Solving Complex Feeder Protection Challenges and Reducing Wildfire Risks With Remote Measurements

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Abstract—In this paper, we propose a comprehensive and cost-effective approach to solving protection challenges for complex distribution and subtransmission feeders, including power line-caused wildfires, high-impedance faults, downed conductors, distributed energy resources, and microgrids. Our approach is not based on marginal improvements to time-overcurrent protection or heuristic methods for detecting high-impedance faults and downed conductors. Nor is it based on using private-band radios or public communications such as cellular networks. Instead, our method uses transmission-grade protection principles made possible through a novel technology of measuring currents and voltages at locations distributed along the feeder without introducing active electronics outside of the substation fence. We propose installing current and voltage transformers throughout the feeder and using all-dielectric self-supporting (ADSS) fiber cables to remotely access the added instrument transformers. This system does not require control power or data networks outside of the substation fence (the system is self-contained and passive) and provides the protection and control devices in the substation with IEC 61850-based current and voltage signals. The paper describes our approach in detail, including installation, scalability, redundancy, feeder protection, backup protection, high-impedance fault detection, downed-conductor detection, microgrid protection, power theft detection, and power loss minimization. By allowing instantaneous current and voltage measurements from the feeder, we dramatically simplify and improve protection and control applications. In our approach, feeder protection becomes fast and sensitive and far more selective compared with today's practice, dramatically reducing wildfire and public safety risks.

I. INTRODUCTION

Electric power grids are the largest systems engineered by humanity, comprising trillions of dollars' worth of assets. In a large power system, thousands of generating units supply loads through hundreds of thousands of miles of transmission lines and millions of miles of distribution feeders. Electrical power underpins all aspects of modern civilization, and its price is a factor in the growth and welfare of society. It is therefore understandable that electrical power systems must be engineered and operated with sensitivity to cost.

Because of their vast size, distribution and subtransmission networks are particularly sensitive to cost. Historically, distribution networks comprised radial feeders. The unidirectional flow of short-circuit currents facilitated simple and cost-effective protection based on time coordination of fuses and overcurrent relays.

Today's distribution and subtransmission networks, however, are becoming more complex with the increase in the electrification of heat and transportation and the ever-increasing reliance on electricity in general. Feeders may be operated in a looped configuration where the short-circuit currents can flow in a variety of patterns between multiple utility connections. Loads are served through multiple laterals from the main trunk of the feeder. Distributed energy resources (DERs) may be tapped to feeders that historically only served loads. Reclosers are added to improve service to consumers by isolating short circuits more selectively and restoring power more quickly to more customers.

Reforestation and housing development that encroaches on fire-prone areas raise the risk of wildfires caused by overhead power lines. Preventive outages, sensitive but unselective tripping, and inhibiting autoreclosing when the weather conditions elevate the fire risk are stopgaps used today to mitigate risks associated with wildfires. Permanent solutions include converting overhead lines to underground cables, replacing overhead conductors with isolated conductors, and rigorously clearing the right of way of potential fuel [1] [2]. All these permanent solutions are expensive and would, in practice, require an exceedingly long time to implement.

While these challenges mount, the electric power industry continues to assume that distribution protection will remain limited to simple overcurrent and directional relays that use time coordination for selectivity. At the same time, in transmission systems, our industry practices much more effective forms of protection. Line current differential and directional comparison protection schemes allow selective, sensitive, and fast protection of transmission lines. It is the cost that prevents our industry from protecting distribution and subtransmission feeders by using established solutions from transmission networks.

In theory, we could sectionalize a complex feeder into smaller and simpler protection zones by adding breakers, relays, and current and voltage transformers (CTs and VTs). We could make the distribution protection schemes faster and more sensitive by adding protection communications channels between the relays. To do this, we would need to add many new substations to a long feeder and, at each site, provide control power, equipment housing, crew access, physical and cyber access control, and so on. A conventional solution exists

for protecting distribution and subtransmission networks; it is just prohibitively expensive.

In this paper, we describe an innovative approach to solving complex feeder protection challenges and reducing the risk of wildfires caused by power lines. Our solution uses remote current and voltage measurements that are distributed along the feeder and accessed without active electronics at the instrument transformer locations [3] [4]. In this solution, a complex feeder is instrumented with pole-mounted CTs and VTs that provide instantaneous measurements in the utility substation through a passive fiber-based system. No active electronics, control power sources, or data networks are used outside of the substation fence. These added measurements allow us to break up a complex feeder into small zones of protection and provide fast and sensitive unit protection for each of the zones. Of course, the location of installed current-interrupting devices (circuit breakers and communications-enabled reclosers) determines the size of the tripping zone (*fault isolation*), but we make *fault detection* much more selective. The additional measurements allow us to apply the full suite of effective protection principles from transmission networks, including line current differential protection for each section of the feeder; much closer coordination of the remote backup for loads; protection redundancy and backup; and if microgrids form spontaneously during certain outage conditions, anti-islanding protection and microgrid monitoring and resynchronization.

II. PROBLEM STATEMENT

Consider a relatively complex distribution feeder as in Fig. 1. For better availability, the feeder is operated as a looped circuit between utility buses B1 and B2, with the tie normally closed. In addition to circuit breakers (CB1 and CB2) with associated protection schemes at the main substations, the feeder comprises multiple reclosers (R1 and R2) with associated measurements, protection, and control power. Often, the reclosers have a provision to communicate with the main substations, typically by using private radio or cellular channels. The reclosers allow better isolation of faults and improve time coordination and quality of service to customers supplied from the unaffected sections of the feeder. Multiple loads (L1 through L3) are supplied from the feeder through multiple laterals emanating from the main trunk. DERs, typically inverter-based sources, may be directly tapped to the feeder (DER1 through DER3).

The feeder in Fig. 1 is typically protected by using time-coordinated overcurrent elements (phase, ground, and negative-sequence) or recently by using distance elements (phase and ground) to alleviate some of the DER challenges. The applied ground fault protection philosophy depends on the method of grounding in the network. Recloser relays coordinate with protection of the loads (fuses and relays). Relays at the main substations coordinate with loads and reclosers. Often, directional protection elements are required at the recloser locations and at the main substations to reduce coordination times by resolving the bidirectional fault current flow problem.

The presence of DERs with typically unconventional and low-current fault response can jeopardize overcurrent and directional protection principles. Automatic voltage regulators, pole-mounted capacitor banks, and single-phase laterals complicate the feeder even more, while large and volatile loads could lead to spurious tripping (cold-load pickup, for example).

Fault locating, a key requirement for fast service restoration, is extremely difficult for feeders, such as those in Fig. 1. Operators often solve the fault-locating problem by installing faulted circuit indicators (FCIs). Line crews inspect the FCIs after a fault (historically) or the Energy Management System (EMS) interrogates the FCIs remotely via a cellular network (newer installations).

