Comparison of Protection Settings Used by Electrical Utilities in the Western US and Canada to Reduce Wildfire Ignition Risk

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Abstract

Testing and field experience have shown that wildfire ignitions due to electrical faults can be reduced by implementing fast trip settings and high impedance ground fault detection schemes. This paper will provide a comparison of different setting methods used at several Western North American utilities to reduce the risk of wildfire ignitions from utility equipment.

Research has found that many other utilities have begun to implement fast trip settings for several years, but with a wide variety of setting criteria. The utilities surveyed are also looking at newer advanced technologies to detect high-impedance faults, falling or broken conductors, and sensitive ground settings. Most of the utilities surveyed are in the testing or pilot phase of evaluating these new technologies. It is understood that many of these measures may impact reliability. Potential fire risk reductions will need to be weighed with reliability impacts (false trips, power shutoffs, etc.). These tradeoffs will differ between utilities based upon the inherent risk profiles between utilities.

A key takeaway from this exercise is that no one individual method can reduce ignition through a defense in depth strategy.

Results of implementing these settings within Pacific Gas & Electric Company's distribution system will be included.

Background

Pacific Gas & Electric Company (PG&E) developed Enhanced Powerline Safety Settings (EPSS) to help reduce wildfire risk by adjusting the sensitivity and speed of protective devices such as circuit breaker relays and reclosers. As currently implemented, circuits enabled with EPSS are configured to provide a maximum relay response time for bolted fault conditions within 100ms.

The purpose of this document is to provide insight into what types of protective device setting changes other western North American utilities, with similar wildfire risks to PG&E, are implementing to mitigate the risk of wildfire ignitions from utility equipment. Previous discussions were limited to other large California utilities. These discussions expanded to include several other utilities along the western region.

The research shows that many other utilities have implemented fast trip settings for several years. Some utilities implementing some form of fast trip settings for about 10 years while others were still in pilot of this style of protection.

Utilities are also looking at new technologies to detect high impedance faults, detecting falling or broken conductors, and implementing sensitive ground fault settings. Some have already enabled protection with these methods/features. Most other of these are in the testing or pilot phase in evaluating these new technologies.

General Protective Features and Methods

Fast Tripping – In regard to fire mitigation and protection, fast tripping is in reference to protection settings that have minimal or no delay from fault detection to sending a trip signal. Reducing the duration of an arc can reduce the potential of a fire ignition or the severity of an ignition if one does occur.

Fuse Overreach (Ganged Operation) – Ganged operation is in reference to a device that can open/de-energize all hot phases of the circuit when utilized to interrupt a fault. Where in a traditional protective scheme, a fuse may be utilized to interrupt a fault for its designated protective zone and only the fuse on the faulted phase(s) might open for single phase fault events. With a more sensitive gang operated, fuse overreaching, scheme an automatic device is set to clear the fault before the fuse opens or at least in addition to the fuse opening. This would mitigate the risk of back feeding into a downed conductor through a service transformer where the downed phase is open from the source by the fuse, but the other energized phases might still create an ignition scenario which is difficult to detect as shown in Figure 1. While this situation can occur in 4-wire systems with delta connected loads it is most prevalent in 3-wire uni-grounded distribution systems where all loads are connected line to line.

