DISTRIBUTION LINE PROTECTION PRACTICES
INDUSTRY SURVEY RESULTS
IEEE POWER SYSTEM RELAYING COMMITTEE REPORT

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Working Group on Distribution Protection: P.T. Carroll, Chairman, C. Fink, Vice Chairman
Contributing Members: J. Appleyard, J. R. Boyle, B. Jackson, J. Johnson, L. Kojovic, E. Krizauskas, L. P. Lawhead, P. J. Lerley, D. Miller, A. Napikoski, R.D. Pettigrew, W. M. Strang, C. R. Sufana, R.P. Taylor, J. T. Tengdin, J. T. Uchiyama, R. M. Westfall, J. B. Williams, P. Winston, J. A. Zipp

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Abstract – This report presents the results of an extensive survey of utility practices for the protection of distribution lines at the substation. The survey was issued in 2000 and responses were received through 2001. Results of similar surveys were published in 1983 (Ref. 1), 1988 (Ref. 2), and in 1995 (Ref.3). In this survey, most of the sections were comparable to the earlier surveys. In addition, these sections were expanded to collect more data on the reasons behind a practice and on the methods used. Two new sections were added to address the impact of organizational considerations on distribution protection, and to summarize emerging technologies and applications relevant to distribution protection. The responses to this survey have been compared to the previous surveys in an attempt to detect any trends in the protection of distribution circuits.

Introduction – The IEEE Power Systems Relaying Committee (PSRC) has the responsibility of reviewing and reporting on current practices in protective relaying. In the distribution area, the "Effectiveness of Distribution Protection" Working Group of the Line Protection Subcommittee has the on-going role to survey the utility industry at periodic intervals. The data collected through this survey, when compared to the previous surveys, indicates that there are some trends emerging. The advantages of these changing practices are discussed within this report. Further surveys will be conducted to determine the extent of these and future trends.

About the Questionnaire – The questionnaire used for this survey was based on the previous questionnaire with two expansions:

1. added a section to determine the impact of organizational /industry considerations on distribution protection in the last five years, and,
2. added a section to summarize emerging technologies and applications relevant to distribution protection

Where appropriate, the data was collected by major voltage class: 5kV, 15kV, 25kV and 35kV.

SECTION 1 – GENERAL

The questionnaire was sent to individuals involved in distribution system protection for investor-owned, cooperative, and municipal utilities and their consultants in the United States and Canada. Responses were received from 49 organizations.

The respondents were asked to limit their replies to actual present practices. Past practices and policies for older portions of the system are not of interest because they would not be applied if that portion were to be installed today. The respondents were requested not to guess at any of the answers.

If the desired information was not readily available or could not be provided in the form requested by the survey, respondents were asked not to answer the question.

The respondents were asked to provide a significant amount of description with their answers. It was feared that this would have a negative impact on the completeness of the returns. This additional information was used in the analysis of the data and preparation of the presented results.

Survey Results – The results of the survey are given for each section. The actual survey questions are not included in this report, as the questionnaire was 19 pages long. In tabulating the results, the number of "yes" responses and "no" responses are given where appropriate, and may not total 49 or 100%. Not all respondents answered every question and some questions had more than one applicable answer.

This section of the survey requested general information about the utility. The respondent was also asked if the utility name could be used in conjunction with any of the results or specific questions. In most cases, the answer was "yes." The predominant distribution voltage class where the practices identified in this survey are applied is 15kV, but most results are also relevant to 5kV, 25kV, and 35kV.

System Load – Each utility was asked to state their total distribution load and distribution station supply transformer size by voltage class, to assure that data was coming from a broad base. 35 utilities reported distribution load ranging from a few MVA to over 20,000 MVA.

TOTAL DISTRIBUTION LOAD	**UTILITIES**
5,000 MVA and above	9
1,000 MVA to 4,999 MVA	14
999 MVA and below	12
No Size Given	14

Voltage Class – Most utilities had more than one distribution class, with 15kV still being the most common when compared to previous surveys. From the reporting the distribution load at each voltage is:

VOLTAGE CLASS	LOAD, MVA	% of TOTAL	NO. of UTILITIES
5 kV	5,057	4	20
15 kV	77,601	59	32
25 kV	24,750	19	15
35 kV	21,711	17	11
Other	2,205	2	2
TOTAL	**131,324**	**100**	

Transformer Size – The following table gives a breakdown by the number of utilities of the typical total transformer capacity and largest total transformer capacity at any one distribution substation on their system:

TRANSFORMER SIZE	TYPICAL	LARGEST
10 MVA or below	4	3
10 - 20 MVA	14	3
20 - 50 MVA	16	17
50 – 100 MVA	10	13
> 100 MVA	0	8

Protective Relays Installed – The following table summarizes the responses to a question on where distribution protective relays are installed:

LOCATION	NUMBER of UTILITIES
Breaker/Recloser location	27
Control House	18
Temperature Controlled	13
Some of each moving to Controlled	11
Some of each, no changes	8
Other	4

SECTION 2 – CONSIDERATIONS

This section was added to the survey in order to identify any issues pertaining to personnel and technological issues in light of the fact that many utilities experienced organizational changes while new technologies were being introduced in the 1990's.

When asked to identify who within their organization was responsible for the application and setting of distribution relays and reclosers the following responses were received:

Distribution Protection Specialists	16%
Distribution Planners	5%
Substation Protection Specialists	32%
Area Engineers/Technicians	12%
Transmission, substation, distribution settings personnel	30%
Other	4%

When asked who within their organization was responsible for the coordination of substation devices with feeder devices and feeder tap protection the following responses were received:

Same response as above	37%
Distribution Protection Specialists	18%
Distribution Planners	4%
Substation Protection Specialists	14%
Area Engineers/Technicians	11%
Transmission, substation, distribution settings personnel	11%
Other	4%

When asked if recent organizational or technology changes caused a change in the responsibilities for application and setting of distribution protection within their organization, 33% responded that changes had been made. 41% of the respondents stated that they apply predominantly standard settings to similar devices (main breakers, feeder breakers, reclosers) in the field, while 59% applied predominantly customized settings. 36% of the respondents stated that they had changed setting practices due to organizational or technology changes in the recent past.