A protection communications channel can be made available between the main stations, especially at subtransmission voltage levels. However, because the feeder in Fig. 1 is a multiterminal network, it is nearly impossible to apply line current differential or directional comparison schemes between two substations and achieve the same speed, sensitivity, and selectivity as for two-terminal transmission lines.
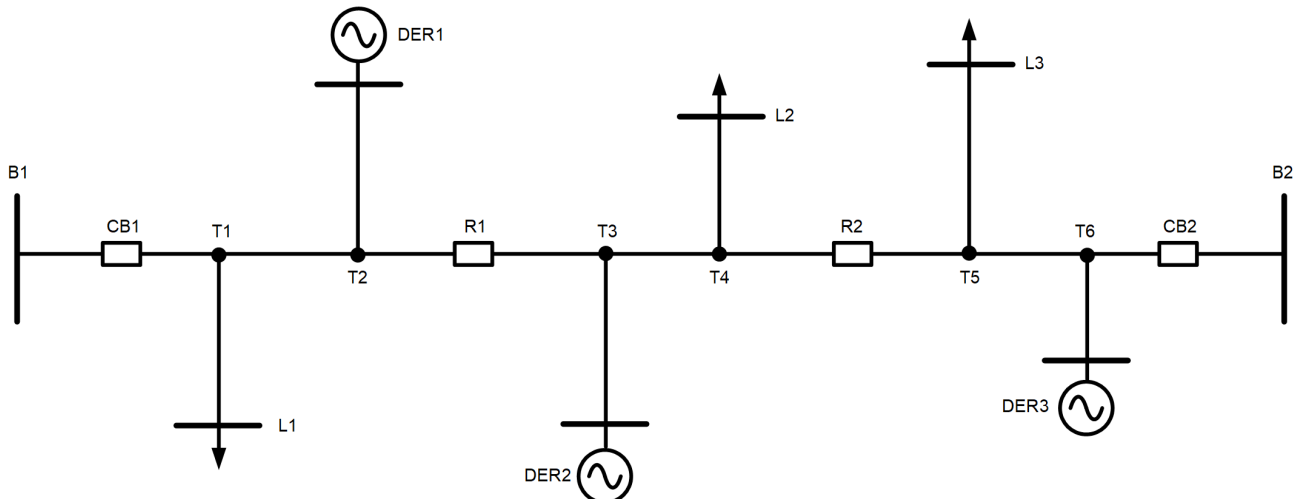

Fig. 1. Example of a complex feeder.

In some cases, feeder relays with specialized high-impedance fault detection features are installed with the objective of detecting low-current faults such as tree contacts or downed conductors [5] [6]. These protection features face considerable challenges in complex feeder applications and are not commonly recognized as remedies for the wildfire problem.

A combination of the following factors makes the protection of subtransmission and distribution feeders increasingly challenging:

- Multiterminal and multisection nature of the feeder.

- Limited visibility into the signals inside the feeder.

- Sources, especially unconventional inverter-based sources, tapped to the feeder.

- Sensitivity to cost.

- Lack of infrastructure along the feeder (measurements, control power, equipment housing, communications) and the de facto requirement that all equipment be pole mounted.

- Time and workforce requirements to execute upgrades.

Because subtransmission and distribution networks use time-coordinated relays, the protection quality is low and has the following implications:

1. Faults in certain locations are cleared slowly because the time-coordination margins accumulate (paradoxically, faults at locations nearer to sources, and therefore with higher fault current levels, are cleared with the slowest times). This tripping delay increases the released energy at the fault location and the risk of power line-caused wildfires, diminishes power quality, challenges the ride-through response of distributed generation, and increases safety risks to the public.

2. Low-current faults, such as a tree contact, are difficult to detect or may be detected after an exceedingly long delay. This raises the risks associated with wildfires and creates a danger to the public.

3. Downed-conductor events are difficult to detect, especially in ungrounded or impedance-grounded systems or when the contact surface is not conducting well (asphalt, for example). This raises the risk of wildfires and creates a danger to the public.

4. Fault locating is particularly challenging and calls for additional investment in FCIs and associated communications infrastructure. Delayed fault locating slows down repairs and service restoration.

5. Microgrid protection is particularly challenging. If a microgrid forms under certain outage scenarios, the low fault current level of the DERs challenges overcurrent protection and makes the microgrid protection problematic.

6. Backup protection for uncleared faults in the load connections downstream from the feeder has a long delay. Additional delays increase fault damage, raise the wildfire risk, and endanger the public and livestock.

In the next section, we show how these problems can be solved in a cost-effective way by adding new measurements along the feeder but doing so without creating new sites with the associated requirements for control power, data networks, cybersecurity, equipment housing, and crew access.

III. GENERAL SOLUTION

A. Additional Measurements

Consider additional voltage and current measurements, as in Fig. 2. It is self-evident that these additional measurements dramatically redefine the protection task. Before we describe the application in more detail, let us summarize improvements in protection and fault locating that are made possible by the additional measurements:

1. Time coordination as a primary protection principle for the feeder is replaced by unit protection based on the differential principle. All feeder faults are cleared without time delay. Time-coordinated overcurrent relays provide backup protection.

2. The differential zones can be as small as a single lateral or a section of the main trunk between two taps. Such two-terminal differential zones further increase protection sensitivity and improve detection of downed conductors.

3. Impedance-based fault locating is dramatically improved by using measurements from all terminals of a faulted zone and further by keeping the differential zones small.

4. Backup protection for loads is improved by using current measurement at the load site rather than the total current at the substation or a recloser.

5. Reclosing is dramatically improved because the faulted section is known with high confidence.

Normally, we do not consider the solution in Fig. 2 viable because of the very high cost. Recently, however, enabling technologies have emerged that redefine what is possible and affordable in distribution and subtransmission protection.

