

Worldwide Study Of The Protective Relay Marketplace In Electric Utilities: 2012-2014

Volume 1 – North American Market

NEWTON-EVANS
RESEARCH
COMPANY 

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SAMPLE

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- 60 17a. Do you currently/plan to outsource preliminary and/or detailed engineering related to protection for any of the following: A. Distribution projects; B. Distribution automation projects; C. Transmission projects; D. Special protection schemes; E. Critical assets above 100kV; F. Generation projects; G. Interconnection projects; H. Smart Grid protection projects; I. Other
- 61 17b. If you are currently outsourcing any of the above, by YE 2014 do you expect outsourcing levels to remain the same, increase, or decrease?
- 62 18. Do you currently/plan to outsource protection-related engineering services? A. Education; Studies; C. Preliminary Engineering; D. Detailed Engineering; E. Integration; F. O&M; G. Strategic Planning
- 63 19a. Is your utility using or planning to use synchronized phasor measurement (synchrophasor) data?
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- By relying exclusively on microprocessor relays
- By moving to microprocessor relays, but not exclusively
- By relying exclusively on stand-alone PMUs
- By moving to stand-alone PMUs, but not exclusively
- 65 19c. What time synchronization methods do you use or plan to use?
- 66 20. Please indicate your level of agreement with the following statements:
- A. It is important that we purchase known relays (a proven product with which we have had prior experience).
- B. When we purchase new relays, it is important that they be proven capable of interoperability.
- C. We are interested in having higher bandwidth connections to relays.
- D. We prefer to have a wireless handheld device/computer to change setting & programming from the street level when relays are mounted on the power pole.
- E. For Distribution Automation applications, we prefer relays integrated with the communication interface (fiber, radio) in one package.
- F. Assuming the same functionalities, we prefer a relay with a smaller footprint in field locations with limited space.
- G. We plan to adopt special applications for Dynamic Line Rating by YE 2014.
- H. By YE 2014, we will be well on our way toward implementing the full digital substation concept.
- I. We plan to increase use of condition based maintenance to reduce maintenance testing time of technicians.

- 69 21a. How often (at what interval) do you perform routine testing of microprocessor relays only?
- 69 21b. How often (at what interval) do you perform routine testing of whole scheme?
- 70 22. At commissioning of multi-function, multi-stage, numerical protection, are all stages of a given function tested, or just those intended for use day one?

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Foreword

Volume One of this 2012 study of protection and control is based on a strong sample of North American utilities, including investor-owned, public and cooperative electric power utilities.

It is important to read the summary findings and related charts and also to utilize the tables found later in the report. The tabular data provides information on a segmented basis by type of utility and by size range. These tables help illustrate occasional important differences in the findings based on the type of utility and/or by the size of the utility.

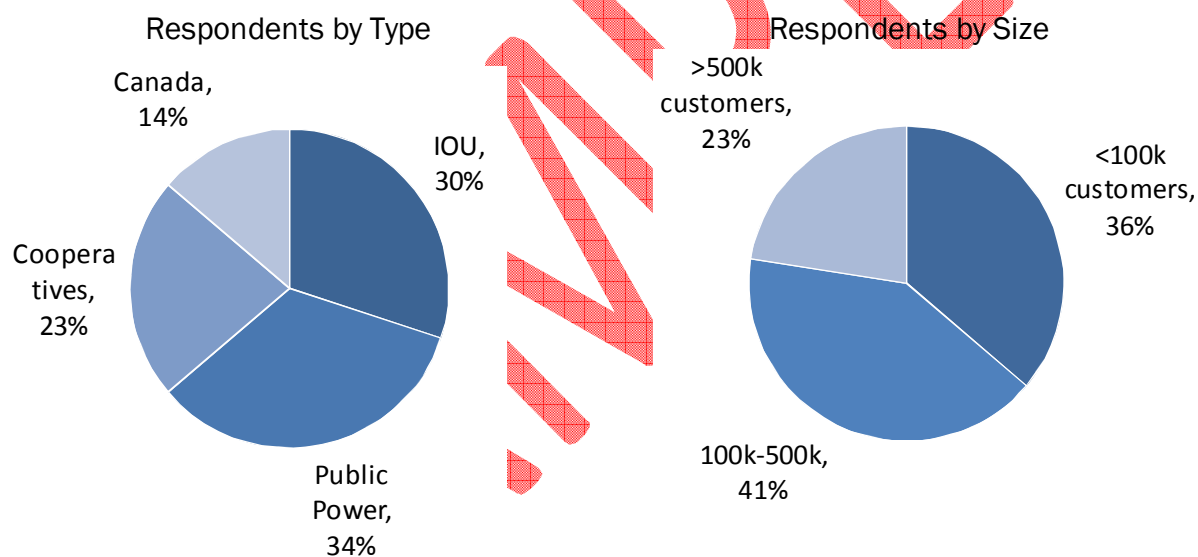
Volume Two in this 2012 series includes findings from utilities located in more than 25 countries outside of North America.

