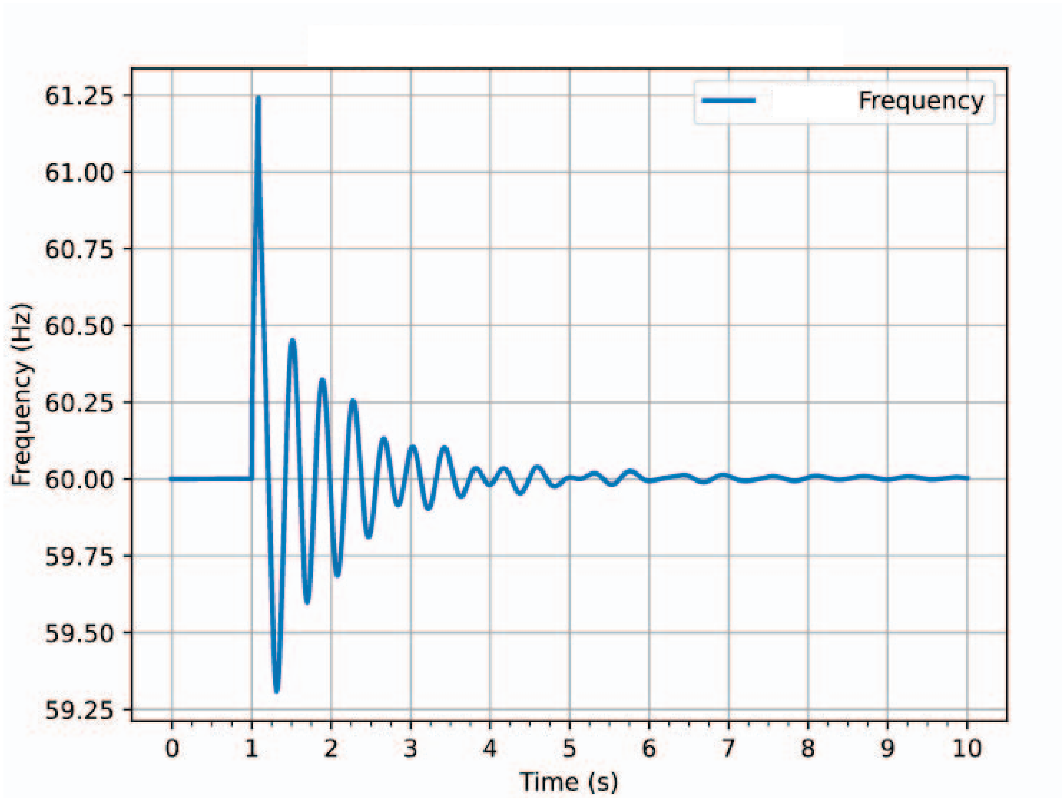

Fig. 13. Switchyard D East Bus Frequency for Fault at Substation B T1 with 2 Units Online (Summer)

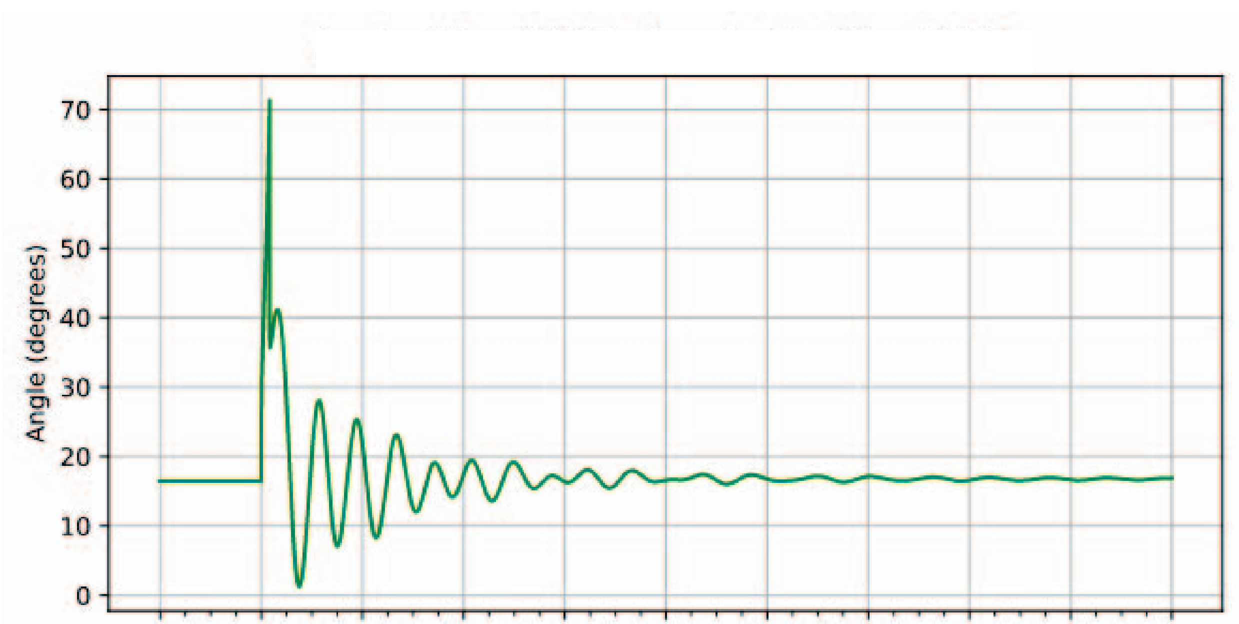

Fig. 14. Voltage Angle Difference Between Switchyard D East Bus and Substation E During a Fault at Substation B T1 with 2 Units in Service

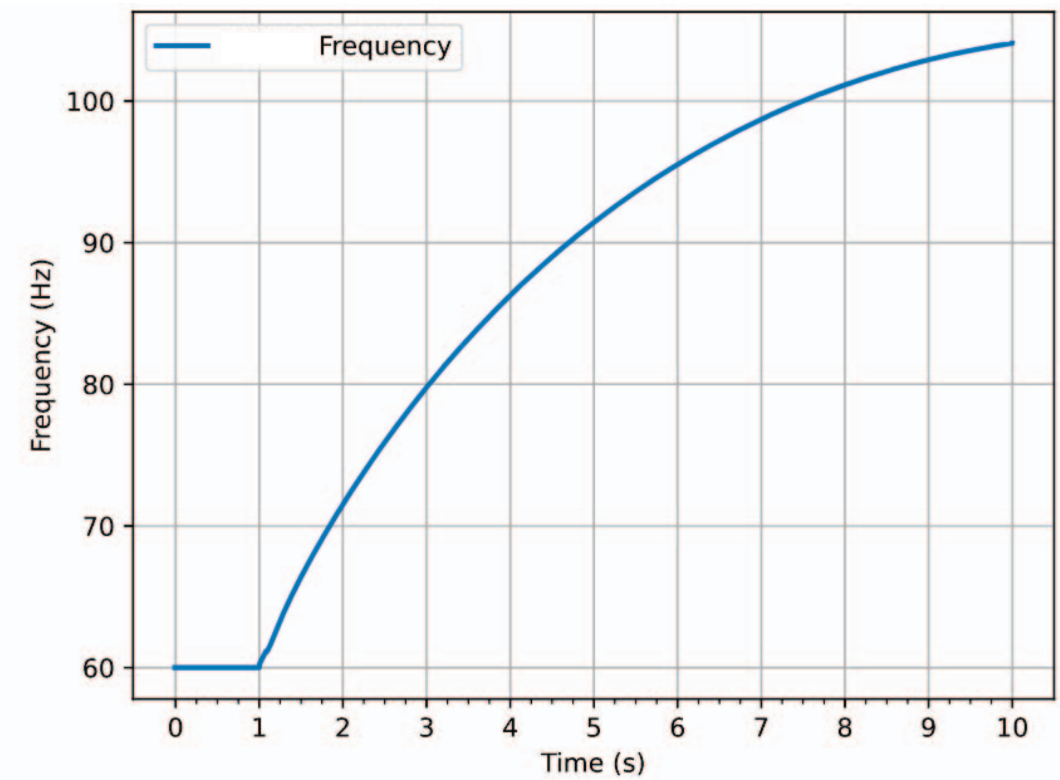

Fig. 15. Switchyard D East Bus Frequency for Fault at Substation B T3 with all Units Online (Winter)

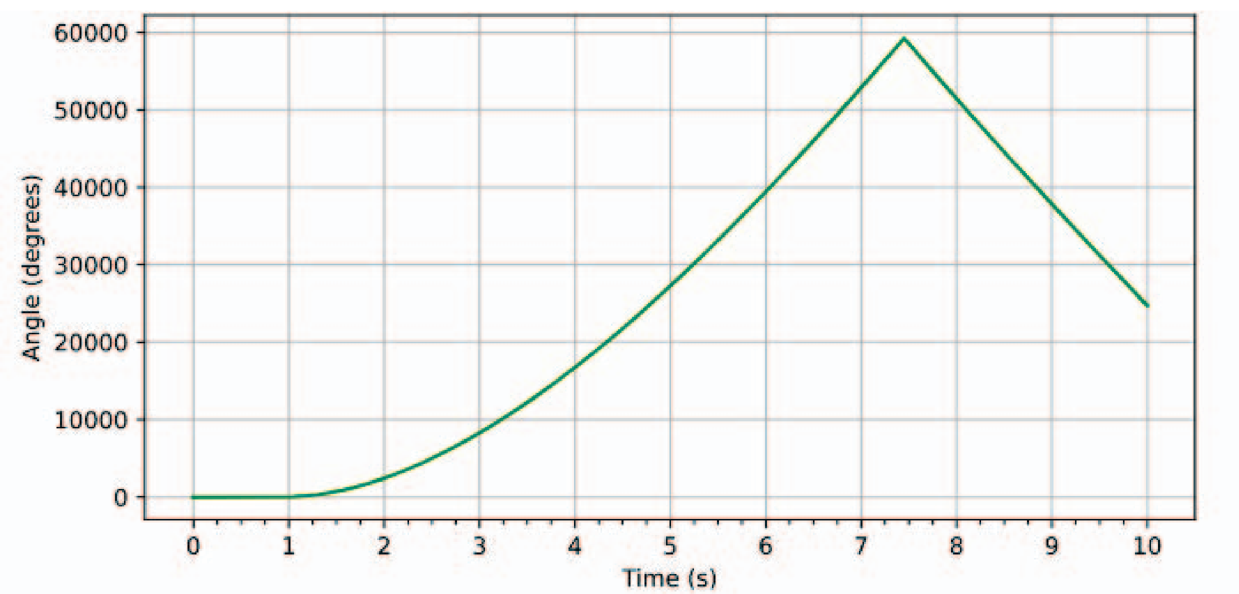

Fig. 16. Voltage Angle Difference Between Switchyard D East Bus and Substation E During a Fault at Substation B with All Units in Service (Winter)

