Enhanced Load Transfer Schemes for Very Reliable Service

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***Abstract*—Modern production processes require very reliable service. A loss of electric power, even for a few seconds, causes a large loss of income to electricity users with time-critical and uninterruptible processes. To raise power system reliability to a higher level, multiple sources are used in combination with an automatic load transfer scheme. This paper examines several different load transfer schemes in use at utility sites today and their operation in preserving load continuity during system interruptions. Examples of successful and unsuccessful load transfer schemes are given.**

This paper addresses how settings are incorporated to maximize the advantages and minimize the drawbacks of different schemes. Analysis of correct and incorrect operations, with applicable event reports, is included. A root cause investigation of problems encountered in performing the expected load transfer, with solutions implemented to correct those problems, is included for each incorrect operation.

Transfer requirements to meet reliability needs for different end-user facilities are presented. Different communications channels and methods for interconnection and interlocking of the incoming feeders are discussed along with the coordination requirements between the feeds. Economics of both the controls and primary equipment required to implement the system are evaluated and compared with the end-user costs of lost service. Conclusions and recommendations are presented to assist power providers in determining the preferred throw-over methodology for given conditions, available communications, and end-user needs.

I. Introduction

The need for improved reliability of electricity supply may require additional power sources to a local load. While it may be possible to connect multiple sources in parallel, the additional requirement to limit fault duty and avoid exposing two sources to a single fault typically prevents direct parallel sources. An alternate arrangement, such as shown in Fig. 1, is commonly used where the breaker connecting to the alternate source is normally open.

To gain the advantage of having an alternate source, we must have a method of closing Breaker 2 and opening Breaker 1 if the primary source is lost for any reason.

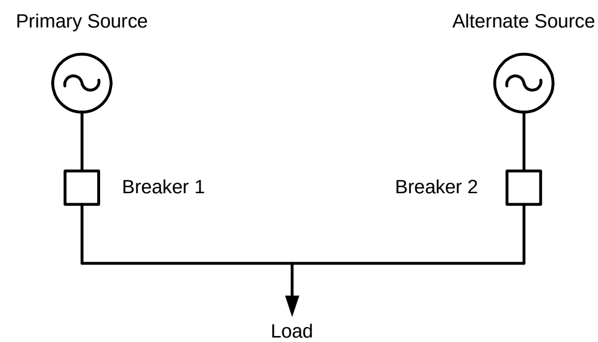

Fig. 1. General Alternate Source Diagram

In many cases, it is advantageous to have some loads served by each of two sources and to close a tie breaker when one source is lost. Often on utility distribution systems, feeders from two different sources will come in close proximity. Utilities may take advantage of this and add a normally open switch along with sectionalizing points or devices along the feeders. This design allows the utility to manually sectionalize and restore service to unfaulted sections of one feeder from the second feeder. With one midpoint device on each feeder, and the addition of an intelligent device and automated switch or recloser at the normally open tie point, the utility can add communications and create an automated main-tie-main scheme. Consider the case where a midpoint recloser is added in the middle of each feeder. Assuming an equal distribution of load along the feeder, the utility can cut its sustained outage numbers in half for faults occurring between the source and the midpoint device. For faults between the midpoint recloser and the normally open point, this midpoint recloser would isolate the fault, eliminating an outage for the first half of the feeder. The addition of this equipment is economical, considering the gain in reliability and resulting customer satisfaction [1]. With the addition of more intelligent sectionalizing devices along the feeders, precise sectionalizing allows for fewer customers to be affected by a permanent outage.

This general case is referred to as a main-tie-main system, as shown in Fig. 2. Sources have a short time capability of serving all the loads, as might be the case with transformers monitored for dynamic loading, and can provide time to restore the other source or shed load in an orderly fashion.

Main-tie-main systems may be part of a single lineup of switchgear or involve circuit breakers that are miles apart. The concerns with this system are the same as the general alternate source of Fig. 1, with the added complication of tie-breaker operation. By increasing the number of possible circuit configurations, the communications and interlocks that must be considered also increase.

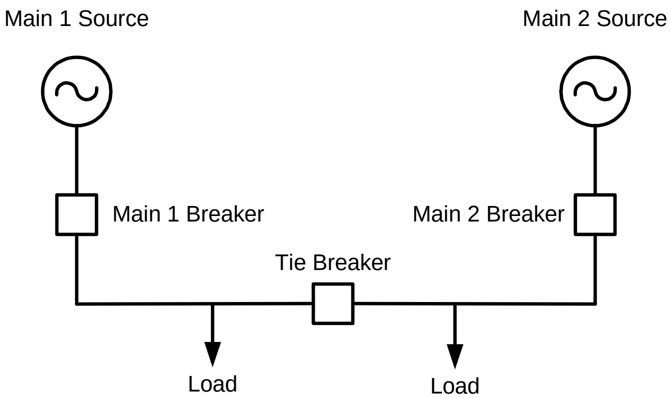

Fig. 2. Main-Tie-Main System

Combinations of the basic and main-tie-main systems can grow in an overall network. Each added source can increase the reliability of the electric supply to the load but, at the same time, increases the chances of accidentally closing or tripping the wrong circuit breaker. Consider the distribution network shown in Fig. 3. With multiple sources available at two different substations, additional possibilities for loop flow from inadvertent transformer paralleling can lead to damaging currents. On the other hand, proper control of open points on the loops can greatly increase service reliability [2].

