Layton, Kimberly

From: Maria Seidler (Services - 6) [maria.seidler@dom.com]
Sent: Monday, June 09, 2014 3:03 PM
To: Comments, Urc
Subject: IURC GAO 2014-1 Dominion Voltage Inc. Comments dated June 9, 2014 -- To Attention of Beth Krogel Roads, General Counsel
Attachments: GAO 2014-1_DVI Comments_6_9_2014.pdf; GAO 2014-1_DVI Exhibits to Comments_6_9_2014.pdf

Dear Sirs:

Please find attached the public comments of Dominion Voltage Inc (DVI) for submittal in the above referenced proceeding. Also attached is a separate document that includes all of the Exhibits to DVI's Comments. Should you have any problems opening either of the two attachments, please do not hesitate to call my office or cell number included in my contact information below.

Please also let me know if you should need any further information. Thank you.

Respectfully,

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Dominion

June 9, 2014

Beth Krogel Roads
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RE: Public Comments of Dominion Voltage Inc. pursuant to General Administrative Order 2014-1-- IURC's EEIDSM Recommendations

Dear Ms. Roads:

Pursuant to the General Administrative Order 2014-1 of the Indiana Utility Regulatory Commission ("Commission"), Dominion Voltage, Inc. ("DVI") respectfully submits these comments to encourage the Commission to consider including in its energy efficiency and demand-side management ("DSM") recommendations to the Governor of Indiana and the Indiana General Assembly voltage optimization ("VO") or advanced conservation voltage reduction ("CVR"). Energy efficiency programs across the country are traditionally designed to incentivize changes in customer behavior regarding energy usage. Advancement in home service technologies and innovative use of the internet can offer customers convenience that is expected to increase energy efficient behavior on the part of the customers. However, DSM and energy efficiency programs that focus only on customers' actions behind-the-meter exclude the potential for the significant energy savings otherwise available from VO and advanced CVR technologies that do not require customers to make any changes or take actions.

Smart grid technology offers operational efficiencies that also result in significant conservation reductions, and while the technology is deployed on the grid-side of customers' meters, the energy savings are directly passed through to customers' electricity bills. As described in DVI's Comments below, states looking for more energy savings, such as Indiana, could find an additional 3-4% from a combined deployment of voltage optimization ("VO") technology and advanced metering infrastructure ("AMI") and thus should be incentivized under a state's energy efficiency or DSM plans. In addition, where the distribution grid has not yet deployed AMI, the avoided energy costs associated with the lower voltage can help build the business case for the AMI adoption. In addition, In addition to the energy savings, VO would provide additional benefits from optimizing grid operations and improving operators' outage response, grid reliability, and voltage stabilization that over the longer term will support increasing installations of intermittent distribution generation resources.

I. Dominion Voltage, Inc.

DVI is a subsidiary of Dominion Resources, Inc. ("DRI"), a holding company that is publicly traded and which operates as an integrated energy company and significant producer and transporter of energy. DRI's portfolio of assets includes approximately 23,500 MW of generation; 11,000 miles of natural gas transmission, gathering, and storage pipeline; 56,900 miles of electric distribution lines; and 6,300 miles of electric transmission lines. DVI's public utility affiliate, Virginia Electric and Power Company, d/b/a Dominion Virginia Power ("DVP"), also a subsidiary of DRI, provides electric service to the public within its certificated service territories in Virginia and northeastern North Carolina, as well as to non-jurisdictional customers in Virginia.

DVI holds, licenses, and sells software in the field of VO, and also maintains the intellectual property rights to such software. To this end, DVI has developed an innovative, state-of-the-art software solution for voltage and volt-ampere reactive (var) control and optimization called EDGE® (which stands for Energy Distribution & Grid Efficiency) that can achieve advanced CVR that is translatable into energy savings for a utility and its customers. The capability of AMI to enhance CVR capability, so that together they can provide dynamic and adaptable voltage control, moves technology solutions beyond mere CVR to VO that facilitates enhanced, verifiable savings measurement capability. DVI's EDGE® software product goes even farther as the only patented[1] platform that can obtain voltage data directly from dynamically selected meters at the end-user level, and then use that data for circuitry distribution planning, voltage control and optimization, and validation of voltage conservation and energy savings.

II. Comments

A. VO Evolution as an AMI-based Grid Solution for Energy Savings and DSM.

1. Conventional CVR: The National Association of Regulatory Utility Commissioners ("NARUC") recognized that VO is an important component of electric power grid modernization in its *Resolution Supporting the Rapid Deployment of Voltage Optimization Technologies* ("*Resolution*").[2] The *Resolution's* intentional specification of VO, as opposed to conventional CVR, implies an understanding that there are significant differences among CVR-based practices and adaptive VO technologies that, when combined with AMI, optimize voltage delivery to customers. Those differences can affect both the level of energy savings and the sustainability of ongoing savings.