B. First Technology Enabler – Remotely Accessed Passive CTs and VTs

Appendix A describes the innovative CT and VT technology in more detail. This new CT and VT technology allows using pole-mounted CTs and VTs and accessing the current and voltage signals remotely from the substation(s). Consider the following key characteristics of this system:
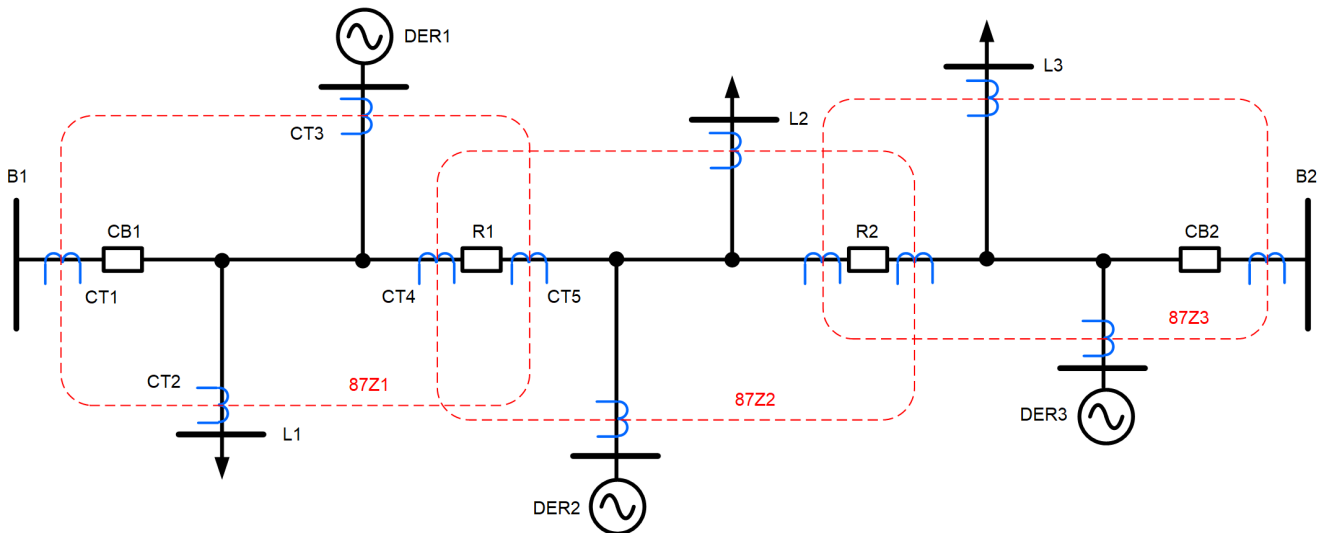
Fig. 2.   A feeder protected with differential zones owing to additional measurements (only a few CTs are shown for simplicity).

1. The additional CTs and VTs are traditional iron-and-copper devices with well-known characteristics, reliability, and lifespan. They are properly rated for weather and temperature (Fig. 3).

2. These instrument transformers include a passive circuit that encodes the electrical measurement into the reflected optical wavelength of a fiber Bragg grating (FBG) filter. This circuit is simple and therefore dependable.

3. The instrument transformers are mounted directly on poles or crossarms and do not require any additional housing, control power, or data networks.

4. Many such instrument transformers are daisy-chained on the same single-mode fiber strand. Each instrument transformer encodes its signal in a different wavelength of the reflected light signal. The daisy-chained instrument transformers share the wide bandwidth of the same fiber strand.

5. A separate device in a substation (an Interrogator, as in Fig. 4) receives the voltage and current signals by shining a broadband light source into the fiber strand and analyzing the peak wavelengths of the light reflected by the fiber Bragg gratings of all the

instrument transformers present on the fiber strand. The voltage and current signals are time-coherent (synchronized) and made available through the IEC 61850 Sampled Values (SV) protocol [7] with sampling frequencies as high as 14.4 ksps. The voltage and current signal latency is negligible (less than a millisecond).

6. The system is scalable. When the number of instrument transformers exceeds the capacity of a single Interrogator, a second Interrogator is used with the second fiber strand, allowing the number of measurements to be doubled. The multiple Interrogators are time-synchronized by using a standard time input, resulting in all measurements being time-coherent.

7. The current and voltage signals are delivered to the substation by using analog communications. No data packets are sent that could be intercepted or altered. The CTs and VTs are not cyber assets located outside of the substation fence.

8. Standard, IEC 61850 SV-capable, protective relays are installed in the substation and use the available measurements to provide all the required protection
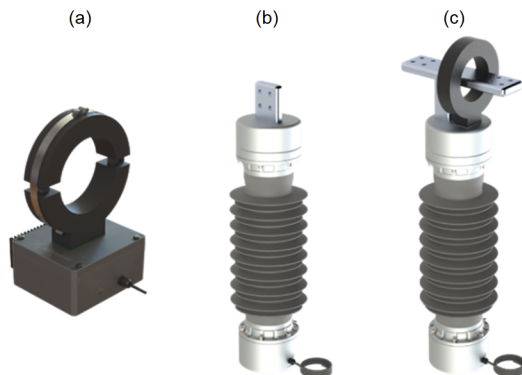

Fig. 3.   Medium voltage remotely accessed instrument transformers: current (a), voltage (b), and combined current and voltage (c).

Fig. 4.   Interrogator installed in a substation: front (a) and back (b) views.

functions (multizone differential, time-overcurrent backup, and multi-ended fault locating). These protection functions can also be implemented in the Interrogator.

9. The recloser relays are connected over an Ethernet local-area network (LAN) that is set up by using extra fiber pairs available in all-dielectric self-supporting (ADSS) cables. The recloser relays communicate with the substation devices, typically by using the IEC 61850 GOOSE protocol. This allows the protective relays in the substation to trip the reclosers and to control reclosing based on the faulted section information. The traditional radio-based communications to and from the reclosers are not needed or are relegated to a backup.

C. Second Technology Enabler – ADSS Cable

The solution we outlined in the previous subsection is conditional on having access to fiber along the protected feeder. We propose that complex feeders be retrofitted with ADSS cables [8] (Fig. 5).

The ADSS cable technology fits very well with the application to distribution and subtransmission networks because of the following factors:

1. The cost of ADSS cables is relatively low, on the order of $2 per meter or $2,000 per km ($3,200 per mile). In most applications, a 12-fiber cable is sufficient.

2. Installation of ADSS cables is convenient and inexpensive relative to the optical ground wire (OPGW) cables because of the low weight and dielectric nature of the ADSS cables, as well as the short pole span of distribution and subtransmission lines.

3. Some utilities already use or allow ADSS cables on power lines and they have experience and a skilled workforce to install them. Increasing the volume of ADSS cable applications should reduce the price.

4. The total fiber length required for a distribution or subtransmission feeder is relatively short, reducing the cost per feeder and eliminating the need for optical amplifiers.
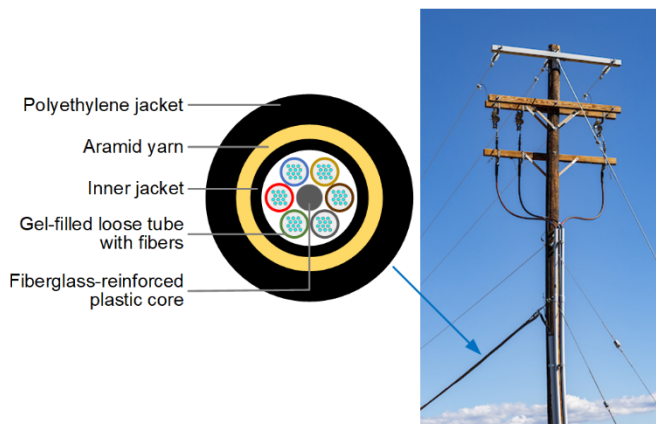
In our concept, the fibers in the ADSS cable are used to daisy-chain the remotely accessed instrument transformers. However, other ADSS fibers could and should be used to provide a terrestrial data network between the sites that already have control power (reclosers, other substations, DER sites). The fast and secure communications that an ADSS cable provides between the substations, reclosers, and DER sites allows the application of a wide range of protection and control principles, as well as cost sharing between applications and parties.