Volume Three is a global market assessment and outlook report.

Volume Four is a set of profiles of more than 25 protective relay manufacturers located throughout the world serving the electric power industry.

The findings in this report are based on survey responses received from 80 electric utilities that include 24 investor-owned, 27 public power, 18 cooperative, and 11 Canadian utilities. This survey was conducted between January and March of 2012. Initial phone calls were placed to utility officials and relay engineers to invite them to complete the survey as a Microsoft Word attachment via email. Reminders were sent via email every 2 weeks until the last call deadline was issued.

The 80 utilities participating in this year's study represent 41,657,000 electricity end users/customers, with 2,537 transmission substations and 9,137 distribution substations covering over 1,452,000 total line miles. This sample is about 29% of the North American customer base and approximately 20% of utility-operated transmission and distribution substations. Using a 5x multiplier to estimate the overall North American electric power utility market may provide reasonable "ballpark" insights.



American and Canadian utilities participating in the earlier 2009 survey represented approximately 25% of the estimated total of North American (U.S. and Canada) customers, and about the same percentage of North American electric utility revenues. The sample utilities accounted for approximately 3,800 transmission substations out of a total of about 16,000 (or about 24%) and for some 10,250 distribution substations out of a total of approximately 48,500 American and Canadian distribution substations (21%) operated by more than 3,000 electric power delivery utilities.

Table 20. Please indicate your level of agreement with the following statements:

SUMMARY

I. We plan to increase use of condition based maintenance to reduce maintenance testing time of technicians.

Strongly Agree	Agree	Neutral	Disagree	Strongly Disagree	Total
Investor Owned					
Strongly Agree	Agree	Neutral	Disagree	Strongly Disagree	Total
Public Power					
Strongly Agree	Agree	Neutral	Disagree	Strongly Disagree	Total
Cooperative					
Strongly Agree	Agree	Neutral	Disagree	Strongly Disagree	Total
Canada					
Strongly Agree	Agree	Neutral	Disagree	Strongly Disagree	Total
<100k customers					
Strongly Agree	Agree	Neutral	Disagree	Strongly Disagree	Total
100k-500k customers					
Strongly Agree	Agree	Neutral	Disagree	Strongly Disagree	Total
>500k customers					
Strongly Agree	Agree	Neutral	Disagree	Strongly Disagree	Total

Table 22. At commissioning of multi-function, multi-stage, numerical protection, are all stages of a given function tested, or just those intended for use day one?

