Protective Relay Upgrade Resolves Planning Criteria Violations

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***Abstract*— In the course of performing transmission system screening assessments, LCRA Transmission Services Corporation (LCRA TSC) identified planning criteria violations for a portion of its system in the form of thermal overloads and low voltage conditions following certain contingencies. Transmission Planning, Transmission Protection, and Engineering staff identified multiple alternatives to resolve the criteria violations, including an autotransformer upgrade, a substation addition, and the reconfiguration of an existing 69-kV network in a three-terminal configuration. Following an evaluation of alternatives, including cost, benefit, time to implement, risk, and future system needs, the reconfiguration of the 69-kV network was selected as the recommended solution. Implementing this solution required the installation of three-terminal differential protective relaying, as well as telecommunications and circuit breaker upgrades, but avoided costlier and more impactful alternatives. This paper will review the system screening and alternative analysis process and demonstrate how protective relay upgrades can be a low-cost and timely solution to address planning criteria violations, provide operational flexibility, and improve system reliability.**

Keywords—transmission planning, three-terminal line, protective relay upgrade

I. Background

LCRA created LCRA TSC as a nonprofit corporation for transmission operations after a 1999 state law changed how electric utilities manage and operate electric transmission facilities. The law required utilities to separate electric generation and transmission operations as part of preparations for a deregulated retail electric market. The law also allowed LCRA to expand its transmission facilities and operations beyond its traditional Central Texas service area.

On Jan. 1, 2002, LCRA transferred ownership of its transmission facilities to LCRA TSC to satisfy the state's requirements. Since its creation, LCRA TSC has invested more than $3.9 billion in transmission projects to meet the growing demand for electricity, improve reliability, connect new generating capacity, address congestion problems that affect the competitive market and help move renewable energy to the market.

Presently, LCRA TSC owns or operates about 430 substations and 5,500 miles of transmission lines within the ERCOT region. LCRA TSC also interconnects about 15,000 MW of generation. LCRA TSC is registered with NERC[1] as a Transmission Owner (TO), Transmission Operator (TOP) and Transmission Planner (TP).

As a NERC-registered Transmission Planner, LCRA TSC performs annual transmission planning assessments to assess system needs and fulfill its obligations related to NERC Transmission Planning ("TPL") reliability standards.

II. System Overview

The Sandstone Mountain area is located northwest of the Austin metro region. The area is served by multiple Distribution Service Providers (DSPs), including Central Texas Electric Cooperative (CTEC) and the City of Llano. LCRA TSC is the Transmission Service Provider (TSP) for the area, with a network of 69-kV and 138-kV facilities located in Llano County. This area is typically a winter-peaking part of the system, i.e., winter season loads exceed those occurring during the summer season. Figure 1 illustrates Llano County and the 69-kV (green) and 138-kV (blue) transmission networks serving the area.

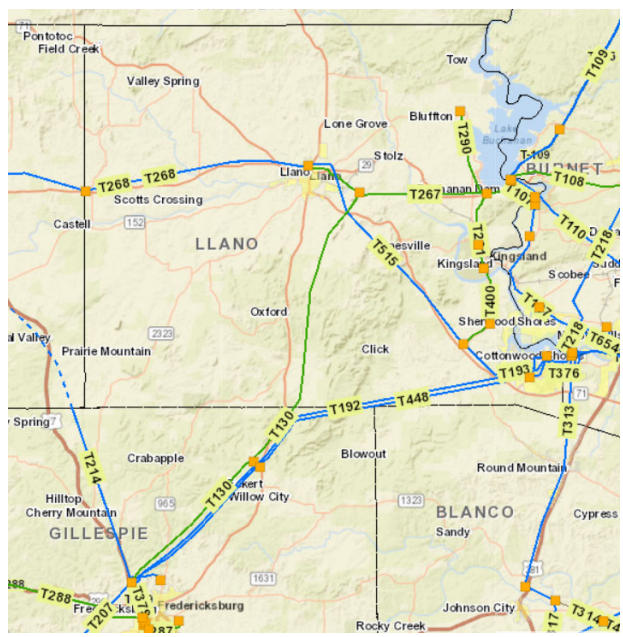

Fig. 1. Communities and Transmission Facilities in the Sandstone Mountain Area

Of interest in this region is the 69-kV network comprised of end points at Gillespie, Pitsburg, and CTEC Buchanan substations. This 69-kV network is identified as "T130" and "T267" above and terminates in a common central point at Sandstone Mountain Substation, which is a small, non-

[1] NERC ID # NCR04091

breakered switching station with no remote telemetry or SCADA control. Historically, the 69-kV switches at Sandstone Mountain have been configured to connect two of the three end points, depending on system needs, but not all three at the same time. These 69-kV switches can only be manually modified and require a site visit and relay setting changes to implement a configuration change. Figure 2 provides a schematic view of this area, with 69-kV facilities in red and 138-kV facilities in blue. Per LCRA TSC standard practice, 138-kV transmission lines utilize one or more protective relay pilot schemes while 69-kV transmission lines do not utilize a pilot scheme.

