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Novel Use of Existing Data for Smart Grid Preliminary Analysis and for Asset Optimization

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SUMMARY

National Grid is conducting a multifaceted smart grid pilot to inform not only on the value (cost versus performance) of each feature but also the integrated value relationship. One aspect of this pilot is investigating the value of using equipment capable of reducing through-fault energy levels for reclosing attempts on the distribution system versus other more traditional means.

To gain an understanding of existing system performance for base line value measurement and also to measure the potential value of Smart systems, the existing reliability performance data, geographic information system location data, as well as asset data has been linked in a novel way to create additional information not previously available. This paper will share results to date along with next steps for enhancement of this analysis.

KEYWORDS

Asset Management, Optimization, Power Transformers, Power System Reliability, Smart Grids, geographical information systems, electric distribution, reclosers, pulse closing

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I. INTRODUCTION

As part of a Smart Grid pilot it is conducting [1]-[5], National Grid desired to base-line performance prior to the pilot implementation. During this process the ability to link existing disparate databases in a novel way to extract new information from the data was created. This new information will not only aid with pilot base-line efforts but also allow quantification of routine value judgment decisions related to reliability improvement versus cost decisions.

For the analysis described in this paper ratio transformer life impacts due to through-fault energy experienced over each transformer's life was investigated. The analysis can be expanded to include any equipment which is tracked and which is impacted by through-fault exposure, such as substation transformers, breakers, cable, and wire.

The questions of interest are whether through-fault energy reduction saves ratio transformer life and can this be quantified. Two methods for reducing through-fault energy are considered: reducing the number of reclose attempts and using pulse technology. As a strategic alternative to reducing through-fault energy, early targeted replacement of ratio transformers is also considered.

II. DESCRIPTION OF EXISTING DATABASES

A. Reliability Data

In recent years many utilities have augmented their interruption databases with geographic information system (GIS) location information. By providing fault location by GIS line section or pole ID in a structured manner rather than in comments fields large volume analysis becomes possible.

The interruption data for a ten year period from 2003 through 2012 were reviewed. Those with GIS location IDs for the fault location were included in this analysis. To supplement the database size, when fault locations were not identified the GIS location of the operating line protective device was used. This doubled the number of useful events and also allowed for some events coded with an unknown cause to be included. This supplemental data will over estimate the fault current slightly since the distance from the substation to protective device will be shorter than if the actual fault location were known. As more GIS location data is collected for fault events and Smart Grid adds more monitors to the system, the volume of useful data will increase improving accuracy for this analysis. Currently the data is still sparse and this first pass analysis with only about 14% of interruption events includable was intended to verify that enough data existed to be usable now and to help quantify early pilot results.

The reliability data used for this analysis included the number of events, the GIS ID for the fault location or the line protective device location, the feeder number, the event date, and the cause for the fault. From the cause data field ratio transformer failures were flagged to identify if they failed and the date of failure for determining equipment life.

B. Asset Data

Asset data has improved dramatically over recent years as geographic information systems (GIS) have increased in use. Currently, National Grid has over 14,500 distribution line ratio transformers on about 1,387 distribution feeders. Many of these line ratio transformers are on side taps, but some are on the main line. These main line ratio transformers are due to a history of substation modernization driven by physical issues coupled with a desire to standardize nominal voltages during a period where distribution feeder load growth was low enough to delay the need for full feeder conversion. Fig. 1 shows the age profile for ratio transformers.

The GIS asset data used for this analysis included the GIS equipment ID, GIS feeder segment ID and length, feeder number, ratio transformer kVA size, winding configuration, as well as high and low side nominal voltage, and ratio transformer installation date. Transformers with missing data were omitted from this analysis.

In addition to the GIS feeder segment ID each upstream line segment GIS ID was also noted. This allowed creation of a connectivity model of each feeder. Using this connectivity model it was possible to trace the distance from each fault location (or protective device location) back to the substation source and for associating a fault event with each upstream line ratio transformer as appropriate. This is the novel new database feature that makes this analysis possible.