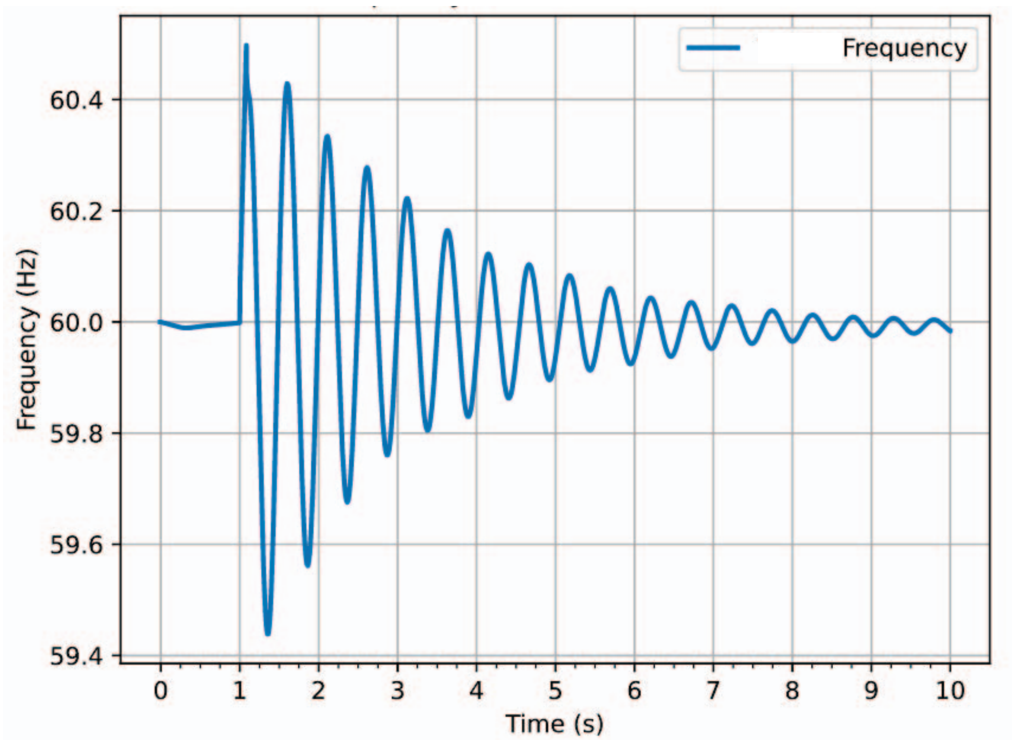

Fig. 17. Switchyard D West Bus Frequency for Fault at Substation B T3 with all Units in Service (Winter)

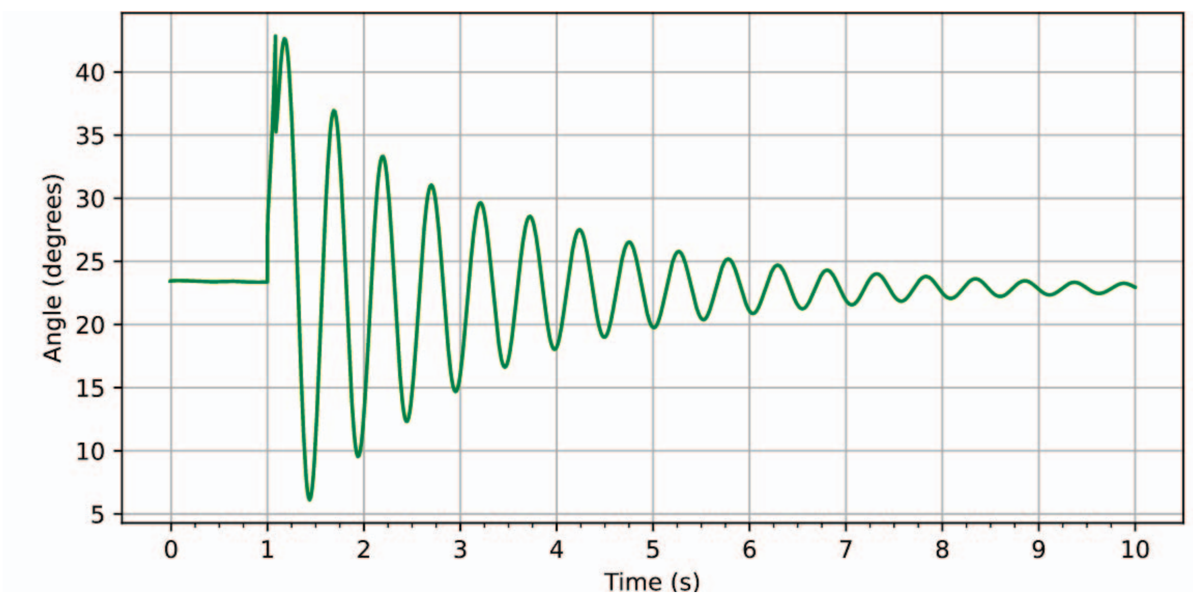

Fig. 18. Voltage Angle Difference Between Switchyard D West Bus and Substation E During a Fault at Substation B with All Units in Service (Winter)

Lesson Learned through Operation and Maintenance of Distribution Electric Grid Connected Utility-Scale Wind Energy Generation Projects

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***Abstract*—Utility-scale distributed energy resources are gaining more and more traction with commercial and industrial customer driven interest. RE100 is a group of companies that made corporate commitments to pursue 100% renewable energy goals. This group is currently 442 companies strong, many of them Fortune-1000 companies. A few of the Nebraskan public power districts and municipal utilities implemented utility-scale wind, solar, and storage projects to assist their current and future customers. This article is a research analysis on some such pioneering wind projects, and the associated operation and maintenance lessons learned over more than 9 years of field operations. The real-world data collected by these distribution grid level Wind SCADA systems is used to evaluate the monthly capacity factors, availability factors, wind speeds, down times, maintenance times, weather outages etc. Finally, the carbon offset value created by these projects is also quantified.**

Keywords—Distribution grid connected generation, Wind, Operations and maintenance, O&M, Green tariff, Ethanol plant, C&I.

I. INTRODUCTION

As a nation, the U.S. hosts approximately 122,810 MW of cumulative utility-scale Solar capacity, and 153,371 MW of cumulative utility-scale Wind capacity by the end of year 2024 [1]. The U.S. Energy Information Administration (EIA) reported the total annual electric generation from all utility-scale generators (>1 MW_{AC} in size) to be approximately 4,304 TWh in the year 2024, out of which, 15.6% (or 672 TWh) is generated from utility-scale Solar (219 TWh) and Wind (453 TWh) projects exceeding 15.2% (or 653 TWh) generated by coal plants, this happened for the first time in the history of U.S. electric grid [2]. The U.S. utility sector has experienced growth in both Solar and Wind generated electric energy while experiencing decline of coal generated electric energy over the past decade as shown in Table 1. Natural gas generated electric energy has also seen tremendous growth primarily replacing the base load needs of coal power plants. The electric energy generated from Nuclear and Hydroelectric sources has remained relatively same over the years while the dependency on other sources such as wood, biomass, petroleum liquids, petroleum coke, other fossil gas etc. has been on the decline.

Table 1. Electric energy generation growth in the U.S. (data from various years of Table ES1.B, EIA Electric Power Monthly [2])

Fuel Source	End of Year 2014	End of Year 2024	Decade of Change (TWh and %)	
Coal (TWh)	1,582	653	-929	-58.7%
Natural Gas (TWh)	1,127	1,865	738	65.5%
Wind (TWh)	182	453	272	149.6%
Solar (TWh)	18	219	201	1135.3%
Nuclear (TWh)	797	782	-15	-1.9%
Hydroelectric (TWh)	259	242	-17	-6.6%
Others (TWh)	129	90	-39	-30.3%
Total (TWh)	4,094	4,304	210	5.1%

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A. Electric Cooperatives and Renewable Energy

Electric cooperatives and public power utilities predominantly serve the electric energy needs of the rural United States. More than 490 electric cooperatives in 43 U.S. States have added solar power, and more than 350 electric cooperatives in 29 U.S. States have added wind power to their generation mix. The overall cumulative solar power capacity by electric cooperatives has reached 3,937 MW by the end of 2023. The overall wind power has reached a cumulative total of 10,256 MW by the end of 2023. The electric cooperatives are expected to add another 5.3 GW in renewable power capacity by the end of 2027 [3]. However, many of these renewable energy projects are tied into the transmission grid, especially when it comes to wind power projects. Hence, the concept of distribution grid connected renewable energy projects is still new to many in the rural electric distribution utility industry.

B. Rural Electric Distribution Grid Connected Projects

Nonetheless, with the growth in distribution grid connected projects in the recent years such as community solar PV projects, single wind turbine projects, lithium-ion battery energy storage system projects etc., there is growing interest to understand the impact of these projects on the local grid networks. These projects have gained popularity due to the locational value [4] that they provide to the local distribution electric utilities such as:

1. Delivering power to areas with high marginal losses
2. Deferring transmission and distribution (T&D) electric infrastructure upgrades
3. Reducing distribution system peak loads
4. Improving the local grid reliability by overcoming the grid congestion issues

Transmission interconnection delays are another strong reason for many renewable energy project developers focusing some of their efforts on distribution grid interconnected projects. Lawrence Berkeley National Laboratory (LBNL) releases an annual report on the status of queues in various Independent System Operators (ISOs) and Regional Transmission Organizations (RTOs) across the country. Currently, most RTO/ISO regions are experiencing a median project development period from interconnection request (IR) to commercial operations date (COD) of approximately five years (60 months), and this duration is increasing with every passing year. Comparatively, projects connected to the distribution electric grid often smaller than 5 MW are experiencing a project development timeline of approximately 20 months, and for the project sizes between 5 MW and 20 MW, the experienced development timeline is approximately 33 months [5].