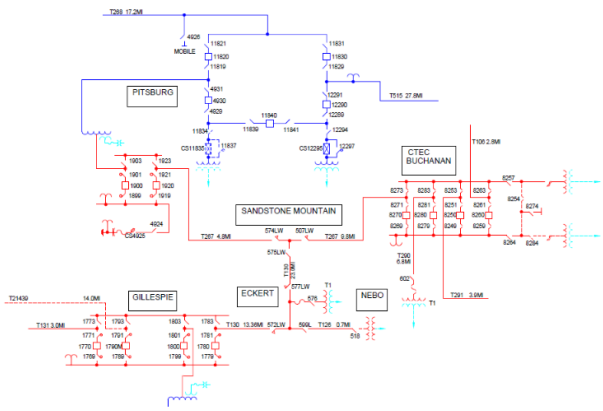

Fig. 2. Sandstone Mountain Area System One-line

III. Transmission Planning Assessments

In early 2020, LCRA TSC finalized a planning assessment for this area based on the performance requirements contained within the LCRA TSC transmission planning criteria, ERCOT Planning Guide and NERC TPL-001-4 Reliability Standard. To this end, the June 2019 release of the ERCOT Steady State Working Group (SSWG) 2025 summer peak and 2020/2021 winter planning cases were used to perform the steady-state assessment. Within the scope of this assessment, the steady-state power flow/contingency analysis was conducted using NERC P0, P1, P2.1, P3.3, P7.1, ERCOT 1 and ERCOT 2 contingency events. Identifying potential voltage and/or thermal violations are of key importance during this assessment.

Regarding the system topology, the configuration of the Sandstone Mountain 69-kV switches has been adjusted at various times per recommendations from System Operations Control Center (SOCC) Engineering depending on system conditions. At the time of this study, the power flow was typically from Pitsburg to Gillespie, and switch 507LW towards CTEC Buchanan was modeled "normally open". This configuration was needed to prevent post-contingency thermal overloading in the Fredericksburg/Gillespie area under high load conditions. The steady state assessments were conducted with the 507LW switch modeled as normally open.

IV. Findings

Under high system loads along with output from a nearby thermal generator, the normally open configuration at Sandstone Mountain leads to a thermal violation on the nearby Sandy Creek 138/69-kV autotransformer under N-1 (P1) contingency. With this configuration in place, the loss of transmission circuit T106 from Buchanan to CTEC Buchanan (an N-1 contingency) results in approximately 45 MW of load (in the 2020/2021 WIN[2] case) being radially served through T291, T400 and the Sandy Creek autotransformer. This radial load results in a thermal overload (> 100% of Rate B) of the Sandy Creek autotransformer.

Table 1 shows the loading on Sandy Creek autotransformer for the loss of T106 from Buchanan to CTEC Buchanan, with criteria violations in red:

Table 1: Most Severe Percent Loading Under N-1

Overloaded Element	Case	Rate B (MVA)	Post-Contingency Loading (%)
Sandy Creek Auto	**2020/2021 WIN1**	**44**	**107.0**
Sandy Creek Auto	**2021 SUM1**	**44**	**97.5**
Sandy Creek Auto	**2025 SUM1**	**44**	**104.6**

The Sandy Creek autotransformer was also identified as having a thermal violation in the 2019 ERCOT Regional Transmission Plan (RTP) studies. The results from the ERCOT reliability analysis are shown in the Table 2 below, with criteria violations in red:

Table: 2 2021 SUM Percent Loading by Case Types

Branch Name	Branch_id	Rate B (MVA)	Post-Contingency Loading (%)
Sandy Creek Auto	7121_7127	44	105.5

In addition to assessment results described above, the steady-state and stability assessment also indicated low post-contingency voltages and voltage recovery violations at Pitsburg. A P2.3 contingency (Breaker Fault - CB 11830) leaves Pitsburg load to be fed radially from the Eckert-Sandstone Mountain-Pitsburg 69-kV path causing unacceptable low voltages.

Table 3 shows the post-contingency voltages at Pitsburg for a breaker-failure contingency, with criteria violations in red:

Table 3: Post-Contingency Voltage in 2021 SUM Case

Monitored Bus	Contingency Type	Contingency Description	Post-contingency Voltage (p.u.)
7119 L_PITSBU9_1Y 69.000	P2.3	BF 11830	0.91
7120 L_PITSBU8_1Y 138.00	P2.3	BF 11830	0.80

[2] The 2020/2021 WIN case projects the system condition for the months of December 2020, January 2021 & February 2021.