Experience has shown that making control schemes that perform automatic load transfer functions without appropriate logic and communications can cause problems. A scheme that transfers load on a low source voltage without other supervision may transfer a fault to the alternate source. A scheme that neglects to monitor communications may incorrectly operate when part of the communications is lost. Examples that follow show successes and challenges in transfer schemes.

II. Problems Found With In-Service Transfer Schemes

A. Lack of Independent Sources

From the very start of a system design, the two sources should be as independent as conditions allow. In one case, a transfer system was created for an industrial area using reclosers with controls as shown in Fig. 4. These recloser controls were linked using digital communications.

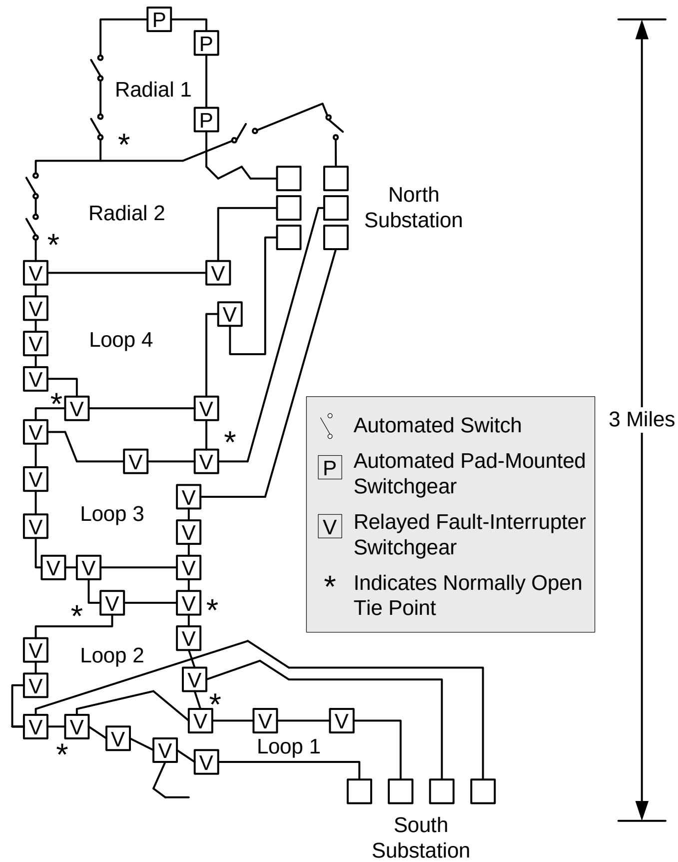

Fig. 3. Large Multisource System With Automatic Load Transfer [2]

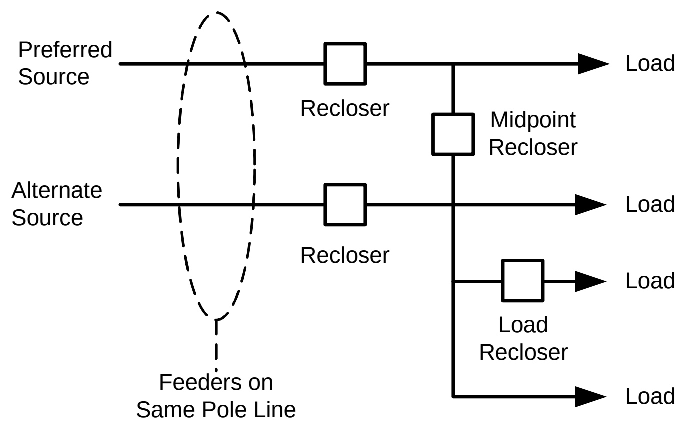

Fig. 4. Preferred and Alternate Source Feeding Multiple Industrial Loads

In this case, the two sources were run on the same poles through a wooded area subject to frequent lightning. A series of events that occurred after a storm resulted in an extended outage and caused great difficulty when technicians attempted to re-energize the system. These events exposed a number of problems with the design, among these a lack of true independence between the sources. Note that the initiating event in Fig. 5 was a simultaneous drop in the voltage at both the primary and alternate sources.