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[1] U.S. Patent No. 8,437,883; issued May 7, 2013 by the United State Patent and Trademark Office ; U.S. Patent No. 8,577,510 Issued Nov. 5, 2013 by the United State Patent and Trademark Office; U.S. Patent Application No. 13/931,145 filed June 28, 2013 with amendments filed Nov. 11, 2013 with the United State Patent and Trademark Office.

[2] National Association of Regulatory Utility Commissioners (NARUC), *EL-2/ERE-3 Resolution Supporting the Rapid Deployment of Voltage Optimization Technologies, adopted November 14, 2012; can be found at* *http://nationinside.org/images/pdf/2012FINAL_AnnualMeetingResolutions.pdf, p. 6-7.* The Resolution is also included in Exhibit 3 to these Comments.

Energy conservation policies since the 1970s have included CVR programs to lower energy consumption through reduced voltage settings. These programs, however, used a low-tech solution involving physical adjustment of a transformer setting that established voltage at the substation level for delivery of energy within the lower one-half of the 10% voltage band required by American National Standards Institute ("ANSI") equipment standards. Since then, utilities have come to rely upon CVR more conventionally as an emergency response to capacity deficiency in times of high demand. Consequently, it is easy for policymakers to consider CVR for its functionality as a demand response ("DR") resource, which can offer the utility a financial revenue opportunity in the DR market.

However, advanced software technology combined with AMI allows grid operators to move from the manual reduction of voltage to an automated response system that can operate on a large-scale basis to adjust voltages within the optimized bandwidth on circuits delivering energy to individual customers' meters.[3] As described more fully below, AMI enables advancement in CVR technology to optimize voltage control that can provide sustainable energy savings –24 hours a day, 7 days a week– or contribute to a utility's DR capacity by the operator's turning on the VO software during periods of peak load. When a VO platform is integrated into an AMI deployment program, it significantly improves the AMI business case by lowering voltages to the customer, which in turn reduces customers' energy consumption, accelerating the accumulation of energy savings toward the State's energy efficiency and DSM goals.

[3] Automated voltage control software that uses actual customer and circuit information gleaned from AMI data and communication capabilities is also superior to simulation modeling techniques that can fail to keep up with the dynamic nature of the distribution system, and that typically have difficulty modeling the proliferation of such technologies as electric vehicles, distributed generation assets, and home area networks. Modeling approaches also have difficulties continuously representing circuit dynamics such as penetration of DSM programs, new customer additions, seasonality of loads, and other changes that can occur unpredictably on a distribution circuit.

2. <u>Advancements in CVR to VO</u>: The two main challenges to large-scale voltage conservation historically have been (1) the need for a practical method of controlling voltage that could be adaptive to the dynamic characteristic of distribution circuits, and (2) the development of a more precise method of measuring and validating the energy saved while a circuit is operating in the more precise lower voltage band. Moving from the traditional voltage management shown in Figure 1 below to the intelligent control using AMI shown in Figure 2 will actualize greater energy savings of VO.

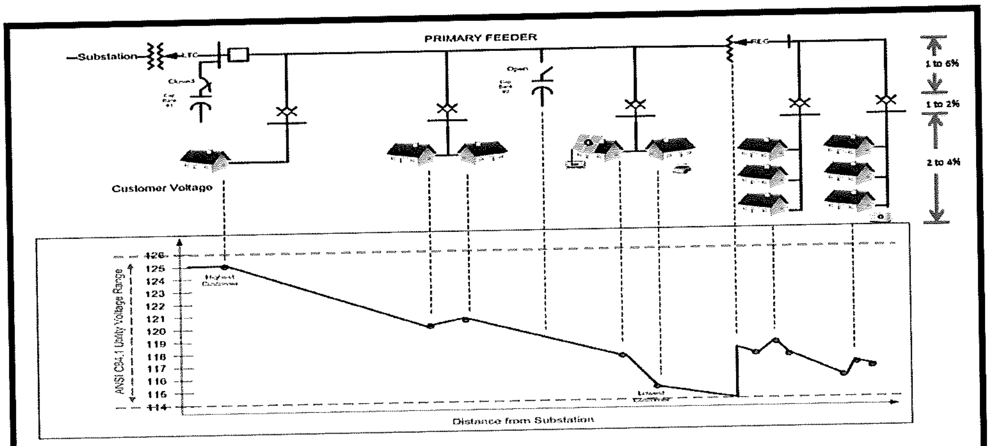


Figure 1. Traditional Voltage Management Design with
Load Compensated Voltage Set-points