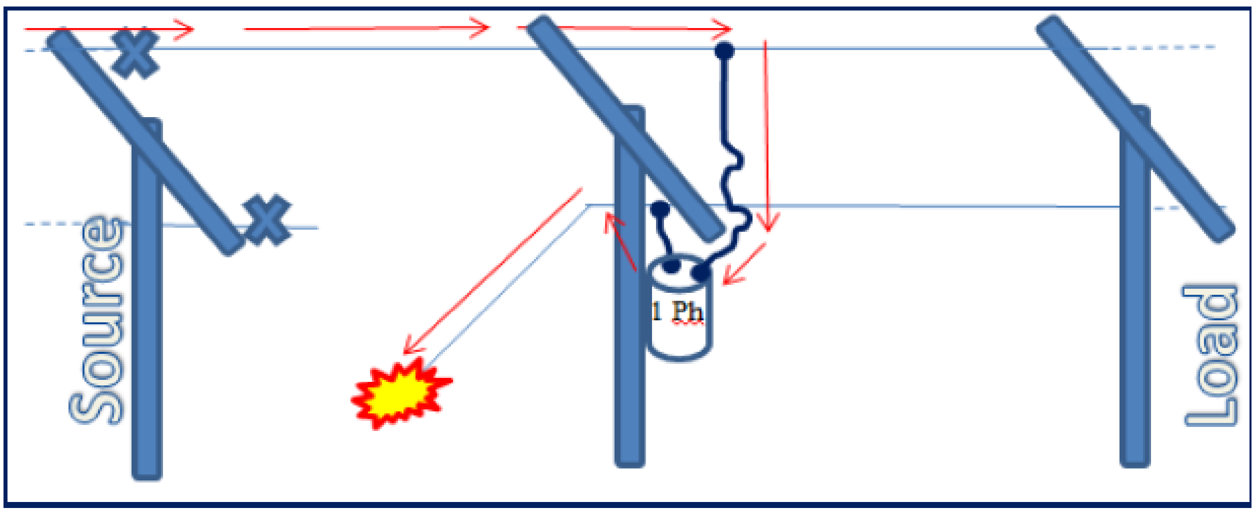

Fig. 1: Example Back Feed Path

Sensitive Ground Fault Detection – Utilization of a low set ground pickup element that has a longer delay/time to operate than a traditional protection setting found in a 50N/50G or 51N/51G element. This protection element is typically best suited for uni-grounded 3-wire systems to detect impedance faults.

High Impedance Protection – These are more sophisticated protective algorithms than the sensitive ground fault protection previously mentioned. The algorithms often are looking for ground current and signatures of a fault, such as 3rd harmonic content and other characteristics. This protective feature is looking to mitigate the ignition risk created by a fault scenario where the fault current is potentially much lower than the settings of typical protective elements due to the fault path having high impedance such as contact with vegetation or a broken phase on certain physical ground surfaces.

Falling Conductor/Open Phase – This protective feature is looking to mitigate the risk caused by a broken conductor at the time that it separates and prior to it encountering the ground surface or very shortly thereafter.

Implementation Considerations

Activation Criteria – There are many factors that could influence the decision of a utility to activate devices and settings to necessitate enhanced protection to mitigate fire ignition potential. Each utility will have its own risk tolerance regarding the combinations of weather forecasts, fuel types and conditions, risk models, and infrastructure health.

Operational Deployment – How these fire mitigating schemes/settings are implemented on the utility systems can have an impact on how they are utilized. Depending on the activation criteria and frequency in which change is required, whether the scheme can be activated remotely or manually would have a significant impact on the functionality of the implementation. If all or a vast majority of the devices in the schemes have remote/SCADA access, then daily activation/deactivation should be achievable. With a system with limited SCADA/remote access penetration or devices with limited remote features, then scheme changes would be more limited to seasonal resolution and more potential customer reliability impacts.

Risk vs Reliability – The guidelines on how devices in a scheme are set along with when devices are activated are heavily informed by the risk tolerance of a utility. Where the most absolute mitigation for an ignition risk from an electric utility source would be to cut power for the duration of the risk period, that is not always an acceptable solution for customer service nor utility operation. Where power shut offs can still be an appropriate tool finding a balance of providing reliable electric service and mitigating risk however having schemes in place that allow customers to remain in service but provide safety through operating for faults to prevent ignitions is also very important.