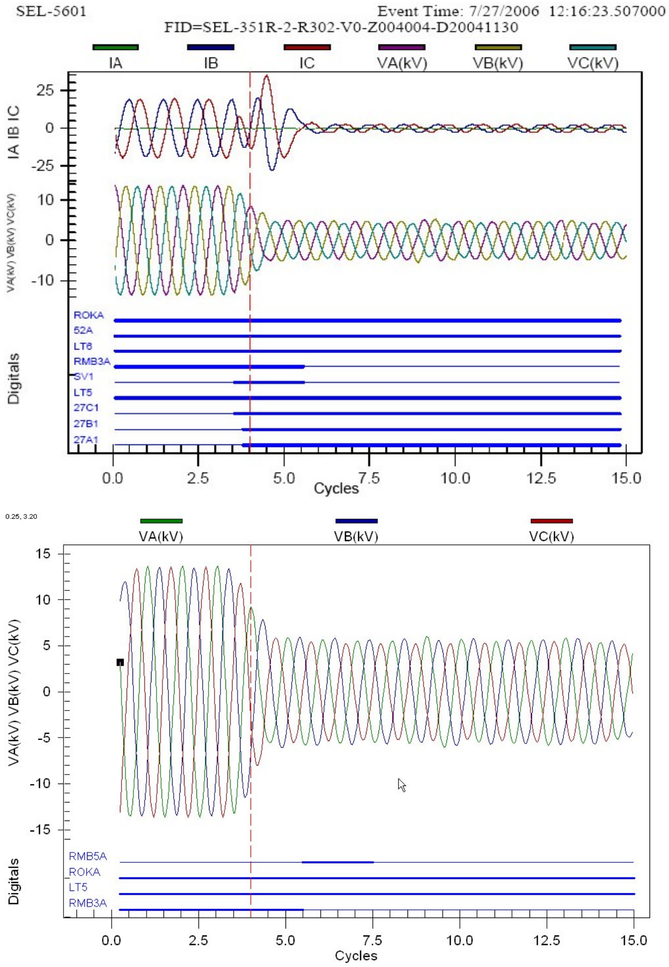

Fig. 5. Loss of Voltage at Preferred (top) and Alternate (bottom) Sources Due to Same Initiating Event

The voltage degradation at both stations at the same time clearly indicates the presence of a common-mode failure that caused a loss of ability to serve the load.

Contrast this with the system in Fig. 3. Here we can see that two independent stations, each with multiple feeders, provide power to the system. Of course, we are limited to the physical system at hand, but an evaluation of the value of a second source should be made based on the probability of that source improving the system availability. Because every component and feeder add exposure to mechanical and environmentally induced failures, it is quite possible that adding elements to a system can actually degrade overall reliability.

An inspection or a more rigorous analysis can assure that the sources involved in a load transfer system are independent. In the case of the system illustrated in Fig. 4, a simple review of the routing of the two sources would have immediately shown the lack of independence. When the connections are more complex, such as shown in Fig. 3, consider a fault-tree analysis to provide a way to calculate overall system reliability. This can be used to evaluate options with different failure modes and different components.

In a communications example given in [3], fault-tree analysis is used to calculate the probability of system failure. This is calculated by evaluating the probability of a particular component failing combined with the relative importance of that component. A block diagram of an analysis is shown in Fig. 6. The probabilities of failure of lower-level, or root, components are combined to calculate the probability of failure of the entire system.

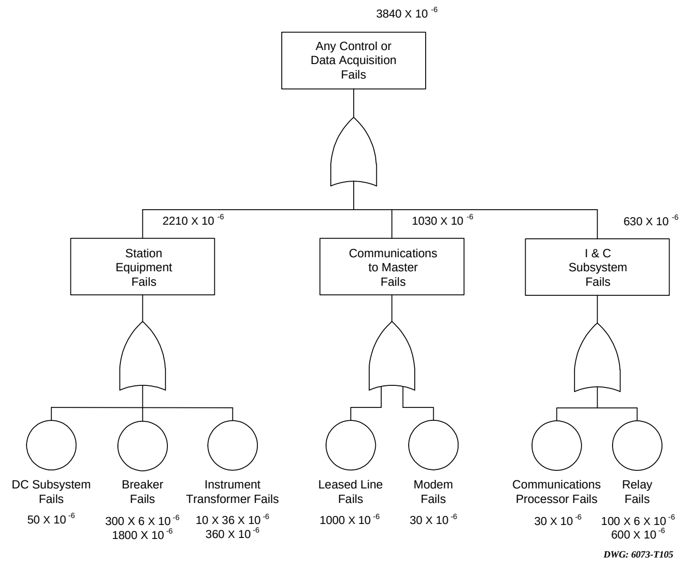

Fig. 6. Fault-Tree Analysis Example

This method is used to evaluate how important it is to use separate transformers, lines, or stations to provide a second feed to a particular location. While a cursory examination can point out obvious problems, a more methodical analysis may point to a more reliable system design. Adding an additional circuit breaker will not decrease the probability of system failure unless it provides a new branch to the fault tree. While added components in each fault-tree branch reduce reliability, added branches increase reliability. In Fig. 6, combining functions using an AND gate (added branches) shows decreasing probability of failure versus an OR gate (added components), which shows reduced reliability.

B. Coordination Problems

In the basic transfer system shown in Fig. 1, the settings of the two relays or controls would be expected to be nearly identical. If the primary feed operates correctly, we would expect the alternate to also operate correctly as long as its source provides proper coordination with upstream devices. Of greater concern are the issues seen in the systems of Figs. 2 and 3.

When the tie breaker in Fig. 2 or the alternate recloser in Fig. 4 closes into the served load, the relays must be set to allow the connected load to be energized without operating the protection. The event reports in Fig. 7 show the current at the midpoint and load reclosers when the system voltage recovered.