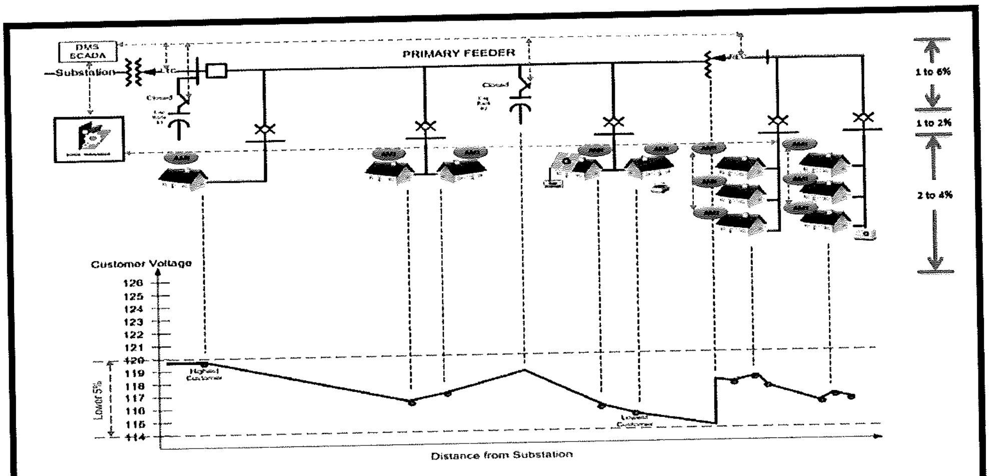
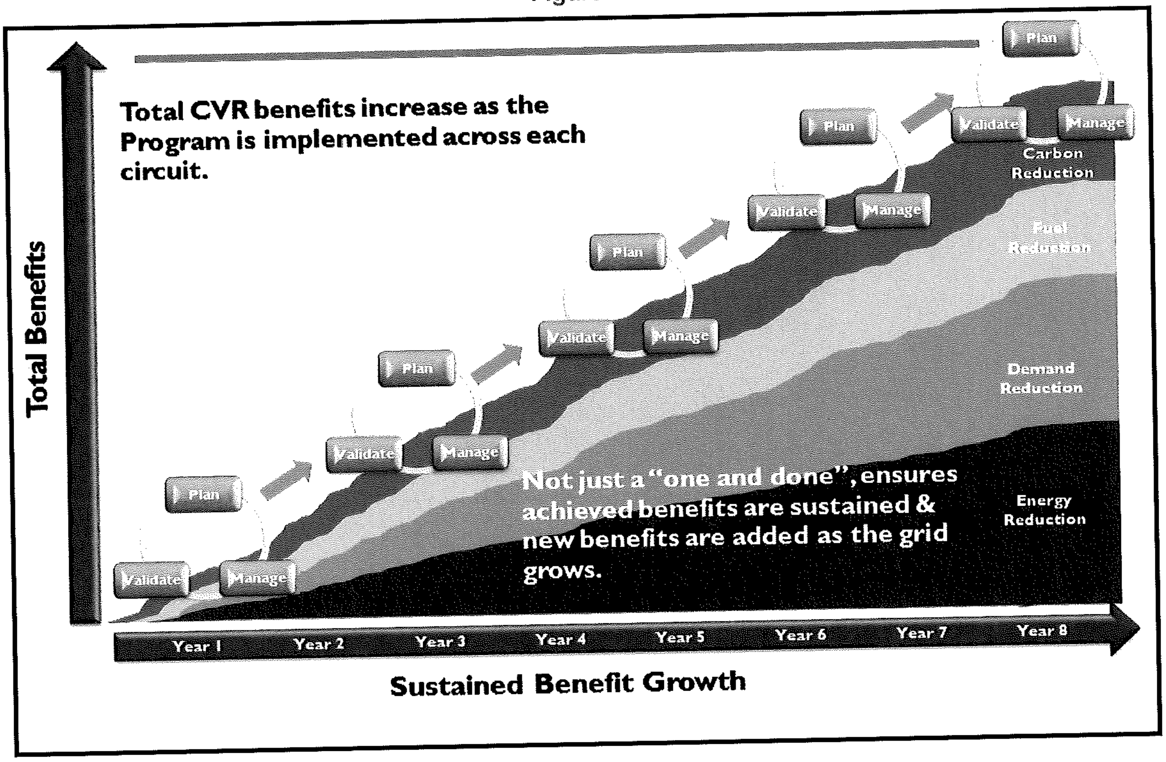


Figure 2. Customer Based Voltage Optimization

Voltage optimization includes planning, constructing, and operating customer voltages in the most efficient lower ANSI range using capacitor banks, line regulators, transformer load tap changers ("LTCs") and customer voltage feedback from an AMI-based system. (Note the following typical voltage drops: primary – 1% to 6 %, service transformer – 1% to 2 %, secondary – 2% to 4 %). DVI's EDGE® platform demonstrates that when VO technology is used with AMI functionality and then combined with a practical statistical measurement and verification ("M&V") technique, a utility can achieve a scalable method of implementing high value energy conservation and a simple, direct process for validating the energy saved. This unique method of advanced CVR implementation easily integrates into a utility's existing planning process to identify circuit improvements that continue to increase voltage performance, and, in turn, sustainability of energy savings.