SUMMARY

All stages are tested at commissioning	We only test for those used on day one	Testing for all or some depends on the situation	Total
--	--	--	-------

Investor Owned

All stages are tested at commissioning	We only test for those used on day one	Testing for all or some depends on the situation	Total
--	--	--	-------

Public Power

All stages are tested at commissioning	We only test for those used on day one	Testing for all or some depends on the situation	Total
--	--	--	-------

Cooperative

All stages are tested at commissioning	We only test for those used on day one	Testing for all or some depends on the situation	Total
--	--	--	-------

Canada

All stages are tested at commissioning	We only test for those used on day one	Testing for all or some depends on the situation	Total
--	--	--	-------

<100k customers

All stages are tested at commissioning	We only test for those used on day one	Testing for all or some depends on the situation	Total
--	--	--	-------

100k-500k customers

All stages are tested at commissioning	We only test for those used on day one	Testing for all or some depends on the situation	Total
--	--	--	-------

>500k customers

All stages are tested at commissioning	We only test for those used on day one	Testing for all or some depends on the situation	Total
--	--	--	-------

Newton-Evans thanks the following utilities for participating in our survey:

Investor Owned:

Baltimore Gas & Electric
Bangor Hydro Electric
Central Hudson Gas & Electric
Empire District Electric Company
Idaho Power Company
Indianapolis Power & Light
ITC Midwest
MidAmerican Energy
New Mexico Public Service Co.
Northeast Utilities (Connecticut L&P)
Northeast Utilities (Western Mass)
NV Energy
Oklahoma Gas & Electric
Oncor
Orange and Rockland Utilities
Otter Tail Power Co.
Pacific Gas & Electric
PECO Energy
Progress Energy Carolinas
Progress Energy Florida
San Diego Gas & Electric
South Carolina Electric & Gas Co.
Southern California Edison
Xcel Energy

Cooperative:

Big Rivers Electric
Blue Ridge EMC
Connexus Energy
Dairyland Power Cooperative
Dakota Electric Association
East Kentucky Power Coop
Energy United
Lee County Electric Cooperative
Mid-Carolina ECI
Middle Tennessee EMC
Ozarks Electric Cooperative Corp.
Rutherford EMC
Southern Maryland Electric Coop
Southern Pine EPA
United Power Inc.
Verendrye Electric Cooperative
Withlacoochee River Electric Cooperative
Wolverine Power Supply Cooperative

Public Power

Alcoa Electric Department
Austin Energy
Burbank, CA Water & Power
Clark PUD
Clinton Utilities Board
Columbus, OH
Cowlitz PUD
Dickson Electric System
Fayetteville PWC
Frankfort Plant Board
Grant PUD
Hagerstown Light Dept.
High Point, NC
Huntsville Utilities
Lakeland Electric
Lansing Board of Water & Light
Lenoir City Utilities Board
Nashville Electric
Omaha Public Power District
Riverside, CA Public Utilities
Roseville, CA Electric
Salem Electric
Silicon Valley Power
Snohomish County PUD
Springfield, MO
St. Charles Municipal Electric
USBR Grand Coulee

Canada:

Enersource Hydro Mississauga
EPCOR Transmission
Fortis BC
Hydro Ottawa Ltd.
Hydro Québec
Hydro-Sherbrooke
London Hydro
Maritime Electric
Medicine Hat
PowerStream Inc.
Whitby Hydro

1a. Please estimate the number of protective relay systems to be purchased from 2012-2014. Also, indicate the approximate percentage of microprocessor relays (including digital & numerical) currently in the installed base.

Type of relay	Purchase Plans for Number of Relay Systems			Microprocessor Relays
	2012	2013	2014	Approx. % of Installed Base Now
Distribution Feeder	[]	[]	[]	[]%
Capacitor Bank Protection	[]	[]	[]	[]%
Transformer	[]	[]	[]	[]%
Transmission Line Distance	[]	[]	[]	[]%
Transmission Line Current Differential	[]	[]	[]	[]%
Bus, Breakers, Motor, etc.	[]	[]	[]	[]%
Generator Protection	[]	[]	[]	[]%
Other, specify:	[]	[]	[]	[]%

1b. Approximately how many individual electromechanical (EM) relays are you planning to upgrade to microprocessor relays on your transmission and distribution systems by YE 2014?