When asked how frequently distribution protection settings are reviewed the following responses were received:

When changes are known to have occurred	75%
When problems occur	57%
Annually	7%
Periodically (2-10 years)	30%
No policy	11%

SECTION 3 – SYSTEM DATA

Substation Transformer Connection – When asked about the predominant distribution transformer connection applied to their system, the vast majority of utilities reported that Delta – Wye grounded transformers were utilized. Smaller numbers of Delta – Wye with resistor or reactor grounding, Wye grounded – Wye grounded, and 3 winding with tertiaries are used.

Transformer High Side Design – A number of questions were asked that related substation transformer size to protection practices. While 8 of the respondents replied that they had no change in practices based on transformer size, 35 replied that they did change practices, most in the 10 – 20 MVA transformer size range. For smaller transformers the vast majority apply fuses as the high side interrupting device. For larger transformers high side circuit switchers and breakers tend to be applied most often. When asked if practices varied based on transformer high side voltage, 29 utilities replied that they did not change practices while 15 replied that they did. For lower voltage applications most apply high side fuses, with some applying high side circuit switchers or breakers. For higher voltage applications high side circuit switchers and breakers are applied the most.

Transformer Low Side Design – When asked to report on transformer low side design practices, the following responses were received (number of utilities):

DESIGN	USED	MOST COMMON
No interrupting device between transformer and feeders	25	17
Main Breaker	27	20
Parallel with other transformer through closed tie breaker	12	1
Parallel with other transformer through closed switch	5	0
Parallel with other transformer through open tie breaker	20	11
Parallel with other transformer through open switch	11	5
Breaker and a half or ring bus	6	2
Other	4	2

Feeder Breakers – When asked to report on the types of feeder breakers used, the following responses were received (number of utilities):

Metalclad Switchgear	30
Outdoor Breakers	34
Electronic Reclosers	27
Hydraulic Reclosers	17

Line Devices – When asked what types of line devices were applied in significant numbers on their distribution feeders, the following responses were received (number of utilities):

Main feeder circuit reclosers	39
Branch circuit reclosers	30
Main feeder circuit sectionalizers	7
Branch circuit sectionalizers	9
Branch circuit fuses	37
Unfused single phase taps	7
Other	1

Transformer Protection – When asked to report on the typical transformer protection practice for large or higher voltage transformers, the following responses were received (number of utilities):

High Side Fuses	5
Differential Relays	38
High Side phase overcurrent relays	34
High Side ground overcurrent relays	13
Low Side neutral overcurrent relays	31
Low Side main breaker overcurrent relays	20
Tertiary overcurrent relays	3
Sudden pressure relays	29
Other	2

For those responses where low side main breaker protection was applicable, most apply phase overcurrent and ground overcurrent relays as their typical protection. It is of interest to note that 9 utilities (20%) stated that they apply automatic reclosing as part of their low side main breaker protection scheme.

Low Side Tie Breaker Protection – Most respondents replied that they use phase and ground overcurrent relays as their typical protection for low side tie breakers, with significant numbers of directionalized overcurrent relays and automatic tie control schemes also in place.

Feeder Protection – When asked to report on the typical relaying applied to their feeders, the following responses were received (number of utilities):

Circuit reclosers	31
Phase overcurrent relays	42
Ground overcurrent relays	41
high impedance fault detection devices	1
Distance relaying	2
Negative sequence relaying	4
Directionalized overcurrent relays	1
Automatic tie control schemes	4

This implies that while new technologies and functionalities have been introduced to the distribution protection realm in the last decade, overcurrent relays and reclosers remain the most used options for feeder protection.

Maximum Fault Current – When asked to report on whether or not they set maximum design limits for fault current levels on their system, 23 utilities responded that they did set limits, while 20 did not. The vast majority set their phase and ground fault limits at the same value, with 10,000 Amps being the predominant level. A number of utilities set their limits above or below the 10,000 level, with 23,500 being the highest and 6000 being the lowest.

Those utilities that limit the fault current on their system do so at the substation level. When asked to report on the methods used to limit fault current on their system, the following responses were received (number of utilities):

METHOD	PHASE FAULT	GROUND FAULT
Phase or neutral transformer reactors	5	7
Phase or neutral feeder reactors	6	0
Transformer impedance only	16	17
Source and transformer impedance	13	14
Resonance grounding	NA	0
Other	0	3

Load Unbalance – When asked if they had a policy or practice to limit their load unbalance, 30 utilities replied that they did, while 14 did not. The vast majority of load imbalance is measured and controlled at the feeder breaker level, with some also taking place at the transformer secondary. In most cases the unbalance currents are obtained by measuring phase currents and calculating the unbalance. A few respondents use meters or transducers in the feeder residual circuits or relays with instrumentation capabilities to measure or calculate the actual imbalance.

When asked to define their limit on transformer load unbalance, the majority of respondents replied that they express the imbalance in terms of the percent of maximum phase current with 20% being a typical value. When asked to define their limit on feeder load imbalance, the responses were split between expressing the imbalance in terms of maximum phase current with 20% being a typical value, and expressing it in terms of straight amperes in the range of 50 – 240 amps.

Harmonics Monitoring – When asked to report on whether they had equipment to monitor distribution system harmonics, 21 utilities (49%) stated that they did while 22 utilities (51%) did not. No utility responded that they were planning to implement harmonic monitoring at this time.

Neutrals – 41 respondents (93%) answered that their distribution circuits have multi-grounded neutrals, while 3 (7%) do not.

It should be noted that as might be expected, when comparing the results of this section to previous surveys, there are few changes in overall distribution substation and system design.

SECTION 4- PHASE PROTECTION

Instantaneous Trip Function – Fuse Saving – 66% of the respondents apply phase overcurrent protective devices with instantaneous trips for downstream fuse saving. The two previous surveys taken in 1995 and 1988 listed responses of 71% and 91% respectively. Only a very small portion of the survey respondents had available data regarding the effectiveness of their fuse saving program. Data ranged from 5% effective to 90% effective with an average response of 49%. Only 5% of the respondents indicated a change in protection practice that would promote fuse saving in the future. Half of the remaining respondents indicated no change in practice, the other half were moving away from a fuse saving philosophy.

Instantaneous Trip Function – Other Purposes – Utilities responding to the survey indicated that the instantaneous trip function is also used for other purposes as shown in the following table. Note that respondents may have selected more that one category.