Figure 3 below outlines the continuous improvement process targeted at energy, demand, fuel, and carbon reduction benefits. The result is a "plan, manage, and validate" process that efficiently manages voltage to the customer, measures the efficiency improvement in distribution system on a circuit-by-circuit basis, and enables a more granular level of circuit planning that continues to improve the circuit's energy efficiency, demand reduction, and reliability. The process is designed to integrate into existing utility processes, enhancing their ability to plan, manage, and verify distribution improvements while also minimizing incremental resources and costs.

Figure 3



The EDGE® platform uses existing voltage regulation equipment with a more precise set point control that processes AMI data to improve accuracy and provide adaptive capability. Its adaptive voltage control is implemented using (i) AMI technology to collect the needed customer voltage readings, (ii) EDGE®'s patented technology to control set point changes, and (iii) Distribution Management System ("DSM") and SCADA to control the local substation LTC controller, circuit voltage regulator, and/or capacitor. The technology also allows set point control for down-line regulators and capacitor banks through distribution automation systems.

One of the key problems with previous implementations of CVR programs is that they were engineered with a very limited number of voltage control points, usually at the primary voltage level. As the dynamic nature of distribution circuits changed, these early CVR initiatives had to be re-engineered to keep customer voltages working in the lower 5% band. Consequently, any relative energy savings were difficult to sustain. EDGE®'s adaptive control using AMI addresses this key issue, allowing near total automatic response to the typical dynamic circuit environment. In addition, the EDGE® solution provides continual verification that the voltage conservation system is not resulting in any customer voltages being served at levels below ANSI C84.1 specifications. EDGE® accomplishes all of this through its three software components:

- *Planner*, which calculates circuit-by-circuit savings potential, checks for errors and outliers, and enables a continuous grid-improvement process;
- *Manager*, which automatically optimizes customer voltages across the entire circuit without the need of a detailed model, using customer voltage data collected from AMI; and
- *Validator*, which measures and tracks the savings for each circuit independent of the optimization process, replacing traditional "on/off" methods to allow savings to continue during verification.

A more detailed description of the EDGE® technology and its three components is included in the whitepaper attached as Exhibit 1 to these Comments.

Voltage optimization provides the benefit of avoided energy costs for the utility while the conservation outcome in reduced voltage provides lower bills for customers without requiring changes in customer behavior or requiring customer purchases or incentives. It could complement customer-based energy efficiency and DSM programs by providing a base-load program for energy savings on which the customer programs could build, creating an overall energy efficiency strategy to the benefit of all customer classes -- residential, commercial and industrials.

B. The Cost/Benefit of VO Makes the Regulatory Business Case for AMI Deployment

Adding VO functionality to AMI can ensure that the combined benefits justify the costs of AMI. VO's energy savings and the associated emission reductions, particularly carbon, help to justify the more significant costs of AMI, even with the incremental costs of the VO technology. Prior CVR studies from both EPRI[4] and the Northwest Energy Efficiency Alliance NEEA)[5] project expected values of 0.6% to 1.2% reduction in energy for every 1% reduction in average voltage. The EPRI study demonstrated savings from 1.82% to 2.71% using six separate circuits from multiple utility companies. However, it is important to consider that many of the measurement techniques used in those studies were based on operating the system in a manner where it is "ON" for one day and "OFF" for the next day, and then doing statistical comparisons between the "ON" and "OFF" states to determine the actual CVR-based savings. While these are accurate techniques, using them for widespread continuous measurement requires a sacrifice of 50% of the savings in order to do measurement.

Figure 4 below provides an illustration of a CVR case study of operating a circuit with AMI-enabled technology in the lower 5% band and the resulting energy savings that were calculated software using a rigorous statistical alternative to the day ON / day OFF technique. The system had been operated for four years with the customer voltage control, resulting in approximately $300,000 annualized energy savings based on the then-current energy price for approximately 6,600 commercial and residential customers.

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[4] *See* the research results from Electric Power Research Institute (EPRI) Distribution Green Circuits Project, http://www.epri.com/search/Pages/results.aspx?k=Distribution%20Green%20Circuits%20Project.
[5] *See Utility Distribution System Efficiency. Initiative (DEI) (Phase I). Final Market Progress and Evaluation Report*, Appendix G, Puget Sound Energy Customer Survey on Power Quality, published by Northwest Energy Efficiency Alliance (June 2008).