These identified branch element overloads and low voltage conditions are criteria violations that require the development of one or more Corrective Action Plans.

V. Alternatives

In order to address the identified criteria violations, an alternative evaluation process was conducted. The alternative analysis process reviews possible Corrective Action Plans through various lenses, including cost, time to implement, regulatory compliance, long-term system benefit, reliability effectiveness, and coordination with future plans, projects, and system needs.

Transmission Planning initially considered closing switch 507LW towards CTEC Buchanan and opening 575LW towards Eckert to relieve the loading on the Sandy Creek autotransformer, but this results in severe post-contingency thermal overloads in the Gillespie/Fredericksburg area under high load conditions. In addition, changing switch configurations at Sandstone Mountain requires that the relay settings for T267 be temporarily modified at Pitsburg. Frequent relay setting modifications creates the risk that incorrect settings could be applied which could lead to a relay misoperation resulting in unintentional loss of load and/or equipment damage.

Manually operating switches in the field requires personnel to travel extended distances and operate high-voltage equipment inside an energized substation. Removing the need to manually operate the switches at Sandstone Mountain in response to changing system conditions will benefit the safety of field personnel.

Based in part on the above factors, two key alternatives above and beyond working with the existing configuration were evaluated: installing a new breakered substation at Sandstone Mountain or converting this 69-kV network into a three-terminal transmission line. A comparison of these alternatives, along with a "do nothing" option is included in the table below.

Table 3: Alternative Analysis

Aspect Under Consideration	Alternative 1: Do nothing	Alternative 2: Install a new breakered substation at Sandstone Mountain	Alternative 3: Install three-terminal protective relaying and circuit breaker upgrades[3]
Addresses identified deficiencies	No	Yes	Yes
Long-term system benefit	No	Yes	Yes
Reliability effectiveness	No	Yes	Yes
Coordination with future plans	N/A	Yes	Yes
Estimated time to implement	N/A	18-24 months	6-12 months
Project cost estimate	N/A	$11.2M	$1.3M

As shown above, both alternatives 2 and 3 address the underlying issue, but the three-terminal protective relaying upgrade is quicker to implement and estimated to be less costly.

Another alternative solution evaluated for this project involved upgrading the Sandy Creek 138/69-kV autotransformer. While this solution addressed the thermal overloads, it was not fully developed as an alternative at the time because it would take longer to implement and also require additional transmission line upgrades along the same path.

VI. Protective Relay Upgrade

Based on the alternative analysis, the project team opted to implement a three-terminal line configuration that would allow closing in all three 69-kV line switches at Sandstone Mountain. Prior to implementing a three-terminal configuration, it was critical to evaluate the existing protective relaying at all three terminals and determine the need for any protective relaying upgrades.

The existing protective relaying for Gillespie and CTEC Buchanan were electro-mechanical relays providing phase distance, directional ground instantaneous over-current, and directional ground time over-current protection. The existing relay package for Pitsburg was a single microprocessor relay with no pilot channel.

An important consideration for a three-terminal configuration is the infeed effect. The infeed effect caused by the three-terminal configuration would require increasing the phase distance element reaches at each terminal to values that would limit the full line rating and prevent the scheme from being secure at high loads. Avoiding this loadability concern would require relay panel upgrades to the existing electro-mechanical relay panels for CTEC Buchanan and Gillespie to microprocessor relays so that load encroachment elements can be enabled to prevent the relays from potentially tripping on high load conditions.

In addition to this identified limitation, there are drawbacks to relying on impedance-based distance protection for the primary protection of a three-terminal line. The infeed effect is a function of short circuit contributions and as the fault duty changes over time there can be an impact on the apparent impedance seen by the relays which could require adjustments of the distance elements to provide adequate protection.

Taking all of this into account, it was decided to implement a line current differential (LCD) pilot scheme and to no longer rely on the distance protection as the primary means of protection. This scheme provides reliable, fast, and secure protection even in a three-terminal configuration. Implementing a line current differential scheme would also require replacement of the Pitsburg CB 1920 T267 single microprocessor relay panel with a line current differential capable relay panel. For redundancy, robustness, and future compatibility, a dual line current differential relay panel (87A and 87B configuration) was recommended for use at Gillespie, Pitsburg, and CTEC Buchanan.

[3] In addition to the protective relay and telecommunication upgrades at each terminal, this alternative includes scope to upgrade an existing, obsolete 69-kV oil circuit breaker at Gillespie Substation to a new 138-kV capable gas circuit breaker.

Implementing the line current differential protection schemes would also require facility upgrades to provide a communications path for the 87A and 87B line current differential pilot channels. Unfortunately, a direct fiber path was not available between any of the three relay terminals. In lieu of direct fiber the telecommunication design would consist of using multiplexers to route traffic over existing channel banks and copper as well as licensed microwave to carry the 87A and 87B differential relay traffic.

