Distribution Automation Effects on Reliability during Major Contingencies

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Abstract—**Distribution automation affects reliability by providing faster restoration ability. In this study, the effect of distribution automation on radial distribution circuits during substation failures at peak load is investigated. The ultimate goal is to compare circuit automation to manual operation, where the comparison evaluates planning criteria reliability for customer interruption hours. The results show that distribution automation can improve reliability measurements such as SAIDI, SAIFI and CAIDI.**

Index Terms— **Distribution Automation, Power System Reliability, System Reconfiguration.**

I. INTRODUCTION

Reliability of distribution systems is one of the major issues in modern power grids due to the cost of customer interruptions. According to a White House Report [1], an estimated 679 widespread power outages occurred due to severe weather events between 2003 and 2012 in the U.S. During all these ten years, the cost of weather-related power outages ranged from $18 to $33 billion. An electric power blackout was experienced in the Midwest and Northeast United States and Ontario, Canada, on August 14, 2003. The outage affected 50 million people and 61,800 MW of electric load. It was estimated that the total cost of this blackout ranged between $4 billion and $10 billion (U.S. dollars) in the United States [2].

Given the component failure rates, reliability indices of an electric power distribution system can be determined for a well-defined set of loads and components. These reliability indices are mostly mean values of probability distributions which measure the frequency, duration and severity of contingencies on the network and provide insight into the performance of the system. Two types of reliability indices are used for distribution level reliability, customer-based reliability indices and load-based reliability indices. Load-based indices look at the connected kVA, and customer-based indices weigh each customer equally. The commonly used customer-based reliability indices are System Average Interruption Frequency Index (SAIFI), System Average Interruption Duration Index (SAIDI), Customer Average Interruption Duration Index (CAIDI), and Average Service Availability Index (ASAI) [3].

There are at least two ways to improve the reliability of a distribution system. The first way is to reduce the number of contingencies by improving or hardening the components of the power system. This way involves performing regular maintenance. The second way is to reduce the effect of contingencies by using distribution automation systems [4]. Smart grid integration with distribution automation allows reconfiguration of power networks and thereby providing opportunities of diverting the power flows, isolating the faults, and preventing the overloading of network components [5]. With smart grid automation technology, automatic switches and monitoring systems can be added into the distribution system with integrated control to fulfill the self-healing functionality such as automated fault location, isolation and restoration. Smart grid automation improves the efficiency and reliability and introduces economic benefits by reducing the service restoration time.

In references [6-11], authors have investigated impacts of smart grid technologies on the reliability of aged infrastructure and showed that smart grid technologies provide improvements to system reliability by reducing the outage duration. The authors of [12] have examined the impact of automatic switches on distribution system reliability using a sequential Monte Carlo simulation method. The functions of distribution automation, such as fault detection, fault isolation and service restoration for smart grid systems in France have been described in [13]. The investigations in [14] show different types of substation automation and demonstrate the improvement of substation reliability indices and the effects of the automated substation on distribution system reliability. In references [15, 16], the positive effects of communication networks on the performance of distribution automation have been studied. Moreover, the authors in [16] have described a distributed multi-agent approach to analyze the performance of a faulty location and isolation along a distribution feeder.

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In this paper, a pilot test system is used as a test network, and the effects of manual switching and automated switching on distribution reliability have been investigated during a station transformer failure at peak load. An integrated system model developed in the DEW software [17] is used to perform the reliability analysis for the whole system. This article is organized as follows: The system used in this study is described in Section 2. The reconfiguration algorithm for contingency restoration is introduced in Section 3. The results obtained from the proposed algorithm are presented in Section 4 and the conclusions are given in Section 5.

II. THE SYSTEM USED

A total of six different models (three of which based on manual switching and three of which based on automated switching) are used to carry out the study over the course of six years (2012-2017). Changes to circuit configurations as a function of time resulting from planned capital system improvements are taken into account when building the models. These changes take place from 2012 to 2014; therefore, the 2014 model is used for years 2014 through 2017. Customer counts and loads are expanded according to the load growth forecasts of the area.