Number of individual EM relays to be upgraded with microprocessor relays: Transmission [] Distribution []

1c. Approximately how many EM relays do you expect to purchase between 2012-2014? []

1d. Does your utility have ANY EM relays? ☐ Yes ☐ No

If your utility has no EM relays, please go to Question 2.

1e. Will EM relays will be replaced as situations dictate? ☐ Yes ☐ No

1f. Will your EM relays will be upgraded via a planned program? ☐ Yes ☐ No

2. Please indicate your estimated annual budget allocation for protective relay hardware for these time frames.

2012 Budget:

☐ <\$100,000 ☐ \$100,000-\$250,000 ☐ \$250,000-\$500,000 ☐ \$500,000-\$1 million ☐ >\$1 million

2013 Budget:

☐ <\$100,000 ☐ \$100,000-\$250,000 ☐ \$250,000-\$500,000 ☐ \$500,000-\$1 million ☐ >\$1 million

2014 Budget:

☐ <\$100,000 ☐ \$100,000-\$250,000 ☐ \$250,000-\$500,000 ☐ \$500,000-\$1 million ☐ >\$1 million

3a. Overall, do you plan to increase, decrease or maintain current levels of capital investment for relay testing equipment, software and training?

☐ Increase capital investment ☐ Decrease capital investment ☐ Maintain current level of capital investment

3b. Do you plan to rely more on third party services for relay testing? ☐ Yes ☐ No

3c. If so, what types of third party services will you use?

4a. Do you operate a Wide Area Network (WAN) for remote access to relays? ☐ Yes ☐ No

4b. If yes, please indicate the approach(es) you are using. (Check all that apply.)

- ☐ Ethernet direct to relays
- ☐ Via serial port terminal servers or data concentrators
- ☐ Routers with encryption or VPN
- ☐ Firewalls
- ☐ Traffic flow monitoring and directional management
- ☐ Authentication
- ☐ Other strategies (please identify)

5. Please indicate your current relay protocol requirement(s).

	Transmission	Distribution
DNP3	<input type="checkbox"/>	<input type="checkbox"/>
MODBUS	<input type="checkbox"/>	<input type="checkbox"/>
UCA2	<input type="checkbox"/>	<input type="checkbox"/>
IEC 61850 Edition 1	<input type="checkbox"/>	<input type="checkbox"/>
IEC 61850 Edition 2	<input type="checkbox"/>	<input type="checkbox"/>
Other (mention): []	<input type="checkbox"/>	<input type="checkbox"/>

6. In your opinion, please rank your favorite three relay manufacturers in order from 1-3 (1 = “the best” etc.) based on the following choices: ABB, Alstom Grid, Basler, Beckwith, Cooper, Cutler Hammer, FKI, GE Multilin, RFL, Schneider, SEL, Siemens, and ZIV.

1. [] 2. [] 3. []

7. Does your utility have any application plans for remedial action schemes (RAS)/special protection systems (SPS)?

☐ No ☐ Unsure ☐ Yes, for the following applications: _____

8a. What type of relay scheme redundancy do you use/plan to use for microprocessor-based relaying terminals? (Check all that apply)

Type of Redundancy	Generator		Transmission		Sub-transmission		Distribution	
	Current	Planned	Current	Planned	Current	Planned	Current	Planned
Same manufacturer with different operating principles	<input type="checkbox"/>	<input type="checkbox"/>	<input type="checkbox"/>	<input type="checkbox"/>	<input type="checkbox"/>	<input type="checkbox"/>	<input type="checkbox"/>	<input type="checkbox"/>
Different manufacturer with different operating principles	<input type="checkbox"/>	<input type="checkbox"/>	<input type="checkbox"/>	<input type="checkbox"/>	<input type="checkbox"/>	<input type="checkbox"/>	<input type="checkbox"/>	<input type="checkbox"/>
Different manufacturer with similar operating principles	<input type="checkbox"/>	<input type="checkbox"/>	<input type="checkbox"/>	<input type="checkbox"/>	<input type="checkbox"/>	<input type="checkbox"/>	<input type="checkbox"/>	<input type="checkbox"/>
Duplicate products	<input type="checkbox"/>	<input type="checkbox"/>	<input type="checkbox"/>	<input type="checkbox"/>	<input type="checkbox"/>	<input type="checkbox"/>	<input type="checkbox"/>	<input type="checkbox"/>
No redundancy	<input type="checkbox"/>	<input type="checkbox"/>	<input type="checkbox"/>	<input type="checkbox"/>	<input type="checkbox"/>	<input type="checkbox"/>	<input type="checkbox"/>	<input type="checkbox"/>

8b. For which applications do you use a different vendor for redundancy?

