

The World Market Study of SCADA, EMS, DMS and OMS in Electric Utilities: 2013-2015

Volume 1: North American Market



©January 2013

SAMPLE

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This 2013 study of the market for SCADA, EMS, DMS and OMS is a continuation of survey-based reporting conducted by Newton-Evans Research Company for over 20 years. The summaries in this first section provide top-level views and synopsis. For more detail and to view responses by type of utility (Investor Owned, Public Power, Cooperative, Canadian) or by size of utility (<50k, 50k-150k, 150k-1million, >1 million customers), see the section on “Detail Tables” toward the end of this report; observations gleaned from this section are mentioned throughout the “Survey Findings” section as well.

According to the U.S. Department of Energy and American Public Power Association records, at year-end 2008 there were 202 investor-owned electric utilities, 2,008 publicly-owned electric utilities, 877 consumer-owned rural electric cooperatives, and 9 Federal electric utilities. Since Federal electric utilities only make up a fraction of a percent of the total population of U.S. electric utilities, in the survey sample Newton-Evans includes them with publicly owned electric utilities. Both TVA and BPA indirectly serve more than 25 million end-use customers.

Source: <http://www.publicpower.org/files/PDFs/NumberofElectricProvidersCustomers.pdf>

There are approximately 239 electric utilities operating in Canada. This number includes 21 investor-owned utilities, 5 TSOs, 23 provincial level utilities, 125 municipals, 64 cooperatives and one public power district. The province of Ontario alone accounts for 43% of the number of Canadian utilities.

Fig. i – Utility Respondents by Type

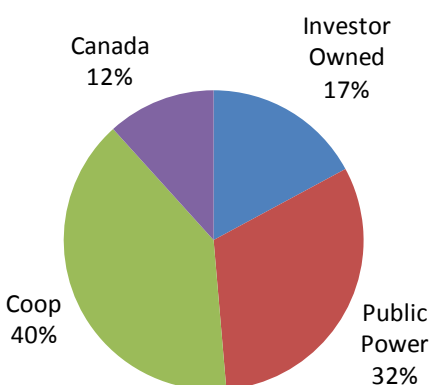
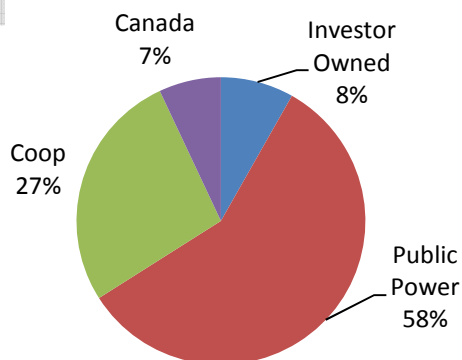


Fig. ii – Proportion of Types of U.S. & Canada Electric Utilities According to the U.S. DOE and PLATTS Directory 2011



Here are some additional characteristics of the survey sample:

<u>Type</u>	<u>#Respondents</u>
Investor Owned	19
Public Power	35
Cooperative	44
Canada	13

<u>#Customers</u>	<u>#Respondents</u>
<50k	39
$50k \leq x < 150k$	33
$150k \leq x < 1\text{million}$	28
$\geq 1\text{ million}$	11

Newton-Evans thanks these utilities for participating in our survey:

Investor-Owned

Avista Corp
Bangor Hydro Electric
Detroit Edison Company
Duke Florida
Empire District Electric Co.
Florida Power & Light
ITC Midwest
MidAmerican Energy Co
NorthWestern Energy
Northwestern Wisconsin Electric Co.
Oklahoma Gas & Electric
Oncor Electric Delivery
Otter Tail Power Co
Portland General Electric
PSE&G
PSNH
San Diego Gas & Electric
Unitil
Westar Energy