	NO. OF UTILITIES USING THIS APPLICATION
Limit duration of fault for personnel safety	14
Limit equipment damage	19
Minimize voltage dip duration	15
Limit outage time	7
Enhance coordination	13
Other	1

Instantaneous Trip Function – Multiple Operations – 63% of the utilities responding use only one instantaneous or fast trip for phase protection on feeder circuits. In the previous survey 73% had the same response. Due to the limited response to this survey it is doubtful that this difference is an indication of a trend occurring in the industry.

Feeder Coordination – 91% of the utilities responding attempt to achieve complete coordination of feeder phase time overcurrent protective devices. 80% of the respondents indicate that complete time overcurrent coordination is maintained during all automatic reclosures of feeder phase protective devices. Miscoordination, when permitted, is allowed for the following reasons:

Low fault currents	44%
High fault currents	24%
Other	32%

The criteria used to determine phase overcurrent pick-up is shown below. Note that respondents may have checked more than one of the criteria.

	NO. OF UTILITIES USING THIS APPLICATION
A multiple of expected feeder load	22
Conductor thermal limits	25
Emergency loading	22
Coordination considerations with downstream devices	31
Coordination considerations with upstream devices	32
Available tail end fault current	19
Other	1

One of the new items in this questionnaire was a series of questions on the application of and the importance of different features of microprocessor distribution relays. The following are the results from that part of the questionnaire:

About 90% provided responses to the questions on microprocessor relays. Of those who responded all were either using or evaluating microprocessor relays. 89% of those who responded are using this type of relay. Of those applying microprocessor relays most of the relays were being installed on new installations, but 58 % were also applying them on retrofits with 28% indicating that their utility has a system upgrade program.

When questioned on the relative importance of different features of the microprocessor relays the following results were obtained. They are shown in descending order of indicated importance.

FEATURE	**% INDICATING FEATURE IS CRITICAL OR VERY IMPORTANT**
Self Diagnostics & Alarm Contacts	84

Reclosing	82
Digital Outputs for Interface with SCADA or Station Computer	75
Event Recording & Logging	64
Multiple Overcurrent Units (inverse, instantaneous) In same package	64
Programmable Scheme Logic	64
Communication Networking Capability	61
Local Display of Measured Values	52
Remote Data Access & Retrieval	52
Monitor Trip Coil Continuity	50
Fault Location Calculation	39
Monitor Breaker Close Circuit	36
Analog Outputs of Local or Remote Display	41
Alternate Setting Groups	43
Breaker Failure Protection	30
Negative Sequence Overcurrent Protection	20
Remote Setting Changes	18

More detailed questions were asked about the importance of the microprocessor relays having particular capabilities in the area of event recording and logging. The results of those questions are shown in descending order of indicated importance.

CAPABILITY	**% INDICATING CAPABILITY IS CRITICAL OR VERY IMPORTANT**
Fault Phase Indication	73
Fault Magnitude Data (phase & ground)	64
Waveform Data (oscillography)	32
Monitor Breaker Operate Time	32

In the area of local or remote displays of data, more detailed questions were asked about the importance of recording, storing, and displaying certain quantities. The results of those questions are listed below in descending order of indicated importance:

QUANTITY	**% INDICATING QUANTITY IS CRITICAL OR VERY IMPORTANT**
Neutral Current	50
Voltage	50

Watt, Var, Power factor (3 phase)	50
Under-Frequency	48
Demand and Peak Demand Level	46
Watt, Var, Power factor (single phase)	41
Total Interrupted Current Accumulation & Alarm	25
Frequency	23

Questions were asked if having multiple functions in the same device was a problem for utilities. On the importance of having "Separate packaging for each phase and for the ground overcurrent functions" 82% indicated that this was of no importance or very little importance. On the importance of having "Separate reclosing package" 77% indicated that this was of no importance or very little importance.

A series of questions probed to see if the application of the microprocessor distribution relays had caused any changes in protection or relay maintenance practices. 73% indicated that their company was reviewing or revising distribution phase protection practices due to the new technologies. 52% also indicated that they were reviewing or revising their ground protection. Having self diagnostics and alarm contacts in the microprocessor relays was indicated to be the most important feature, and 66% of those utilities applying these relays had revised their maintenance practices due to the presence of this feature.

SECTION 5- GROUND PROTECTION

Application of Ground Overcurrent Protection – 70% of the respondents replied that they apply ground current protection to the transformer low side main interrupting device, while 10% do not and the issue is not applicable to 20% of the respondents.

Basis for Time Delay Overcurrent Pickup Settings – Utilities indicated the following criteria were used to establish pickup settings for ground time overcurrent protection located on transformer low side main interrupting devices:

	NO. OF UTILITIES USING THIS APPLICATION
Percent of transformer full load current	5
Percent of transformer normal, maximum load	0
Percent of phase trip pickup level	7
Percent or multiple of largest feeder maximum load	2
Multiple of feeder ground device pickup level	11

Fixed current level	2
Other	4

Application of Ground Overcurrent Feeder Protection – 98% of the respondents using phase relay overcurrent protective devices also apply ground protection on feeder interrupting devices. The percentages are essentially the same as in previous survey results.

Basis for Feeder Time Delay Overcurrent Pickup Settings – Utilities indicated the following criteria were used to establish pickup settings for ground time overcurrent protection located on feeder interrupting devices:

	NO. OF UTILITIES USING THIS APPLICATION
Percentage of feeder maximum capacity	1
Percent of feeder expected maximum load	3
Percent of phase device pickup level	7
Fixed current level	5
Based on maximum downstream fuse size	10
Available tail end fault current	14
Other	3

Feeder Time Overcurrent Characteristics – The majority (98%) of utility respondents use relays with inverse time characteristics for feeder protection. 65% apply ground instantaneous functions, and 14% apply devices with definite time delay characteristics.

Feeder Ground Coordination – 81% of the respondents attempt to achieve complete coordination of ground time overcurrent protective devices. The same percent of respondents maintain complete coordination during all automatic reclosures of the feeder interrupting devices. Miscoordination, when permitted, is allowed for the following reasons.

Low fault currents	46%
High fault currents	36%
Other	18%

Ground Instantaneous Devices – 74% of the utilities apply ground overcurrent protective devices with instantaneous or fast trip devices. The primary reasons for application of the instantaneous protection is summarized in the following table. Note that respondents may have selected more that one category.