Tabular Comparison

Table 1: Utility Comparison: Fast Trip Settings Comparison

	PG&E	Utility 2	Utility 3	Utility 4	Utility 5	Utility 6
Voltages (kV)	4, 12, 17, 21	4, 12, 16, 33	4, 12	4.2-20.8	13.2, 24, 34	12, 25
Config./ Grounding	3-wire uni-ground, 4-wire multi-ground	3-wire uni-ground, 4-wire multi-ground	3-wire uni-ground, 3-wire multi-ground via line-installed ground banks, 4-wire multi-ground	3 wire delta, 3 wire uni-ground, 4 wire wye	4-wire multi-ground	4-wire multi-ground
Fast Trip	Yes	Yes	Yes	Yes	Yes	Testing & Pilot
Reclosing	Disabled	Disabled	Disabled	Disabled	Profile dependent	Disabled
Fast Trip Designation	Enhanced Powerline Safety Settings (EPSS)	Fast Curve (FC) Settings	Sensitive Relay Profile (SRP)	Sophisticated Program Control Settings (SPCS)	Fire Safety Mode (FSM)	NA
Year in Service	2021	2018	~2010	2021	2021	NA
Operating Mode(s)	1	1	4	2	3	1
Settings Applied:	Circuit Specific	Circuit Specific	Circuit Specific	Circuit Specific	Circuit Specific	Circuit Specific
Schedule	Daily (was seasonal in 2021)	Daily and Seasonal	Daily	Daily	Daily	Season
Fuse Over-reach (upstream 3-ph ganged trip)	Yes	Primarily No (potential use in limited cases)	Yes	Unsure	Yes	None
Activation Methods	Mostly Remote	Mostly Remote	Mostly Remote	Mostly Manual	Mostly Remote	Manual
Activation Trigger	Weather Conditions, circuit and fire risk designation	Weather and Fuel Conditions	Extreme Fire Potential Index (FPI) or PSPS Forecasted	Weather Conditions	Fire Risk Potential Score (Risk =Prob. x Impact)	Weather Conditions

	PG&E	Utility 2	Utility 3	Utility 4	Utility 5	Utility 6
Settings Description	- Set phase and ground instantaneous pickups to see EOL for fused taps within the device protective zone (DPZ). - Set definite time with delay not to exceed 100 milliseconds and use 20 ms margin for coordinating between devices.	- Used multiples of normal minimum trip to set fast curve settings with a time delay of typically 33 ms. These settings typically help coordinate with other line protection devices, including fuses, while balancing ignition risk. - Utility 2 currently is deploying its updated settings that use a lower minimum trip multiple with a time delay of 66 ms and piloting faster-acting settings using same minimum trip multiple but a reduced time delay of 66 ms on select circuits to assess additional ignition risk reduction. - All reclosing is blocked while fast curve settings are enabled.	- Phase elements are set to trip at a minimum of 50% above peak historical load. - Ground elements are based on peak historical trends and set utilizing a specific table contained within the settings methodology. - Set definite time with 8 ms delay. - Multiple devices set with SRP may operate for downstream faults due to sensitivity and reduced protection margins.	The settings profiles include (but are not limited to): - Normal (fuse saving application): Instantaneous trip followed by reclosing attempts with time-overcurrent trips. - Elevated risk, no line reclosers, fuses on the line: Substation breaker will have an instantaneous trip followed by single reclose attempt after sufficient time to limit the persistence of fire. - Elevated risk, line reclosers: Substation breaker will have instantaneous trip with no reclose attempt. - Extreme risk, no line reclosers, fuses on line: Substation breaker will have instantaneous trip with no reclose attempt. - Safety hold: for line worker usage during line operations where no reclosing occurs.	The settings profiles include: - Underreach 50: Stops short of downstream FSM recloser. No Delay. - Overreach 50: Reaches to end of fused taps of rly zone. Breaker Coordinated Delay - 51: fuse coordinated - Per/phase Inrush Blk Base Fire Safety Mode: - Trip on 50 element, single reclose, trip on 51 (50s disabled) – Reduces fire risk by fast trip of temp faults. Perm faults fuse coordinate (Base FSM used for lower fire risk) Elevated Fire Safety Mode: - Trip on 50, reclose, trip on 50 Extreme FSM: - Trip on 50 with no reclosing	- Fast Trip tested in one area using Siemens Fuse Savers (FS). - Similar to Hot Line tag settings, used for worker safety: 50 ms Phase, 500 ms Ground (less false trips, better coord.). Also Implemented single shot lockout