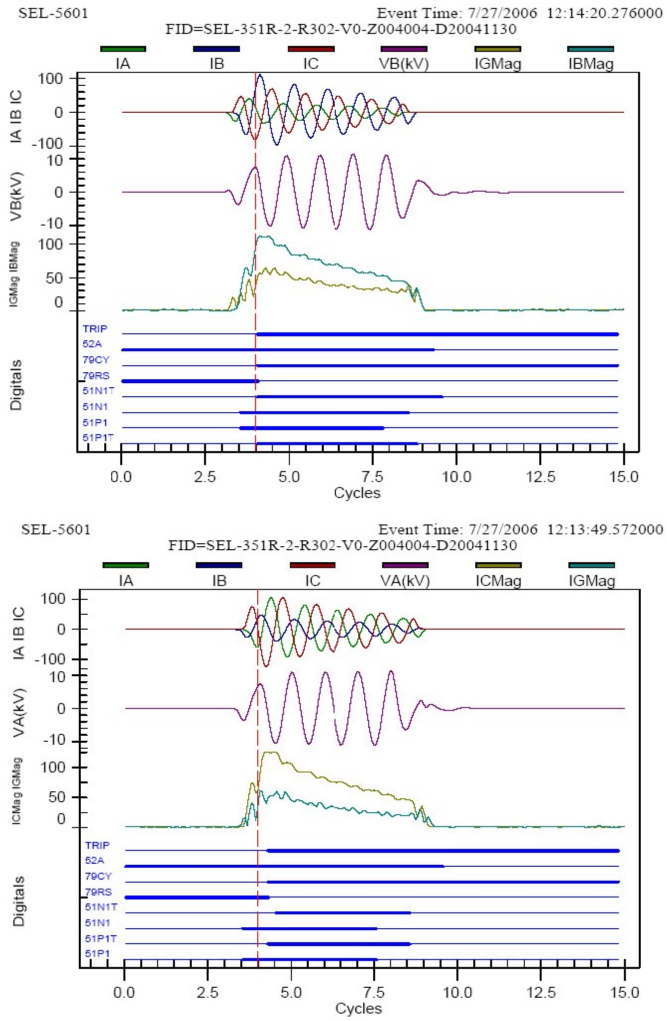

Fig. 7. Trip After Voltage Recovery at Load (top) and Midpoint (bottom) Reclosers

In this case, the minimum trip currents of the midpoint recloser were 60 amperes phase and 25 amperes ground, and the minimum trip currents of the load recloser were 50 amperes phase and 25 amperes ground. Both were set to the same fast curves and would operate in 1–1 1/2 cycles at 200 percent of pickup. As seen in these event reports, immediately after voltage recovered, both reclosers did indeed see currents above 200 percent of the minimum trip current on the phase and ground elements. After only four cycles, the current had decayed to the minimum trip current, but by then the damage was done, and both reclosers tripped. This event disconnected all power serving the loads for an extended time. Analysis of this event identified several problems.

The first problem here was that the "cold" load, or the load present at closing back into the loads, was well above the pickup of the midpoint and load reclosers. Consideration needs to be taken of all transformer and motor loads that will be picked up, and protection settings must compensate for the significant inrush that will occur.

Typically, recloser controls have a cold-load pickup function that increases the minimum pickup current and may disable fast tripping when the switch has been open for a time and is then closed. This cold-load function was not enabled in this application. However, it is important to point out that the cold-load function is effective only when the switch itself has been open and is subsequently closed. This would have been of no benefit in this situation, where voltage was recovered by closing one of the source switches. This situation exemplifies the importance of ensuring that the protective relays for breakers and switches involved in a transfer scheme will not operate when the load is transferred. This problem went undetected during the installation and commissioning of the system. The recloser switches were placed in service by first closing a manual bypass switch. The recloser switch was then closed, and the bypass was then opened. As a result, the recloser switch never closed onto a cold load, and the settings issues went undiscovered.

The second problem is that the load and midpoint recloser have almost the same settings. In order to provide coordination between the two reclosers, there needs to be a difference in pickup current and time delay. Coordination is necessary to avoid overtripping during fault conditions and when picking up additional load. Lack of coordination also makes it difficult to analyze events and locate faults.

Another coordination problem may occur with a main-tie-main transfer scheme when the sources have substantially different source impedances. This situation affects the available fault current and subsequent coordination between the tie device and the main that feeds the load as well as coordination with other downline fuses or tripping devices. The settings required by the tie device to provide adequate coordination may depend on which source is feeding the load through the tie. Studies should be done to determine coordination margins for each contingency. If required, it is possible that the scheme can incorporate an automated settings change by the tie device, depending on which source is available.

C. *Incorrect Load Transfer*

Several factors can cause an incorrect load transfer from the primary to an alternate source. These factors can apply to any of the system configurations illustrated in Figs. 1 through 4 and can relate to a loss of coordination (as discussed in Section B) or to missed communications.

One way or another, the controls for the breakers switching the two sources must communicate with each other. The most basic form of communication is to use the power system itself.

In a basic system, such as shown in Fig. 1, if the load is normally served by the primary source and the voltage on the load bus goes to zero, the alternate source will know that the primary source is lost. This communication is very simple, but a message has been sent. The loss of primary voltage is a "message" to the alternate breaker that the primary source breaker may have opened.

To improve this message, we need to send additional information from the primary breaker relay to the relay controlling the closing of the alternate source breaker. This would also apply if we were closing the tie breaker in Fig. 2 or the midpoint recloser in Fig. 4.

In successful throw-over schemes, relays share several data points. Table I shows the data used for the tie and main controls in one main-tie-main configuration.