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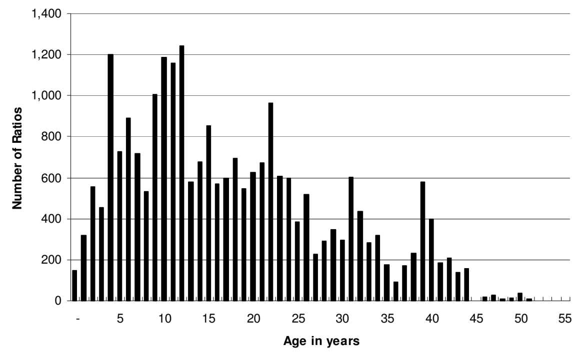

Fig. 1. Ratio Transformer Age Distribution

C. System Data

System Protection personnel routinely calculate the fault current at each substation low side bus for use in protection coordination analyses as well as equipment fault duty reviews. This data is a well tested and relied upon source for fault current at the low side substation bus. The substation low side bus fault current was adjusted for each fault event using a proxy calculation to account for distribution conductor and ratio transformer impedance impacts on fault current levels.

This time saving proxy was only used here to reduce labor commitment for the GIS data extraction process until this analysis could be shown to be worth the greater effort. It will be eliminated in future analysis by using GIS data about conductor spacing and conductor size to calculate line impedance more precisely as well as line ratio transformer impedance between each fault location and the source substation for each of the 1,387 feeders.

In general fault current will drop off proportional to the inverse of the distance between the fault location and the substation source. Typical fault profiles can be found in [6]. Table 1 shows a few points derived from the curve in [6]. These were used for this analysis. Linear interpolation between these points is acceptable. Greater distances used the last table value for percent available fault.

The proxy equation (1) uses this inverse relationship to adjust the substation low side bus fault current based upon fault location.

$$I_F = I_{Sub} * Function\ (D_F) \qquad (1)$$

Where I_F is the fault current in Amperes, I_{Sub} is the fault current available at the substation low side bus in Amperes, D_F is the distance from the substation to the fault in feet, and Function(D_F) is interpolated values from Table 1.

III. DATA LINKS AND GEOGRAPHIC TRACING PROCESS

For this analysis data was mined from the reliability and asset databases and organized into a new custom relational database. The feeder network model is an essential component and was also integrated into this database for establishing upstream/downstream hierarchy as well as tracing to the station breaker to determine distances. The system data for substation low side fault current was then appended to this relational data that links the two via a distribution feeder number key.

Fault locations, protective devices, and ratio transformers were all associated to their parent primary feeder segment, which then served as the entry point into the network model. Fig. 2 is a simplified representation of this network model. Ratio Transformer 1 (RT1) is on Segment 2 (S2); RT2 is on S5. A total of four interruptions have occurred on this circuit, F1-F4.

For every interruption record, an upstream trace was initiated at the fault location or at the protective device primary feeder segment if fault location was unavailable. For the example in Fig. 2 the trace process is executed four times, once for each fault. The trace process traversed the network model, keeping a tally of primary length as it navigated upstream, and noted if any primary segments containing a ratio transformer were encountered. Using this iterative process revealed all ratios impacted by fault current, as well as fault distance. For the example in Fig. 2 the fault at F1 does not impact any ratio transformers; F2 impacts only RT1; F3 impacts both ratio transformers; F4 impacts only RT1. Thus, the script yields RT1 impacted three times, and RT2 impacted once.

distance from sub to fault location in feet	Percent of fault current available at sub
0	100%
2,640	70%
5,280	53%
7,920	43%
10,560	35%
13,200	30%
15,840	28%
18,480	25%
21,120	21%
23,760	20%
26,400	18%
29,040	16%
31,680	15%
34,320	14%
36,960	13%
39,600	12%
42,240	12%
44,880	11%
47,520	11%
50,160	11%
52,800	10%

Table 1 Fault Current Profile

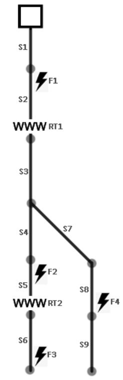

Fig. 2 Network Model Representation

IV. ANALYSIS

The data obtained from the new relational database was reviewed for possible trends due to age, winding configuration, nominal voltage, and number of fault events experienced by transformer. No patterns were observable. However, when ratio failures versus through-fault energy (I^2t) were reviewed a pattern was observed.