This paper discusses the lessons learned through operations and maintenance of such distribution grid connected wind projects operated by an independent power provider (IPP) in rural Nebraska.

II. Projects Discussion

In this research study, grid data analytics are performed using real world data from operating wind projects of an IPP, who is the owner and the operator of these assets. The collected real-world data is attributed to 19 wind turbine generators (WTG) from 10 different wind projects. The IPP also operates 5 different solar PV system projects, and 2 different battery energy storage system (BESS) projects. All these projects are connected to 12 different rural electric distribution electric grids at their respective grid voltages of 12.47 kV, 34.5 kV, or 69 kV. Table 2 and Table 3 enumerates all these distribution grid connected projects. The SCADA systems are in place monitoring various performance parameters of all these Wind, Solar, and Storage projects. An attempt is made to summarize the operation and maintenance issues of the distribution electric grid connected wind power generation projects.

Table 2. Distribution grid connected wind turbine generator projects used in the operations and maintenance analysis.

Project Size (kW_{AC})	Grid Interconnect Voltage	Type of WT Generator	Operations Start Date
3,000	12.47 kV	2 × 1.5 MW	Jul-2011
1,850	12.47 kV	1 × 1.85 MW	Oct-2014

Project Size (kW_{AC})	Grid Interconnect Voltage	Type of WT Generator	Operations Start Date
6,800	34.5 kV	4 × 1.7 MW	Dec-2015
1,700	12.47 kV	1 × 1.7 MW	Dec-2016
6,900	34.5 kV	3 × 2.3 MW	Jun-2017
1,700	12.47 kV	1 × 1.7 MW	Dec-2017
6,900	12.47 kV	3 × 2.3 MW	Jul-2018
2,500	34.5 kV	1 × 2.5 MW	Dec-2018
2,500	34.5 kV	1 × 2.5 MW	Dec-2019
5,640	69 kV	2 × 2.82 MW	Sep-2022

Table 3. Distribution grid connected Solar PV and BESS projects that are part of the operations and maintenance analysis.

Project Size (kW_{AC})	Grid Interconnect Voltage (kV)	Type of Generator	Operations Start Date
500	12.47 kV	Solar PV	Dec-2020
1,160	12.47 kV	Solar PV	Dec-2020
1,000	12.47 kV	Solar PV+BESS	Jun-2021
1,000	12.47 kV	Solar PV+BESS	Jun-2021
4,375	12.47 kV	Solar PV	Nov-2023

A. Load Mix of the Partnered Rural Electric Utilities

All the twelve power offtakers (the purchaser of the generated power) of these renewable energy projects are all Rural Electric Utilities (REU) whose customers are classified into three categories namely – residential, commercial, and industrial/agricultural – as shown in Table 4 and Table 5.

Table 4. Metered Customers of the Partnered Rural Electric Utilities hosting Wind Turbine Generator Projects

Rural Electric Utility	Residential Meters	Commercial Meters	Industrial/ Agricultural Meters
REU-1 (3 MW)	73,900	19,504	60
REU-2 (1.85 MW)	1,806	552	0
REU-3 (6.8 MW)	16,333	3,876	599
REU-4 (1.7 MW)	11,645	2,337	38
REU-3 (6.9 MW)	16,333	3,876	599
REU-5 (1.7 MW)	2,839	757	0
REU-6 (6.9 MW)	4,119	1,105	2,434
REU-7 (2.5 MW)	2,270	568	1,988
REU-8 (2.5 MW)	2,972	360	748
REU-9 (5.64 MW)	15,219	2,880	9,988

Table 5. Metered Customers of the Partnered Rural Electric Utilities hosting Solar PV System/BESS Projects

Rural Electric Utility	Residential Meters	Commercial Meters	Industrial/ Agricultural Meters
REU-10 (0.5 MW)	17,315	2,855	83
REU-10 (1.2 MW)	17,315	2,855	83
REU-11 (1 MW)	3,492	325	479
REU-11 (1 MW)	3,492	325	479
REU-12 (4.4 MW)	53,601	11,610	7,909

III. Discussion of WTG Power Generation, Operations, and Maintenance

The installed wind turbine generator technologies operate at wind speeds between 7.5 mph (cut-in speed) and 71.5 mph (cut-out speed), with the peak generation occurring at wind speeds between 24 mph and 50 mph (rated speed range).

	Average Capacity Factor [%] of All Operational Years (2015-2024)												
WTG Name	**Jan**	**Feb**	**Mar**	**Apr**	**May**	**Jun**	**Jul**	**Aug**	**Sep**	**Oct**	**Nov**	**Dec**	**Year**
CR01	47.0	50.4	56.5	57.8	47.9	40.2	30.1	33.0	49.6	51.6	58.4	45.4	**47.3**
CR02	51.8	52.4	50.4	56.5	47.9	45.7	32.8	33.7	50.1	56.9	56.8	56.9	**49.4**
CR03	49.7	53.5	61.5	63.2	47.2	43.9	33.6	36.4	50.8	52.8	52.7	51.9	**49.8**
CR04	50.0	50.8	53.0	49.8	41.3	41.5	29.8	34.7	47.8	56.3	53.0	56.8	**47.1**
CR2-01	57.4	53.6	58.2	59.9	48.1	43.9	31.3	34.3	49.4	57.4	61.5	58.1	**51.1**
CR2-02	50.9	52.5	58.1	64.7	45.2	38.5	27.3	34.4	47.4	53.6	58.2	57.3	**48.9**
CR2-03	55.8	45.5	55.7	61.9	47.6	40.9	33.0	35.0	43.7	53.8	50.3	58.9	**48.5**
CCR-T1	35.0	44.7	49.8	55.2	50.0	47.4	32.8	43.0	50.2	46.6	46.6	60.5	**46.6**
CCC-01	47.5	58.6	61.3	61.2	51.7	44.0	33.5	34.7	50.5	50.0	56.2	49.1	**50.0**
PCR-01	54.0	65.3	62.3	70.8	55.0	40.5	35.5	29.8	36.3	44.5	51.8	60.0	**50.5**
SW-01	42.0	63.6	62.9	67.7	51.0	42.6	28.7	31.9	38.1	58.8	58.9	54.3	**50.4**
PW_T3	52.9	61.4	65.8	67.5	40.6	46.8	36.0	38.2	53.2	58.4	65.4	60.5	**53.9**
PW_T2	55.7	61.8	62.1	71.9	47.0	46.4	35.3	35.4	47.2	60.3	65.7	60.8	**54.1**
PW_T1	55.3	61.7	65.7	72.6	47.4	43.4	38.2	40.7	52.2	57.5	56.8	60.1	**54.3**
SPPW1_T1	36.8	57.2	62.1	67.7	45.7	44.4	30.6	37.9	46.6	53.3	54.5	55.5	**49.8**
SPPW1_T2	49.3	59.9	62.6	69.6	46.9	47.1	33.9	30.4	43.5	57.0	61.5	57.0	**52.0**
All WTGs	**50.7**	**54.4**	**58.4**	**62.1**	**47.2**	**43.3**	**32.5**	**35.4**	**48.2**	**54.5**	**56.8**	**56.1**	50.0

Figure 1. Heatmap of monthly average capacity factors (%) of all the 16 operating WTGs during 2016-2024.

	Average Availability Factor [%] of All Operational Years												
WTG Name	**Jan**	**Feb**	**Mar**	**Apr**	**May**	**Jun**	**Jul**	**Aug**	**Sep**	**Oct**	**Nov**	**Dec**	**Year**
CR01	86.1	96.1	94.7	91.3	95.8	84.6	86.1	90.7	96.5	90.1	96.8	79.5	**90.7**
CR02	94.0	98.1	84.2	86.8	94.4	94.2	96.7	92.8	96.8	96.7	93.3	94.5	**93.6**
CR03	91.1	99.0	98.6	96.7	94.5	95.8	96.7	97.1	97.8	88.8	85.6	87.7	**94.1**
CR04	93.7	93.6	85.2	78.6	81.3	87.7	85.9	96.6	95.2	93.9	89.6	92.2	**89.5**
CR2-01	99.3	93.1	94.7	90.4	97.4	97.3	96.6	96.7	98.8	98.3	99.1	96.4	**96.6**
CR2-02	90.8	93.0	94.6	97.7	92.7	80.3	82.6	97.3	95.7	92.9	94.6	98.2	**92.6**
CR2-03	96.8	81.1	87.6	91.7	93.9	85.3	97.2	96.6	86.6	96.5	91.2	97.3	**92.0**
CCR-T1	59.5	77.3	79.7	77.9	92.2	98.0	94.7	97.9	94.8	77.1	74.6	99.6	**84.9**
CCC-01	93.2	97.1	97.4	95.2	99.6	93.1	92.8	90.5	97.3	88.3	90.0	90.6	**93.8**
PCR-01	95.3	95.8	90.0	97.9	97.1	90.1	99.0	70.6	66.8	73.9	76.9	95.7	**87.4**
SW-01	84.4	96.4	98.7	98.6	93.2	96.8	92.6	90.6	70.4	94.2	91.6	93.4	**91.9**
PW_T3	95.5	98.9	99.8	98.1	86.9	94.5	96.0	92.1	99.6	98.3	99.2	99.0	**96.5**
PW_T2	99.5	99.8	96.5	98.1	97.0	92.1	96.0	84.4	89.7	99.6	99.0	99.4	**95.9**
PW_T1	99.0	98.5	99.2	98.3	97.9	88.4	99.9	98.1	94.9	97.7	85.7	95.9	**96.0**
SPPW1_T1	78.0	97.3	99.2	97.7	99.6	98.6	98.7	99.9	99.6	98.6	90.4	98.0	**96.4**
SPPW1_T2	100.0	98.7	97.8	99.5	97.8	99.9	97.6	75.9	86.2	98.3	99.5	99.9	**95.9**
All WTGs	**92.2**	**94.4**	**92.9**	**92.3**	**93.8**	**91.2**	**93.5**	**93.0**	**93.4**	**93.1**	**91.6**	**94.0**	92.9

Figure 2. Heatmap of monthly average availability factors (%) of all the 16 operating WTGs during 2016-2024.