Automation is implemented by the use of reclosers for three specific functions on each radial circuit. The first type of recloser is called a midpoint recloser due to its placement roughly at the midpoint of the circuit. The next type of recloser, referred to as a tie recloser, is placed at the tie point between the two adjacent circuits. The final recloser type is the SCADA operable switch which is placed to sectionalize the circuit for every 250 customers.
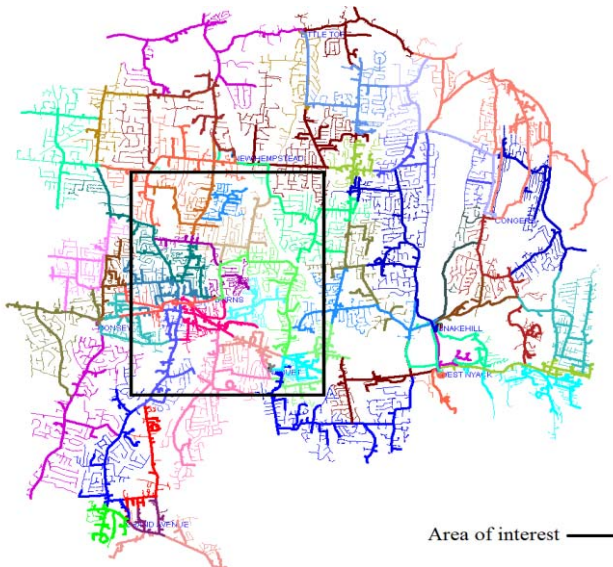

Figure 1. System model

Fig. 1 illustrates the geographical area of concern, and Fig. 2 represents the pilot substation used in the study. The substation has eight (8) 13.2 kV feeders that cover an area of roughly ten square miles and provides electrical service to

approximately 21,000 customers. It can be seen that adjacent circuits have normally open, automated tie breakers that will automatically transfer the load on one circuit to an adjacent circuit in the event of a bank or bus fault. For example, for loss of Bank 1 or the 13.2 kV bus fed from Bank 1, the feeder breaker for circuit Feeder 5 will open and the tie breaker will close, automatically transferring the load to Feeder 1. Each of the other feeders served by Bank 1 will also transfer to the adjacent feeder, providing the combined load of both feeders does not exceed the ampacity of the limiting element, which could be either the bus, feeder breaker, or the feeder exit.

MR: Midpoint Recloser   TR:Tie-breaker Recloser   SR: SCADA operable Recloser
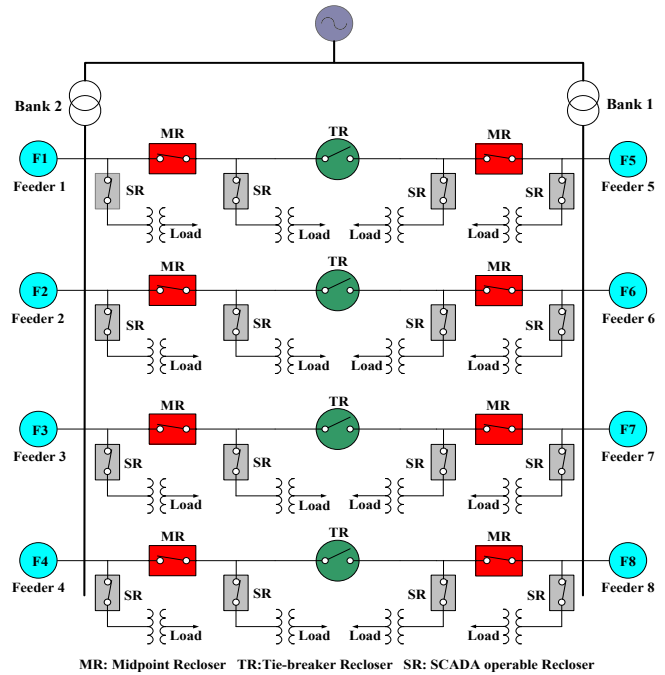
Figure 2. Pilot substation used for study

Listed in the Table I are the feeders that were equipped with smart grid auto restoration equipment and the year the equipment was installed in the 6 years study.

TABLE I.   CIRCUITS AUTOMATED IN THE FOLLOWING ORDER

Year	Automated Circuits	Bank
2012	Feeder 7, Feeder 8	1
2013	Feeder 4, Feeder 1	2
2014	Feeder 3, Feeder 6, Feeder 5	1 and 2

III. RECONFIGURATION FOR CONTINGENCY RESTORATION

The objective of reconfiguration is to operate sectionalizing devices to restore power. The reconfiguration algorithm for restoration proposed in [18] is used for this study. The reconfiguration algorithm is started to operate right after following major contingencies and both automated switch and manual switch operations needed to restore customer power are determined as quickly as possible. First, the reconfiguration algorithm isolates the faulty area in a way to make it as small as possible. When the faulty area is

isolated, the reconfiguration algorithm next generates a list of available switches to close to restore the power. If closing a switch violates any constraint, such as an overcurrent or low-voltage constraint, the algorithm reopens the switch and removes that switch from the available switch list. If there are no violations, then the algorithm looks to see if any additional closures are available for restoring power. This process is repeated until either the outage area is fully restored or there are no more possible switching actions that may be performed to restore power. Finally, once the repair time is completed, the algorithm recloses the switches that implemented the isolation. The numbers of customers at each load bus are included in the model, and the total numbers of hours of customer interruption are then calculated.