For both the primary and secondary relays an LCD communication channel was provided from each terminal to each of the other two terminals (e.g., Pitsburg had one relay communication channel with CTEC Buchanan, and another relay communication channel with Gillespie, etc.). It was necessary to specify a relay which would accommodate the appropriate LCD communication channels. By having a complete LCD ring between the three terminals, if a single communication path was lost, then the relay that still had a communication path with both other terminals would become the lead relay and LCD tripping would still be possible. This design helps improve the redundancy of the relay communication channel and helps to improve the availability so that the LCD scheme can be in-service to provide faster tripping for all fault conditions. Figure 3 below shows the high-level relay communication block diagram for the Sandstone Mountain three-terminal 69-kV line.

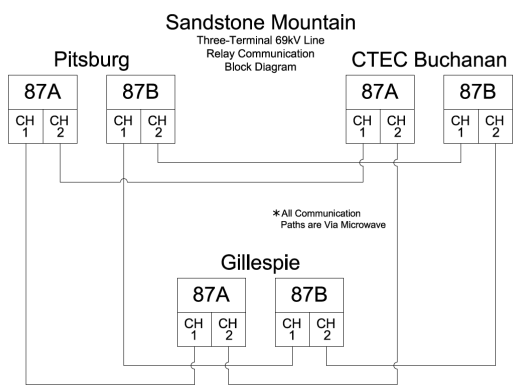

Fig. 3. Sandstone Mountain Three-Terminal Line Relay Communication Block Diagram

VII. Protection Philosophy and Relay Setting Development

To provide reliable, secure, and fast operation, the following protection schemes were utilized: line current differential pilot relaying as the primary protection and phase and ground distance, directional ground instantaneous overcurrent, and directional ground time overcurrent for backup protection. Additionally, a second settings group was also created to accommodate (and optimize the protection during) an alternative configuration of the 69-kV switches at Sandstone Mountain.

For the line current differential protection, phase and ground differential elements are implemented. The phase differential element is relied on for detection of three line-to-ground and line-line faults. The ground differential element is relied on for detection of single line-to-ground and double line-to-ground faults. A negative sequence element was considered but was not applied due to concerns of being able to set the element securely to restrain for external faults and still be sensitive enough to operate for internal faults. Also, it is LCRA TSC's standard practice to not typically set a negative sequence differential element.

The chosen philosophy for the phase differential pickup is to set this value to 150% of the maximum phase differential current seen for a low side fault on the load serving transformers at Eckert and Nebo Substations (in-line tapped substations served from the Sandstone Mountain three-terminal line). This is necessary to allow the three-terminal line's protection elements to be secure for faults on the low side of either of these transformers and allow for the transformers' own protection to isolate any low side faults. A challenge in implementing this is the desire to maintain adequate sensitivity for any internal faults considering a single transmission system contingency which will reduce the available fault current. LCRA TSC's standard margin for sensitivity is setting the pickup to two thirds of the minimum fault current.

In this particular application, the phase differential fault current seen for a line-line fault close in to the Gillespie bus with the single contingency of Gillespie circuit breaker 1780 (CB 1780) out of service (note that Gillespie Substation is the strongest source of the three terminals) is low enough that it was not possible to set the phase differential pickup below this fault with margin and also be set securely for the faults on the low side of the transformers at Eckert and Nebo. Therefore, the compromise that had to be made was setting the phase differential pickup high enough to be secure for faults on the low side of the transformers at Eckert and Nebo. This could prevent the line current differential scheme from being able to trip for the single contingency of Gillespie CB 1780 open. However, in this case, the line would still be protected, but the fault would need to be isolated on a time delay by the backup protection: the zone 2 phase distance element, which will be discussed in greater detail in a later paragraph.

To obtain fast tripping for the contingency of Gillespie CB 1780 open, it was recommended to LCRA TSC's System Operation Control Center (SOCC) to open switch 572LW at Eckert if Gillespie CB 1780 is out of service, to allow the line current differential scheme to still be able to trip for all internal faults. The chosen philosophy for the ground differential pickup is to set this value to two thirds of the minimum internal fault ground differential current considering a single contingency. Due to both the Eckert and Nebo transformers' high side connections being connected in a delta configuration, there are no concerns of the ground differential current element from tripping for low side transformer faults since the high side delta connections prevent any zero-sequence current from flowing in the line current differential's zone of protection.

An important part of any protection scheme is being reliable even during equipment failures. For example, if the communication assisted tripping scheme is out of service it is essential to include backup elements that can trip under various fault conditions. The backup elements that are employed for this three-terminal line are phase and ground distance, directional ground instantaneous over-current, and directional ground time over-current.