	Average Wind Speed [mph] of All Operational Years												
WTG Name	**Jan**	**Feb**	**Mar**	**Apr**	**May**	**Jun**	**Jul**	**Aug**	**Sep**	**Oct**	**Nov**	**Dec**	**Year**
CR01	17.5	18.3	18.7	19.5	16.0	15.2	12.3	12.7	15.9	17.1	18.4	18.3	**16.7**
CR02	17.8	18.5	18.3	19.3	16.1	15.9	13.0	13.2	16.0	17.5	18.4	18.9	**16.9**
CR03	17.7	18.5	19.1	20.0	16.2	15.9	13.3	13.4	16.1	17.4	18.2	18.4	**17.0**
CR04	17.7	18.5	18.7	19.4	15.8	15.4	12.6	13.2	15.8	17.5	18.3	18.9	**16.8**
CR2-01	19.2	19.3	19.8	20.5	17.2	16.6	13.7	14.2	16.8	18.9	19.6	19.6	**17.9**
CR2-02	18.9	18.9	19.7	20.9	17.0	16.9	13.9	14.2	16.7	18.6	19.2	19.2	**17.8**
CR2-03	18.5	19.4	19.0	20.1	16.1	15.8	12.9	13.3	15.7	17.7	17.7	18.6	**17.0**
CCR-T1	21.2	20.4	20.3	23.2	17.8	17.0	13.9	15.2	17.2	19.1	22.1	19.2	**18.9**
CCC-01	15.4	17.4	18.3	19.4	15.8	16.0	13.4	13.6	15.7	17.2	18.0	17.5	**16.5**
PCR-01	18.9	21.1	21.2	22.6	18.2	16.5	14.0	16.2	15.0	14.2	19.9	19.8	**18.1**
SW-01	17.8	19.4	19.3	21.4	17.0	15.4	13.1	13.6	16.8	18.2	19.2	18.7	**17.6**
PW_T3	19.0	20.3	21.4	23.0	18.6	18.1	15.3	15.9	18.5	19.8	21.0	20.3	**19.3**
PW_T2	18.5	19.5	20.6	21.9	17.6	17.1	14.3	15.0	17.8	18.8	20.1	19.5	**18.4**
PW_T1	19.2	20.4	21.2	22.7	18.2	17.8	14.8	15.4	18.1	19.4	20.7	20.3	**19.0**
SPPW1_T1	16.4	18.5	19.1	21.9	16.5	15.9	13.3	14.4	16.8	18.0	19.1	17.9	**17.4**
SPPW1_T2	17.0	19.1	19.8	22.3	16.8	16.1	13.6	14.7	17.2	18.4	19.3	18.5	**17.8**
All WTGs	**18.2**	**19.1**	**19.5**	**20.8**	**16.8**	**16.3**	**13.5**	**14.1**	**16.6**	**18.0**	**19.2**	**19.0**	**17.6**

Figure 3. Heatmap of monthly average wind speeds (mph) of all the 16 operating WTGs during 2016-2024.

Over the past few years, the WTG models from the original equipment manufacturers (OEMs) have grown in physical size with taller hub heights, and larger rotor diameters/swept areas which led to increased annual power production. It can be observed from Table 2 that the WTG rated capacities increased from 1.5 MW in 2011 to 2.82 MW in 2022. There are also more sensors and SCADA system-collected datapoints available on newer model turbines whose operational start year is 2022 compared to those with operational start year of 2011. For simplicity of data processing, three of the oldest turbine models have not been included in the heatmaps here. All the heatmaps show the analysis of the 16 WTGs that started operations after Dec. 2015.

A. Capacity Factor (%) and Availability Factor (%)

Both the capacity factor (%), and the availability factor (%) are important parameters in determining the energy production of an energy project. Accounting for over 9 years of operational data, the average capacity factors and the average availability factors of all the 16 WTGs serving seven different rural electric utilities are evaluated as shown in the heat maps of Figure 1 and Figure 2 respectively. The average availability of all the 16 WTGs is found to be approximately 93%. Occasional, mechanical part failures have hampered this number. Upon keen observation of the figures, we can notice that the capacity factor and availability factor are directly proportional to each other. For instance, CR01 experienced a mechanical gear box failure in a December month, which hampered the capacity factor for that month. Strong service contracts and vendor relationships with the original turbine equipment manufacturer are critical in addressing such O&M issues in a timely manner.

B. Wind Speeds (mph)

The wind speeds are dependent on the microsited geographic location primarily. However, since the average wind speeds are measured at the respective wind turbine hub heights, it also has a direct effect on the wind speeds which consequently affects the capacity factors and the electric energy outputs. It may be noticed from Figure 3 that the WTG labeled CR-01 through CR-04, and CCC-01 have lower wind speeds possibly due to those turbines being 1.7 MW turbine platforms which are at the hub height of 80 meters (~263 feet). Whereas the latest turbines such as SPPW1_T1 and SPPW1_T2 are built at the hub height of 89 meters (~292 feet). This hub height difference is reflected in the difference in captured wind speeds, the taller hub heights lead to better wind speeds.

Although the wind turbine siting did take the distance between the turbines into consideration, there is a mutual wake effect experienced by CR, CR2, PW, and SPPW1 projects due to the presence of multiple WTGs in closer proximity. This Wake Effect plays a role in hampering the wind speeds, especially when the turbines are located adjacent to each other which is the case with CR01 through CR04 (four WTGs), CR2-01 through CR2-03 (three WTGs), PW-T1 through PW-T3 (three WTGs), and SPPW1_T1 through SPPW1_T2 (two WTGs). This can be prominently observed by the small wind speed differences in the summer months as seen in Figure 3. None of these projects employ any Artificial intelligence controls that monitors this phenomenon but there may be a future where mutual communication between adjacent wind turbines will allow the adjustment in Yaw pitch to reduce this type of loss.

C. Typical Wind Turbine Generator (WTG) Failures

All the wind turbine generators are three bladed, upwind, horizontal-axis wind turbine models where the turbine rotor and nacelle are mounted on top of a tubular tower. The WTGs use two key controls – (a) Active yaw control which enables steering the nacelle and turbine blades to face the wind direction (b) Active blade pitch control which enables regulation of the turbine rotor speed by adjusting the blade pitch angle between 0° and 90°. The rotor diameters and hub heights are different for different models resulting in different power ratings. Some of the typical modes of failure noticed in the WTGs have been recorded in the following Table 6 derived from experience of operating and maintaining distribution grid connected, large WTG projects (ten projects) in the past 14 years. Moreover, the visual inspection assessment of components is often employed to detect surface defects such as corrosion, mechanical damage, leaks/sealing, deformation, incomplete signage, soiling/foreign material etc.

Table 6. Typical Modes of failure in WTGs

WTG Component	Typical Mode of Failure
Blades	Fracture, edge crack, stuck, motor failure, pitch bearing failure
Rotor Shaft	Fracture
Yaw System	Increased bearing friction
High-speed shaft	Low or higher brake torque
Gearbox	Internal gear tooth wear or material failure
Hub assembly	Structure failure; bolt failure
Oil seals	Cut or wear in lip
Filters	Case leakage
Generator	Overheat; fault; jammed bearing; bearing seizure; overspeed
Lubrication	Loss of oil; overheating; oil under temperature
Coolant Pump	Mechanical failure

D. Summary of Output Losses

The WTGs have experienced various losses during these nine years of operation due to one or more of the various failures mentioned in the previous section. Although efficient and timely response has mitigated the effect, nonetheless, there was loss in power generation. The major losses are quantified in the following sub-sections.

1) Weather Outages

The weather outages can occur for various reasons such as high wind speeds above the wind turbine's design limits, lightning strikes, icing on turbine blades or moving parts etc. The total time of weather-related outages for the whole fleet is evaluated as shown in Figure 4 accounting for the past 9 years of operational life. The 16 WTGs are expected to operate for a total of 464,280 hours (53 × 8760) accounting for the years 2016 through 2024. During this time period, the weather outages accounted to a total of 12,365 hours out of the 464,280 operating hours of all turbines (53 × 8760 hours) i.e. approximately 2.66% of the total operating time period as seen on the heatmap in Figure 4.

2) Maintenance Time

The maintenance time corresponds to scheduled periods to do works on the wind turbine to ensure it operates efficiently and safely. The maintenance schedules typically depend on the environment of operation and the wind turbine model. It is commonly performed on lubricated parts, turbine blades, and electrical components. The maintenance time accounted to a total of 4,835 hours out of the 464,280 operating hours of all turbines (53 × 8760 hours) i.e., approximately 1.04% of the total operating time period. As seen on Figure 5, more maintenance is scheduled to happen in transitional months of March, April, September, and October when utility demand is less. However, there will be unplanned maintenance that might occur after an extreme weather event such as the polar vortices.

3) Down Time

The down time is the time during which the turbine is fully non-operational. Over the years, the down time accounted to a total of 22,249 hours out of the 464,280 operating hours of all turbines (53 × 8760 hours) i.e. approximately 4.8% of the total operating time period. In general, the older 1.72 MW model wind turbines experienced more down time than the newer 2.82 MW model wind turbines as observed from the heatmap on Figure 6. This is also due to the comparatively longer operated life of the older turbines.