TABLE I
INTER-RELAY COMMUNICATIONS

Main Breaker Relay	**Tie-Breaker Relay**
Comm to Tie OK	Comm to Source 1 OK
Comm to Tie to Other Main OK	Comm to Source 2 OK
Status (open / close) of Tie	Source 2 Closed
Good Voltage on Other Source	Source 2 Tripped on Low Voltage (not overcurrent)
Tripped on Low Voltage	Source 1 Voltage OK
Preferred Selected	Source 1 Breaker Closed
	Source 1 Tripped Due to Low Voltage (not overcurrent)
	Source 2 Voltage OK

Several key pieces of information are sent, and the scheme is not complete if anything is missing. The first thing to note is that nothing is armed if the communications are not confirmed to be in service. One advantage of digital communications is the ability to continuously monitor the communications status of not only the communications from the main to the tie, but between the other main and tie as well.

The tie breaker is closed if the main has tripped due to undervoltage, but only if that undervoltage was not caused by an internal fault. This ensures that we are not just transferring the fault from one feeder to another.

How these signals are transmitted depends on the distance between devices. If the relays or controls are physically next to each other, then either contact I/O or a digital cable can be used for relay-to-relay exchange of data. In the case of the system in Fig. 4, the circuit sources are 1–2 kilometers apart from each other. In this situation, copper wires cannot be used, so we have to choose between fiber optics and radio for communication. Table II gives a general comparison of the tradeoffs between these two options [4].

TABLE II
COMMUNICATIONS CHANNEL COMPARISON

	Spread-Spectrum Radio	**Direct Fiber-Optic Cable**
Channel Unavailability (typical)	0.0003	< 0.0001
Longest Failure (typical)	1 s	<< 1 s
Cost (10 km, two terminals)	$8,000 (U.S.)	$150,000 (U.S.)
Communications Delay	4 ms	0.1 ms
Data Rate	115.2 kbps	4 Gbps

In terms of speed and availability, both options are technically acceptable for load transfer schemes. Because of the frequency bands available for spread-spectrum radio, a line of sight is required between the two terminals. If this is the case, station batteries or modern recloser controls have sufficient power to run one or two radios for communication. If no line of sight is possible and repeaters are not practical, then fiber optics are an option. Fiber-optic transceivers are available to transmit data up to 80 kilometers without repeaters.

When establishing the zones of protection, take care that a fault is not transferred between sources. Consider the transformer and feeder zones of protection shown in Fig. 8.

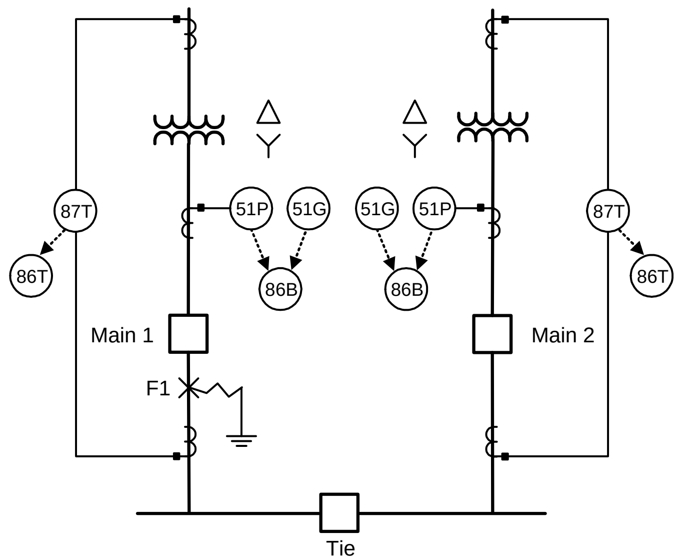

Fig. 8. Main-Tie-Main With Transformer Zone

The designer of this main-tie-main transfer scheme in an industrial installation wanted to prevent the tie breaker from closing in the event of a fault on one of the buses. Phase and ground time-overcurrent relays 51P and 51G were applied on each main breaker to operate bus lockout relay 86B. This lockout relay was connected to trip the main breaker and block closing of the tie breaker. Differential relays 87T were provided to protect the source transformers. The zone of coverage for these relays extended to the bus side of the main breakers to ensure that the zone of protection of the differential relay overlapped that of the overcurrent elements. Time-delayed undervoltage logic was used to trip the main breakers for automatic transfer, and the tie-breaker control logic was arranged to close the breaker if either main breaker was open and neither bus lockout 86B had operated.

This design failed to consider the possibility of fault F1 within the main breaker itself. When such a fault did occur, the main breaker was quickly tripped by operation of the transformer differential relay, and the time-overcurrent elements did not have sufficient time to assert and operate 86B. The bus voltage was lost due to heavy fault and subsequent opening of the source breaker. Once the main breaker opened, the logic was satisfied for the tie breaker to close. This transferred the fault to the other source, resulting in the loss of both sources and prolonging the duration of the fault.

Closing of tie breakers should be supervised not only by main breaker position, but also by a transfer initiate signal that is blocked if the main breaker is opened by any signal other than the transfer scheme. This ensures that the transfer will not occur if the breaker is opened manually or automatically by protective relays. In addition, the protection scheme in Fig. 8 can be improved by moving the low-voltage CT for the transformer differential relay to the other side of the main breaker, while still maintaining the overlap with the CT for the overcurrent relays. With the differential CT located as shown, operation of the transformer differential relay should lock out *both* the transformer and the bus, because the fault could be on the bus side of the breaker. This requirement defeats one purpose of the transfer scheme to maintain power to the load in the event of a transformer fault. Moving the CT allows the transfer to proceed when the transformer differential relay operates, because no portion of the system that could be energized from the alternate source is inside the zone of protection of this relay.