To provide security, the zone 1 phase and ground distance reaches must be set to not overreach the shortest terminal

without infeed. The zone 1 reaches are set to 85% of the shortest path without infeed. For clearing of faults outside of the zone 1 reaches, a zone 2 element is set. This zone 2 element must be set to see all the way to either of the two remote ends when considering infeed.

The infeed effect is a result of the three-terminal line and causes the apparent impedance seen by the local terminal to be greater than the line impedance from the local terminal to the fault. If the infeed effect is not considered, the relay terminal could underreach for faults in the three-terminal line's zone of protection. Therefore, the phase and ground distance zone 2 reaches are set to be 120% of the apparent impedance seen by the local relays for a fault at either end of the line with that ends breaker either closed or open. Due to the zone 2 reaches needing to be set "long" to accommodate the infeed effect, three additional items had to be considered to maintain security.

- First, it must be verified that the phase distance reach does not pickup for low side transformer faults at either Eckert or Nebo.
- Second, load encroachment is enabled to prevent the phase distance reaches from tripping on load conditions.
- Lastly, the zone 2 time delays were increased for all three terminals to 48 cycles. This is necessary to provide 18 cycles (0.3 seconds) coordination margin with the next forward lines' zone 2 time delays under single contingency conditions.

The figure below illustrates the application of each of these considerations as part of determining the phase distance element settings. This figure illustrates the reach of the Pitsburg terminal relay phase distance element for a 69-kV bus fault at Gillespie, even with infeed effects.

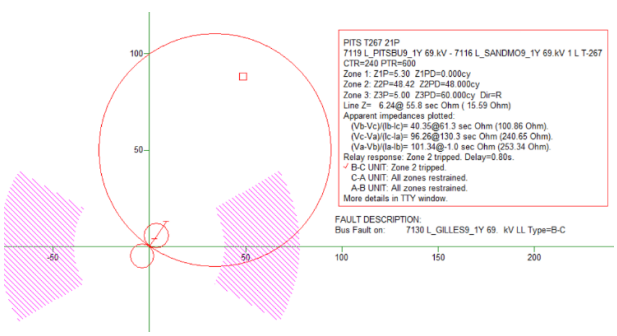

Fig. 4. Phase Distance Element Settings With Infeed Effects and Load Encroachment

Directional ground overcurrent elements are also applied. A directional ground instantaneous element is set to 125% of the maximum ground current for a fault at the end of the shortest path without infeed to prevent misoperations of this element. Also, to provide protection for high impedance faults, a sensitive ground time over-current element is set.

Another aspect of three-terminal line protection that must be considered is varying system topologies. Since there are three 69-kV switches at Sandstone Mountain, these switches can potentially be configured in four possible ways:

1. Three-terminal configuration (all three switches closed)
2. Gillespie tied to Pitsburg (switches 574LW and 575LW closed; 507LW open)
3. Pitsburg tied to CTEC Buchanan (switches 574LW, 507LW closed; 575LW open)
4. Gillespie tied to CTEC Buchanan (switches 575LW, 507LW closed; 574LW open)

An advantage of microprocessor relays is the ability to apply multiple group settings within a single relay. By having multiple group settings set within the same relay this drastically decreases the amount of time needed to be able to accommodate a different system configuration, since the required protection studies can be completed ahead of time and accounted for in one of the additional group settings. An additional benefit of using multiple setting groups is the simplification of steps that are required when field crews are changing the settings, which can help prevent possible "traps" and human error when uploading relay settings.

Due to the extensive protection coordination studies required for all four configurations and the uncertainty of how often certain configurations of the Sandstone Mountain switches would be used, it was decided two group settings would be set in both the primary and secondary relay: Group 1 and Group 2. Group 1 is set for the "normal" configuration: all three switches closed at Sandstone Mountain; the three-terminal configuration. Group 2 is optimized for the most common two terminal configuration.

To determine the most common two terminal configuration, the Transmission Protection team reached out to the SOCC Engineering team and determined that the most likely alternative configuration of the Sandstone Mountain switches is Gillespie tied to Pitsburg (Sandstone Mountain switches 574LW and 575LW closed; 507LW open). In the Group 2 settings, LCD relay communications are enabled for Gillespie and Pitsburg and disabled for CTEC Buchanan.

In addition to changing the active settings group, there are a few manual setting changes required when changing groups between Group 1 and Group 2, and vice versa. A procedure was created to document the multiple group settings being utilized for these relays along with specifying which changes must be made when switching between groups. For any reconfiguration of the 69-kV switches at Sandstone Mountain, the LCRA TSC System Operations Control Center is required to send a notification to the Transmission Protection team for review to determine if any temporary relay settings are necessary for the proposed configuration (including the specification of changing the active settings group).