Figure 4

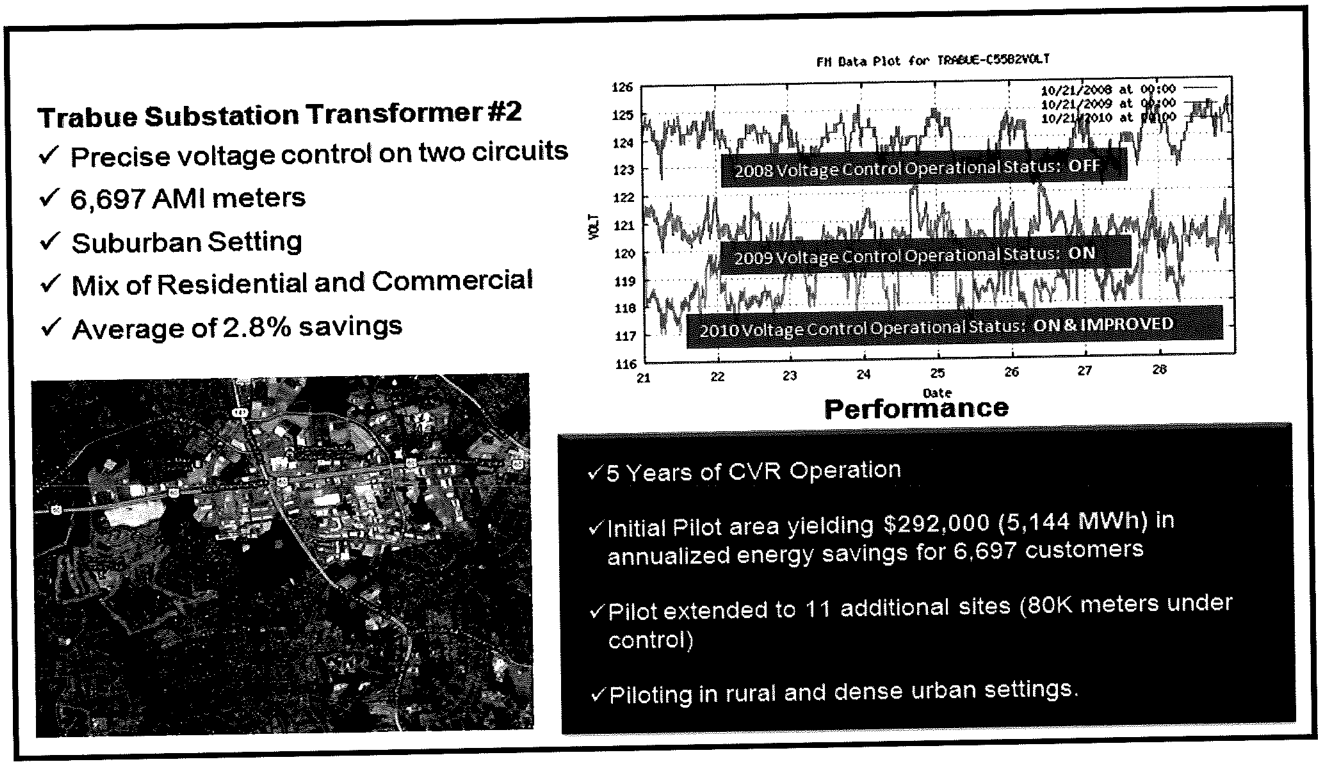
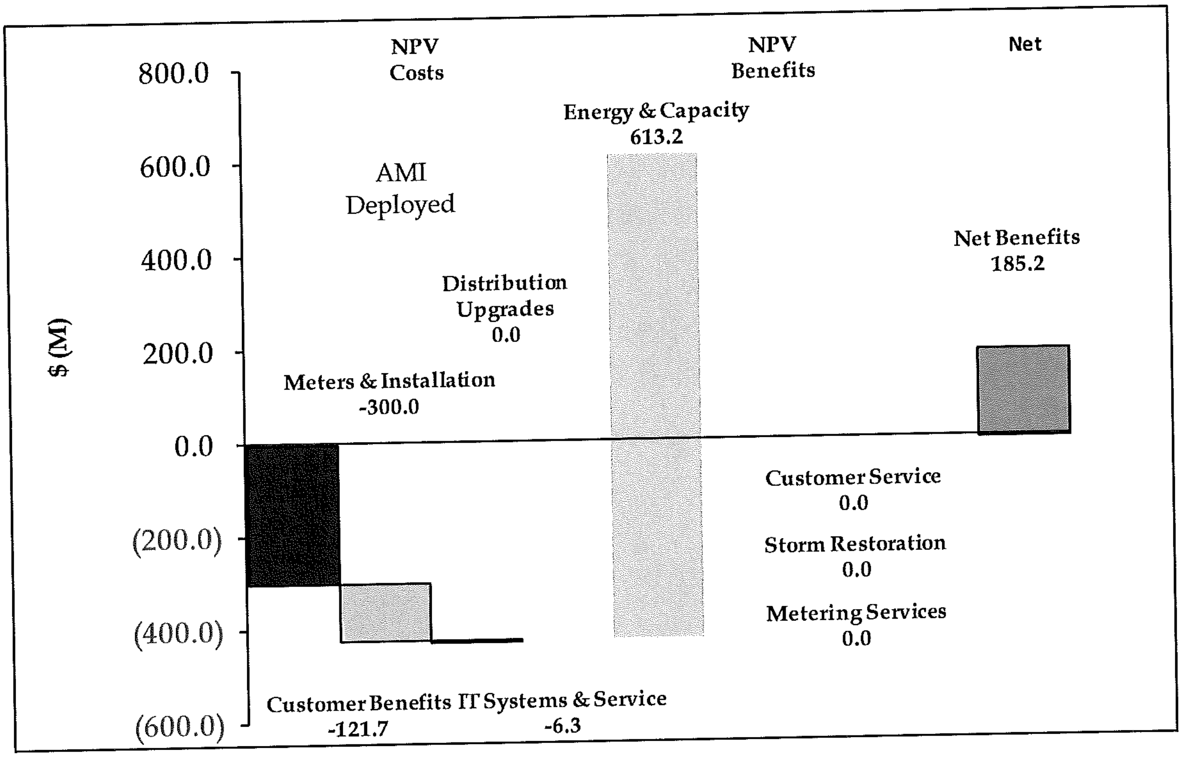