Fault current was calculated using (1) for each interruption event and attributed to the proper ratio transformers that would have experienced that fault current using the new tracing feature. Equation (2) was used to normalize the fault current based on the ratio transformer rated current using its kVA rating and nominal voltage.

$$I = \left[\frac{I_F}{kVA/(\sqrt{3} * kV)} \right] \qquad (2)$$

Where I is unit-less current in multiples of rated current, I_F is the fault current in Amperes calculated using (1), kVA is the ratio transformer three phase rating in thousand Volt-Amperes, and kV is the ratio transformer nominal line-line voltage rating in thousand Volts.

The time for the fault was assumed to be 8 cycles for the recloser to sense the fault and operate and 6 cycles for subsequent reclose attempts. This time was converted from cycles to seconds. Thus the I^2t in equation (3) is in unit-less current in multiples of rated current and duration is in seconds. This is a quantity similar to that commonly used for defining transformer short circuit characteristics.

$$I^2 t = Evnts * (t_1 + Rtry * t_2) * I^2 \qquad (3)$$

Where Evnts is the number of fault events experienced downstream of a ratio transformer, Rtry is the number of reclosing attempts of the line recloser, t_1 is time in seconds for the initial fault, t_2 is the time in seconds for the subsequent retry attempts, and I is derived from equation (2).

It was assumed reclosers used three reclose attempts. A future refinement will be to prorate the reclose attempts by success rate for first, second, and third reclosing attempts to account for successful reclosing. Once the Smart Grid pilot is in service monitoring equipment will provide additional data that can further enhance this estimate.

Ratio transformers were collected into I^2t bins of 10. The percent failed for ratio transformers was calculated for each bin and the result plotted in Fig. 3. While there is a lot of scatter a pattern of increasing failures as I^2t increases is noticeable.

Fig. 4 shows the number of ratio transformers experiencing fault current and whether they failed or not. Not many units experience high fault current levels; probably due to system design and also that faults tend to be further away from substations owing to the amount of line exposure.

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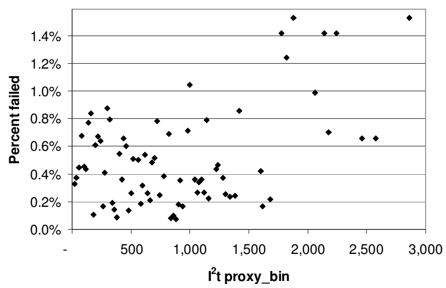

Fig. 3. Annualized percent line ratio transformers failed by I^2t proxy

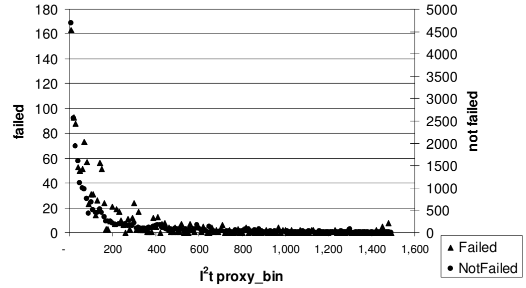

Fig. 4. Number of Ratio Transformers Experiencing Faults

V. RESULTS OBTAINED

Fig. 5 shows the cumulative I^2t for each ratio transformer against the annualized failure rate over the ten year period. Using the cumulative curve for three reclose attempts in Fig. 5 an equation (4) was fitted with an R of 91.2%.

$$\text{Annual Percent Failed} = 0.0003*\text{Ln}(\text{cumulative } I^2t) - 0.0007 \quad (4)$$