VIII. Field Implementation & Testing

After relay settings were developed for both Group 1 and Group 2, the new relay panels were installed, and the relay communication channels were placed in service between all three terminals, a test plan was developed for confirming the functionality of the complete protective relaying system (consisting of the relay communication channels, relay wiring, and relay settings).

For the three-terminal configuration (Group 1 settings), GPS time synchronized end-end relay testing involving the use of GPS-synchronized fault simulators was performed at all three terminals by the System Control team. A set of technicians were present at each of the three terminals and

simultaneously injected voltages and currents into the relays using fault simulations that were provided by the Transmission Protection team. The fault simulation files were applied to both the primary and secondary relays. An element that made this testing even more challenging was that one of the terminals had to remain in-service to serve the tapped load at Eckert and Nebo. So, the relay technicians had to be extremely careful to isolate the protective relay that was being tested to prevent causing a power outage. They also had to ensure that the other protective relay was in-service to provide protection of the terminal if a fault did occur on the protected transmission line.

The three-terminal configuration fault simulation files consisted of 26 total faults and were synchronously applied one at a time to each set of three relays.

- There were 12 internal faults ran to confirm instantaneous operation of the protective relaying systems for these conditions. Three sets of 3LG, 2LG, 1LG, and LL faults were applied at 10% of each of the three terminals. The faults were within one of the terminal's zone 1 instantaneous reach and the other two terminals would trip via line current differential element.
- In addition, 14 external faults were run to verify that all ends' relays restrain from tripping for these conditions. A set of 3LG, 2LG, 1LG, and LL faults were applied behind each of the three terminals. Also, 3LG and LL faults on the low side of the Nebo power transformer were applied.

Relay technicians confirmed that all 26 faults for both the primary and secondary relays operated correctly; the appropriate elements tripped for internal faults and restrained from tripping for external faults.

One additional GPS time synchronized test was performed for the three-terminal setup to confirm that the 87 Direct Transfer Trip (87 DTT) elements would trip when one of the communication paths was down. This test was executed for both the primary and secondary relays. The test was performed with the fiber cables pulled from the back of the Pitsburg relay for the communication path to CTEC Buchanan. A close-in fault 10% from Gillespie was then ran simultaneously at all three terminals. For this test, Gillespie acts as the lead relay (since both communication paths to the Gillespie relays would still be intact); the Pitsburg and CTEC Buchanan terminals trip via the 87 DTT elements received from Gillespie (the lead relay in this example) and still provide fast tripping for this scenario of a single communication path out of service. The relay technicians confirmed that both the primary and secondary relays tripped appropriately via the 87 DTT elements for this test.

In addition to the three-terminal tests it was also necessary to test the Group 2 settings to confirm appropriate operation of the line current differential scheme for the two-terminal configuration: Gillespie tied to Pitsburg with switch 507LW open at Sandstone Mountain. All relays would need to be placed into Group 2 as the active settings group prior to testing. GPS time synchronized end-end relay testing was performed between Gillespie and Pitsburg. At Gillespie and Pitsburg, the relay technicians simultaneously inject voltages and currents into the relays utilizing test sets using fault simulations that were provided by the Transmission Protection team. The relay technicians positioned at CTEC Buchanan were there to verify that the CTEC Buchanan relays did not trip for any of the faults that were applied. The fault simulation files were executed for both the primary and secondary relays.

The two-terminal configuration fault simulation files consisted of 22 total faults and were synchronously applied one at a time to each set of three relays.

- There were 12 internal faults ran to confirm instantaneous operation of the protective relaying systems for these conditions. Three sets of 3LG, 2LG, 1LG, and LL faults were applied at 10%, 50% and 90% of the line. The relay technicians verified that the relays at Gillespie and Pitsburg tripped on the line current differential elements and the relays at CTEC Buchanan restrained from tripping.
- In addition, 10 external faults were run to verify that all ends' relays restrain from tripping for these conditions. A set of 3LG, 2LG, 1LG, and LL faults were applied behind the Gillespie and Pitsburg terminals. Also, 3LG and LL faults on the low side of the Nebo power transformer were applied.

Relay technicians confirmed that all 22 faults for both the primary and secondary relays operated correctly; the appropriate elements tripped for internal faults and restrained from tripping for external faults.