In addition, transfer logic should be designed so that undervoltage-based transfer initiate timers operate only when the undervoltage is due to loss of the source, and not when undervoltage is caused by faults on the bus or on load feeders. This requirement can be met by setting undervoltage qualification timers longer than the maximum time expected for faults to clear, and in microprocessor-based relays, preventing undervoltage qualification timers from running when phase or ground overcurrent elements are asserted.

Many transfer schemes use open transitions for automatic transfers but allow manual closed-transition transfers to prevent load interruption during normal switching activities. Closed-transition transfers must be properly supervised, especially when two diverse sources are used. Breakers should be allowed to close only when the incoming source and the bus are synchronized, or when one or both of the sources are dead. “Dead-bus” supervision must be set appropriately. In one case, the tie breaker in a main-tie-main scheme like that shown in Fig. 2 was allowed to close if:

- The bus voltages on both sides of the tie breaker were synchronized;
- Bus A voltage was between 75 and 110 percent of nominal, and Bus B voltage was less than 75 percent of nominal; or
- Bus B voltage was between 75 and 110 percent of nominal, and Bus A voltage was less than 75 percent of nominal.

Observe that this logic effectively bypasses the synchronism-check logic if either bus voltage is less than 75 percent of nominal. Allowing breakers to close without synchronism supervision at voltages as high as 75 percent of nominal is a significant hazard. Dead-bus voltage thresholds are typically set for 25–30 percent of nominal or less.

D. Hardware Issues

The availability of a second power source is not an excuse to disregard the importance of testing and commissioning to ensure the proper operation of all equipment associated with each source. Referring back to the top reports in Fig. 5, notice that the current is missing any input from Phase A. This could have resulted from a CT failure or something as simple as a test switch left in the shorted position. In general, the question of test-switch practices is well discussed in [7]. The lack of Phase A current did not cause a trip during normal operation because the load current was very low. However, this was not the case during the load inrush following the recovery of voltage after the initial voltage sag.

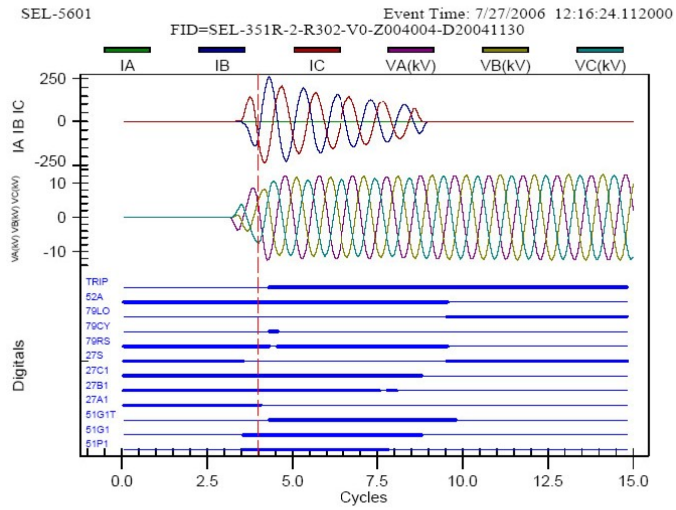

Fig. 9. Attempted Load Restoration With Missing Current

The digital elements displayed at the bottom of the report in Fig. 9 show that the phase and ground overcurrent elements 51P1 and 51G1 picked up; however, only the ground element 51G1T finished its timing cycle. This caused a trip within one cycle after voltage recovered. The 51G1T element is an inverse-time ground overcurrent element that operates from the residual current calculated using the three-phase currents within the recloser control. The missing Phase A current caused the recloser control to calculate residual current when in fact there was no ground fault on the system. The missing Phase A current was later traced to a problem at the CT that went undiscovered during system commissioning. In this case, because this was the preferred source, the failure to pick up load was part of why the overall scheme failed to operate properly. As discussed in Section C, because this relay “thought” there was a fault in the protected zone, the transfer scheme properly blocked all further attempts to transfer the load to the alternate source.

This type of problem would have been easily detected at commissioning by the use of meter information available in most microprocessor-based relays and controls. In this case, the recloser switch was bypassed during most of the commissioning effort, and current metering was not verified when the bypass switches were finally opened.

A more subtle hardware issue was discovered after the unsuccessful load transfer attempt in the system in Fig. 4. The recloser controls used in the application have separate power supply terminals for relay power and switch closing power, and the controls are manufactured with these terminals connected together by a removable jumper. In this design, the relay incorporates a battery charger to maintain a standby battery. In this installation, the common power input was supplied from the facility side of the switch, because this was thought to provide the most reliable source of power for battery charging. However, when all power was lost inside the facility during the event, the switches would not reclose or close manually due to lack of closing power. This was corrected by connecting the closing power supply for the switches to Phase A on the utility side of the switch.

When switches used in a transfer scheme require ac power for closing, the design must take into account what power will be available when the transfer scheme is required to operate. In some cases, where closing power may be available on either side of the switch under different system conditions, control power transfer switches or dc closing may be necessary.

E. Performance

How well a recloser-based load transfer scheme can perform is shown by event records from the utility feed for an industrial plant in Jackson, Tennessee. This installation is fed from two lines in an arrangement similar to Fig. 1. Because there is some distance between the two feeds, remote communications are provided between the main and alternate source.