IV. INSTALLATION CONSIDERATIONS

A. Additional CT and VT Locations

In general, it is beneficial to install CTs to demarcate all loads and sources and form protection measurement zones that are not larger than the associated protection tripping zones. For example, the 87Z1 zone in Fig. 2 includes CT1 to distinguish feeder faults from reverse faults in the system connecting the B1 bus. It includes CT2 and CT3 to demarcate the L1 load and the DER1 sites. It includes CT5 to terminate the 87Z1 fault detection zone at the R1 recloser. When the 87Z1 differential scheme operates, it trips CB1 and R1. It further initiates breaker failure protection for CB1 and R1. If CB1 fails to open, the scheme trips all other breakers connected to the B1 bus. If R1 fails to open, the scheme trips R2 and initiates a direct transfer trip (DTT) toward DER2.

However, it is even more beneficial to install additional CTs to detect faults separately for each section of the feeder. Fig. 6 shows the same segment of the feeder in Fig. 2, but it assumes all sections of the main trunk and all laterals are protected as individual two-terminal differential zones. Having current measurements at each end of every section allows much higher protection sensitivity (high-impedance fault detection), and it enables detecting downed conductors by simply monitoring load currents on a per-phase basis. Also, fault locating is more accurate if the protection measurement zone is a two-terminal zone.

Fig. 6 covers the same segment of the feeder but with five differential zones, made possible by adding CTs at four

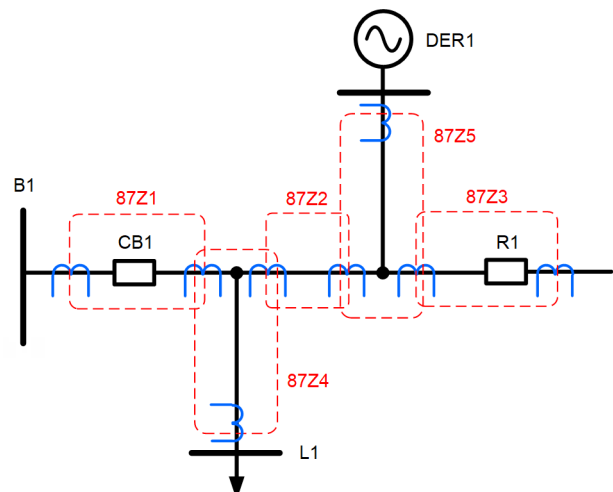Fig. 5.   Sample ADSS cable.

Fig. 6.   A sample application with more CTs and smaller protection zones (compare with Fig. 2).

additional locations compared with the application in Fig. 2. This increases the cost but brings additional benefits. When very sensitive and fast protection is required, it is good practice to protect all feeder sections that are longer than a certain threshold as two-terminal zones, while leaving shorter sections as parts of multiterminal zones. The nature and criticality of the connected loads may also influence the strategy for defining protection and isolation zones.

Of course, the protection tripping zones in Fig. 2 and Fig. 6 are the same. The five differential zones possible in the application in Fig. 6 still trip CB1 and R1, but they provide even more selective and sensitive protection than the single zone application in Fig. 2.

Fig. 7 shows another option where only two additional CTs are needed compared with the application in Fig. 2. These CTs are installed at each tap point to demarcate the laterals. In this application, three differential zones are used: one protects the main trunk between the substation and the recloser, and the other two zones protect the two laterals.

Additional CTs dramatically improve protection sensitivity, selectivity, and speed. Additional VTs improve fault locating and allow power measurements and voltage-based functions that may be needed for microgrid protection, monitoring, and control. Multizone protection narrows down the fault location to a small section of the feeder. To locate the fault within the protection zone that operated for a fault, we need VTs at all zone terminals except for one [9]. For example, if we use a two-terminal zone, we need a VT at one terminal (in addition to CTs at both terminals) to find the fault location. If we use a three-terminal zone, we need VTs at two terminals (in addition to CTs at all three terminals).

Additional VTs increase cost. It may be justified to add VTs for all feeder sections that are longer than a certain threshold. A system comprising only CTs and no VTs would still be able to identify a faulted segment. Subsection V.G provides more information on fault locating and a method to reduce the number of required VTs.

In general, the number and location of CTs and VTs can be determined by using traditional rules of protective relaying.
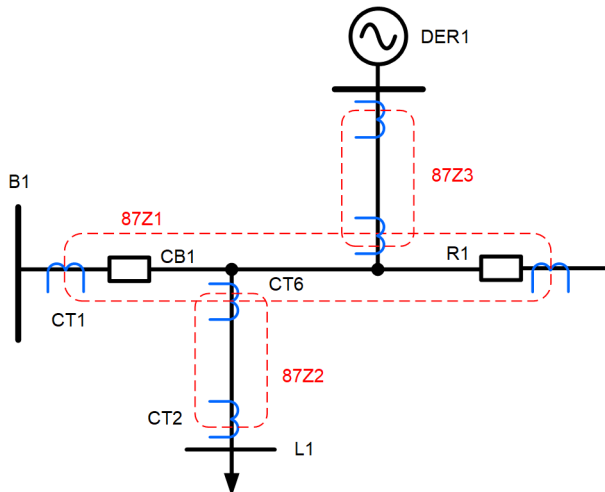
Flexibility and tradeoffs are possible between the number of additional CTs and VTs and the resulting sensitivity of protection, granularity of faulted section detection, and accuracy of fault locating.

B. ADSS Cable

The ADSS cable is directly suspended from the feeder poles. The ADSS cable "follows the wires" to reach all CTs and VTs along the feeder. It is important to remember that the remotely accessed CTs and VTs in our concept only need a single fiber core (not a fiber pair for duplex data communications). The following installation guidelines apply (see Fig. 8):

1. Install a multifiber ADSS cable along the main trunk of the feeder. Splice the cable at each tap and recloser location. Splice the CTs and VTs located at the taps and recloser locations.

2. Install an ADSS cable on each lateral. Use a fiber pair to connect the main trunk ADSS cable to and from the CTs and VTs located on the lateral. The lateral fiber core is effectively a loop spliced into a fiber core in the main trunk cable.

3. Use a fiber pair in the main trunk ADSS cable to provide data connection among the substation devices and the reclosers. This communications channel is used for tripping during feeder faults and intertripping during a failure of an upstream recloser to clear the fault. The reclosers can be daisy-chained if they have Ethernet switch capabilities (no need for recloser-to-substation fiber for each of the reclosers). For better reliability, consider providing a separate fiber pair for each recloser location.

4. Use a fiber pair for DER sites in the main trunk ADSS cable to provide data connection among the substation devices and DERs. This channel is used for anti-islanding tripping and a range of other applications, including monitoring and metering. The DER sites can be daisy-chained on the same fiber pair by using Ethernet switches.