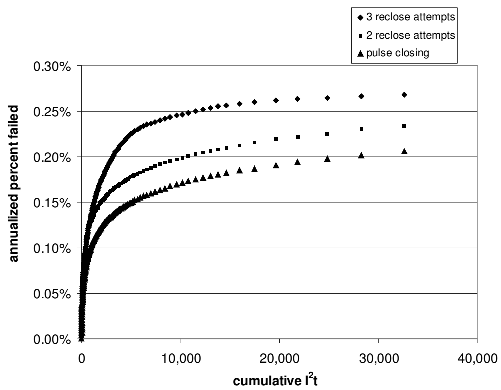

Fig. 5 Annualized Percent Line Ratio Transformers Failed by cumulative I^2t proxy

A. Value of Reducing the Number of Reclose Attempts

If we limit the amount of cumulative I^2t experienced by limiting reclosing to two rather than three reclosing attempts and model this using equation (2) with the same data a new curve can be calculated to find an estimated change in failure rate. This new curve is also shown in Fig 5.

The difference between these curves shows a likely advantage of increased life. Failure rate is reduced from 0.27% per year to 0.23% per year. The anticipated reduction of units failing and thus equipment cost savings can be calculated from this information. In this analysis the historical 40 units failed per year could be reduced to 34 units per year for a cost savings of about $150,000 per year.

This can then be compared to expected reliability degradation from the third reclosing that would no longer be attempted. (Each reclose attempt success rate diminishes dramatically: first attempts succeed about 83%, second attempts about 10%, and third attempts about 1.4% [7].)

Customers value both reliability and low cost. The value of reliability to customers can be obtained through such means as described in [8].

B. Value of Early Replacement

As an asset management strategy, monitoring the cumulative I^2t and using it to target early replacement of ratios would reduce failure risk. For example, using the data presented limiting cumulative I^2t to 1,000 for each ratio would halve the number of failures reducing the total failure rate from 0.27% per year to 0.14% per year. When a ratio transformer reached this limit the transformer could be removed from service and if economical refurbished rather than scraped. For the sample population (14,500) this would result in 20 less failures per year or about $500,000 per year saved.

Avoiding failures in this way would result in the discarding of remaining useful life of ratio

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transformers. Depending on the frequency of fault events this could be a substantial number of useful years. This would be the cost for avoiding the interruption associated with a ratio transformer failure.

C. Value of Pulse Closing

Another way to reduce the cumulative I^2t experienced and still provide the reliability improvement obtained from the second and third reclosing attempts would be to use reclosers that employ pulse closing technology. This technology sends a limited energy pulse for reclosing to sense for faults before allowing a full energy reclose. The added cost of the equipment is balanced against the equipment life saving and the retention of reliability performance.

Using (4) and pulse closing for all reclose attempts provides additional improvement to the benefit curve shown in Fig. 5. Pulse closing is projected to save 9 units per year or $225,000 per year.

VI. NEXT STEPS FOR ANALYSIS

The relational connectivity model and tracing routine will be enhanced to also pull the ratio transformer impedance, the wire size, wire type, and the pole physical configuration so that impedance from the fault to the substation bus can be calculated for each feeder segment. Using this precise impedance information fault current can be calculated more accurately.

In future this analysis will also be expanded to include substation transformers.
This analysis with next step improvement added will be used in bench marking and in further analysis of National Grid's Smart Grid pilot.

Due to the sparse nature of the historical data, National Grid believes there is an opportunity for the industry to cooperate in a collective pooling of data in a confidential manner. If companies are interested in such collaboration please contact the author for further discussion.

VII. CONCLUSION

Several disparate databases were interconnected in a traceable relational database that used GIS information in a novel way which created new information from existing data. How this was done, the results obtained, and future enhancements were shared in this paper.

Results show that cumulative I^2t by ratio transformer can be used to predict failure risk. This result can now be used to flag devices for maintenance, early replacement, or to change reclosing strategy based on value to the customer in terms of equipment cost versus change in reliability.

As an alternative, reclosers with pulse technology can be used, retaining reliability performance and improving equipment life. This choice of methods can now be quantified.

VIII. ACKNOWLEDGMENT

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