Figure 5 below reflects the potential cumulative costs and benefits if the performance of the example circuit in the above Figure 4 were to be scaled, hypothetically, across a broader service territory serving 2.4 million customers. The business case demonstrated by Figure 5 would reveal that after paying for the AMI system costs of $305 million ($127 per meter installed with VO software) and using an average energy price of $40, the avoided energy costs to the utility would be $610 million and the net benefit to customers would equate to $185 million over a ten year period.

Figure 5



Assuming the deployment of AMI-based VO on circuits comprising 65% -80% of the load estimated for Indiana, a 3% VO savings would equate to 1.0 million MWh of avoided wholesale power requirements. At the historic weighted average (2006-2013) of Indiana Hub price of $46 per MWh, the estimated avoided wholesale purchase costs would be $46.0 million per year, which can aptly cover the costs of customers' AMI.

Further, while VO technology is deployed on the grid, it is the customer who directly benefits from the efficiency gains from VO, as described in more details in the white paper, *Customer Efficiency Program or Grid Efficiency Program*, attached as Exhibit 2 to these Comments. AMI-enabled VO is clearly a DSM tool. Studies show that 95% of VO efficiency improvement occurs in the customer's equipment. Consequently, the meter records less energy usage for the same appliance usage and results in immediate savings for the customer. The remaining 5% constitutes grid-side efficiency improvements.[6] VO clearly meets the objectives that have cost justified other incentivized DSM and energy efficiency programs.

C. *AMI-Based VO Improves Reliability and Reduces Customers' Outage Times*

Voltage optimization that relies on AMI voltage data can contribute to improved reliability. It provides significantly increased voltage stability by narrowing the bandwidth at which voltage is delivered to customers. Additionally, because utility operators can see voltages at the customer meters, they are able to identify the most significant voltage outliers and adjust voltages accordingly, which, in turn, can significantly reduce customer voltage complaints. For example, on two of DVP's CVR test circuits, customer voltage complaints were reduced from an average of one to two per month to only one complaint over a three year period. Finally, because AMI provides transparency into grid operations on a granular level previously not available, operators can be alerted to outage situations much earlier that allow faster response time and, in turn, can help contain outages so they are much smaller events than they might otherwise be.

VO is also being studied to improve grid stability on circuits with high penetrations of DG – particularly distributed solar photovoltaic ("PV") generation. Because a solar PV installation is an intermittent, non-dispatchable generating resource, reliability problems can occur in association with extreme voltage fluctuations on circuits or circuit segments with a high saturation of solar PV DG. AMI-enabled voltage optimization technologies, such as DVI's EDGE® platform, can use the continuous customer-level voltage readings to dynamically adjust

[6] One of the best studies of customer-efficiency improvements was performed as part of the Distribution System Efficiency Initiative in the Pacific Northwest region of the United States in 2008. In this study, voltage control was placed on the entrances of customer facilities to measure only customer savings from CVR. Comparing these measurements to the combined savings on both the grid-side and customer-side of the meter revealed that the customer portion of the savings conservatively averaged approximately 2.9%. Utility Distribution System Efficiency Initiative (DEI) Phase 1, Final Market Progress Evaluation Report, No 3, E08-192 (7/2008), **E08-192.** This 2.9% value is consistent with other major studies. *See, e.g.*, Green Circuit Field Demonstrations. EPRI, Palo Alto, CA: 2009. Report 1016520; and Conservation Voltage Reduction at Northeast Utilities, D.M. Lauria, IEEE, 1987.

voltages to compensate for these fluctuations. Additionally, EDGE®'s monitoring and planning functions can assist utility planners and operators in making other distribution system modifications that may be needed or desirable to accommodate higher penetrations of variable renewable DG resources.