On August 29, 2007, on the road next to the primary source, a car went off the road and took out the utility pole. From that we have the event records shown in Table III.

TABLE III
SEQUENTIAL EVENTS RECORDER REPORT OF LOAD TRANSFER

	A	B	C	D	E
				MAIN MENU	
1	Rec	Date	Time	Element	State
1792	172	08/29/2007	07:03:47.460	Source Voltage [3P59Y]	Low [Deasserted]
1793	171	08/29/2007	07:03:47.460	Local Voltage Indication (If in Automatic) [TMB3A]	Low [Deasserted]
1794	170	08/29/2007	07:03:47.468	51G1	Asserted
1795	169	08/29/2007	07:03:47.468	C Phase Source Voltage [27YC1]	Low [Asserted]
1796	168	08/29/2007	07:03:47.468	Preferred Source Low Volt Trip Timer [SV23]	Timing [Asserted]
1797	167	08/29/2007	07:03:47.485	Load Transfer Trip Variable [SV30]	Asserted
1798	166	08/29/2007	07:03:47.485	Preferred Source Low Volt Trip Timer [SV23T]	Asserted
1799	165	08/29/2007	07:03:47.489	Low Voltage Trip [LT14]	Memorized [Asserted]
1800	164	08/29/2007	07:03:47.489	Automatic Transfer Logic [SV28]	Blocked [Deasserted]
1801	163	08/29/2007	07:03:47.489	Preferred Source Low Volt Trip Timer [SV23]	Deasserted
1802	162	08/29/2007	07:03:47.489	Automatic Reclosing [79LO3P]	Lockout State [Asserted]
1803	161	08/29/2007	07:03:47.489	Automatic Reclosing [79RS3P]	Deasserted
1804	160	08/29/2007	07:03:47.489	Trip Equation [TRIP3P]	Asserted
1805	159	08/29/2007	07:03:47.489	Local Low Voltage Trip Indication (If in Automatic	Sent [Asserted]
1806	158	08/29/2007	07:03:47.493	Fourth Shot [SH43P]	Asserted
1807	157	08/29/2007	07:03:47.493	Shot Zero [SH03P]	Deasserted
1808	156	08/29/2007	07:03:47.501	51G1T	Asserted
1809	155	08/29/2007	07:03:47.534	51G1	Deasserted
1810	154	08/29/2007	07:03:47.543	51G1T	Deasserted
1811	153	08/29/2007	07:03:47.559	Pole 1 [IN201]	Open [Deasserted]
1812	152	08/29/2007	07:03:47.559	Pole 2 [IN202]	Open [Deasserted]
1813	151	08/29/2007	07:03:47.559	Pole 3 [IN203]	Open [Deasserted]
1814	150	08/29/2007	07:03:47.568	Recloser Interruptors [52A3P]	Open [Deasserted]
1815	149	08/29/2007	07:03:47.568	Local Switch Indication [TMB6A]	Open [Deasserted]
1816	148	08/29/2007	07:03:47.572	Load Voltage [3P27Z]	Dead [Asserted]
1817	147	08/29/2007	07:03:47.630	Load Voltage [3P27Z]	Deasserted
1818	146	08/29/2007	07:03:47.647	Remote Voltage Indication (If in Automatic) [RMB3A	Low [Deasserted]
1819	145	08/29/2007	07:03:47.647	Opposite Switch Indication [RMB6A]	Closed [Asserted]
1820	144	08/29/2007	07:03:47.651	Opposite Switch Closed Indication [LT12]	Memorized [Asserted]
1821	143	08/29/2007	07:03:47.651	Local Low Voltage Trip Indication (If in Automatic	Deasserted
1822	142	08/29/2007	07:03:47.738	Load Transfer Trip Variable [SV30]	Deasserted
1823	141	08/29/2007	07:03:47.738	Preferred Source Low Volt Trip Timer [SV23T]	Deasserted
1824	140	08/29/2007	07:03:47.742	Trip Equation [TRIP3P]	Deasserted

Here a low voltage was detected at 7:03:47:460, and that voltage was restored (Local Low Voltage Trip Deasserted) at 7:03:47:651, for a total of 191 milliseconds or 11 1/2 cycles of low voltage. For this end user, this was a very acceptable condition.

An interesting point is that the Sequential Events Recorder data (in the same report, but not shown in Table III) indicated an operation of the scheme a few weeks earlier of which the utility had no knowledge. The customer did not notify the utility of the earlier operation because no production time was lost from loss of the preferred feeder. In this instance, the load transfer scheme shifts the customer to the alternate source for temporary faults on the preferred feeder to reduce the customer's exposure to follow-up recloses on the preferred source feeder. The transfer scheme automatically returns the customer to the preferred feeder after it is restored to health.

This system used the electric utility's standard reclosers and controls. The incremental cost of the control scheme was only in adding the communications channels and performing the engineering to provide settings to the controls.

An installed recloser and control typically costs \$20,000–\$40,000 depending on the type selected and feeder construction. According to a survey published in the *IEEE Gold Book* [5], 25 percent of industrial plants must completely restart production if service is interrupted for more than ten cycles. The survey also indicated that the average restart time is 17 hours. In terms of economic tradeoffs, for a modest manufacturing facility, a single prevented outage would pay for the transfer scheme.