The relay panel upgrades at Gillespie, Pitsburg, and CTEC Buchanan along with the Gillespie CB 1780 circuit breaker replacement were completed and placed into service on 10/16/2020. Due to outage constraints in the area, initially the 69-kV switches at Sandstone Mountain could not be closed to operate the line as a three-terminal line. The switches at Sandstone Mountain continued to be configured for Gillespie being connected to Pitsburg as a two-terminal line with switch 507LW open at Sandstone Mountain. Relay communication channels were not placed into service at this time and the relaying continued to be operated with upgraded protective relaying, but without pilot protection. With outages scheduled to end in the area on 9/15/21, the line was planned to be operated as a three-terminal line beginning on 9/16/21. The three-terminal and two-terminal GPS time synchronized end-end relay testing for the line current differential relay schemes was completed successfully on 9/14/21 and 9/15/21 respectively. The three-terminal configuration with dual line current differential relay communications was successfully commissioned and placed into service on 9/16/21.

IX. Results

The best way to fully verify that a protection scheme is operating as designed is to analyze its operation for real-world events, including both internal and external faults. The first opportunity for the new relay panel at Gillespie CB 1780 T130 to operate for a fault event was 2/14/21. At 05:53 while Gillespie T130 was radially serving the Eckert and Nebo load-serving substations, an A-G fault occurred on T130 due to ice. Gillespie CB 1780 tripped and reclosed automatically. As seen in the Gillespie T130 primary relay's oscillography shown in Figure 4, the relay tripped on zone 1 ground distance and directional ground instantaneous overcurrent elements for the A-G fault. Recall that the three-terminal configuration with dual line current differential relay communications was

not yet in place at the time of this event. This relay event was deemed a correct operation.

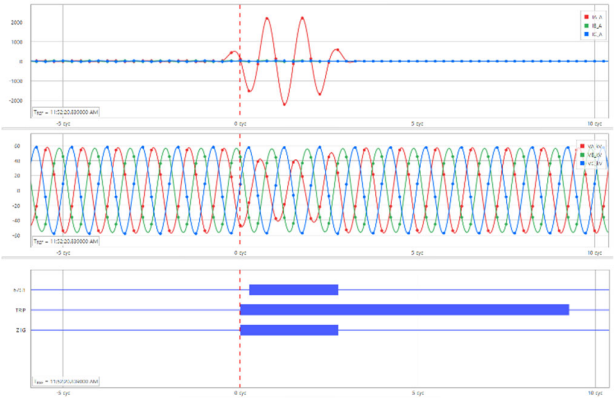

Fig. 5. Gillespie T130 Primary Relay: Internal Fault on 2/14/21

Another important real-world test for a relay protection scheme is restraining from operating for a fault outside of the relay's zone of protection, i.e., an external fault. Several external faults nearby the three-terminal line have occurred since the three-terminal configuration went into service on 9/16/21. Faults on T106 CTEC Buchanan to Buchanan Dam, T291 CTEC Buchanan to Kingsland 1, and T400 Kingsland 1 to Sandy Creek have occurred and for each of these fault events the three-terminal line protection properly restrained from tripping.

For the T291 fault which occurred on 11/16/21 at 17:40, the three-terminal line relaying restrained from tripping for an A-G fault. The CTEC Buchanan T291 relaying tripped and reclosed automatically for this fault and the Kingsland 1 T291 relaying tripped and was closed back in manually, all per design. The cause of the fault was found inside the CTEC Buchanan Substation on the line side of CTEC Buchanan T291. The primary relays for all three line terminals associated with the Sandstone Mountain three-terminal line triggered fault event oscillography. We can see from the fault event oscillography in Figures 5, 6, and 7 how the Gillespie and Pitsburg relays saw the fault as forward and restrained from tripping and the CTEC Buchanan relay saw the fault as reverse and also restrained from tripping.