Table 1: Utility Comparison: Other Technologies Being Evaluated or In Service

	PG&E	Utility 2	Utility 3	Utility 4	Utility 5	Utility 6
Sensitive Ground Fault (SGF) Detection Schemes	In service, thresholds set to start at 10 Amp, 10 sec . Evaluating lower base thresholds.	Generally, none; however, Utility 2 has several dozen stations in service with impedance grounding to limit ground faults to less than 150 amps (low ground) or 50 amps (sensitive ground) where sensitive ground relay settings are applied	In service year-round. Set by evaluating peak neutral imbalance current on specific line section to set the SGF setting. SGF settings reviewed once per year for each device or when device operates in the field.	None	None	None
High Impedance Fault (HIF) or Down Conductor Detection (DCD) Schemes	Deployed starting 2022	Pilot, in monitor/alarm mode only. Under specific circumstances, they apply these setting modes on line reclosers as part of their normal settings	In service since 2011	Pilot, enabled in monitoring mode only	Plan to deploy to reclosers on trouble ckts meeting min load required by HIF algorithm	None
Falling Conductor & Open Phase Detection	AMI Voltage Detection	AMI Voltage Detection, piloting Open Phase Detection	AMI Voltage Detection, Pilot on several feeders with falling wires scheme (voltage synchrophasor based system)	None	None	None

Utility Specific Method Summaries

PG&E

The base EPSS plan for PG&E was developed to focus on addressing three main issues for ignition prevention. First, reduction of arc through fast tripping. Second, detection of high impedance faults. Third, prevention of back feed fault scenarios through gang operation.

To achieve fast tripping to reduce arc duration of a fault, initially PG&E was utilizing the Hot Line Tag (HLT) feature of devices. HLT could be enabled remotely by operators via SCADA and offered a zero-delay instantaneous operation for devices. For devices in series this would result in multiple devices locking out as they all would trip for the same event. Shortly thereafter guidelines were developed for EPSS settings that utilized the 50 elements of the devices with delays set to provide a chance for coordination. The maximum allowed delay being 100 milliseconds for any device and the minimum delay separation between devices is 20 ms. A delay of 20 ms is not practical for most devices to allow for coordination but when there are multiple devices operating on the same event, analysis can be assessed to provide focused areas to patrol and focus restoration efforts. Where there are minimal devices in series, the delays can be optimized for practical operating speeds of the equipment.

Detection of high impedance faults was implemented through year-round sensitive set ground fault detection for all devices where applicable. There are a larger number of EPSS circuits that are uni-grounded and allow for the application of a sensitive ground detection setting. In late 2022, PG&E began to deploy a Down Conductor Detection (DCD) feature on certain capable recloser devices when EPSS settings are enabled.

Prevention of electric back feed into a downed conductor or fault situation is achieved through gang operation of the nearest three phase gang operated device. Specifically, recloser devices are set to overreach and see end of line faults beyond single phase devices such as fuses and operate before, when possible, or at the same time. PG&E is also implementing operator in the loop SCADA de-energizations when AMI partial voltage indications occur during EPSS activations.

Utility 2

In 2018, Utility 2 initiated a program to deploy fast curve settings at substation circuit breaker relays and automatic reclosers and developed a plan for upgrading non-compatible and older vintage electromechanical and microprocessor relays for feeder circuits in high fire risk areas between 2020-2024.

Utility 2 expects to complete upgrades to over 90% of all circuit breaker relays in high fire risk areas by 2022, with the remaining circuits upgraded by 2024.

Utility 2's initial fast curve settings use multiples of normal minimum trip with a time delay of typically 33 ms. Normal minimum trip for each device is set to 150% of peak load. These settings typically help coordinate with other line protection devices, including fuses.

In 2022, Utility 2 conducted an engineering assessment on fast curve settings to further reduce ignition risk while maintaining similar reliability impacts as the initial settings. Utility 2's updated settings extend fast curve protection along the entire length of a circuit while maintaining coordination among the protective devices to minimize customers impacted. The updated fast curve settings, which is now the new standard for any new circuits receiving fast curve capabilities in high fire risk areas, use a lower minimum trip multiple with a time delay of 66 ms.

Based on benchmarking with other IOUs, Utility 2 determined it would be beneficial to test faster operating settings to determine ignition risk benefits while also assessing reliability impacts and how it complements other mitigations. On 16 select circuits in our highest fire risk areas, Utility 2 is piloting settings that provide even faster responsiveness to assess additional ignition risk reduction. The pilot settings use the same updated settings with a time delay of 33 ms and will be evaluated over the next year.