5. Use a fiber pair in the main trunk ADSS cable to provide point-to-point data connection between the substations. This channel is used for intertripping during a failure of an upstream recloser to clear the

Fig. 7.   A sample application with more CTs and smaller protection zones (compare with Fig. 2 and Fig. 6).
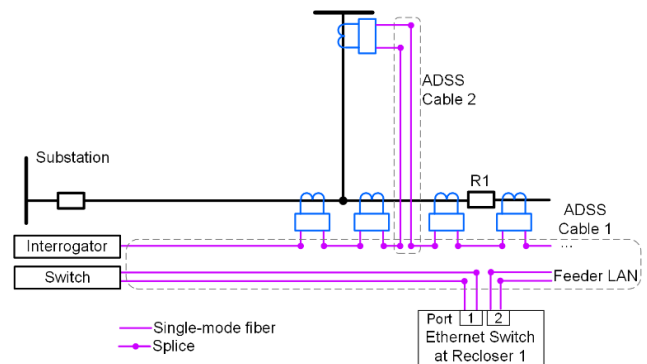

Fig. 8.   Fiber installation.

fault or a failure of local protection during feeder faults. This channel can be a separate point-to-point channel or a part of the network that links the reclosers and DERs.

C. Scalability and Redundancy

The proposed protection system is scalable and can be set up with varying degrees of redundancy according to user preferences and requirements.

It is possible to instrument a complex feeder with just a few remote CTs to provide ultra-high-speed and sensitive protection to the most critical sections of the feeder, such as those traversing fire prone areas. Alternatively, a complex feeder may be instrumented with many remote CTs to divide the entire feeder into the smallest zones of protection possible to maximize the benefits of protection speed and sensitivity, as well as selectivity of autoreclosing (compare Fig. 2, Fig. 6, and Fig. 7). Also, new remote CTs can be conveniently added when the feeder is expanded over time to include new sections and laterals, or when the conditions and requirements change (for example, when an additional tap point is added to connect a new DER).

When the number of CTs and VTs exceeds the capacity of an Interrogator (such as 10 three-phase CT or VT sets), more Interrogators may be added to accommodate them (Fig. 9). Provide the local Interrogators with a common timing signal to ensure their voltage and current data streams are time-coherent when available on the IEC 61850 process bus LAN.

The remote CT and VT signals can be made available to the protection and control system in one substation or in multiple substations for redundancy. Fig. 10 illustrates this opportunity by showing the current measurements interfaced to the nearest substations (Fig. 10a) and to two substations simultaneously (Fig. 10b) for redundancy. The application in Fig. 10b requires two CTs or a dual-output CT with two fiber-optic interfaces.

When the remote CT and VT signals are available at more than one substation, the protection and control functions that
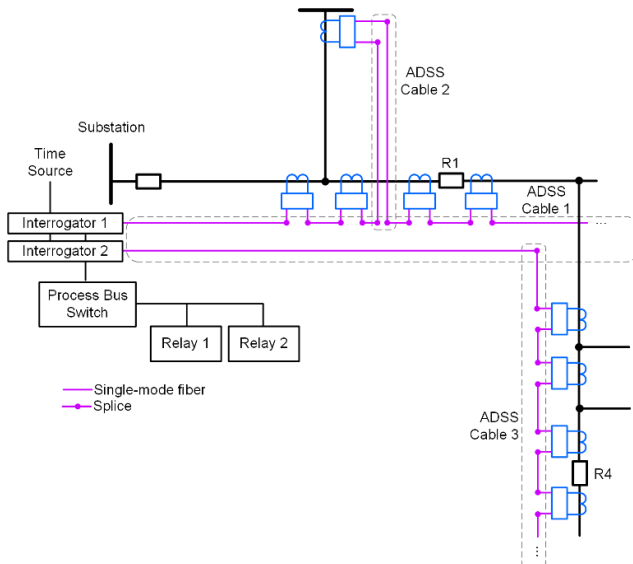

Fig. 9.   Adding more instrument transformers by using additional fiber cores and Interrogators.
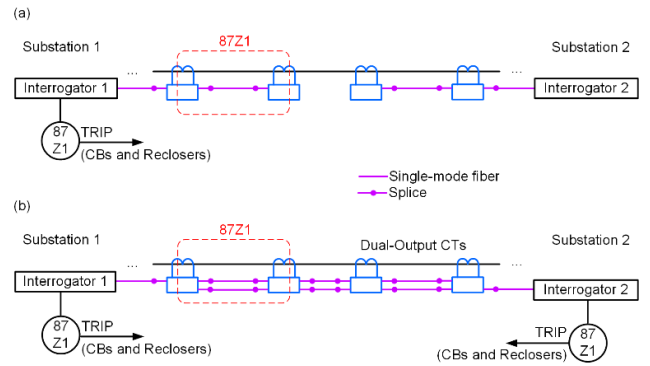

Fig. 10.   Nonredundant (a) and redundant (b) instrument transformer connections.

use these signals can be duplicated at different sites. This provides a high degree of redundancy, assuming both substations have DTT channels to trip the associated breakers and reclosers. The latter requirement is not difficult to meet if an ADSS cable is installed and used to provide the feeder LAN functionality, as explained in Subsection IV.B.

In general, the proposed system is flexible and scalable. The remote CTs and VTs can be deployed gradually based on workforce limitations and changing requirements. The number of measurements is not limited, and new measurements can be added by using additional ADSS cable fiber strands and additional Interrogators. If desirable, the measurements can be made redundant. As a result, the protection system is not only powerful but also very flexible and resilient to failures.

V.   APPLICATION CONSIDERATIONS AND BENEFITS

In this section, we will discuss the many benefits of the proposed protection system.

A. Feeder Protection

In the proposed approach, time-coordinated overcurrent or distance protection is relegated to the role of backup and the feeder is protected using the preferred unit protection principle: line current differential. Additionally, the zones of protection can be made small, further increasing protection sensitivity. Each section of the feeder can be protected individually (even if larger portions of the feeder are tripped upon fault detection).

To maximize the benefits of the proposed approach, a differential protection element can be designed that operates on the order of half a power cycle. This high operating speed is possible because of the following factors:

- Exceptionally low latency for the current signals.
- High fidelity of the current signals.
- Very small line charging current.
- Low latency when executing recloser trip signals over the ADSS fiber-based feeder LAN.

This extraordinarily fast tripping would further reduce the risk of wildfires caused by power lines, improve public and livestock safety, improve power quality, relax the DER ride-

through requirements, and increase the chances of successfully autoreclosing after transient faults.

Differential protection elements are considerably easier to set than any of the alternatives. In applications to sections of a feeder, a differential element can be used with universal settings, eliminating the need for settings calculation and coordination. Also, phase differential protection can be naturally applied to portions of the feeder that contain both three-phase sections and single-phase laterals. This ease-of-use aspect is an important positive factor in the adoption of the proposed transmission-grade approach in the distribution domain (see the case study in [10] for more information about ease of use and workforce considerations when bringing new technology to distribution protection).

B. High-Impedance Fault Detection

Differential protection is the most sensitive protection principle at our disposal. It becomes especially sensitive in line protection applications when the following conditions are met:

- Each zone is small and uses the minimum amount of restraint possible, given the need to account for errors of a small number of CTs (ideally each zone is a two-terminal zone with only two CTs comprising the zone).

- There is no appreciable line charging current.

- There are no unmeasured tapped loads or pole-mounted capacitors.