	NO. OF UTILITIES USING THIS APPLICATION
Limit duration of fault for personnel safety	13
Limit equipment damage	24
Minimize voltage dip duration	17
Limit outage time	7
Enhance coordination	13
Other	4

SECTION 6- RECLOSING

The questions in this section assume a "standard" distribution circuit, with no distributed sources of generation.

Automatic Reclosing – Virtually all (98%) of the respondents report applying automatic reclosing of the feeder interrupting device on overhead distribution circuits. Only one respondent did not report using reclosing. Previous surveys reported 100% use of automatic reclosing.

Number of Reclosing Attempts – Most of the responding utilities used either 2 or 3 reclosing attempts. No one reported 4 attempts. The utilities responding reported reclosing attempts as follows:

RECLOSING ATTEMPTS:

1 Attempt	7 responses	16%
2 Attempts	15 responses	35%
3 Attempts	21 responses	49%
4 Attempts	0 responses	0%

There is an apparent trend based on previous survey data. Compared to the previous survey, Single Shot Reclosing has increased (up to 16% from 8%), and use of 4 reclosing attempts has declined (down to 0% from 10%). The ratios for 2 and 3 shots are almost identical (35% vs. 35% and 48% vs. 47%). The old survey reported reclosing attempts broken down by voltage class, which showed minor variations. This comparison is with the totals.

Open Interval Between Interrupter Trip and First Reclosing Attempt - Most responding utilities reported a first reclosing time of less than 5 seconds (86%), split about evenly between less than 1 second and between 1 and 5 seconds. There is perhaps a trend away from fast (less than 1 second) first reclose attempts, (down to 44% from 52%), 86% report first reclose 5 seconds or below, versus 91% previously. This is small change, however, and may not be statistically significant.

FIRST RECLOSING TIME

Less Than 1 second	19 responses	44%
1 to 2 seconds	6 responses	14%
2+ to 5 seconds	12 responses	28%
5+ to 15 seconds	4 responses	9%
>15 seconds	2 responses	5%

Second reclose attempt – Among the users employing more than one reclosing attempt, most used a significant time delay. As with first attempts, there may be a slight trend away from "fast" reclose times. A significant number (21%) previously reported second reclosing times of 1 to 5 seconds, compared to the current report of only 8% less than 5 seconds.

SECOND RECLOSING TIME

Less Than 5 seconds	3 responses	8%
5+ to 15 seconds	27 responses	69%
More than 15 seconds	9 responses	23%

Reset Time Setting – There is not a strong consensus among respondents with regard to reset times, except that most users reported times of at least 5 seconds. There seems to be a slight trend towards longer reset times. Only 32% report reset times 30 seconds or below, versus 41% previously.

RESET TIMES

Less Than 5 seconds	1 response	2%
5+ to 30 seconds	13 responses	30%
30+ to 60 seconds	14 responses	33%
More than 60 seconds	15 responses	35%

Special Cases – Utilities were asked if they deviated from the standard reclosing sequence and/or timing for various special cases. The only significant factor was type of load served. Compared to the previous survey, there were some significant differences. Separate reclosing practices to allow operation of downstream sectionalizers were only reported by 19% of respondents, compared to 40% previously. Its not clear whether the standard schemes more likely accommodate downstream sectionalizers, or if it reflects a move away from fuse-saving schemes. There was a dramatic decrease in the number of utilities deviating reclosing practices to limit feeder interrupting duty, from 1 in 4 to approximately 1 in 20.

25% of respondents modify their schemes for "other" reasons, but no further data was available.

	Current Data	Previous Data
The presence of supervisory control at the substation	14%	16%
To limit transformer through fault duty	14%	18%
To allow downstream sectionalizers to trip	19%	40%
To limit feeder interrupting duty	6%	26%
In substations fed directly from the transmission system	6%	8%
If the feeder has shield wires	0%	2%
Due to type of load served	58%	N/A
Other	25%	N/A

Reclosing on Feeders with Cable – Just over half of the respondents employ reclosing on feeders with underground sections. The responses were very similar to the previous survey.

Feeders with less than 25% Underground	17% use reclosing
Feeders with between 25 and 50% Underground	12% use reclosing
Feeders with between 50 and 75% Underground	7% use reclosing
Feeders with greater Than 75% Underground	22% use reclosing
No automatic reclosing on feeders with underground	42%

Adaptive Reclosing – Very few responding utilities use any sort of adaptive reclosing schemes. Only 4 of 43 respondents (9%) use adaptive reclosing. No trend can be determined, as no similar question was asked in previous surveys.

No adaptive reclosing now in effect	91%
Reclosing adapts to weather in area	0%
Reclosing adapts to fault current level	7%
Reclosing adapts to type of fault (1Φ vs. 3Φ)	0%
Other	2%

Reclosing Statistics – Over 80% of respondents do not keep statistics on the effectiveness of reclosing. This is comparable to previous surveys. Only 2 of the 8 utilities who keep statistics report that this data indicates a need to modify present reclosing practices.

Changing Practices – Just over a third of the respondents have changed reclosing practices in the past 5 years. This is increased from about 1 in 4 in the previous survey. The most common change was to increase the first reclosing interval (53%), followed by decreasing the number of attempts (47%). Note that this is consistent with previous answers. Details are shown below:

Decrease the number of attempts per fault	47%
Increase the number of attempts per fault	6%
Lengthen the first reclosing interval	53%
Shorten the first interval	6%
Lengthen subsequent intervals or reset time	6%

Shorten subsequent intervals or reset time	6%
Add adaptive features	12%
Other	0%

Reclosing Hardware – When asked if their company was using something other than a dedicated automatic reclosing relay to accomplish reclosing, over 60% reported yes (including 7% trial installations and 2% planning to change). Of those 93% are using integral reclosing within the overcurrent relay. Details are shown below:

Integral reclosing within the overcurrent relay	93%
Programmable Logic Controller – dedicated to 1 feeder	10%
Programmable Logic Controller – multiple feeders	4%
RTU programmable capabilities	4%
Station Computer	0%
Other	4%

Ancillary Functions – Utilities were asked which recloser accessory features were used. The predominant response was Fuse Saving, with 61% using this function. Other features with significant use include: Force to Lockout (39%), Sequence Coordination with downstream reclosers (36%) and reclose fail timing (25%). Specific responses are as follows:

Reclose Fail timer	25%
Maximum Cycle timer	5%
Block Transformer LTC	11%
Sequence Coordination with downstream reclosers	36%
Fuse saving	61%
Wait (suspend reclosing)	2%
Force to Lockout (from input)	39%
Built in performance statistics	0%
None	14%
Other	0%

SECTION 7- SYSTEM FAULTS

Fault Statistics –Fully 93% of the respondents keep statistics on the number of outages on the distribution system, which is almost universal. This is a substantial increase from the 73% who reported "yes" in the previous survey. But only 44% keep statistics on the types of faults on the distribution system, and only 42% keep statistics on the performance of the distribution protection. When asked about monitoring the accumulated symmetrical interrupted current for distribution breakers to aid in breaker maintenance scheduling, only 9% said yes. 26% say they're planning to implement this feature in the near future. Only 3% were monitoring current for maintenance scheduling in the previous survey. This is a significant and continuing increase.

High Impedance Ground Faults (HIGF)- 16% of the respondents have a program in place to report high impedance ground faults (in particular, downed conductors). This is significantly higher then the 7% reported in the last survey, and appears to be a growing area of concern. There were only 7 utilities who reported how many high impedance faults have been reported in the past year. Their responses were: 10, 2, 1, 1, 0, 0, 0. This represents an average of 2 HIGFs per year. This data seems extremely low, especially when compared with the previous survey. That survey reported 148 HIGFs not detected by relays, 82 HIGFs not detected by reclosers and 94 HIGFs not detected by fuses (107 reporting utilities). The previous survey reported average "percent of total recorded ground faults not cleared" as between 1.5% and 3.5% depending on voltage classification. It is suspected that there may be an issue with the way in which the questions were worded in the two surveys. In the previous survey at least 98 utilities responded with HGIF not detected, although only 7 had reported that they kept records. In the current survey, respondents were not asked how many faults they'd seen unless they said they kept records.

Most of the responding companies (84%) do not have trial programs to evaluate new technology for downed conductor or high impedance ground fault detection. 16% (7 of 43) are evaluating High Impedance Fault / Open Conductor Detection systems, and 5% (2 of 43) are also evaluating Loss of Load Reporting System.

When asked if their company has applied any type of protection scheme solely for the purpose of detecting high impedance ground faults, 14% said yes, with another 2% considering. 84% are not using or considering HIGF schemes. This is virtually unchanged since the previous survey. Of those reporting yes, there was a 50/50 split between those applying the scheme to trip or to alarm only. Of those using HIGF schemes, 83% have seen operations in which no problem was found, and 67% have alarmed or tripped for otherwise undetectable conditions.

When asked about a new approach to improve protection of overhead distribution feeders which uses distribution transformers connected phase to neutral to an insulated overhead neutral separated from the system ground (5 wire distribution), 82% of the respondents were unfamiliar with this scheme. 18% were familiar with it but none have any installed or planned.

Breaker Failure Experience – The vast majority of respondents (80%) have experienced failures of distribution breakers in the last two years. 33% reported failures due to protection or control issues, and 65% report failures due to breaker problems (such as trip coil fail). 23% report "fail to clear" problems. Only 45% of the companies apply breaker failure protection on distribution feeder breakers. Of the companies applying breaker failure on distribution feeder breakers, 60% are applied on all new distribution breaker installations. Complete responses are shown below:

All distribution feeders	20%
Selected breakers, due to criticality	10%

All new distribution breaker installations	60%
All metalclad switchgear breakers	0%
Selected breakers, due to breaker failure history	5%
Other	10%

Among respondents using distribution breaker failure schemes, 87% have experienced proper trips, 20% have experiences false trips, and 7% have experienced fail to trip situations.

Conductor Burndowns – 72% of responding utilities have experienced conductor burndowns due to protection not operating or operating too slowly. The majority (81%, 25 of 31) report these problems only rarely, with 19% reporting occasionally, and none reporting frequent problems.

Clearing Times – Only 24% of the respondents have defined protective device clearing time criteria for distribution line protection (considering the last protective device upstream from the end of a distribution line). Of those with a criteria, there was no consensus for a maximum end-of-the-line clearing time. The specific responses were as follows:

Less than or equal to 60 cycles	27%
Between 60+ and 90 cycles	18%
Between 90+ and 120 cycles	9%
Between 120+ and 180 cycles	27%
More than 180 cycles	9%
Other	9%

When asked if they still employ time criteria when adding an impedance into fault current calculations, 45% of the respondents said yes. But there were very few (11) respondents, so this is not statistically significant. The specific responses were as follows:

Less than or equal to 60 cycles	20%
Between 60+ and 90 cycles	20%
Between 90+ and 120 cycles	40%
Between 120+ and 180 cycles	0%
More than 180 cycles	20%
Other	0%

Percentage of line end fault current was the most common “other” criteria used to select or set the last upstream device (58% of respondents). About a third of respondents (32%) use multiple of minimum trip current, 29% use size of trip current to load ratio, and 5% use some other (unspecified) criteria.

SECTION 8- COLD LOAD PICKUP

Cold-Load Pickup (CLPU) – Only 43 utilities responded to this section with only about half that responding to most questions and less than 10 to some questions. Of those responding to the survey with knowledge of whether that had or did not experience cold-load pickup 63%(24) respondents reported problems. This is down somewhat from the last survey. Of the 25 respondents to the types of trips that they received, 18 reported phase overcurrent trips while 16 reported ground overcurrent trips, with 4 respondents reporting other trips or did not know.
Of those 24 responding to experiencing cold-load pickup, 16 experienced CLPU on residential loads, 9 on commercial loads, 7 on rural loads, 2 on Industrial loads, and 8 did not know.

To reduce or eliminate the CLPU tripping the vast majority reported sectionalizing to pick up less load as the action that they take (83%). A third of the respondents replied that they have blocked instantaneous or fast tripping, or increased the phase overcurrent relay pickup. A sixth of the respondents increased the ground overcurrent pickup and 8 percent of the respondents increased the phase time overcurrent delay.

Only 4 respondents reported having attempted to measure cold load currents (magnitude and duration). The trend through the last several surveys is to resolve the CLPU issues with increased sectionalizing and/or increased relay settings and away from disabling tripping.