The operational efficiencies and reliability benefits only enhances the cost-benefit analysis of AMI-enabled VO as part of an energy efficiency or DSM plan for Indiana – in addition to the other benefits of AMI from more accurate customer billings and remote meter readings, connects and disconnects that reduce costs associated with less truck rolls.

III. Conclusions

AMI-based VO technology is an energy efficiency and DSM tool that will result in even more energy savings and associated environmental benefits from emissions avoidance. It is being recognized for its cost-effective potential across industry segments. In addition to the NARUC *Resolution*, energy efficiency organizations, such as the American Council for an Energy-Efficient Economy ("ACEEE") have likewise endorsed VO. Excerpts on voltage optimization from the ACEEE Report, *Frontiers of Energy Efficiency: Next Generation Programs Reach for High Energy Savings,* and other documents[7] indicating wide support and interest in VO are included in Exhibit 3 to these comments. DVI would encourage the Commission to include AMI-enabled VO in its recommendations to the Governor as a cost-effective DSM tool that should be a part of the State's energy efficiency strategy for the benefit of customers and the economic development of Indiana.

[7] Other documents include those published by (i) the National Electrical Manufacturer Association, *Volt/VAR Optimization Improves Grid Efficiency;* (ii) Carlman, Susan Frick, Naperville Sun, *Naperville launches study of reduced voltage use*, May 30, 2014; (iii) Central Lincoln People's Utility District, *Voltage Management at Central Lincoln PUD,* Smart Grid Investment Grant 2014 Report, Project ID 09-0269; and (iv) Jackson, Jerry, Ph.D., Smart Grid Research Consortium, *Low Cost CVR May Pay for Your AMI System: New Study Turns Traditional Smart Grid Business Case Analysis on its Head,"* Feb. 6, 2014.

IV. DVI Contacts and Communications

Any communications and correspondence related to DVI's Comments and/or its participation in this proceeding should be directed to the following representatives of DVI:

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DVI again appreciates the opportunity to provide these Comments to the Commission in response to its Administrative Order. Should the Commission or its Staff have questions based upon these Comments, or to the extent that DVI can provide any additional information regarding the technical or operational aspects of VO implementation generally – or its experience in working with the EDGE® software product – DVI would be pleased for the its experience in working with the EDGE® software product – DVI would be pleased for the opportunity to provide such information or conduct a workshop that would allow fuller discussion of the Commission and/or Staff's questions.

Respectfully,

DOMINION VOLTAGE, INC.

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Director
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EXHIBITS

Dominion Voltage Inc.

Public Comments

IURC's General Administrative Order 2014-1

EEIDSM Recommendations

EXHIBIT 1

Conservation Voltage Reduction at Dominion

DVI **8/27/2013**

VOLTAGE CONSERVATION USING ADVANCED METERING INFRASTRUCTURE (AMI) AND SUBSTATION CENTRALIZED VOLTAGE CONTROL

ENERGY EFFICIENCY, DEMAND REDUCTION, AND CUSTOMER RELIABILITY

DVI is a subsidiary of Dominion Resources, Inc., and is backed by the financial strength of one of the nation's largest producers and transporters of energy. Headquartered in Richmond, Virginia, Dominion manages 27,500 megawatts of generation, 6,000 miles of transmission line, and serves 2.4 million electric customers.

In April, 2007, the Virginia General Assembly enacted a statutory goal for Dominion Virginia Power of 10% reduction in retail energy consumption over 2006 levels by 2022.[1] This legislation aligned well with existing goals at Dominion and heightened overall emphasis on energy reduction programs. DVI was set up to work with other Dominion business units to develop sustainable alternative energy solutions, and the EDGE® Technology is one of its products.

DVI evaluated a number of energy conservation programs and focused on implementation of a novel Conservation Voltage Reduction (CVR) program[2] that leverages Advanced Metering Infrastructure (AMI) to implement an adaptive voltage control using a practical statistical method to directly meter energy savings and provide circuit level performance verification.