Public Power

Alabama Municipal Electric Authority
Ames Municipal Electric System
AMP Ohio
Austin Energy
Benton County PUD#1
Bonneville Power Administration
Bryan, TX
Burbank Water & Power
Clallum County PUD#1
Clark PUD
Cleveland, TN
Clinton Utilities Board
Colorado Springs Utilities
Columbus, OH
Eugene Water & Elec. Board
Fort Collins, CO
Frankfort Plant Board (Frankfort, KY)
Grant PUD
Hagerstown Light Dept.
Harrisonburg Electric Commission
High Point, NC
Huntsville, AL
Independence Power & Light
Kissimmee Utility Authority
Lafayette Utilities System
Lakeland Electric
Lenoir, TN
Loup River PPD
Orangeburg, SC
Owensboro Municipal Utilities
Roseville Electric
Salem, VA
Silicon Valley Power
SMUD
Snohomish County PUD

Cooperatives

Amicola EMC
Appalachian Electric Cooperative
Carroll Electric Coop
Carroll EMC
Cass County Electric Coop
Cobb EMC
Dairyland Power Coop
Dakota Electric Association
East Kentucky Power Coop
Fayette Electric Coop
Garkane Energy
Great Lakes Energy
Greystone Power Corp
Hart EMC
Haywood EMC
Holy Cross Energy
Inland Power & Light Co.
Jackson EMC
Mecklenburg Electric Cop
Medina Electric Coop
Mid-Carolina ECI
Middle Tennessee EMC
New Hampshire Elec. Coop
NIPCO
NOVEC
Old Dominion Electric Coop
Owen Electric Cooperative
Pee Dee Electric Cooperative, Inc.
Pickwick Electric Coop
Poudre Valley REA
Rutherford EMC
Salt River Electric
SMECO
SMEPA
South KY RECC
Southern Pine EPA
Tri-County Electric Coop
Tri-County Electric Coop (KS)
United Power Inc.
Upper Cumberland EMC
Verendrye Electric
Warren Rural Elec. Coop
Washington-St. Tammany Elec. Coop
Withlacoochee River Electric Coop

Canada

AltaLink
EPCOR D&T
Guelph Hydro Electric Systems, Inc.
Horizon Utilities Corp.
Hydro One
Hydro Ottawa Ltd.
Hydro-Québec TransÉnergie
Hydro-Sherbrooke
London Hydro
Maritime Electric
Medicine Hat, ON
PowerStream, Inc.
Saint John Energy

1. Please provide an overview of your utility's use of Energy Management (EMS), Supervisory Control and Data Acquisition (SCADA), Distribution Management (DMS), and Outage Management (OMS) systems.

System	Currently Installed	Current Vendor (or "in-house")	Future Plans by YE 2015		Planned Estimated Budget Range			No Plans
			New/ Replace	Upgrade/ Retrofit	\$1-5m	\$5-10m	>\$10m	
EMS	<input type="checkbox"/>	[]	<input type="checkbox"/>	<input type="checkbox"/>	<input type="checkbox"/>	<input type="checkbox"/>	<input type="checkbox"/>	<input type="checkbox"/>
			New/ Replace	Upgrade/ Retrofit	<\$250k	\$250k-\$750k	>\$750k	
SCADA	<input type="checkbox"/>	[]	<input type="checkbox"/>	<input type="checkbox"/>	<input type="checkbox"/>	<input type="checkbox"/>	<input type="checkbox"/>	<input type="checkbox"/>
			New/ Replace	Upgrade/ Retrofit	<\$500k	\$500k-\$2m	>\$2m	
DMS	<input type="checkbox"/>	[]	<input type="checkbox"/>	<input type="checkbox"/>	<input type="checkbox"/>	<input type="checkbox"/>	<input type="checkbox"/>	<input type="checkbox"/>
OMS	<input type="checkbox"/>	[]	<input type="checkbox"/>	<input type="checkbox"/>	<input type="checkbox"/>	<input type="checkbox"/>	<input type="checkbox"/>	<input type="checkbox"/>

2a. If your utility has a DMS, does your EMS/SCADA group also support DMS? ☐ Yes ☐ No ☐ Do not have a DMS

2b. If your utility has an OMS, does your EMS/SCADA group also support OMS? ☐ Yes ☐ No ☐ Do not have a OMS

3a. Do you have any interest in combining EMS and DMS on a common platform?