The planning criteria require that the load on a substation transformer bank not exceed the bank's normal rating or appropriate planning measures must be taken to relieve the load. Additionally, in a two bank station, failure of one bank requires that 62% of the load of the failed bank be restored by transferring to the remaining bank, and through load transfers to adjacent substations via circuit ties. The remaining 38% of the load is to be restored by the installation of a portable substation, and the total customer interruption hours must be below 60,000 based on a 24 hours installation time for the portable substation. Appropriate planning measures must be taken to insure that the maximum customer interruption hours resulting from a failed substation transformer bank remains within the 60,000 customer hour planning criteria.

Assumptions made for this study include:

- One crew for switching per circuit starting at the moment of failure.
- One hour for the initial switch move and 15 minutes for each additional move (on that circuit).
- For the four (4) hour period following the fault, ANSI/IEEE C84 B ratings are used, which permit voltages to drop to 109 Volts minimum. Also, the station transformer Long Term Emergency (LTE) 4 hour rating of 51 MVA is used for the transformer banks. The remaining failure period (>4 hours) is subject to 114 Volts minimum and 42 MVA normal transformer bank ratings.
- 24 hours is used as the time it would take to install a mobile substation for emergency backup to restore customers that could not be restored using the second bank within the station or the circuit ties.

At peak load, one transformer bank is failed and the reconfiguration algorithm is operated using the emergency voltage levels and LTE transformer ratings to maximize the restored customers. The reason to run study at peak load is assuming the worst case happening at peak load. The devices permitted to operate within the *Radial Reconfiguration* application are as follows:

- Substation feeder breakers
- Substation bus tie breakers
- Distribution disconnect switches
- Distribution gang-operated air break (GOAB) switches

The same algorithm is operated four (4) hours after peak, where the transformer loading must not exceed the normal rating and the more stringent voltage requirement of 114 Volts applies. From the reconfiguration algorithm results, customer interruption hours are calculated for manual switching scenarios only based on the times given in the criteria above and are added to the calculated results for the first four (4) hours.

The same procedure is repeated for the second transformer failure while the first transformer is working. The annual customer interruption hours are collected, result of these processes, between 2012 and 2017.

This procedure is then repeated on the models equipped with smart grid automation devices to determine the customer interruption hour savings. Only after the smart grid automation devices are operated, the manual switching is used to further reduce the customer interruption hours. The automated devices allowed to operate are as follows:

- Substation feeder breakers
- Substation bus tie breakers
- Distribution electronic reclosers
- Distribution SCADA operable switches

Only after these devices are used to restore the power, manually operated distribution GOAB and disconnect switches are used to further reduce customers affected by the outage. Customer interruption hours are calculated as described above.

IV. RESULTS AND DISCUSSION

The graph in Fig. 3 illustrates the customer interruption hours per year as generated by a transformer failure of Bank 1, or a failure of the 13.2 kV bus served by Bank 1, for both the manual and automated cases. A slight increase in the manual column between 2012 and 2013 is caused by an increased number of manual switching steps required due to increased load. This increase does not appear in the auto column for Feeder 7 and Feeder 8, requiring more manual switching steps. Both columns decrease from 2013 to 2014 because of a transformer capacity upgrade at the neighboring station in 2014 that aids backup of Feeder 5. The automation of Feeder 5 and Feeder 6 in 2014 eliminates all manual switching steps and resulting customer interruption hours. The addition of smart grid automation in conjunction with capacity increases in substations results in 100% backup of Bank 1 and zero customer interruption hours generated by manual switching steps. The net number of customer interruption hours eliminated by smart grid automation on Bank 1 is 8,101 hours.