Magnetizing Inrush – Of the 34 respondents reporting whether they had magnetizing inrush events, 2% reported occasional inrush tripping and another 19% reported rare inrush tripping. The most common solution to these problems is to raise or add time delay to the phase or ground overcurrent settings. 22% chose to block tripping. In this survey no respondents chose to add harmonic restrained protection.

SECTION 9- SYSTEM OPERATION

Overvoltage - 5 respondents (12%) reported they had experienced sustained primary overvoltages due to neutral shift on multi-grounded systems. 26 respondents indicated they did not experience overvoltage problems and 13 respondents indicated they did not know. Of those who experienced overvoltages, the overvoltages resulted in surge arrester failures and/or “other” unidentified failures. There were no transformer fuse operations due to saturation or transformer failures reported as a result of overvoltage.

Sympathetic Tripping – 12 respondents (28%) reported sympathetic trips of breakers on unfaulted feeders that were supplied from the same bus as a faulted feeder. 21 respondents reported no sympathetic trips and 12 respondents indicated that they did not know. Of those experiencing sympathetic trips all applicable relays causing the sympathetic trip were reported as follows:

4 responses	33%	Phase instantaneous overcurrent relay
3 responses	25%	Ground instantaneous overcurrent relay
0 responses	0%	Phase time overcurrent relay

2 responses	17%	Ground time overcurrent relay
5 responses	42%	Unknown
0 responses	0%	Other

Capacitor Switching – 3 respondents (7%) reported incorrect feeder trips due to switching of capacitor banks connected to the feeder. 30 respondents indicated they did not experience any incorrect trips and 10 respondents indicated they did not know.

Coordination Between Bus and Feeder Relays – Survey responses to the minimum coordination margin between transformer or bus overcurrent relays at the maximum coordinating current level were as follows:

3 responses	7%	No policy
4 responses	9%	<0.2 seconds (<12 cycles)
28 responses	64%	0.2 - 0.4 seconds (12 - 24 cycles)
8 responses	18%	0.4+ - 0.6 seconds (24+ - 36 cycles)
1 response	2%	>0.6 seconds (>36 cycles)

Survey responses to the type of overcurrent relay reset was as follows:

19 responses	44%	Inverse (typical of electromechanical relays)
20 responses	47%	Fast reset (typical of circuit reclosers & some newer relays)
4 responses	9%	Settable time delay

Only 7 (16%) respondents indicated a requirement for all overcurrent relays to be completely reset before automatically reclosing.

Coordination Between Feeder Devices and Fuses – Survey recipients were asked to indicate the minimum coordination time margin between their feeder protective device time current curve and a downstream fuse total clearing time.

When the feeder protective device is an electromechanical disk overcurrent relay the responses were as follows:

4 responses	9%	No policy
8 responses	19%	<0.2 seconds (<12 cycles)
27 responses	63%	0.2 - 0.4 seconds (12-24 cycles)
3 responses	7%	0.4+ - 0.6 seconds (24+-36 cycles)
1 response	2%	>0.6 seconds (>36 cycles)

When the feeder protective device is an electronic or microprocessor-based relay the responses were as follows:

4 responses	9%	No policy
13 responses	30%	<0.2 seconds (<12 cycles)
22 responses	51%	0.2 - 0.4 seconds (12-24 cycles)
2 responses	5%	0.4+ - 0.6 seconds (24+-36 cycles)
2 responses	5%	>0.6 seconds (>36 cycles)

When the feeder protective device is a hydraulic recloser (for slow curves) the responses were as follows:

9 responses	21%	No policy
8 responses	19%	<0.2 seconds (<12 cycles)
20 responses	46%	0.2 - 0.4 seconds (12-24 cycles)
4 responses	9%	0.4+ - 0.6 seconds (24+-36 cycles)
2 responses	5%	>0.6 seconds (>36 cycles)

When the feeder protective device is a electronic recloser (for slow curves) the responses were as follows:

6 responses	14%	No policy
11 responses	25%	<0.2 seconds (<12 cycles)
21 responses	49%	0.2 - 0.4 seconds (12-24 cycles)
3 responses	7%	0.4+ - 0.6 seconds (24+-36 cycles)
2 responses	5%	>0.6 seconds (>36 cycles)

Current Limiting Fuses (CLFs) – Twenty-nine respondents (66%) indicated they use CLFs. Eight CLF users reported coordination or application problems with either general purpose or back up CLFs. All applications for which respondents use CLFs are listed as follows:

10 responses	34%	General purpose CLF (or full range)
19 responses	66%	Back-up CLF (or non-full range)
5 responses	17%	At overhead distribution line laterals (such as tap points)
8 responses	28%	At underground distribution line laterals

All reasons when respondents use CLFs are listed as follows:

14 responses	48%	High fault currents that exceed expulsion fuse rating
16 responses	55%	Limiting I-squared let-through
8 responses	28%	Locations that require non-expulsion fuses

1 responses	3%	Convenience of system standard
19 responses	66%	Safety (on transformer or capacitor banks)
1 response	3%	Other

When asked if CLFs are applied on the source side and/or load side of Completely Self-Protecting (CSP) transformers, 14 respondents (50%) indicated they apply CLFs on the source side only. No one reported using CLFs on the load side of these transformers. The remaining 14 respondents indicated they do not use CLFs on CSP transformers.

Automatic Sectionalizers – 26 respondents (60%) apply sectionalizers on distribution systems. The survey listed four specific types plus "other". Of those that use sectionalizers, responses to all types of sectionalizers applied are as follows:

18 responses	69%	Single phase hydraulic
11 responses	42%	Three phase hydraulic
18 responses	69%	Three phase electronic
9 responses	35%	Single phase "dry" type
3 responses	12%	Other

No problems were reported due to long reset times of sectionalizers and only 4 respondents indicated a problem with short reset times.