☐ Yes ☐ No ☐ Have already combined systems

3b. Do you have any interest in combining DMS and OMS on a common platform?

☐ Yes ☐ No ☐ Have already combined systems

3c. Do you have cyber security concerns if EMS/DMS are combined? ☐ Yes ☐ No

3d. Do you have cyber security concerns if DMS/OMS are combined? ☐ Yes ☐ No

4a. Has your utility converged SCADA/DMS and OMS functions? ☐ Yes ☐ No, but plan to by YE 2015 ☐ No, skip to Q. 5a

4b. What functions have been converged/or plan to be converged? []

5a. Does your utility currently have real-time linkages between SCADA and GIS or OMS?

☐ Between SCADA/GIS ☐ Between SCADA/OMS ☐ Neither, skip to Question 6a

5b. Are there any cyber-security concerns that you had to overcome? ☐ Yes ☐ No

5c. If yes, please identify:

--

6a. Please indicate your current and planned use of protocol(s) *within* the substation, and *from* the substation to external EMS/SCADA/DMS host/network. Check all that apply.

Protocols	Protocols Within Substation		Protocols from Substation to External Host/Network	
	Current	By YE 2015	Current	By YE 2015
DNP 3.0 LAN	<input type="checkbox"/>	<input type="checkbox"/>	<input type="checkbox"/>	<input type="checkbox"/>
DNP 3.0 Serial	<input type="checkbox"/>	<input type="checkbox"/>	<input type="checkbox"/>	<input type="checkbox"/>
IEC 61850 (UCA 2/MMS)	<input type="checkbox"/>	<input type="checkbox"/>	<input type="checkbox"/>	<input type="checkbox"/>
IEC 60870-5 101	<input type="checkbox"/>	<input type="checkbox"/>	<input type="checkbox"/>	<input type="checkbox"/>
IEC 60870-5 104	<input type="checkbox"/>	<input type="checkbox"/>	<input type="checkbox"/>	<input type="checkbox"/>
Modbus Plus	<input type="checkbox"/>	<input type="checkbox"/>	<input type="checkbox"/>	<input type="checkbox"/>
Modbus Serial	<input type="checkbox"/>	<input type="checkbox"/>	<input type="checkbox"/>	<input type="checkbox"/>
TCP/IP	<input type="checkbox"/>	<input type="checkbox"/>	<input type="checkbox"/>	<input type="checkbox"/>
ICCP/MMS	<input type="checkbox"/>	<input type="checkbox"/>	<input type="checkbox"/>	<input type="checkbox"/>
Legacy/Other: []	<input type="checkbox"/>	<input type="checkbox"/>	<input type="checkbox"/>	<input type="checkbox"/>

6b. If the box for IEC 61850 was not checked in 6a above, please respond to the following question: Is your utility planning to implement IEC 61850 beyond 2015? Check all that apply.

- ☐ Yes ☐ Maybe ☐ No, because:
- ☐ Advantages not that great ☐ Continue to use other protocols ☐ Minimum awareness of it
- ☐ DNP now a IEEE standard ☐ Insufficient staff and/or funding
- ☐ Other reason: []

7. What communications method(s) do you use to connect your SCADA system to substations? Check all that apply.

	Now	By YE2015		Now	By YE2015
Cellular	<input type="checkbox"/>	<input type="checkbox"/>	Satellite	<input type="checkbox"/>	<input type="checkbox"/>
Fiber	<input type="checkbox"/>	<input type="checkbox"/>	Frame relay	<input type="checkbox"/>	<input type="checkbox"/>
Licensed Radio	<input type="checkbox"/>	<input type="checkbox"/>	Leased analog lines	<input type="checkbox"/>	<input type="checkbox"/>
Unlicensed Radio	<input type="checkbox"/>	<input type="checkbox"/>	Microwave	<input type="checkbox"/>	<input type="checkbox"/>
Other (specify below)	<input type="checkbox"/>	<input type="checkbox"/>	Telephony	<input type="checkbox"/>	<input type="checkbox"/>
Other:					