The first two conditions are naturally met in the proposed solution. If protection sensitivity is paramount, such as when addressing wildfire risks, one should satisfy the third requirement by measuring all tapped loads and capacitor banks or avoiding tapping those feeder sections for which protection sensitivity is important.

During low-current faults, protection CTs allow reliable measurement of current differences as low as 25 A (5 percent of 500 A nominal, for example). As a result, it is possible for a two-terminal differential zone to detect a current unbalance as low as 25 to 50 A. This natural sensitivity can be amplified by proper design of the differential element that takes advantage of the high fidelity of current measurement from the remote CTs and accounts for the potentially intermittent nature of the differential current during high-impedance faults (arcing faults create intermittent fault current [5] [6]).

The proposed differential protection is markedly superior to the present high-impedance protective relays, such as those exemplified in [5] and [6]. Consider the following benefits:

- The differential scheme can operate in milliseconds instead of seconds, tens of seconds, or even minutes, as is typical when using the traditional high-impedance protective relays installed in the substation.

- The differential scheme does not require any initial tuning or adaptation to the changing load conditions. It follows a fully deterministic protection principle that is easy to use, test, and troubleshoot.

- The differential scheme is extremely unlikely to issue any spurious trips or alarms. High security and selectivity improve the trust of operators and by doing so, improve the system performance considering operational and human factors.

- The differential scheme has only two settings (the pickup and the degree of restraint, typically the percentage restraint setting). It is therefore easy to control its sensitivity via settings groups such as by making it extremely sensitive during certain weather conditions (dry season or high winds, for example). Additionally, different sections of the feeder can be protected with different sensitivities depending on their individual risks. For example, sections that traverse forests can be protected with much higher sensitivity even at the price of increasing the risk of inadvertent tripping.

- By using small differential zones, the proposed approach allows impedance-based fault locating. The traditional high-impedance protective relays do not allow locating high-impedance faults at all.

C. Downed-Conductor Detection

A downed-conductor condition can be extremely dangerous in the context of wildfires and public safety. High-impedance protective relays claim downed-conductor detection, but their performance is limited, and their detection times are measured in seconds or minutes [5] [6] instead of the preferred milliseconds. Other solutions apply phasor measurement units along the feeder and use a combination of first principles and heuristics to detect broken-conductor conditions [11].

In our solution, broken-conductor detection becomes considerably easier. Consider the following:

In a looped feeder, a sudden loss of load in one phase without a corresponding change in the current at the load points is a clear indication of a downed conductor. In this case, the affected feeder section can be de-energized well before the broken conductor hits the ground and causes any danger to life or the environment (it takes more than a second for the conductor in free fall to hit the ground [11]). For this mode of detection to work, we estimate that the affected feeder section must carry at least 20 A of load. When VTs are available at both ends of the protected section, a negative-sequence directional comparison scheme can detect a broken-conductor condition. One can further improve detection by using remote VTs to measure and respond to the sudden change in the voltage difference between the terminals of the protected section [11].

If the feeder section carries no or little load current, the downed conductor (open-phase condition) cannot be detected reliably. This blind spot is not limited to our method. However, when the conductor hits the ground in solidly and impedance-grounded systems, the differential element operates with high speed and sensitivity. This sets our solution apart from all other known methods.

As a complementary technique, conductor vibration and tension may be measured by compatible passive and remotely interrogated line-mounted sensors, providing an instantaneous, but localized and less discriminative, detection of tower or line strikes or rapid movement [12].

In general, our system provides high dependability for broken- and downed-conductor conditions and can trip before a broken conductor becomes a downed conductor (i.e., *before* the falling conductor hits the ground).

D. Cable Section Protection and Monitoring

The proposed approach improves protection of cable sections in at least the following three areas.

The sensitive differential protection scheme allows detecting incipient (self-extinguishing) cable faults with a much higher sensitivity than when using the substation current alone [13].

Protecting cable sections with a differential scheme allows unambiguous faulted section identification and selective autoreclosing (inhibiting reclosing for cable sections).

The proposed system allows temperature and sheath current measurements to be added using the same passive fiber connection. These measurements greatly improve monitoring and allow predictive maintenance of the cable sections and joints.

E. Backup Protection

There are several aspects of backup protection to consider in this application.

Firstly, the proposed approach allows optimum coordination with the load protective relays and fuses. In reference to Fig. 2, our system uses the CT2 current at the load, and not the CT1 current at the substation, to provide time-coordinated backup for faults in the load L1 network downstream from CT2. The use of CT2 typically allows removing a few steps of time coordination and by doing so, allows faster backup trips. Also, when our system trips in a backup mode, it allows faster restoration because it naturally identified which primary protection element failed to trip. After the backup trip, our system allows reconfiguring the feeder optimally and reclosing larger portions of the feeder.

Secondly, when the measurements are available at more than one substation, some or all protection functions can be duplicated while using the ADSS cable for tripping remote circuit breakers and disconnect switches (see Fig. 10). This increases the protection system reliability.

Thirdly, if the proposed system suffers a partial failure, such as a loss of several remote CT signals, the system can fall back gracefully, providing protection that is still superior compared to today's time-coordinated systems. The fallback may involve protecting larger differential zones by merging zones that can no longer be separated because of the lost measurements. For example, if the system loses access to CT5 in Fig. 2, it can switch to CT4 at the expense of creating a small blind spot between the 87Z1 and 87Z2 zones or it can merge the 87Z1 and 87Z2 zones. The fallback may include

switching from the differential to time-coordinated protection, but it still uses fine measurements along the feeder rather than crude measurements from only the circuit breaker and recloser locations. For example, if the system loses access to CT2 in Fig. 7, it may move the time-overcurrent protection from CT2 to CT6 and protect the lateral section by using the time-overcurrent protection, normally meant only as a backup for the load. Similarly, if the system loses access to CT6, it can replace it with CT2 in the 87Z2 zone and protect both the section of the main trunk and the lateral in one zone.

Finally, breaker failure protection becomes an attractive option in the proposed approach. By having access to currents at the recloser locations, the proposed system can use breaker failure protection (instead of time-coordinated backup) and can trip adjacent circuit breakers or reclosers without delay when it detects a failure to interrupt the fault current by any of the breakers or reclosers.

F. Reclosing

The proposed approach allows excellent faulted section identification. It also allows distinguishing between tripping for feeder faults (differential trips) and backup tripping for load faults or feeder faults (time-overcurrent trips). As a result, the feeder reconfiguration and autoreclosing functions become much more selective. The absolute minimum feeder section can be isolated before reclosing, and to improve the odds of successful reclosing, reclosing can take place only for feeder faults that were cleared quickly. Reclosing can be inhibited if the faulted zone includes high-risk sections of the feeder (fire prone sections, cable sections, etc.).

G. Fault Locating

The proposed approach allows excellent fault locating within the faulted section. By dividing a complex, branched, and multiterminal feeder into small two-terminal sections and having current measurements from both ends of the section, impedance-based fault locating can be made reliable and accurate. A wide range of methods are available for this application [9]. Because the measurements are time-coherent, multi-ended synchronized fault-locating methods can be used, yielding excellent results.