	Total Weather Outage Time [hours] in All Operational Years												
WTG Name	**Jan**	**Feb**	**Mar**	**Apr**	**May**	**Jun**	**Jul**	**Aug**	**Sep**	**Oct**	**Nov**	**Dec**	**Year**
CR01	120	85	136	124	61	105	117	126	65	47	84	101	1176
CR02	106	39	87	104	54	93	123	100	55	37	66	75	945
CR03	117	52	105	102	56	115	162	149	74	45	58	110	1151
CR04	305	42	91	89	49	121	124	150	79	55	74	93	1278
CR2-01	113	67	45	35	45	108	175	159	85	61	82	90	1068
CR2-02	139	62	49	33	36	67	120	223	83	55	81	114	1068
CR2-03	126	83	54	53	54	109	210	208	99	55	76	102	1236
CCR-T1	24	18	18	10	10	31	59	32	21	20	42	24	315
CCC-01	114	32	47	41	59	86	91	76	63	42	47	79	780
PCR-01	35	14	21	13	14	47	70	37	26	15	22	23	343
SW-01	6	25	53	74	2	9	7	14	5	12	21	48	281
PW_T3	101	61	50	28	25	47	71	110	57	40	73	84	751
PW_T2	102	62	49	24	37	69	101	107	69	50	74	78	827
PW_T1	75	43	38	21	31	59	85	108	42	38	46	60	652
SPPW1_T1	60	11	14	3	12	18	21	22	16	18	18	23	242
SPPW1_T2	37	11	15	5	13	21	27	12	14	26	22	37	246
All WTGs	**1587**	**716**	**881**	**765**	**566**	**1113**	**1569**	**1641**	**859**	**623**	**893**	**1148**	**12365**

Figure 4. Heatmap of monthly totals of weather outage time (hours) of all the 16 operating WTGs during 2016-2024.

	Total Maintenance Time [hours] in All Operational Years												
WTG Name	**Jan**	**Feb**	**Mar**	**Apr**	**May**	**Jun**	**Jul**	**Aug**	**Sep**	**Oct**	**Nov**	**Dec**	**Year**
CR01	6	66	24	26	15	22	19	11	60	82	5	4	345
CR02	5	4	162	16	130	18	46	9	21	38	20	19	492
CR03	35	0	24	18	66	28	16	8	16	23	24	5	267
CR04	131	0	44	46	47	3	18	6	10	44	16	17	387
CR2-01	13	5	37	15	17	5	9	10	9	20	31	19	195
CR2-02	17	6	18	5	43	17	30	31	9	29	37	23	271
CR2-03	17	3	21	4	25	15	7	9	16	56	16	5	198
CCR-T1	0	5	4	29	32	4	9	1	25	2	10	0	126
CCC-01	1	7	21	9	10	13	3	6	34	42	23	14	187
PCR-01	0	0	4	0	15	2	1	3	3	0	8	6	46
SW-01	0	0	0	0	6	11	12	0	0	1	0	2	35
PW_T3	8	20	2	29	0	10	5	2	2	9	34	11	138
PW_T2	2	3	0	15	13	6	7	2	0	5	33	12	102
PW_T1	9	14	0	41	1	19	2	1	70	40	90	9	302
SPPW1_T1	1631	2	6	29	0	0	3	0	5	0	16	0	1695
SPPW1_T2	0	0	7	3	16	1	0	0	0	1	9	0	41
All WTGs	**1880**	**138**	**379**	**293**	**442**	**181**	**193**	**106**	**287**	**399**	**378**	**154**	**4835**

Figure 5. Heatmap of monthly totals of maintenance time (hours) of all the 16 operating WTGs during 2016-2024.

	Total Down Time [hours] in All Operational Years												
WTG Name	**Jan**	**Feb**	**Mar**	**Apr**	**May**	**Jun**	**Jul**	**Aug**	**Sep**	**Oct**	**Nov**	**Dec**	**Year**
CR01	642	61	209	392	144	221	139	62	125	348	180	1169	3698
CR02	399	90	258	306	203	255	127	112	118	157	314	236	2580
CR03	258	52	59	153	256	206	73	126	114	184	334	60	1881
CR04	310	192	143	103	103	42	240	101	15	68	545	143	2010
CR2-01	38	339	128	177	64	110	148	174	50	70	17	28	1349
CR2-02	265	290	20	100	48	237	233	82	149	301	43	80	1853
CR2-03	92	9	51	385	115	119	123	174	221	54	116	16	1478
CCR-T1	14	14	6	41	74	65	130	74	60	89	161	11	747
CCC-01	32	145	66	180	10	105	52	140	48	255	427	312	1776
PCR-01	130	110	132	55	53	73	18	65	1	25	13	118	799
SW-01	0	0	0	0	71	48	23	0	71	0	5	55	276
PW_T3	206	22	6	8	537	38	144	307	16	60	5	32	1386
PW_T2	22	4	79	39	104	165	98	64	5	11	17	15	627
PW_T1	36	37	33	4	71	30	1	85	171	45	229	123	869
SPPW1_T1	143	25	5	1	5	17	16	0	2	26	28	40	314
SPPW1_T2	0	7	22	3	15	0	33	186	294	33	0	1	598
All WTGs	**2593**	**1405**	**1223**	**1952**	**1881**	**1737**	**1606**	**1762**	**1468**	**1731**	**2438**	**2446**	**22249**

Figure 6. Heatmap of monthly totals of Down time (hours) of all the 16 operating WTGs during 2016-2024.

IV. Carbon Emissions Mitigation Assessment from All the Operating Projects

The overall electric energy generation from all the 19 WTGs with total capacity of 39.5 MW_{AC}, and 5 solar PV projects with total capacity of 8.1 MW_{AC} account to approximately 1,196,070 MWh over the operating life of 96 combined project years with an average project age of 8 years for wind projects, and 3.5 years for solar PV projects by the end of year 2024. This total generated electric energy has offset the emissions of CO_2 equivalent of 1,162,072 metric tons. As listed in Table 7, besides Carbon-di-Oxide (CO_2), other hazardous air pollutants such as Sulphur-di-Oxide (SO_2), Nitrous Oxides (NO_X), and particulate matter are also mitigated as a result of these renewable energy projects.

Table 7. Overall emissions mitigated because of 39.5 MW_{AC} of Wind or 8.1 MW_{AC} of solar PV projects measured until 2024.

Emission Type	lbs./MWh	Total Avoided Emissions (lbs.)
SO_2	1.450	1,734,760
NO_X	1.101	1,316,554
CO_2	1850	2,213,043,077
$PM_{2.5}$	0.065	77,895

V. Conclusions

The research analysis validates the fact that wind turbine power generation is stronger in the winter months over the summer months. Strong operations and maintenance team of the project owner and operator play a key role in sustaining healthy operations with predictable pattern of power generation. The overall capacity factor of the fleet of these 16 turbines is approximately 50% with an availability factor of approximately 93%, referring to the percentage of time the WTGs are available and operational to produce electricity. The data analytics research also evaluated that an overall 8.5% of the total operational life hours of 464,280 (53 × 8760 hours) is accounted towards weather outage hours, maintenance time, and down time. The IPP was able to achieve this strong performance due to proactive maintenance and repair work enabled via contractual service agreements with the wind turbine OEMs. This business model puts forth a strong case for distribution grid connected wind power, especially in the Midwest and the Great Plains geographic regions of the United States.

Acknowledgments

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Practical Considerations for Appropriate Arrester Selection

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***Abstract*— This paper explores the technical challenges and considerations involved in the selection and sizing of surge arrester protection. A recent review of surge arrester sizing based on dynamic simulation results suggested the need for a higher maximum continuous operating voltage (MCOV) rating than what was preliminarily specified. However, subsequent insulation coordination studies, a detailed engineering assessment, along with historical equipment performance considerations indicated that the originally specified arrester size still provides appropriate system protection. By analyzing key standards such as IEEE C62.82.2-2022, this paper examines the balance between protecting equipment insulation and ensuring arrester reliability. The discussion addresses the considerations between upsizing arresters for improved protection margins and the potential drawbacks of specifying arresters with oversized MCOV ratings. Alternative solutions, including dynamic protection settings and advanced insulation coordination techniques, are also considered. The paper concludes by offering recommendations for selecting appropriate arrester sizes that emphasize the need for a pragmatic approach that combines dynamic simulation results along with practical engineering analysis.

Keywords- Transient Overvoltage, Temporary Overvoltage, Insulation Coordination, Surge Arresters, MCOV rating, IEEE C62.22.2, commercial and Residential Generation, Industrial Systems, Coefficient of Grounding (COG)

I. Introduction

Surge arresters play a critical role in the protection of electrical power systems by mitigating transient overvoltage conditions caused by switching operations, lightning strikes, and fault conditions. The proper selection and application of surge arresters is essential to ensure protection of power system components with increasing penetration of renewable energy resources and complex grounding configurations. The selection process is governed by industry standards such as IEEE Std. C62.22 and IEC 60099, which provide guidelines on insulation coordination, temporary overvoltage (TOV) withstand capability, and protective margin requirements.

Traditional arrester selection methods primarily focus on steady-state conditions and temporary overvoltages, but they may not fully account for transient overvoltage scenarios that arise during a variety of operating conditions. Grid-scale renewable generation, distributed generation, capacitor bank switching, and line regulators introduce unique overvoltage challenges that necessitate advanced analysis, such as transient overvoltage studies using simulation tools such as PSCAD, EMTP, and ATP. Proper transient analysis helps identify potential conditions that will be encountered by the arrester, including conditions that may lead to insulation breakdown, equipment damage, and operational disruptions.

Practical application of IEEE Std. C62.22 and other industry standards requires balancing multiple factors, including system voltage, grounding methods, environmental conditions, and dynamic overvoltages. This paper highlights the importance of integrating different analyses to enhance the effectiveness of surge protection strategies through practical case studies and analytical insights.

II. Understanding Arrester Sizing

A surge arrester, also known as a lightning arrester, is a protective device used in substations to shield electrical equipment from overvoltage transients caused by lightning strikes and switching operations. Technically, surge arresters consist of metal oxide varistors (MOVs) or silicon carbide elements, which have highly nonlinear voltage-current characteristics. Under normal operating conditions, these components exhibit high resistance, allowing normal voltage levels to pass uninterrupted. However, when a surge occurs, their resistance drops drastically, diverting the excess energy safely through a connection to ground. Once the surge dissipates, the arrester returns to its high-resistance state, ensuring continued normal operation of the electrical system.