--

9. Does your utility's control system use protocol IEC 61850 for:

Substation Automation	<input type="checkbox"/> Yes	<input type="checkbox"/> No, but we plan to by YE _____	<input type="checkbox"/> No, not at all
Protection	<input type="checkbox"/> Yes	<input type="checkbox"/> No, but we plan to by YE _____	<input type="checkbox"/> No, not at all
Control	<input type="checkbox"/> Yes	<input type="checkbox"/> No, but we plan to by YE _____	<input type="checkbox"/> No, not at all
SCADA	<input type="checkbox"/> Yes	<input type="checkbox"/> No, but we plan to by YE _____	<input type="checkbox"/> No, not at all
Other: _____	<input type="checkbox"/> Yes	<input type="checkbox"/> No, but we plan to by YE _____	<input type="checkbox"/> No, not at all

☐ Have no plans for IEC 61850 by YE 2014. Please go to Question 14a.

10a. Does your utility use IEC 61850 protocols within the substation? ☐ Yes ☐ No

If not, please go to Question 14a.

10b. If your utility uses IEC 61850 within the substation, what advantages, disadvantages have you seen?

--

10c. Which features of IEC 61850 are being/will be used in new projects?

- ☐ **Data Modeling** -- Complete functionality of the substation is modeled into different standard logical nodes which can be grouped under different logical devices. There are logical nodes for data/functions related to the logical device (LLNO) and physical device (LPHD).
- ☐ **Reporting Schemes** -- There are various reporting schemes (BRCB & URCB) for reporting data from server through a server-client relationship which can be triggered based on pre-defined trigger conditions.
- ☐ **GOOSE** -- For high speed control including critical status reporting and breaker tripping over the LAN/WAN.
- ☐ **Setting Groups** -- The setting group control Blocks (SGCB) are defined to handle the setting groups so that user can switch to any active group according to the requirement.
- ☐ **Sampled Data Transfer** -- Schemes are also defined to handle transfer of sampled values using Sampled Value Control blocks (SVCB).
- ☐ **Commands** -- Various command types are also supported by IEC 61850 which include direct & SBO commands with normal and enhanced securities.
- ☐ **Data Storage** -- SCL (Substation Configuration Language) is defined for complete storage of configured data of the substation in a specific format.

11. Please indicate the planned level of implementation of IEC 61850 in your substations by YE 2014.

____ % of new substations will use IEC 61850
____ % of substations will be retrofitted with IEC 61850

12a. Do you/will you apply IEC 61850 at ALL voltage levels? ☐ Yes (Go to Question 13) ☐ No

12b. If not, then at which voltage levels is IEC 61850 applied: ☐ 4kV-26kV ☐ 33kV-69kV ☐ Over 69kV

13. What has been your experience with the implementation of IEC 61850 in terms of cost savings?

14a. Does your utility use fiber optics to connect substations? ☐ Yes ☐ No

If not, please go to Question 16.

14b. Does your utility use dedicated end to end single mode fiber directly connected to relays?

☐ Yes ☐ No ☐ Sometimes (explain)

14c. Does your utility use multiplexing signals from different applications into a multi-mode fiber through a digital gateway switch?