8. Check any external assistance or third-party services needed for the following control center activities

Activity	Currently Use	Not yet, but by 2015	Not at all
Critical Infrastructure Protection	<input type="checkbox"/>	<input type="checkbox"/>	<input type="checkbox"/>
Cyber Security Monitoring	<input type="checkbox"/>	<input type="checkbox"/>	<input type="checkbox"/>
Managing transition to DMS architecture	<input type="checkbox"/>	<input type="checkbox"/>	<input type="checkbox"/>
Smart Grid Consulting Services	<input type="checkbox"/>	<input type="checkbox"/>	<input type="checkbox"/>
Vulnerability assessment	<input type="checkbox"/>	<input type="checkbox"/>	<input type="checkbox"/>
Vulnerability remediation	<input type="checkbox"/>	<input type="checkbox"/>	<input type="checkbox"/>
Cyclic Patch Management	<input type="checkbox"/>	<input type="checkbox"/>	<input type="checkbox"/>
Other services: []	<input type="checkbox"/>	<input type="checkbox"/>	<input type="checkbox"/>

9. Please specify the *approximate* number of RTUs, PLCs, substation platforms, etc. currently installed/planned to be installed in your EMS/SCADA/DMS systems.

	# units currently installed	# units to be retrofitted/upgraded 2013-2015	# new units planned 2013-2015
Poletop RTUs	[]	[]	[]
Feeder/secondary RTU's/Smart DA devices	[]	[]	[]
Substation RTUs	[]	[]	[]
Substation PLCs	[]	[]	[]
Substation automation platforms	[]	[]	[]
Synchrophasor measurement units	[]	[]	[]
Substation level phasor data concentrators	[]	[]	[]

10. If your utility has a DMS/SCADA combined system, does the SCADA functionality and network modeling stop at the distribution substation level or does it reach all the way to the service transformers?

- ☐ Stops at the distribution substation level ☐ Do not have a DMS/SCADA combined system
- ☐ Reaches all the way to the service transformers

11. What is the (approximate) total number of points scanned by SCADA (includes Transmission, Distribution, and Generation)?

Number: []

12. What is the (approximate) total number of power flow buses in your EMS system? Number: [] ☐ Do not have an EMS system

13a. With regards to As Is Engineering to Operations Integration (GIS to DMS/OMS) model maintenance, how do distribution circuit designs move from GIS to DMS in your current processes?

How is it captured and transferred?	<input type="checkbox"/> Manually recaptured, but <u>not</u> electronically transferred	or	<input type="checkbox"/> Manually recaptured & electronically transferred	or	<input type="checkbox"/> Automatically recaptured & transferred
How is it updated?	<input type="checkbox"/> On demand updates	or	<input type="checkbox"/> Nightly/regular batch builds	or	<input type="checkbox"/> Not at all
What standard?	<input type="checkbox"/> Use CIM standard	or	<input type="checkbox"/> Use other standard	or	<input type="checkbox"/> Use vendor data formats
What system is master?	<input type="checkbox"/> GIS is the master	or	<input type="checkbox"/> Both systems master different aspects	or	<input type="checkbox"/> DMS/OMS is the master

13b. With regards to Desired Engineering to Operations Integration (GIS to DMS/OMS) model maintenance, how do distribution circuit designs move from GIS to DMS in your target processes?

How is it captured and transferred?	<input type="checkbox"/> Manually recaptured, but <u>not</u> electronically transferred	or	<input type="checkbox"/> Manually recaptured & electronically transferred	or	<input type="checkbox"/> Automatically recaptured & transferred
How is it updated?	<input type="checkbox"/> On demand updates	or	<input type="checkbox"/> Nightly/regular batch builds	or	<input type="checkbox"/> Not at all
What standard?	<input type="checkbox"/> Use CIM standard	or	<input type="checkbox"/> Use other standard	or	<input type="checkbox"/> Use vendor data formats
What system is master?	<input type="checkbox"/> GIS is the master	or	<input type="checkbox"/> Both systems master different aspects	or	<input type="checkbox"/> DMS/OMS is the master