Thus, by providing a low-impedance path to ground for excessive voltage surges, they limit the voltage that reaches protected equipment. Improper arrester design can lead to premature failures, causing power outages and costly equipment damage.

When an arrester fails, it typically results in a complete short circuit within its housing. This failure is often due to dielectric breakdown, where the internal structure has degraded to the extent that the arrester can no longer withstand the applied voltage. This could be the normal system voltage, temporary power frequency overvoltage (such as after external line faults or switching), or lightning and switching surge overvoltages. Typically, 20%–30% of arrester failures are caused by thermal runaway, where the internal temperature rises due to incorrect MCOV sizing, making them highly conductive and leading to failure. Additionally, 15%–25% of arrester failures are due to overloading caused by excessive surge energy from lightning or frequent switching overvoltages.

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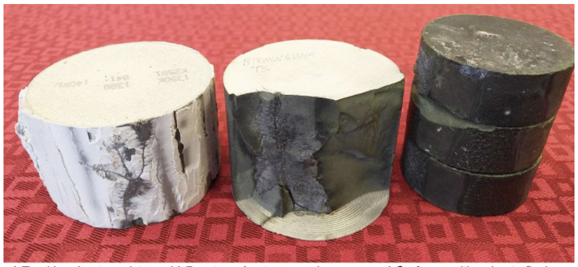


a) Tracking due to moisture. b) Puncture due to excessive energy. c) Surface melting due to flashover

Fig. 1. Examples of failed MOV blocks [1]

There are several categories of arresters, each designed for specific applications and protection levels depending on their location within the grid.

A. Substation arresters

Substation arresters are deployed in high-voltage (HV) and extra-high voltage (EHV) substations to protect power transformers, circuit breakers, busbars, and other critical substation assets from overvoltages caused by lightning strikes, switching transients, and system faults. Since substations interconnect transmission and distribution networks, failures in substation insulation can lead to wide-scale outages and severe equipment damage. Typically, substation arresters must withstand large energy surges, often rated in kilojoules (kJ) (500-1500kJ for 138kV), depending on system voltage and fault exposure. Substation arresters must be carefully coordinated with insulation levels (BIL and BSL) to prevent overvoltage stress on transformers.

B. Distribution arresters

The primary distinction between substation arresters and distribution arresters lies in their voltage class, energy-handling capacity, and application environment. Distribution arresters are installed along medium-voltage feeder lines to protect pole mounted transformers, reclosers, cables, capacitor banks, and other distribution equipment from transient overvoltages. They are categorized based on their placement: overhead and underground applications, each with unique protective considerations coordinated with line-to-ground voltage and temporary overvoltages. Energy ratings are typically in the range of 5–50 kJ, with heavier-duty arresters reaching 100 kJ in areas with high lightning activity.

1) Overhead:

Overhead distribution systems are highly exposed to lightning strikes and switching surges due to their open-air configuration. Arresters in these systems are typically mounted on utility poles near transformers and critical line equipment. These arresters must be rated based on line-to-ground voltage, expected transient overvoltages, and environmental conditions (e.g., contamination, pollution). Common ratings for overhead arresters range from 9 kV to 36 kV MCOV, depending on the distribution system voltage. Additionally, they should have sufficient creepage distance to withstand contamination in coastal or industrial environments.

2) Underground:

Underground distribution systems experience fewer direct lightning strikes but are susceptible to switching surges, cable resonance, and capacitive charging effects. Arresters for underground applications are typically installed in pad-mounted enclosures, on cable terminations, and within switchgear to mitigate transient overvoltages. Compared to overhead systems, underground arresters must have a higher energy absorption capacity to handle trapped charge effects in long cable runs. Additionally, due to enclosed spaces, they must be designed to operate under higher thermal stress while ensuring a low residual voltage to protect cable insulation.

Substation arresters are designed for high-energy dissipation and insulation coordination to protect critical grid infrastructure, while distribution arresters focus on protecting medium-voltage equipment from transient overvoltages.

III. Methods for Arrester Design

Before selecting an arrester, it is essential to understand several key parameters that are crucial for interpreting an arrester datasheet. Below are some fundamental definitions and their importance for this paper, but full definitions and other terms are found in IEEE C62.22 [1][3]:

Maximum Continuous Operating Voltage (MCOV)

The maximum voltage that the arrester can continuously withstand without degrading. This value should be higher than the system's maximum operating voltage to ensure the arrester can handle normal system conditions, i.e. higher is generally better.

Rated Voltage – Rating of the arrester but not directly relevant to the actual operating voltage, it is still commonly used to specify arresters.

Discharge voltage -The voltage that appears across the arrester during a surge event. It indicates the arrester's ability to clamp lightning and switching surges. A lower discharge voltage means better protection for the equipment.

Temporary Overvoltage (TOV) Rating- The maximum voltage the arrester can withstand for a short duration during temporary overvoltage conditions. It ensures the arrester can handle temporary overvoltages caused by events like line faults or load rejection. Higher is generally better.

Energy Handling Capability The amount of energy the arrester can absorb and dissipate during surge events. Higher is always better.

STYLE NO.	RATINGS (kV rms)		TOV (kV rms)	MAXIMUM RESIDUAL VOLTAGE WITH CURRENT WAVE (kV PEAK)				
	VOLTAGE Vr	MCOV Vmcov	WITH PRIOR ENERGY SINGLE IMPULSE OF 4.5 kJ/kVr	SPL (SIPL) 30/60 µS	LPL (LIPL) 8/20 µS			FOW 0.5 µS
				500 A	3 kA	10 kA	20 kA	10 kA
STANDARD CREEP								
Q024SA019A	24	19.5	@10 sec = 26.3	47.7	53.5	57.6	63.9	63.0
Q027SA022A	27	22.0	@10 sec = 29.6	53.6	60.1	64.8	71.8	70.8

Fig. 2. Example of Arrester Datasheet

A. Standard Vendor Datasheet Selection

A more straightforward approach to designing an arrester is to use a common rule of thumb sizing, using the arrester as recommended for a particular voltage level as shown in ArresterWorks selection guide [2]. The design sheet provides a detailed and structured approach to selecting the appropriate arrester, considering various factors such as system voltage, grounding, and environmental conditions for a typical system. It aligns with both ANSI and IEC standards, ensuring that the selected arrester meets industry requirements and best practice without favoring any particular manufacturer. However the guide does not include complex analysis for all unique scenarios or specific requirements of a particular system such as cap bank switching, voltage regulators, industrial grounded system, line regulators or distributed generation and many more.

Typical ANSI System Voltages				Suggested ANSI Arrester MCOV Rating			
Nom Line to Line Voltage	Max Line to Line Voltage	Max Line to Grnd Voltage		Solid Multi-grounded Systems (4 wire)	Uni-grounded Systems (3 wire)	Impedance grounded, Ungrounded and Delta Systems	Transmission Line Arresters for Lightning Protection Only
kV rms	kV rms	kV rms		MCOV	MCOV [*]	MCOV [*]	
2.40	2.52	1.46				2.55	
4.16	4.37	2.52		2.55	5.1	5.1	
4.80	5.04	2.91				5.1	
6.90	7.25	4.19				7.65	
8.32	8.74	5.05		5.1	7.65		
12.0	12.6	7.28		7.65	10.2		
12.5	13.1	7.57		7.65	12.7 [7.65]		
13.2	13.9	8.01		8.4	12.7 [8.4]		
13.8	14.5	8.38		8.4	12.7 [8.4]	15.3 [8.4]	15.3
20.8	21.8	12.6		12.7	15.3 [12.7]		21
22.9	24.0	13.9		15.3	19.5 [15.3]		22-24
23.0	24.2	14.0		15.3-17		24.4 [15.3]	22-24
24.9	26.2	15.1		15.3	22 [15.3]		24-29
27.6	29.0	16.8		17	24.4 [17]		24-29
34.5	36.2	20.9		22	29 [22]	36-39 [22]	29-36
46.0	48.3	27.9			29	39	29-39
69.0	72.5	41.9			42-48	53-67	48-67
115.0	121	69.8			70-76	84-98	76-98
138.0	145	83.8			84-98	106-115	98-115
161.0	169	98			98-115	115-131	115-131
230.0	242	140			140-152	182-190	152-190
345.0	362	209			209-245	230-289	245-289
500.0	525	303			318-452		>452
765.0	800	462			462-490		>490

Fig. 3. Simple Arrester Selection Table for ANSI Arresters [2]

B. Steady State Analysis

The coefficient of grounding (COG) is a crucial aspect of arrester sizing, particularly in systems with different grounding configurations. The COG helps determine the maximum overvoltage that can occur during a ground fault. It is defined as the ratio of the maximum phase-to-ground voltage during a fault to the nominal phase-to-ground voltage as seen in short circuit study. This traditional surge arrester sizing based on system grounding is temporary overvoltage focused (due to ground faults). Protecting equipment is the primary function of a surge arrester. A crucial part of the selection process involves assessing the protection margin between the arrester and the equipment it safeguards. The IEEE Std. C62.22 [3] standard provides guidelines for the selection, application, and testing of surge arresters in power systems, including substations.

According to IEEE Std. C62.22 [3], a minimum protective margin of 15% is recommended between the surge arrester and power transformer insulation. For most other applications, a 20% margin is advised. Arrester protective levels and insulation withstand capabilities are defined in IEEE Std. C62.22 [3] as follows:

Insulation:

- Basic lightning impulse insulation level (BIL)
- Basic switching impulse insulation level (BSL)
- Chopped wave withstand (CWW)

Arresters

- Lightning protective level (LPL)
- Switching protective level (SPL)
- Front-of-wave protective level (FOW)

$$PR_{L1} = \frac{CWW}{FOW} \geq 1.2 \; acceptable$$

$$PR_{L2} = \frac{BIL}{LPLW} \geq 1.2 \; acceptable$$

$$PR_{S} = \frac{BSL}{SPL} \geq 1.15 \; acceptable$$

PR_{L1} is the protection level for fast lightning (crests under 2 μs)

PR_{L2} is the protection level for slow lightning (crests in 8 μs)

PR_{S} is the protection level for switching surges

The insulation coordination study analyzes the protection level of the arresters against the withstand capabilities of the equipment. A substation is effectively grounded when the COG is under 80% per IEEE C62.92.1 [4] and that the arrester protective ratios are within the margins. The most common challenge is determining the capabilities of the equipment since insulation failure is dependent on many factors that can't be directly calculated. Testing by the manufacturer is the most common method, but insulation degrades over time. So, IEEE values or utility practice is used to estimate the capability based on risk tolerance and experience.