☐ Yes ☐ No ☐ Sometimes (explain)

15. What methods of testing does your utility use to ensure timely tripping when using fiber?
(Check all that apply.)

- ☐ Metallic trip comparison at end device
- ☐ End to end time stamp comparisons
- ☐ Comparison of synchronized time stamps in the end devices
- ☐ Other (specify) []
- ☐ No testing done

16. At what voltage(s) does your utility specify arc flash protection in switchgear?

☐ 480v-600v ☐ 1kV-5kV ☐ 5kV-15kV ☐ 25kV-38kV ☐ Above 38kV ☐ None ☐ Does Not Apply

17a. Do you currently/plan to outsource preliminary and/or detailed engineering related to protection for:

	<u>Outsource Now</u>	<u>By YE 2014</u>	<u>No Plans</u>
A. Distribution projects	<input type="checkbox"/>	<input type="checkbox"/>	<input type="checkbox"/>
B. Distribution automation projects	<input type="checkbox"/>	<input type="checkbox"/>	<input type="checkbox"/>
C. Transmission projects	<input type="checkbox"/>	<input type="checkbox"/>	<input type="checkbox"/>
D. Special protection schemes	<input type="checkbox"/>	<input type="checkbox"/>	<input type="checkbox"/>
E. Critical assets above 100kV	<input type="checkbox"/>	<input type="checkbox"/>	<input type="checkbox"/>
F. Generation projects	<input type="checkbox"/>	<input type="checkbox"/>	<input type="checkbox"/>
G. Interconnection projects	<input type="checkbox"/>	<input type="checkbox"/>	<input type="checkbox"/>
H. Smart Grid protection projects	<input type="checkbox"/>	<input type="checkbox"/>	<input type="checkbox"/>
I. Other (specify below)	<input type="checkbox"/>	<input type="checkbox"/>	<input type="checkbox"/>

17b. If you are currently outsourcing any of the above, by YE 2014 do you expect outsourcing levels to: ☐ Remain about the same ☐ Increase ☐ Decrease

18. Do you currently/plan to outsource protection-related engineering services? (Check all that apply.)

	<u>Outsource Now</u>	<u>By YE 2014</u>	<u>No Plans</u>
A. Education	<input type="checkbox"/>	<input type="checkbox"/>	<input type="checkbox"/>
B. Studies	<input type="checkbox"/>	<input type="checkbox"/>	<input type="checkbox"/>
C. Preliminary Engineering	<input type="checkbox"/>	<input type="checkbox"/>	<input type="checkbox"/>
D. Detailed Engineering	<input type="checkbox"/>	<input type="checkbox"/>	<input type="checkbox"/>
E. Integration	<input type="checkbox"/>	<input type="checkbox"/>	<input type="checkbox"/>
F. O&M	<input type="checkbox"/>	<input type="checkbox"/>	<input type="checkbox"/>
G. Strategic Planning	<input type="checkbox"/>	<input type="checkbox"/>	<input type="checkbox"/>

Key to above services

- A. Education - Learning about protective relay functions and operations
- B. Studies - Performing protection-related studies to develop settings
- C. Preliminary Engineering - Developing preliminary schematics and diagrams for protective relays
- D. Detailed Engineering - Developing detailed schematics and diagrams for protective relays
- E. Integration - Designing communication and integration solutions for protective relays
- F. O&M - Interpretation of event information to guide operation and maintenance improvements
- G. Strategic Planning – How to design protection systems communications, and enterprise integration around new or coming technologies and industry factors

19a. Is your utility using or planning to use synchronized phasor measurement (synchrophasor) data?

☐ Yes ☐ No, but we plan to by YE _____ ☐ No, not at all (Go to Question 20)

19b. How?

	<u>Do Now</u>	<u>By YE 2014</u>	<u>No Plans</u>
By relying exclusively on microprocessor relays	<input type="checkbox"/>	<input type="checkbox"/>	<input type="checkbox"/>
By moving to microprocessor relays, but not exclusively	<input type="checkbox"/>	<input type="checkbox"/>	<input type="checkbox"/>
By relying exclusively on stand-alone PMUs	<input type="checkbox"/>	<input type="checkbox"/>	<input type="checkbox"/>
By moving to stand-alone PMUs, but not exclusively	<input type="checkbox"/>	<input type="checkbox"/>	<input type="checkbox"/>

19c. What time synchronization methods do you use or plan to use?