Utility 3

When extreme fire weather conditions or PSPS events are forecasted, Utility 3 remotely enables Sensitive Relay Profile (SRP) on its system; SRP includes settings which make protective devices such as reclosers and circuit breakers more sensitive to faults on the overhead distribution system and activate quickly to interrupt power. Utility 3 pre-identifies and maintains a list of these devices and can quickly communicate with its distribution operations control center to enable SRP when conditions warrant and in observance of wildfire safety efforts.

SRP settings include standard settings for all HFTD circuits:

- The phase minimum to trip set is at 50% above peak load on the circuit spanning a 5-year history.
- The ground minimum to trip is based on peak historical trends and set using a specific table contained within the settings methodology.
- Definite time set with 50 ms delay.

The advantage of these settings is that there is a definite tripping time for all fault currents above minimum to trip. The disadvantage is that devices potentially do not coordinate, so downstream faults may lock out multiple devices. If multiple devices trip during an event when sensitive settings are enabled, Utility 3 retains protection engineers and field resources available 24/7 to review event records to help determine if mis-coordination contributed to the event. These standby resources review each event in real-time and provide detailed information back to our operations teams and the EOC for situational awareness.

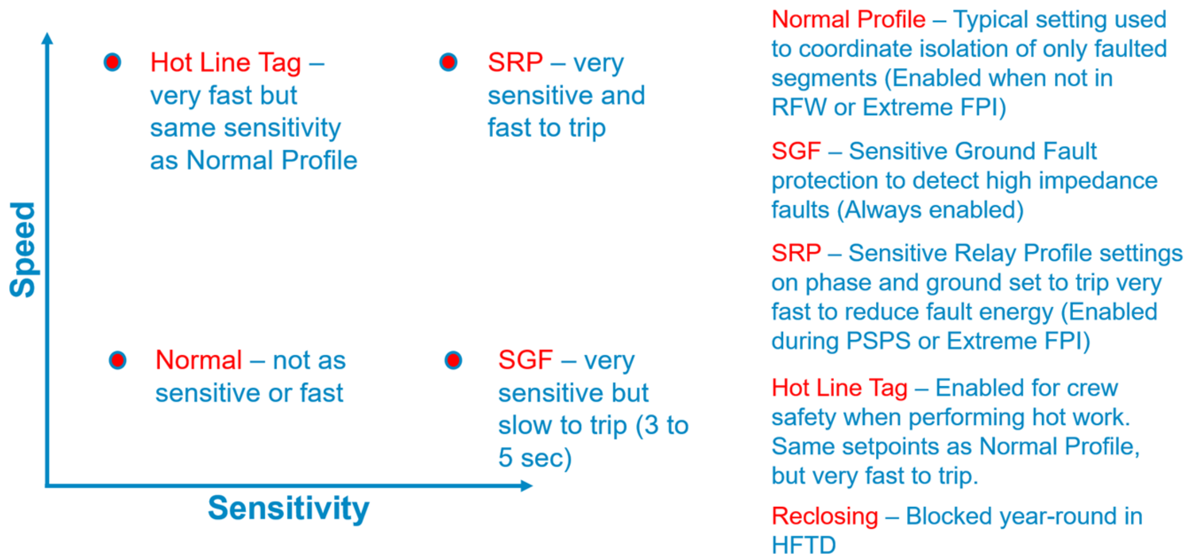

Fig. 2: Utility 3's Sensitive Settings Comparison

Utility 4

Utility 4 conducted a pilot of Sophisticated Program Control Settings (SPCS) in 2021. This pilot evaluated the optimal approaches in using sensitive and sophisticated device settings to reduce wildfire risk and improve reliability. Devices, including relays, reclosers, and fuses, all have methods by which they are programmed to operate in response to a fault condition. If there is limited coordination between devices, it can increase the probability of equipment damage or delayed device operations, creating and extending an ignition risk. After experimenting and making minor modifications, Utility 4 has adopted these settings as standard.