Impedance-based fault-locating methods require voltage measurements. However, the system can use voltage measurements from one, two, or even three feeder sections away. The fault-locating algorithm can calculate voltage at the terminals of the faulted section by using a nearby voltage. The algorithm obtains the faulted section voltage by using the voltage measured one or two sections away and compensating it for the voltage drops along the healthy sections by using current measurements from these sections. For example, the voltage at recloser R1 in Fig. 2 for a fault between R1 and R2 can be calculated from the Substation 1 voltage with the use of these currents in the sections between the substation and the recloser: CT1, CT1 + CT2, and CT1 + CT2 + CT3 (which is the same as –CT4). Of course, the error in the derived voltage is larger than if the voltage were measured directly. However, by strategically placing a few VTs along the feeder, one can

ensure that reasonably accurate voltage signals are available for fault locating for any section of the feeder.

Additionally, because faults are cleared quickly, the fault resistance and fault type are not likely to vary during the fault, further improving the fault-locating accuracy (faults tripped in 0.5 s or 1 s by time-overcurrent relays tend to evolve before they are cleared).

We estimate that fault-locating accuracy on the order of 5 percent can be guaranteed [9]. Given that the feeder sections are relatively short, the 5 percent error leaves a very short section to be patrolled (5 percent of 5 km is only 250 m, 5 percent of 3 mi is only 800 ft, for example).

H. Microgrid Operation

The proposed approach provides a high degree of visibility into the feeder and by doing so, improves operations with microgrids. Consider the following:

- If a microgrid forms by design or inadvertently, the utility has access to currents and voltages inside the feeder sections that became a part of the microgrid. This access is independent of the DER owners and operators.

- The sections of the feeder that are a part of a microgrid and are electrically isolated from the main substations are still protected by using the differential principle. The trip signals are sent to the DERs and reclosers. The utility may provide additional protection for the microgrid such as over- and undervoltage and over- and underfrequency.

- Synchronization of a microgrid becomes easier because the utility has access to remote voltages and can measure the voltage angle and frequency relative to the substation sources. In cases where microgrid operation is not permitted, reclosing is made more convenient because of the explicit confirmation that the DERs are disconnected and the feeder section is de-energized.

- The ADSS fiber network allows better control of reclosers, DERs, and loads.

I. Power Measurement Benefits

The proposed approach allows measuring and monitoring current and power flows inside the feeder with great granularity, assuming VTs are installed at the required points along the feeder. Consider the following applications:

- Electricity theft detection becomes easier because the feeder sections are now individually monitored for losses and the loads are individually monitored for power consumption.

- Feeder losses can be better understood, aiding deployment and control of capacitors and automatic voltage regulators.

- The total feeder load can be monitored despite the presence of the DERs, allowing the utility to better prepare for the sudden loss of DER generation. Loads are monitored, allowing for more selective shedding.

- The loads can be characterized better (load response to voltage and frequency variations), allowing for more nuanced load shedding by operating reclosers in addition to substation circuit breakers.

- The load of individual feeder sections can be monitored, allowing the thermal capacity of the conductors to be maximized.

VI. Economical Implementation of Protection, Control, and Monitoring Functions

The proposed solution can be used with today's relays based on the IEC 61850 SV protocol. In this concept, the protection signals flow as follows:

- The Interrogator(s) publishes the remote voltage and current measurements on the process bus LAN. The local voltage and current come from a traditional merging unit in the substation or can be measured by using the remote instrument transformer technology (secondary-connected fiber Bragg grating converter).

- Several protective relays with appropriate protection, control, and monitoring functions are used to provide the required functionality.

- These relays trip the local circuit breaker, intertrip the remote circuit breaker via the IEC 61850 GOOSE or similar channel, trip the reclosers, and control reclosing via the IEC 61850 GOOSE messages through the feeder LAN that is deployed over the ADSS cable.

However, the proposed approach would call for a considerable number of relays per feeder because of the following practical constraints:

- Line current differential relays typically incorporate a single differential element. A line current differential scheme for a two-terminal line comprises two relays. A complex feeder would require multiple differential zones of protection and would call for multiple relays.

- To cope with a loss of CT signals or feeder reconfiguration, the application may require reconfigurable zones of protection (similar to a dynamic bus replica in bus differential relays). Line current differential relays typically do not provide reconfigurable zones.

- Bus differential relays provide multiple zones of protection, but they tend to be more expensive, and they do not include other functions beneficial to this application such as fault locating.

- Line or feeder relays include a single instance of a fault-locating function. Complex feeders would benefit from multiple fault locators (one fault locator per each protection zone) or a single fault locator that is dynamically associated with a faulted section of the feeder.

- Line or feeder relays include a limited number of time-overcurrent elements. A complex feeder may require multiple overcurrent elements that can take advantage

of the current measurements at the load and DER sites to coordinate optimally with loads and reclosers.

- Line or feeder relays include a single instance of a power metering function. Complex feeders would benefit from multiple power measurement instances.

- Microgrids require voltage and frequency protection. Multiple elements can be required if multiple microgrids can form inside the protected feeder.

To make the proposed approach more economical and easier to use, an optimized protection device may be beneficial. Such a protection device would provide multiple instances of the differential, overcurrent, voltage, and frequency protection elements; multiple instances of the fault-locating function; and multiple instances of the power measurement function. The device would be based on IEC 61850 SVs and GOOSE and would function like a centralized protection device [14]. However, it would not use multiple instances of protection, control, and monitoring functions to cover multiple feeders, transformers, or lines, but rather to cover a single feeder in a more granular way with more instances of functions that apply to smaller portions of the same feeder.

We anticipate that the early applications of the proposed approach would use several standard IEC 61850-based line and feeder relays, but the at-scale deployment would benefit from centralized protection that offers multiple instances of the required functions listed above [15] [16].

VII. Conclusions

In this paper, we have proposed a novel approach to protecting complex feeders while addressing the wildfire, public safety, and DER challenges. The approach is based on a brute-force method of adding current and voltage measurements, made possible by fiber-based connections without active electronics and data networks outside of the substation fence. These measurements in turn permit the application of established transmission-grade protection and control principles. These principles include deploying differential protection, dividing the protected feeder into small protection zones, and eliminating time-delayed trips while providing better time coordination for backup protection. The application of the principles and practices that are known and practiced in transmission systems would reduce the learning curve and accelerate adoption in distribution networks.

The proposed solution uses an economical way to obtain the remote voltage and current measurements throughout the feeder. These measurements use a passive technology (no control power or data network required) that is based on traditional iron-and-copper instrument transformers fitted with fiber Bragg grating transducers. We propose retrofitting a feeder with economical ADSS cables to allow interrogating the remote CTs and VTs and providing the measurement to substation protection and control devices. We also advocate using the ADSS cables to provide reliable terrestrial Ethernet connectivity to and from reclosers, DER sites, and remote substations.