The graph in Fig. 4 is a representation of the customer interruption hours per year as generated by a transformer failure of Bank 2, or a failure of the 13.2 kV bus served by Bank 2, for both the manual and automated cases. The increased capacity at the neighboring station in 2013 provides additional tie backup to Feeder 3, which accounts for the decrease in customer interruption hours between 2012 and 2013 for both manual and automated cases. Feeder 1 and
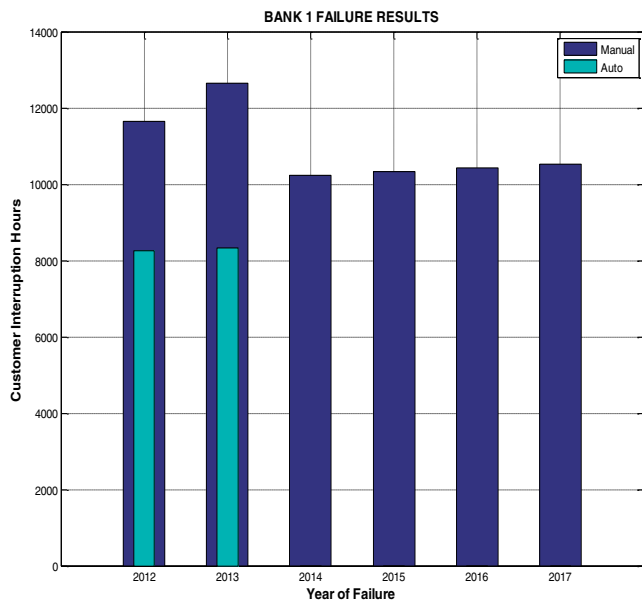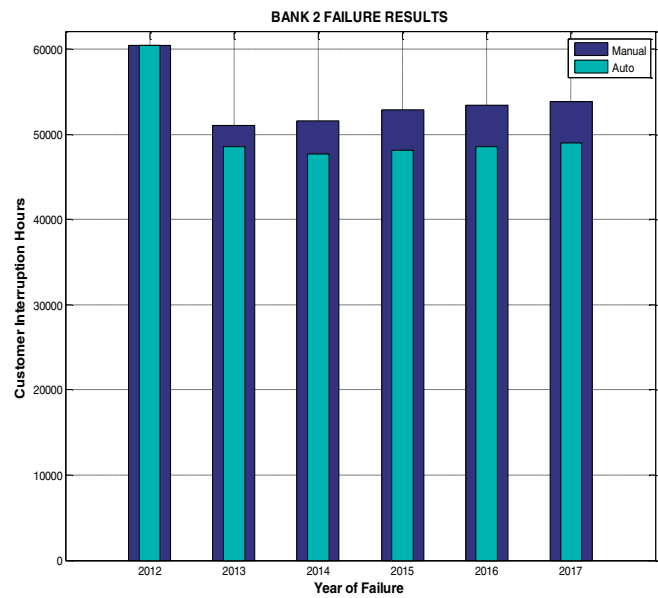
Figure 3. Bank 1 results

Figure 4. Bank 2 results

Feeder 4 in 2013 are the cause for the difference between the manual and automated columns, with most of the savings generated by the elimination of manual switching steps on Feeder 1. Feeder 4, lightly loaded in comparison, requires less manual switching steps due to the automated station bus transfer and abundant backup from the neighboring station.

The automation of Feeder 3 in 2014 yields additional decreases in interruption hours. The increase in the manual column in 2015 is due to load growth, requiring more manual switching steps. The majority of the customer interruption hours comes from the prolonged outage (>4 hrs) of Feeder 2, which requires mobile substation deployment for restoration. The net number of customer interruption hours eliminated by

smart grid automation on Bank 2 is 4,850 hours.

Table II shows the reliability improvement results. The reliability indices SAIDI, CAIDI and SAIFI are also shown in Table II. It should be noted that data in Table II is the result of a substation bank failure. As a result of the study, it can be observed that the automation of the substation yielded a customer interruption hour decreases when compared to the manual switching results. The reduction of crew switching time in the automated scenario is the reason for the decrease. By automating circuits, with their respective adjacent ties, it is possible to eliminate or reduce customer interruption hours resulting from manual switching operations.

TABLE II.   RELIABILITY RESULTS FROM STUDY

Metric	2012 (Base line)				2017 (After project completion)			
	Manual		Auto		Manual		Auto	
	Bank 1	Bank 2	Bank 1	Bank 2	Bank 1	Bank 2	Bank 1	Bank 2
Total Number of Customers Interrupted	7037	7328	3192	7328	5825	7328	0.00	7328
Customers Interruption Durations (hours)	8.75	50.75	5.50	50.75	8.00	50.25	0.00	28.00
Total Number of Customers Served	7037	8883	7037	8883	6098	9299	6098	9299
SAIDI	0.001243	0.005713	0.000782	0.005713	0.001312	0.005404	0.000000	0.003011
CAIDI	0.001243	0.006925	0.001723	0.006925	0.001373	0.006857	0.000000	0.003821
SAIFI	1.000000	0.824947	0.453602	0.824947	0.955243	0.788024	0.000000	0.788024

V.   CONCLUSIONS

Smart grid automation for improving reliability by replacing manual switches with automated ones has been investigated in a particular case study. In the case study seven feeders fed by two distribution substations are used to

evaluate the reliability improvement with automation. Assumptions involving number of crews available and crew switching operation times are presented. By using a radial reconfiguration algorithm that determines how both automated and manual switches should be operated to restore power, it has been demonstrated that customer hours of

interruption can be significantly reduced by employing automated switches. The case study results showed that distribution automation improves reliability for the contingencies evaluated. In terms of reliability indices, after completion of project in 2017, while SAIDI, SAIFI and CAIDI indices improve up to 100% for Bank 1, the improvement of SAIDI and CAIDI for Bank 2 will be obtained as 44.27%. But SAIFI indices for Bank 2 will remain same value, so that there will be no improvement.

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