The settings profiles include (but are not limited to):

- Normal (fuse saving application): Instantaneous trip followed by reclosing attempts with time-overcurrent trips.
- Elevated risk, no line reclosers, fuses on the line: Substation breaker will have an instantaneous trip followed by single reclose attempt after sufficient time to limit the persistence of fire.
- Elevated risk, line reclosers: Substation breaker will have instantaneous trip with no reclose attempt.
- Extreme risk, no line reclosers, fuses on line: Substation breaker will have instantaneous trip with no reclose attempt.
- Safety hold: for line worker usage during line operations where no reclosing occurs.

These settings use definite time delays (200 ms for substation breakers, 100 ms between reclosers) to improve coordination. The settings also implement fuse overreach and harmonic blocking schemes. They are not currently enabling any sensitive ground fault detection.

Utility 5

Utility 5 experiences a fire season beginning around mid-July and lasting until late September or early October. During this season, Utility 5 has historically disabled instantaneous overcurrent (50) tripping and reclosing on its distribution protection system, seeking to reduce spark ignition potential while maintaining coordination via time-overcurrent (51) elements.

As part of its ongoing effort to strengthen its wildfire resiliency program, Utility 5 devised a new approach to its distribution operations during the fire season that seeks to calculate circuit-specific fire risks and allow operators to alter relay operating behaviors in response to the fire risk dynamically. The feeder relays and reclosers are programmed with three different "Fire Safety Modes". Each mode further reduces electrical fault energy by reprioritizing instantaneous overcurrent (50) elements over time-overcurrent (51) elements. In addition, reclosing is reduced or disabled.

The settings profiles include:

- Underreaching 50 elements – Reach stops short of downstream Fire Safety Mode (FSM) Recloser and trips without any delay (50Q have 25 ms delay).
- Overreaching 50 elements – Reaches to end of fused laterals in relays protection zone (and overreaches downstream FSM Recloser, so has a breaker-coordinated definite-time delay of 100 ms.
- 51 elements – Set for fuse coordination.
- Per/phase 2nd Harmonic Inrush Blocking – Per/phase inrush blocking allows for fast tripping on faulted phase when reclosing into a fault (for Extreme FSM, see below).
- Base FSM: Fast Trip on instantaneous overcurrent followed by a single reclose attempt and switching to time-overcurrent elements. This behavior will quickly clear temporary faults, reducing fire risk, but maintain service reliability by coordinating with fuses for permanent faults. Base FSM is used when there is lower fire risk on a circuit.
- Elevated FSM: Fast Trip on instantaneous overcurrent followed by a single reclose attempt after and trip again on instantaneous overcurrent elements. Elevated FSM is used when there is an increased fire risk on a circuit.
- Extreme FSM: Fast Trip on instantaneous overcurrent with no reclosing. Extreme FSM is used for the highest fire risk on a circuit.

Utility 5 calculates a fire risk potential considering various weather, environmental, and operational data for the different distribution circuits. Based on real-time fire risk calculations.

The protective devices on a specific circuit can be moved into the appropriate "Fire Safe Mode", allowing for a dynamic scheme that attempts to balance fire resiliency with service reliability.

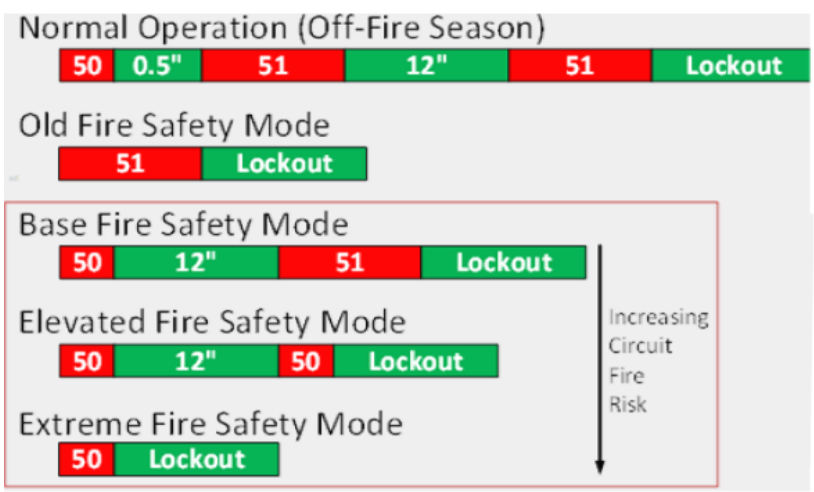

Figure 3: Utility 5's Fast Trip Approach (“ indicates seconds)