Distance Relays – 6 respondents (13%) reported it necessary to use distance relays on distribution circuits. The predominant reason for applying distance relays (5 out of 6 respondents) was to provide better discrimination between load and faults, followed by the need for faster clearing times and torque control of overcurrent relays. Responses to all types of phase distance relays used are as follows:

5 responses	83%	Phase distance only
2 responses	33%	Phase and ground distance
2 responses	33%	Single zone
5 responses	83%	Multi zone

Transfer Buses – 24 respondents (54%) reported use of a transfer bus arrangement. All applicable types of protection were reported as follows:

0 responses	0%	Fuses
7 responses	29%	Independent relayed interrupting devices
16 responses	67%	Protection incorporated with another feeder
4 responses	17%	Protection dedicated to a specific feeder
2 responses	8%	Protection incorporated with the transformer protection
0 responses	0%	Other

21 respondents (84%) require manual switching of the transfer bus. The remaining respondents utilize SCADA or some other means of switching.

Differential Relaying – While 42 respondents (95%) utilize transformer differential relaying to protect transformers, the minimum transformer size criterion for applying differential relaying varies. Responses to the minimum substation transformer size at which transformer differential relaying is normally applied is as follows:

1 response	2%	<5 MVA
4 responses	9%	5+ - 10 MVA
24 responses	55%	10+ - 20 MVA
13 responses	30%	>20 MVA
2 responses	5%	Not installed on any size

17 respondents (40%) replied that they include the low voltage bus as part of the transformer differential protection zone.

26 respondents (59%) indicated the use of high-speed low voltage bus protection at distribution substations. Of those that use bus protection schemes, responses to all types of applications are as follows:

5 responses	19%	On all distribution buses
2 responses	8%	On selected buses due to criticality
10 responses	34%	On buses served by transformers above a certain size
8 responses	28%	On new installations
7 responses	24%	On metalclad switchgear buses
3 responses	10%	On outdoor buses
2 responses	8%	Other

Backup Relaying – 39 respondents (89%) indicated they normally use an upstream device to provide backup protection for their distribution feeders. Types of backup protection reported as being used are as follows:

7 responses	18%	Transformer high side overcurrent relays
23 responses	59%	Transformer low side or main breaker overcurrent relays
2 responses	5%	Transformer neutral overcurrent relays
2 responses	5%	Dedicated backup relaying
5 responses	13%	Other

When asked what type of backup protection is provided for failure of a microprocessor distribution relay with 3 phases and ground protection within the same relay, the following responses were received:

9 responses	20%	A separate comparable relay on the same feeder
1 response	2%	A separate ground relay (only) on the same feeder
1 response	2%	Separate phase and ground relays on the same feeder
21 responses	48%	Normal upstream device relays
2 responses	5%	A dedicated backup relay on an upstream device
6 responses	4%	Unknown or Not applicable
4 responses	9%	Other

21 respondents (48%) do not require their backup protection to be able to operate with the same sensitivity for feeder ground faults as the normal feeder ground protection. 13 respondents (29%) indicated it is desirable but not always achievable and 10 respondents (23%) reported it as a requirement.

Time Based Maintenance Schedules – 14 respondents (33%) indicated they make adjustments to their time based feeder maintenance schedules due to the number of interrupted operations. 2 respondents (5%) make adjustments based on the total interrupted current (or some related value) and 2 make adjustments based on target or fault analysis data. 24 respondents (57%) indicated they do not make any adjustments to their maintenance schedule.

Accumulated Feeder Breaker Interrupt Currents – 31 respondents (72%) indicated they do not measure or determine accumulated feeder breaker interrupt currents. However, 4 of these respondents indicated they have future plans to do so either with a dedicated feeder breaker monitor or a microprocessor- based relay. Of the 12 respondents that do measure or determine accumulated feeder breaker interrupt currents, their reported means of capturing this data is as follows:

11 responses	92%	Microprocessor distribution relays
2 responses	17%	Estimated fault values with manual entry
1 responses	8%	Relay provided fault values with manual entry

No one reported the use of a dedicated feeder breaker monitor.

Remote Communications with Relays – 33 respondents (75%) indicated they presently communicate remotely with distribution protection relays.

Distribution Feeder Fault Location – 12 respondents (28%) are using distribution relay fault location to help determine how far out on a feeder a fault has occurred with satisfactory results. 4 respondents (9%) are using this capability with unsatisfactory results and 37 respondents (63%) either do not use this feature or do not have relays with this capability.

Substation Automation and Integration – Asked if their company applies some sort of substation automation or substation communication integration that incorporates distribution protection, the following responses were received:

16 responses	38%	Yes, this is current company policy
7 responses	17%	Yes, on a trial basis
5 responses	12%	Planning or specification process
14 responses	33%	No

Microprocessor Based Retrofit or Upgrade Programs - Asked if their company is in the process of retrofit or upgrade of distribution protection to install microprocessor based protection, control, data and monitoring packages, the following responses were received:

17 responses	39%	Yes
1 response	2%	Yes, on a trial basis
10 responses	23%	Planning or specification basis
16 responses	36%	No

SECTION 10- DISPERSED GENERATION

This was the second Distribution Protection Survey where the utilities were asked about the effect of Disbursed Sources of Generation (DSG) on their distribution protection practices. This section summarizes those responses and compares the responses with similar questions on the prior survey. 36 of the survey respondents provided information about DSG effects on their distribution protection. These 36 respondents did not always answer all of the questions regarding DSG.

Presence of DSG – 80% of the respondents indicated that they have DSG on distribution feeder(s). On the previous survey 75% indicated the presence of DGS on their feeders.

Effect of DSG on Protection Practices - Approximately 78% of the respondents indicated that DSG had effects on the protection of the feeder to which it was applied. The most common changes on the feeder protection practices were:

- Revised substation reclosing practices – 50%
- Added transfer trip capabilities – 47%
- Revised coordination of feeder relaying – 39%
- Added voltage relays – 36%
- Added directional ground overcurrent relays – 25%
- Added directional phase overcurrent relays – 22%
- Added supervisory control to the feeder – 22%
- No effect – 22%
- Revised substation manual switching procedures – 19%
- Revised settings of existing phase relays – 14%
- Other effects – 14%

These results were similar to the previous survey but more details were provided.

Effect of DSG on Reclosing Practices - The most common changes made to automatic reclosing practices due to DSG are:

- Added voltage check supervision – 46%
- Extended first shot recluse time – 26%
- Added communications permission/control – 20%
- Eliminated all reclosing on the feeder – 14%
- Added synchronism supervision – 14%
- Reduced number of reclose attempts – 6%
- Added logic supervision – 6%
- Other – 6%

Extending reclose time was the predominant change on the previous survey. The results were generally similar with those of the previous survey. Eliminating reclosing did not appear as a change on the previous survey.