By instrumenting the feeder this way and providing high-speed communications along the feeder, you can dramatically improve feeder protection with the following specific benefits:

- Reduction of the risk of power line-caused wildfires by using ultra-high-speed sensitive protection.

- Detection of high-impedance faults with several orders of magnitude better sensitivity and speed compared to traditional approaches.

- Detection of and tripping for broken-conductor conditions before the conductor becomes a downed conductor (i.e., before the broken conductor hits the ground).

- Adaptive autoreclosing for hybrid (mixed circuit) feeders that allows reclosing for overhead sections and inhibits autoreclosing for cable sections.

- Detection of incipient cable faults.

- Monitoring, protection, and synchronization of microgrids if they form intentionally.

- Anti-islanding protection for microgrids that form unintentionally.

- Optimum feeder reconfiguration by dramatically improved faulted section detection.

- Outage duration reduction by dramatically improving the accuracy of the fault location (or providing the fault location where it was not previously available).

The presented approach is flexible and scalable and can be field tested and deployed today. It creates opportunities for cost savings and simplicity by using centralized protection and control devices. The underlying technology is currently deployed operationally in transmission networks for autoreclose blocking on mixed circuits, differential protection of multi-ended circuits, and centralized bus protection [15] [16].

The presented approach requires field work (retrofitting the remote CTs and VTs and installing the ADSS cables). The associated effort and cost are not negligible, of course, but they are exceedingly small by comparison to other solutions, such as undergrounding overhead feeders to eliminate the risk of wildfires caused by power lines.

We effectively advocate to define a modern complex feeder, not as a network of conductors, but as an integral system with power conductors, ADSS cables, distributed instrument transformers, and reclosers.

The presented approach is based on mature principles. It involves an innovative technology in the form of remotely interrogated passive CTs and VTs. This recent technology, however, is simple and based on well-understood optical and electrical principles. Therefore, when used at scale, the technology is guaranteed to reach the cost and reliability expected in this application.

VIII. APPENDIX A
PASSIVE REMOTELY INTERROGATED CT AND VT TECHNOLOGY

The passive measurement technique considered in this paper combines established fiber-optic sensing practices with an intermediate transducer to convert secondary voltages or currents at the output terminals of conventional iron-and-copper instrument transformers into an optical signal, measurable over a long distance at low latency. Each passive sensor's primary functional components are an FBG and a multilayer piezoelectric actuator ("piezo").

A. FBG Sensors

FBGs are periodic perturbations of the refractive index along a fiber core, having peak optical reflection at a specific wavelength, known as the Bragg wavelength [17], and having a typical physical length of 5–10 mm. In sensor applications, their wavelength-encoding nature, coupled with their simple reflected spectra, means that FBGs are relatively easy to interrogate and multiplex and are effectively immune to the problems of light intensity fluctuations and attenuation [18]. For these reasons, the FBG is ubiquitous in the field of optical instrumentation [19] [20].

Peak optical reflection from FBGs occurs at a wavelength λ equal to twice the grating period, i.e., at $\lambda / n = 2\Lambda$, where n is the fiber refractive index and Λ is the pitch of the grating. Thus, straining or compressing the fiber longitudinally at the location of the grating shifts up or down, respectively, the peak reflected wavelength. Illumination of the FBG by broadband light, and some form of peak wavelength detection and tracking, may therefore be employed to use the FBG as a high-resolution strain or temperature sensor.

B. FBG Sensor Networks and Interrogation

The generic architecture of an FBG sensor scheme is illustrated in Fig. 11. Light from an optical source is guided by the fiber to an array of serially multiplexed FBGs. Reflections from all FBGs are returned via a coupler to the interrogating device, at which the peak reflected wavelength from each sensor is extracted. Commonly, the optical source and interrogating optics are housed in one rack-mountable unit.

Simultaneous interrogation of all sensors arrayed in the fiber is carried out in various ways: for example, by scanning a laser or filter over the wavelength range of all sensors and sampling continuously or by using a spectrometer to capture an "image" of the full sensor spectrum (containing all sensors in the array) at the desired sample rate.

Low-level, strictly timed processing may be done by dedicated circuitry or a field programmable gate array (FPGA) to extract the peak wavelength of each sensor and track their changes over time. Real-time processing may then be
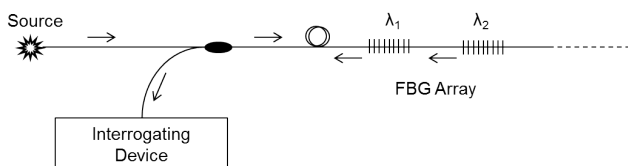
deployed to convert the "raw" measurements into the instantaneously measured parameter based on calibration coefficients.

This complete measurement operation can be straightforwardly carried out at kilohertz rates for every sensor in an array over distances of around 60 km with a total latency from event to data publishing of less than 1 ms. None of the sensors in the array requires a local power supply. The speed and resource efficiency of this measurement platform lends itself to a myriad of applications in structural health monitoring, dynamic condition monitoring of the plant, and particularly monitoring applications requiring high-resolution measurements over long distances or in harsh locations where the supply of power to electronics is either impractical or not permitted.

C. Optical Wavelength Encoding of Electrical Signals

The encoding of CT or VT secondary signals passively into an optical signal is performed primarily by a piezoelectric actuator (Fig. 12). Piezoelectric actuators are commonly manufactured to high precision for use in aerospace and medical applications to enable precision voltage-controlled displacement or vibration devices. The application of a voltage to the terminals of the device aligns the electric field along the axis of the actuator, forcing microscopic domain volumes in the material to align in the field direction, causing the material to elongate proportionally in that direction. Conversely, if a negative voltage is applied, the material will be compressed. In this way, a conversion from applied voltage to material strain is made. Electrically, the device may be considered a capacitor, storing charge while it is elongated and discharging it as it relaxes.

By binding an FBG sensor to the piezoelectric actuator, the voltage-induced strain in the material is imparted to the fiber, which, as described in Subsection A, has the effect of shifting the peak reflected wavelength of that sensor. In this way, a sinusoidal voltage, for example, is converted to a proportional sinusoidal wavelength change that can be monitored in real time by the interrogating system. To monitor current, a precision resistance can be used to first convert the signal to voltage [21] [22].
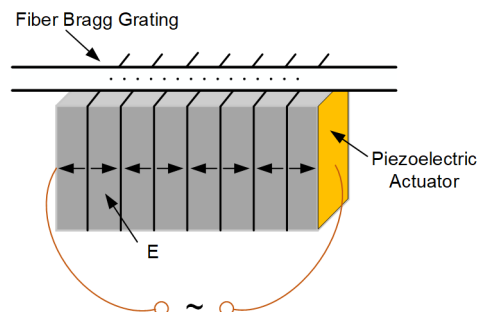
Fig. 11.   A generic FBG measurement scheme illustrating the multiplexed and reflection-mode topology. λ_1 and λ_2 are peak reflected wavelengths.

Fig. 12.   Encoding voltage signals in optical wavelength by piezoelectric actuation of an FBG.

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