Fire Risk Potential

- Risk = Probability · Impact
- Probability Factors
  - Wind Gusts
  - Sustained Winds
  - Wind Direction
  - Relative Humidity
  - Fuel Type
  - USDM Drought Index
  - Fire Preparedness Levels
  - Feeder OMS Data
  - Feeder Health
- Impact Factors
  - Public Safety
  - Societal Costs
  - WUI Map
    - Infrastructure
    - Development
    - Fuel Type
    - Ignition Probability
    - Fire-Spread Risk
    - WUI Tier 0-3
- Fire Risk Score for each distribution circuit
  - 8-Day Forecast

Figure 4: Utility 5's Fire Risk Potential Methodology

Utility 6

Utility 6 performed lab testing and conducted a field pilot of distribution circuit fast trip settings. Their implementation used Siemens Fuse Saver (FS) devices. FS devices are capable of very fast tripping (10 ms). However, these devices have limited load current ratings and fault duty capability (100A and 4kA, respectively), restricting their use to taps and lateral sections of circuits. The FS are programmed with coordinated tripping, fast tripping mode, and single-shot reclosing lockout settings. Utility 6 envisions using circuit specific settings that provide some level of coordination between devices. The Fast Trip settings were tested at Powertech before the field pilot. They do not implement any sensitive ground fault settings or high-impedance (HIF) fault detection schemes.

The fast trip settings are similar to hot line tag settings used for worker safety: 50ms Phase-overcurrent and 500 ms Ground-overcurrent. The settings are tailored to minimize false trips and provide better coordination.

PG&E Results

In 2022 there was an 88% reduction in the acres impacted by ignitions with EPSS being put in place as compared to the 3-year 2018-2020 average. The 3-year average for 2018-2020 were 110 ignitions per year with a total average of 1,736 acres impacted per year*. In 2022 there were 70 ignitions with 210 acres impacted. Similar in 2022, there was as 68% reductions in CPUC reportable ignitions** in the High Fire-Threat Districts compared to the 2018-2020 average. In late 2021 we started to implement EPSS settings on the highest risk circuits so the results for that year are were not included for the comparison. Prior to the start of the typical fire season of 2022, we had essentially deployed EPSS coverage to all distribution devices that could have EPSS settings.

Where EPSS protection does have positive correlation to ignition prevention, it does have an impact to overall outages and customer reliability. There was a 95% increase in SAIDI in 2022 compared to the 2018-2020 average SAIDI, and a 16% increase in CAIDI on circuits designated as having EPSS devices. This calculation was made however comparing EPSS designated circuits for the entire year, not only when EPSS was active. The non-EPSS circuit SAIDI numbers indicated a 58% increase in SAIDI and 28% increase in CAIDI. The primary outage cause drivers for EPSS circuits were unknown causes (no cause was identified during the restoration process) and equipment failures, where only equipment failures were identified as the primary driver for non-EPSS circuits. The impact of the unknown cause reliability impact may primarily stem from causes that may have been momentary in nature locking out a device since reclosing is disabled during EPSS activation. As noted in the decrease in reliability performance on the non-EPSS circuits, there are other factors in the system contributing apart from just wildfire settings.

* The average is excluding a single catastrophic ignition event (Zogg Fire) which impacted 56,338 acres at a location EPSS was not yet active.
** CPUC-reportable ignitions in High Fire-Threat Districts on distribution powerlines (compared to the weather-normalized 2018-2020 average).

Associated Customer support

PG&E understands how disruptive it is for customers to lose power. That is why they are taking specific proactive steps have been implemented to support customers and communities and reduce the impact of outages. These efforts include providing: portable batteries, generator and battery rebates, devices for easy and safe connection to a generator, and improved notifications and updates about when power will be back on and outage causes. Part of the EPSS program includes extensive focus and commitment on improving the customer reliability experience while mitigating ignition risk.