Fault Current Contribution from the DSG - Again in this survey the phase fault current contribution from the DSG is primarily determined by the DSG size or type and the transformer impedance. Only one respondent indicated use of phase reactors.

Ground fault current contribution was determined by DSG size (31%) and Transformer impedance (23%). 26% indicated there was no limitation on ground fault current. In the prior survey 70% of respondents indicated that transformer impedance determined ground fault current. Only 8% of respondents indicated use of neutral resistors or reactors to limit ground fault current. In the prior survey the transformer impedance was sited by 70% of respondents as the primary determination of ground fault current.

Fault current contribution from induction generators was considered by 30% of the respondents vs. 16% in the prior survey.

Load Unbalance with DSG - All of the respondents indicated that no difference in load unbalance was permissible with a DSG on the feeder. This is similar to the previous survey data.

Recommended (Feeder Side) Interface Transformer Connections - No interface transformer was required by 30% of the respondents. The respondents requiring transformer connections indicated Grounded Wye either required or recommended by 58% of respondents. Delta connections were required or recommended by 9% of respondents. This result is markedly changed from the previous survey where an equal number of respondents indicated Delta and Wye connections used.

Ferroresonance Problems - 97 % of respondents indicated no problems with ferroresonance or they didn't know of any problems.

Automatic Throwover Equipment - Automatic throwover equipment was allowed to be used with the DSG by 59% of respondents.

Network Protectors - DSG's were not allowed to be used with network protectors by 52% of respondents. 39 % indicated this was not applicable on their systems.

Standard Relay Specification for DSG's - Standard relay specifications were in place by 69% of the respondents. The relay standard depends on several factors including:

- Generator Size (75%)
- Interconnection Type (75%)
- Voltage Level (54%)
- Existing Line Protection (29%)
- Loading on the DSG Line (17%)
- Other factors (13%)

SECTION 11- PRESENTATION SUMMARY

Over the course of the time that the "Effectiveness of Distribution Protection" Working Group worked to prepare, distribute, and summarize the utility practices survey, a number of presentations and discussions were made to the group that addressed emerging technological trends in the field of distribution protection. Some of these presentations discussed new protection technologies or applications, while others addressed issues related to event analysis now possible through the deployment of digital relays and fault recorders. A brief summary of these issues follows:

"High Speed Fault Sectionalizing for Underground Distribution Networks" and "International Drive Distribution Automation and Protection"- These presentations discussed an advanced technological application for a high reliability portion of one utility's distribution system that applies transmission protection practices at the distribution level. The goal of this application is to provide restoration of an underground system failure in 6 cycles and an overhead system failure in less than 1 minute. This application includes both a Permissive Overreaching Transfer Trip (POTT) scheme and a Directional Comparison Blocking (DCB) scheme and relies on fiber optics for inter-relay communications between numerous padmounted pieces of equipment. Multiple communications paths are used to provide self-healing in case of communications circuit dig-ins. Each piece of padmount gear is treated as a mini-bus and each section of cable is treated as a transmission line. Voltage sensing is also used to provide directionality/polarizing quantities. Non-communication based time overcurrent protection is provided at the source substation as a backup.

"Using Voltage to Enhance Distribution Protection"- This presentation discussed the use of voltage as an input to microprocessor-based relays, allowing for additional protection functionality. Examples include the detection of single phasing conditions due to delta-wye transformer high side open phase conditions, improved discrimination of fault vs. load current conditions, overcurrent directionality, better supervision of manual and automatic reclosing, undervoltage/frequency load shedding, enhanced fault analysis, and comprehensive metering.

"Improved Relay Coordination Through Curve Shaping"- This presentation discussed improving relay coordination for high duty faults by integrating relay functions to reduce operating times. This was accomplished through coordination of instantaneous elements through curve shaping, and separate 'zones' of definite time overcurrent protection defined for close-in, midline, and line end of a distribution circuit. Different curve shapes were utilized to develop a composite operating curve in a microprocessor-based relay in order to reduce operate times to less than 1 second.

"Distributed Generation Interconnection Issue Overview"- This was a discussion of a Power Systems Relaying Committee Working Group created to address issues associated with IEEE Standards Coordinating Committee 21's development of P1547, the Standard for Distributed Resources Interconnected with Electric Power Systems.

"Use of LAN's/WAN's to protect Distributed Generation on Utility Feeders"- This presentation discussed a concept for transfer tripping of merchant generation plants via the internet in 200 milliseconds or less. The concept was developed using the assumption that the utility source distribution substation is integrated and has a substation Local Area Network (LAN). The substation LAN could carry a transfer trip signal through a utility Wide Area Network (WAN) and ultimately to a customer/generator LAN via the internet. Challenges to implementing this concept may include security issues and internet traffic.

"Event Abnormalities in Distribution Circuits"- This presentation discussed the application of 5 fault recorders to monitor distribution circuits over a 2 year study period. Analysis of events implies that fuse saving may not work in many cases in the field due to fuse operating times being faster than typical distribution circuit breaker operating times. Many 1/2-cycle events that were seen are believed to be arrester operations or insulator flashovers rather than fuse operations. Other events studied included overexcitation and saturation of distribution transformers in light load/system overvoltage conditions that resulted in characteristic sawtooth waveforms.

"Analysis of Distribution Faults Using a Power Quality Monitor and Potential Protection Modifications"- This presentation discussed the use of permanent power quality monitors as event recorders. The recordings demonstrated that single phase faults frequently evolved into multi-phase faults on distribution circuits if not interrupted quickly. Many 1-4 cycle fuse operations with simultaneous recloser trip operations due to instantaneous relay trips were experienced. The utility that presented this material has considered moving from instantaneous to .10 second definite time trips and adding reclosing where none exists to reduce fault clearing times and reduce the number of evolving faults and subsequent damage and restoration times.

"Sympathetic Tripping"- This presentation discussed fault records for system events with sympathetic trips. These fault records indicate that post-fault three-phase currents of three times prefault current are sometimes seen on distribution circuits under low voltage conditions. It is believed that AC motor load inrush, occurring for a number of seconds, is causing this problem. In some cases where fuse saving is applied 'sympathetic trips' have occurred on distribution circuits supplied from the same bus as a faulted circuit.

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