	Now	By YE 2014
Transmission Substations	<input type="checkbox"/> IRIG-B <input type="checkbox"/> NTP <input type="checkbox"/> PTP (IEEE 1588) <input type="checkbox"/> Other <input type="checkbox"/> None	<input type="checkbox"/> IRIG-B <input type="checkbox"/> NTP <input type="checkbox"/> PTP (IEEE 1588) <input type="checkbox"/> Other <input type="checkbox"/> None
Distribution Substations	<input type="checkbox"/> IRIG-B <input type="checkbox"/> NTP <input type="checkbox"/> PTP (IEEE 1588) <input type="checkbox"/> Other <input type="checkbox"/> None	<input type="checkbox"/> IRIG-B <input type="checkbox"/> NTP <input type="checkbox"/> PTP (IEEE 1588) <input type="checkbox"/> Other <input type="checkbox"/> None
Remote Recloser Controls or Similar	<input type="checkbox"/> IRIG-B <input type="checkbox"/> NTP <input type="checkbox"/> PTP (IEEE 1588) <input type="checkbox"/> Other <input type="checkbox"/> None	<input type="checkbox"/> IRIG-B <input type="checkbox"/> NTP <input type="checkbox"/> PTP (IEEE 1588) <input type="checkbox"/> Other <input type="checkbox"/> None

20. Please indicate your level of agreement with the following statements:

- A. It is important that we purchase known relays (a proven product with which we have had prior experience).
☐ Strongly Agree ☐ Agree ☐ Neutral ☐ Disagree ☐ Strongly Disagree
- B. When we purchase new relays, it is important that they be proven capable of interoperability.
☐ Strongly Agree ☐ Agree ☐ Neutral ☐ Disagree ☐ Strongly Disagree
- C. We are interested in having higher bandwidth connections to relays.
☐ Strongly Agree ☐ Agree ☐ Neutral ☐ Disagree ☐ Strongly Disagree
- D. We prefer to have a wireless handheld device/computer to change setting & programming from the street level when relays are mounted on the power pole.
☐ Strongly Agree ☐ Agree ☐ Neutral ☐ Disagree ☐ Strongly Disagree
- E. For Distribution Automation applications, we prefer relays integrated with the communication interface (fiber, radio) in one package.
☐ Strongly Agree ☐ Agree ☐ Neutral ☐ Disagree ☐ Strongly Disagree
- F. Assuming the same functionalities, we prefer a relay with a smaller footprint in field locations with limited space.
☐ Strongly Agree ☐ Agree ☐ Neutral ☐ Disagree ☐ Strongly Disagree
- G. We plan to adopt special applications for Dynamic Line Rating by YE 2014.
☐ Strongly Agree ☐ Agree ☐ Neutral ☐ Disagree ☐ Strongly Disagree
- H. By YE 2014, we will be well on our way toward implementing the full digital substation concept.
☐ Strongly Agree ☐ Agree ☐ Neutral ☐ Disagree ☐ Strongly Disagree
- I. We plan to increase use of condition based maintenance to reduce maintenance testing time of technicians.
☐ Strongly Agree ☐ Agree ☐ Neutral ☐ Disagree ☐ Strongly Disagree

21a. How often (at what interval) do you perform routine testing of microprocessor relays only: []

21b. How often (at what interval) do you perform routine testing of whole scheme: []

22. At commissioning of multi-function, multi-stage, numerical protection, are all stages of a given function tested, or just those intended for use day one? (Example: where there are 4 over-current stages, but only 2 being used at first, are all 4 stages tested so they can easily be 'switched on' later, without an outage for re-commissioning)

- ☐ All stages are tested at commissioning
☐ We only test for those used on day one
☐ Testing for all or some depends on the situation

THANK YOU FOR YOUR PARTICIPATION