C. Dynamic Analysis

In a power distribution network where switching operations are performed (including lines/loads, capacitor banks, motors, and/or transformers) these operations can generate transient overvoltages that travel through the network and impact equipment. A transient overvoltage study is an analysis aimed at understanding and evaluating the impact of transient overvoltages on an electrical power system. These overvoltages are short-duration, high-magnitude voltage spikes that can occur due to various events such as lightning strikes, switching operations, and faults. They can cause significant stress on electrical equipment, potentially leading to insulation failure and equipment damage. Transient overvoltage studies often use simulation tools like PSCAD, EMTP, or ATP to model the power system and simulate transient events. These tools help visualize the overvoltage waveforms and assess their impact on the system. [5][6]

IV. Applications and Methodology: Challenges & Failures

A. Industrial Applications:

While the same recommendations in IEEE C62.22 [3] are considered for industrial applications, particular attention to outage considerations, COG, and temporary overvoltage (TOV) conditions are observed.

Facility power outages in industrial facilities tend to be infrequent and undesired from operators due to loss of product, costly system restarts, and equipment malfunctions resulting from interrupted service. Engineering judgement is used in system design to balance equipment protection, system reliability, and cost. It is not uncommon to see higher MCOV rated arresters, decreased security of relay protection, and onsite spare electrical equipment (i.e. transformers, motors, breakers, etc.) in industrial facilities, as it can be more cost effective to increase reliability to avoid outages at the expense of equipment protection. Depending on the application, it can be desired to maintain facility operation during a ground fault to allow operators to locate the fault and minimize system outage by isolating the fault.

Industrial facilities' power systems are often grounded with a resistor between the neutral and ground connection. Low resistance grounded (LRG) systems (50A-1000A) are common for medium voltage industrial distribution systems, while high resistance grounded (HRG) systems (<25A) are common for low voltage and large medium voltage generation equipment. While ungrounded systems can still be found in industrial systems, newer facility installations typically prefer LRG and HRG for safety considerations due primarily to undetected ground faults or arcing faults leading to voltage escalation. Ungrounded, LRG, and HRG systems increase your non-faulted phase voltage to line-to-line voltage during single phase ground fault (i.e. COG is equal to 1). This ultimately increases your arrester's MCOV rating compared to solidly grounded or effectively grounded systems of the same line-to-line voltage. As a result, a common arrester sizing methodology when system COG is 1, is to size arrester MCOV to 110% or greater of your system line-to-line. While this method minimizes facility outages, the increased MCOV rating of the arrester could decrease the sensitivity of protection for lower magnitude events.

B. Medium Voltage Feeders with generation:

A typical COG analysis is useful for grounding coordination and steady-state potential rise in large-scale renewable generation, however, medium voltage feeder with generation increases overvoltage risks, as noted in IEEE 2800 [7]. They present unique voltage, frequency, and transient stability challenges.

In a generation facility, one surge arrester is placed on the feeder side of the MV breaker, and another at the end of the feeder, on the high side of the pad mount transformer (PMT). These facilities are sometimes equipped with large capacitor banks to meet interconnection VAR requirements at the point of interconnection (POI). Capacitor banks may introduce overvoltage risks during switching; however, their effects may not be adequately identified during an initial insulation coordination study during the site design process. Performing a transient overvoltage study helps assess capacitor bank operations and overall site inverter impacts on transient overvoltage risks and expected magnitudes. It is noted that these studies are a more complex modeling analysis than an independent insulation coordination study that requires significant engineering labor and adds cost to a project. The need for transient overvoltage analysis is an engineering consideration that must be balanced with the overarching site design. In our experience, these studies generally affirm our initial designs and rarely alter the final designs. However given the complexity of the evolving power systems and capital and operating costs of replacing damaged equipment, a majority of generation designs include transient overvoltage studies as part of the equipment selection process.

Anti-islanding is a safety feature in solar power system inverters that ensures the inverter stops supplying power to the grid by not going into the island mode when the grid is disconnected intentionally or unintentionally. In high-penetration renewable energy environments, however, fault ride through (FRT) requires inverters to remain connected for a defined period during transient voltage sags or swells, allowing the grid to recover from disturbances. IEEE 1547 and NERC PRC-024 specify low-voltage ride-through (LVRT) and high-voltage ride-through (HVRT) curves that determine acceptable operating windows for voltage ride-through. Delayed tripping (ride through) increases temporary overvoltage (TOV) conditions, stressing surge arresters. If the voltage exceeds the arrester's Maximum Continuous Operating Voltage (MCOV) for an extended duration, it can lead to thermal runaway and degradation of the metal oxide varistor (MOV) blocks inside the arrester. With anti-islanding measures in place, inverter sources may continue feeding the system after a disturbance, potentially sustaining an overvoltage event longer than expected. This extended exposure can cause arrester failure, especially if the arrester is designed for short-duration transient overvoltages rather than prolonged TOV conditions.

A case study was examined at a grid scale photovoltaic (PV) generation site, where a 24.4kV arrester passed the initial insulation coordination study but upon transient modeling and analysis, its energy rating was exceeded during a more detailed breaker operation scenario following the application of a single-line-to-ground (SLG) fault. This initially necessitated upsizing the arrester. Below figure displays the maximum over-voltages and energy absorbed by the surge arresters for a substation fault condition followed by a breaker tripping scenario. Figure 4 shows the energy absorption for a 24.4kV breaker arrester rated to absorb 219.6kJ, while Figure 5 shows the energy absorption for a 29kV arrester rated to absorb 261kJ.

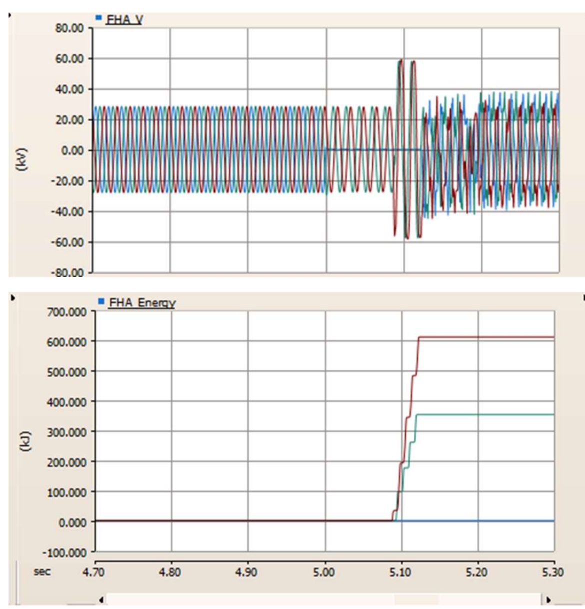
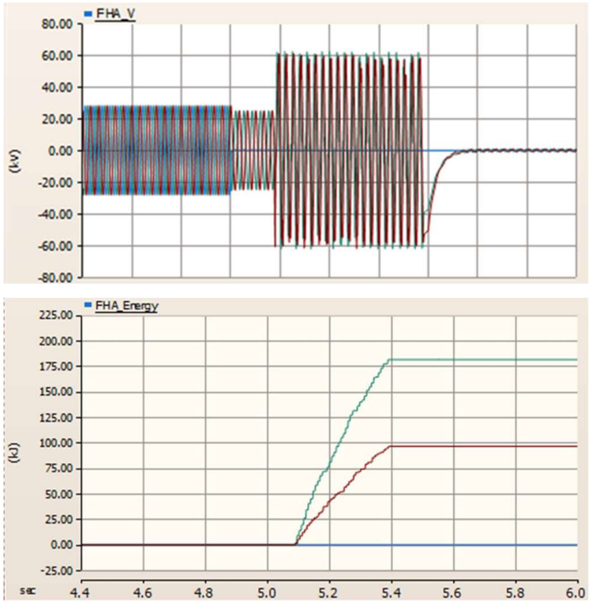


Fig. 4. Arrester Energy Waveform for 24.4kV MCOV



Arrester Energy Waveform for 29kV MCOV

Upsizing an arrester provides several benefits in terms of reliability and potentially decreases equipment loss of life, but it also reduces equipment protection. High rated arrester may not clamp voltage as effectively as they operate at higher discharge voltage.

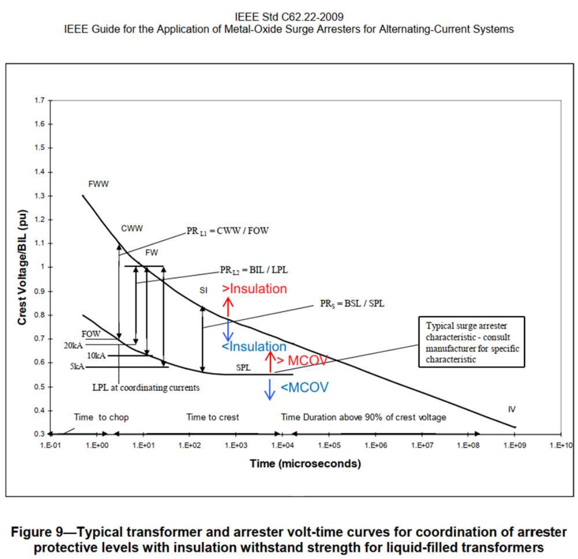


Fig. 5. Transformer and Arrester Protection Coordination

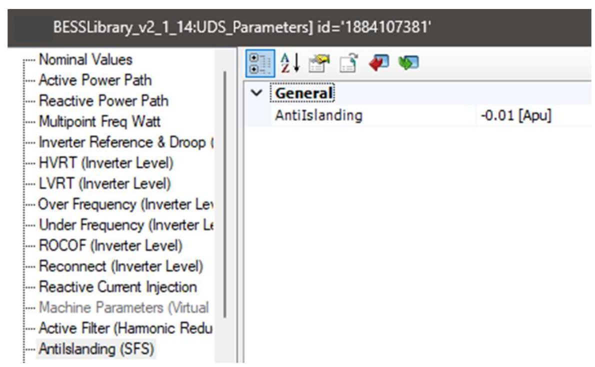
C. Distribution Generation:

Distributed generation can affect overvoltage conditions, but small residential PV generally has minimal impact [6-1547] For residential PV systems, a full dynamic study (e.g., transient simulation) is not necessary because of the residential systems generating at smaller scale (typically <20 kW), meaning standardized surge protection guidelines generally suffice.