14. Does your utility currently have or plan to deploy some form of analytics by YE 2015?

	Currently Have	Plan to Deploy	No Plans
OMS analytics (i.e. fault location, etc.)	<input type="checkbox"/>	<input type="checkbox"/>	<input type="checkbox"/>
Asset analytics	<input type="checkbox"/>	<input type="checkbox"/>	<input type="checkbox"/>
DMS analytics (i.e. load and voltage balance, etc.)	<input type="checkbox"/>	<input type="checkbox"/>	<input type="checkbox"/>
Customer analytics	<input type="checkbox"/>	<input type="checkbox"/>	<input type="checkbox"/>

15. Relative to your control systems, please check your level of agreement/disagreement with the following statements:

	Agree	Neutral	Disagree
Our utility requires Open Platform Communications (OPC) as a standard	<input type="checkbox"/>	<input type="checkbox"/>	<input type="checkbox"/>
For smart grid auto restoration schemes our utility uses a centralized approach rather than a distributed logic/control in the field approach	<input type="checkbox"/>	<input type="checkbox"/>	<input type="checkbox"/>
In our utility, Service Oriented Architecture (SOA) is making headway over older technology and proprietary systems	<input type="checkbox"/>	<input type="checkbox"/>	<input type="checkbox"/>
Vendors could do more to make NERC compliance/regulatory reporting easier and more automated	<input type="checkbox"/>	<input type="checkbox"/>	<input type="checkbox"/>
We prefer cyber security features designed as an integral part of the system, not an add-on	<input type="checkbox"/>	<input type="checkbox"/>	<input type="checkbox"/>
Vendors need to add additional cyber security features to their products	<input type="checkbox"/>	<input type="checkbox"/>	<input type="checkbox"/>
We want to specify our network equipment, but would welcome an out of the box CIP compliant solution	<input type="checkbox"/>	<input type="checkbox"/>	<input type="checkbox"/>
Cloud implementation is of interest to our utility	<input type="checkbox"/>	<input type="checkbox"/>	<input type="checkbox"/>

16. Does your utility prefer: A: ☐ a fully integrated system with the applications embedded in the control system platform
or B: ☐ the applications sourced from third parties and ported onto the base SCADA platform

17. Does your utility prefer: A: ☐ all of the applications provided upfront
or B: ☐ the option of purchasing only the applications we need initially and port the others as needed

18. Is your EMS/SCADA group responsible for hardware server maintenance? ☐ Yes ☐ No

19. For which of the following applications does your utility use synchrophasors?

	Now	By YE2015	<input type="checkbox"/> We do not use/have plans for synchrophasors
Wide area monitoring	<input type="checkbox"/>	<input type="checkbox"/>	
Improved operational situational awareness	<input type="checkbox"/>	<input type="checkbox"/>	
Enhanced state estimation	<input type="checkbox"/>	<input type="checkbox"/>	
Improved operator visualization	<input type="checkbox"/>	<input type="checkbox"/>	
Other:	<input type="checkbox"/>	<input type="checkbox"/>	

20a. What level of **budget** increases has your utility experienced due to NERC CIP or other regulatory compliance efforts?

☐ Little ☐ Moderate ☐ Significant ☐ Does not apply – no critical assets

20b. What level of **work load** increases has your utility experienced due to NERC CIP or other regulatory compliance efforts?

☐ Little ☐ Moderate ☐ Significant ☐ Does not apply – no critical assets

21. With experienced personnel leaving the workforce due to retirements, how is your utility able to maintain a “Qualified Support Staff” for EMS/SCADA systems?

22. Use this space for comments, or to suggest new features, tools, applications or services that you need or expect to see available from EMS/SCADA/DMS vendors (e.g. service oriented architecture, additional cyber security features, NERC compliance reporting, etc.) Please describe below. Your ideas DO make a difference.

THANK YOU FOR YOUR PARTICIPATION