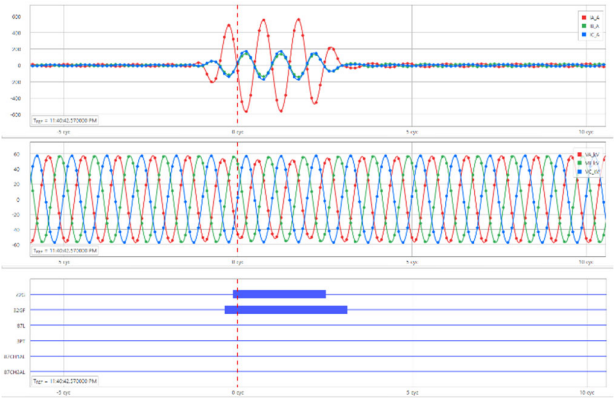

Fig. 6. Gillespie T130 Primary Relay: External Fault on T291 from 11/16/21

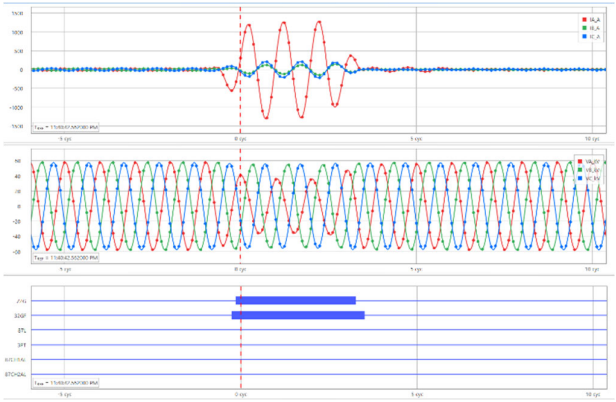

Fig. 7. Pitsburg T267 Primary Relay: External Fault on T291 from 11/16/21

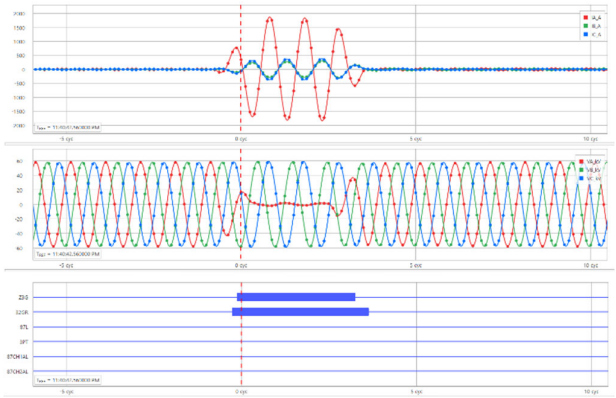

Fig. 8. CTEC Buchanan T267 Primary Relay: External Fault on T291 from 11/16/21

Note at this point in time, the three-terminal configuration with dual line current differential relay communications had been in service for about two months. Since being enabled in this mode, there has not been an internal fault, as of March 2022.

In addition to validating the protective relaying system performance, following implementation of the full scope of work, a post-project estimate review was completed which revealed that the project was implemented for significantly less than the approved budget ($554,000 vs. $1,285,000).

X. Future Plans

When reviewing alternatives to address criteria violations, future plans for the impacted area are a consideration. Great care is taken to ensure recommended system improvements are compatible with anticipated needs in the future. In this instance, the protective relay upgrade provides good future value by virtue of being a relatively low cost system improvement that maintains compatibility with multiple future system improvements.

Similar to other parts of the LCRA TSC system and ERCOT grid, a potential future scenario for this 69-kV three-terminal line is a conversion to 138-kV operation. Doubling the operating voltage of a transmission circuit provides great system benefits in terms of available capacity and voltage performance, while utilizing existing transmission line right-

of-way (ROW). Should system needs dictate this type of improvement, the protective relaying upgrade investment will be suitable for 138-kV operation, and can take advantage of an OPGW addition, should that telecommunications improvement be included as part of a voltage conversion project scope.

Similarly, if a future breakered substation is necessary at Sandstone Mountain, at either 69-kV or 138-kV, this protective relaying scheme can be converted to three double terminal protective relaying schemes, with minimal re-work or additional investment.

As can be seen, this protective relay upgrade has performed well and is a good "no regrets" investment that addresses the immediate need but also pairs well with multiple potential system upgrades, should future needs require them.

XI. Summary

Protective relay upgrades are often driven by asset management goals related to obsolete equipment, or a desire to improve fault clearing capabilities or other functions "core" to protective relaying. This project and paper demonstrate that protective relay upgrades can also be used to address transmission planning criteria violations such as thermal overloads and low voltages by allowing for more advanced system topologies such as a three-terminal line.

In this instance, the protective relay upgrade was the least expensive and quickest to implement alternative, when compared to other options such as a transmission line capacity upgrade, autotransformer capacity upgrade, or substation addition. The protective relay upgrade defers greater cost options while improving operational flexibility. The selected alternative also maintains "optionality" by being compatible with multiple future potential improvements.

The project implementation itself was a success and became LCRA TSC's first operational three-terminal transmission line. Implementation challenges such as the presence of multiple tapped loads internal to the zone of protection, three-terminal infeed effects, and the potential for multiple operating configurations were overcome by a novel approach to the relay scheme design. Field commissioning and three-terminal fault simulations were used to validate the relay scheme philosophy, field wiring, and relay pilot channels. A number of system faults have occurred since the protective relay upgrade which further confirm the relay scheme functionality via successful real-world results.

XII. Acknowledgments

The authors would like to thank the following people who contributed to the successful implementation of this project and/or the development of this paper:

- Transmission Planning
  - Naved Khan and Dylan Preas
- Transmission Protection
  - Kyle Williams, Travis Havins, Jason Cooley and Matt Dailey
- Substation Engineering
  - Todd Warren, Randi See and Rodney Siders
- System Control
  - Blake Cox, William (Billy) Hammes, Adam Moreno, Eric Rejcek, Steve McClendon, Michael Ingram, Zack Vater, and Ken Febuary
- Telecommunication Engineering
  - Mark Hoffman

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