Commercial and industrial facility generators introduce unique challenges in surge arrester selection due to their various operating modes, interaction with the power system, and anti-islanding settings. IEEE 2800 establishes minimum performance capabilities for generators connected to bulk power system (BPS) and ensure stability under various operating conditions:

Many commercial and industrial generators provide voltage support to maintain grid stability. This often involves reactive power compensation, where generators adjust their output to regulate local voltage levels. During voltage support operations, arresters may experience elevated continuous voltage levels, requiring higher MCOV ratings to prevent excessive leakage currents and premature degradation. Some generators, especially those with advanced inverters, actively inject or absorb reactive power to support grid stability. This reactive power compensation can lead to temporary overvoltages (TOVs) under switching conditions, increasing the stress on surge arresters. Proper selection of MCOV and energy-handling capacity is necessary to withstand these voltage fluctuations. In order to be in compliance with IEEE 2800 they are required to have voltage ride through (VRT) settings to remain connected during certain grid disturbances rather than disconnecting immediately. Different anti-islanding trip thresholds and response times impact how long a generator remains in operation under abnormal conditions.

If anti-islanding detection is delayed, surge arresters must withstand sustained overvoltages, especially if reactive power injection continues after the loss of grid reference.



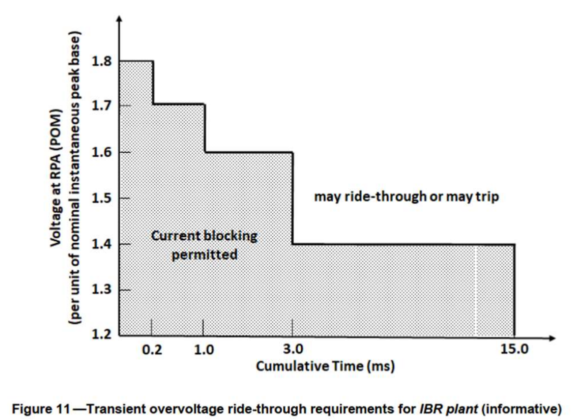


Fig. 6. Anti Islanding and IEEE 2800 VRT Requirements [7]

PV manufacturers provide recommended surge protection specifications. Rule of thumb sizing based on system voltage, location, and lightning risk is usually adequate

D. Challengis of Complex Power Systems:

1. Line Regulators application:

A line regulator is used in electrical distribution systems to maintain voltage within acceptable limits are power flows through transmission and distribution systems. Voltage fluctuations are common and occur due to changes in load demand or voltage drop due to long distribution lines. Line regulator systems can cause issues for surge arresters due to their role in adjusting voltage levels on power lines. These regulators, typically using tap-changing transformers or voltage-controlled devices, introduce temporary overvoltages (TOVs) when adjusting voltage levels, especially during switching operations. In addition, loss of significant load (due to tripping on a fault or simply stopping a large motor) also causes a voltage rise since the voltage drop (Ohm's Law) decreased proportionally to current change. This could cause increased Thermal Stress on surge arresters that are designed to handle transient surges, but prolonged overvoltages from line regulators can cause continuous heating, leading to premature degradation or failure. When a line regulator switch taps, a momentary voltage imbalance can occur, potentially exceeding the arrester's designed limits and causing stress on its metal oxide varistor (MOV) blocks. If a regulator operates in an ungrounded or floating neutral condition, it can shift system voltages unexpectedly, increasing stress on arresters not rated for such conditions. Most importantly if the surge arrester's rated voltage (MCOV - Maximum Continuous Operating Voltage) is too low, it might misoperate or fail due to sustained overvoltage conditions. Proper arrester selection based on IEEE C62.22 both steady state and dynamic analysis, ensuring MCOV and energy-handling capability match system requirements can help mitigate arrester failure thereby confirming reliability and longevity in power distribution systems.

2. *Ferroresonance Phenomena:*

Ferroresonance is a nonlinear electrical phenomenon that occurs in power systems, particularly in transformer circuits, when there is an interaction between the system's inductance (such as in transformers) and capacitance (such as from underground cables). Unlike normal resonance, which follows a linear frequency response, ferroresonance can lead to unstable and highly distorted overvoltages and overcurrents, often damaging equipment. Overvoltages can exceed 2-3 times the normal system voltage, stressing insulation. Ferroresonance is difficult to predict due to its nonlinear nature, but dynamic analysis can help in designing high-energy handling arresters that can withstand overvoltages without failure.

V. Conclusion

The selection and application of surge arresters in modern power systems require a comprehensive approach that considers both steady-state and transient overvoltage conditions. While traditional selection methodologies based on system grounding and temporary overvoltage analysis provide a solid foundation, they often fall short in addressing the dynamic challenges introduced by renewable energy integration, capacitor bank switching, and line regulation. As demonstrated, insulation coordination studies alone may not sufficiently capture the risks associated with fast transients, requiring additional transient overvoltage simulations to ensure the robustness of arrester performance under real-world operating conditions.

Incorporating advanced simulation tools can help in accurately modeling transient overvoltages and optimizing arrester ratings for enhanced system protection. However, the complexity and cost associated with these studies must be weighed against their benefits, particularly for smaller-scale distributed generation applications where standardized protection measures may suffice. Ultimately, achieving a balance between arrester reliability, energy absorption capability, and effective clamping voltage is key to ensuring system stability and long-term operational resilience. Future advancements in arrester technology and analytical methodologies will continue to refine surge protection strategies, enabling more adaptive and resilient electrical networks. Table I shown below provides a clear breakdown of methodologies for different applications, emphasizing when they are necessary and why.

TABLE I. Summary Comparison For Various Applications

Power System Application	Methodology	Applicability	Justification
Industrial Power Systems	Steady State Analysis	Yes	Ensures that equipment insulation levels are adequate to withstand system overvoltages
	Dynamic Analysis	Conditional	May be necessary if the system reliabiity is critical to avoid outages
Medium Voltage Feeders with Generation	Steady State Analysis	Yes	Helps determine effectively grounded system within sufficient protective margins
	Dynamic Analysis	Yes	Inverter-based resources introduce fast switching transients that insulation coordination studies may overklook. Dynamic studies ensure proper arrester rating and energy absorption capacity
Distributed Generation (Commercial, Residentail, Industrial)	Rule-of-Thumb Sizing	Yes	Small scale residential PV has minimal impaction grid wide transients so simplified protection is sufficient
	Steady State Analysis	Yes	PV inverter and surge protection device manufacturers provide recommendations that generallly suffice
	Dynamic Analysis	Conditional	Commerical Industrial Generators operating in different dynamic modes with voltage ride through capability may necessiate the need of transient analysis
Line Regulators - LTC Long Transmission Lines	Steady State Analysis	Yes	Ensures arresters are rated correctly to handle line voltage variations
	Dynamic Analysis	Conditional	Needed if prologed overvoltage occur due to tap changes or floating neutral conditions
Capacitor Bank Switching	Steady State Analysis	No	Cap bank transients can be severe and require detailed analysis rather than approximations
	Dynamic Analysis	Yes	Switching event causes fast transient and requring power arrester selection and placement
Ferroresonance-Prone Systems	Steady State Analysis	Yes	Helps determine appropriate surge protection but must be supplimented with transient analysis
	Dynamic Simulation	Yes	Ferroresonance is a non linear phenomena, requiring advances simulations to predict voltage distortions

VI. Biography

Chaitali Naik has eight years of experience in the power industry and currently serves as a team lead in NEI's System Studies department. Her primary responsibilities involve conducting power system studies for renewables plants and utility substation while managing a team of study engineers and study portfolios for large scale design projects. She received her master's degree in electrical engineering from Michigan Tech in 2017.

Chad Brotherton has 10 years of experience in utility and industrial power system design. His primary role as team lead for industrial substations involves developing, designing, and commissioning projects for utility, datacenter, petrochemical, and other industrial sectors. Chad holds a B.S. degree in Electrical Engineering from the University of Colorado State and is a registered Professional Engineer in the State of Colorado & Texas.

Carson Bates (SM'09) received his B.S. degree in engineering with electrical specialty in 2010, his M.S. in electrical engineering in 2013, and his Ph.D. in electrical engineering in 2018, all from the Colorado School of Mines, Golden, CO. He currently works as a full-time engineer at NEI Electric Power Engineering in Lakewood, CO, where he provides high and medium voltage electric power design engineering services for the utility, petrochemical, and renewable industries. He served in the IAS PCIC as IT Subcommittee Chair (2012-2024) and in IAS I&CPS as Power Systems Protection Committee Chair (2022-2024). He is also involved in PES Insulated Conductors Committee and PES Renewable Systems Integration Coordinating Committee.

Eric Senkowicz has over 30 years of experience in the utility industry. He currently works as the Director of the System Studies group at NEI Electric Power Engineering in Lakewood, CO, where he oversees a team of electrical studies subject matter experts that provide high and medium voltage electric power design engineering services for the utility, petrochemical, and renewable industries. His experience includes nuclear plant design engineering, component failure analysis and protective relaying installation and maintenance. His experience also includes twenty years in bulk power system operations and planning. Eric has been active on various stakeholder groups facilitating the development of national and local grid reliability and planning policy. Eric holds a B.S. degree in Electrical Engineering from the University of Florida and is a NERC Certified System Operator and a registered Professional Engineer in the State of Florida.

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