III. FAST BUS TRANSFER

In the case shown in Section E, the signal to initiate load transfer is not sent until after the primary source is tripped. It is possible to initiate closing of the alternate source at the same time, or even before the tripping of the primary source. This would bring the low-voltage time on the load bus down to less than ten cycles. This is usually considered a "fast transfer."

The object of a fast transfer is to maintain continuity of a process by keeping the motors running. Quoting ANSI standard C50.41-2000, "To limit the possibility of damaging a motor … it is recommended that … the resultant volts per hertz vector between the motor residual volts per hertz vector and the incoming source volts per hertz vector at the instant of transfer … does not exceed 1.33 per unit volts per hertz on the motor rated voltage and frequency bases" [6].

While the speed of the transfer may make meeting this requirement possible, a study should be done of the motor load type and system characteristics to confirm that the transfer will be successful.

Two different loads will respond very differently to a loss of voltage, as shown in Fig. 10, where E_R is the voltage-difference vector between the motor bus and the incoming source.

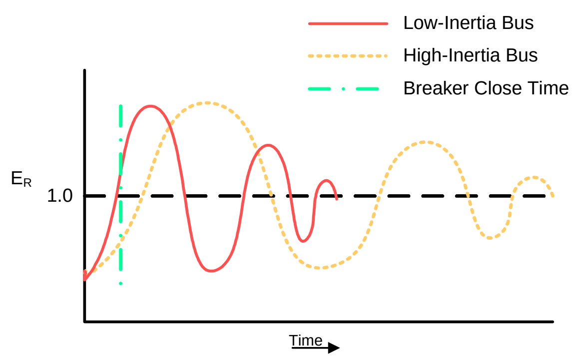

Fig. 10. Motor Response to Loss of Voltage

Here a bus supplying motors with predominately low-inertia mechanical loads will pull out of synchronism relative to the incoming source much faster than a bus supplying motors with high-inertia mechanical loads. Even when fast transfer studies indicate that such a transfer may be safely accomplished, variations in system conditions, such as the number and type of motors that are running, may cause actual transfers to deviate from the modeled conditions. To prevent motor damage in such situations, the fast transfer scheme may be supervised with a relay that will measure the bus and incoming voltages and calculate for known breaker close times if a safe transfer can be accomplished.

IV. Conclusions and Recommendations

Application of proven systems to transfer load on loss of a single source can significantly improve service reliability. A few simple steps will ensure that the end customer sees the benefits of the transfer scheme.

1. Ensure that sources involved in the transfer scheme are truly independent.
2. Check all settings to ensure the normal load and added load from the transfer can be picked up under worst-case and cold-load pickup conditions.
3. Make sure that no fault in the zone of protection can be transferred to the alternate source. Block transfer for all possible faults on the load.
4. Use communications to send data between relays or controls to ensure proper operation.
5. Properly supervise closed-transition transfers with synchronism-check elements. Ensure that dead-bus and dead-line elements are set so that synchronism-check elements are not improperly bypassed.
6. Test the transfer scheme, and verify proper operation of all equipment during commissioning.
7. Verify that system conditions that require the transfer scheme to operate will not cause closing power to be lost.
8. Follow up on all unexpected operations to correct any overlooked problems. Use event reports and other data recorded by relays to fully analyze all events, including successful load transfers.
9. If fast transfer is anticipated, supervise closing to avoid motor damage.

V. References

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VI. Biographies

Roy Moxley has a B.S. in Electrical Engineering from the University of Colorado. He joined Schweitzer Engineering Laboratories in 2000 and serves as a senior product manager. Prior to joining SEL, he was with General Electric Company as a relay application engineer, transmission and distribution (T&D) field application engineer, and T&D account manager. He is a registered professional engineer in the State of Pennsylvania and has authored numerous technical papers presented at U.S. and international relay and automation conferences.

Lee Underwood received a B.S. in Electrical Engineering from the University of Virginia in Charlottesville in 1990. From 1990 to 1996, Lee worked as a design and systems engineer for Duke Power Oconee Nuclear Station, with emphasis on dc power systems, medium- and low-voltage switchgear, and protective relaying. In 1996, he joined Duke/Fluor-Daniel and participated in the design and construction of electrical systems for coal-fired power plants. He joined Schweitzer Engineering Laboratories as a field application engineer in 2004. Lee is a member of the IEEE Power Engineering Society and a registered professional engineer.

Mike Collum, P.E. started working with Schweitzer Engineering Laboratories in 1997 as a field application engineer. He is currently a senior field application engineer for the East Region out of Tupelo, Mississippi. For 11 years prior to joining SEL, he was director of planning and protection for South Mississippi Electric Power Association, where he was involved in transmission planning and system protection applications. Mike graduated from Mississippi State University with a B.S. in Electrical Engineering and is a registered professional engineer in the state of Mississippi.

Greg Hataway received his B.S. in Electrical Engineering from the University of Alabama in 1991. He has broad experience in the field of power system operations and protection. Upon graduating, he served nearly 12 years at Alabama Electric Cooperative, where he worked in distribution, transmission, and substation protection before assuming the role of superintendent of technical services at the cooperative. In this position, he coordinated the utility’s efforts in protection and power quality. He joined Schweitzer Engineering Laboratories in 2002 as a field application engineer in the Southeast Region.

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