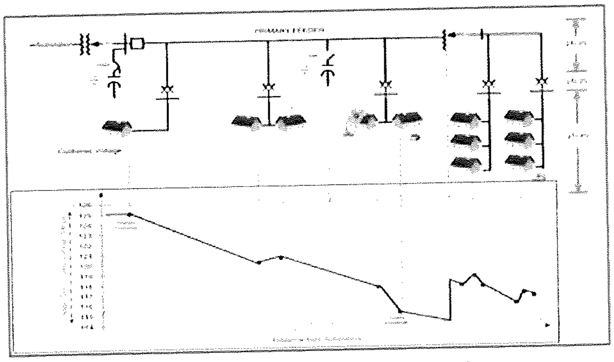

Figure 1 Traditional Circuit Voltage Design

Conservation Voltage Reduction

Conservation Voltage Reduction has been around the industry for over 30 years and is based on precision operation of electric customer voltages in the lower half of the 10% voltage band required by ANSI equipment standards. This energy savings has been tested in numerous field tests over this time period.[3,4,5,6] The results of these studies support an average savings of .6% to 1.2% energy reduction for every 1% average reduction in circuit voltage. The two main issues with implementing large scale voltage conservation are to develop a practical method of controlling voltage that is adaptive to the dynamic changes characteristic of distribution circuits and to develop a clear method of measuring the energy saved when the circuit is operating in the more precise lower voltage band. Moving from the traditional voltage operation in Figure 1 to the intelligent control of Figure 2 will actualize the savings of CVR with voltage

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[1] http://www.scc.virginia.gov/newsrel/ves_launch_10.aspx
[2] Patent Application No. 13/567,473 Title of Invention: Voltage Conservation Using Advanced Metering Infrastructure and Substation Centralized Voltage Control. Date Approved 2/11/2013 United States Patent and Trademark Office.
[3] Green Circuit Field Demonstrations. EPRI, Palo Alto, CA: 2009. Report 1016520
[4] Conservation Voltage Reduction at Northeast Utilities, D.M. Lauria, IEEE, 1987
[5] Utility Distribution System Efficiency Initiative (DEI) Phase 1, Final Market Progress Evaluation Report, No 3, E08-192 (7/2008) E08-192
[6] Evaluation of Conservation Voltage Reduction (CVR) on a National Level, PNNL-19596, Prepared for the U.S. Department of Energy under Contract DE-AC05-76RL01830, Pacific Northwest National Lab, July 2010

optimization. Voltage optimization includes planning, constructing, and operating the customer voltages in the most efficient band using capacitor banks, line regulators, transformer LTC's, and customer voltage feedback from an AMI-based system. (Note: typical voltage drops are 1 to 6% on the primary, 1 to 2% at the service transformer, and 2 to 4% on the secondary.) Using AMI technology along with a practical statistical measuring technique, DVI's EDGE® voltage control provides a scalable method of implementing high value energy conservation and a simple direct method to validate the energy saved. This unique method of CVR implementation easily integrates into the existing planning process to identify circuit improvements that continue to increase voltage performance. Figure 3 outlines the continuous improvement process targeted at energy, demand, fuel and carbon reduction benefits. The result is a plan, manage, and validate process that efficiently manages voltage to the customer, measures the efficiency improvement in the distribution system circuit by circuit, and enables a granular level of circuit planning that continues to improve the circuit's energy efficiency, demand reduction, and reliability.

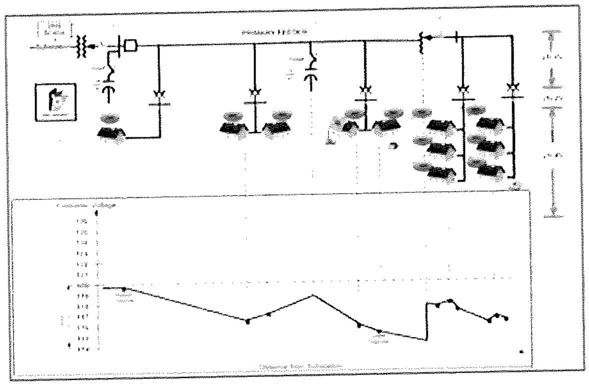


Figure 2 EDGE® Circuit Voltage Design

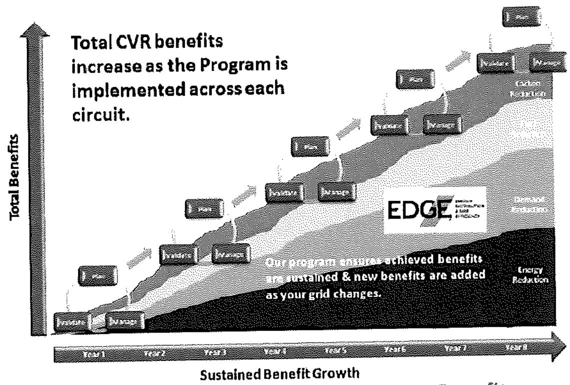


Figure 3 Distribution Efficiency Program Benefits

Figure 4 is an example of operating a circuit with AMI-based technology in the lower 5% band and the resulting savings in energy. The system was put in place in January 2009 and has operated for four years with the customer voltage control, resulting in approximately $300,000 annualized energy savings for approximately 6,600 commercial and residential customers.

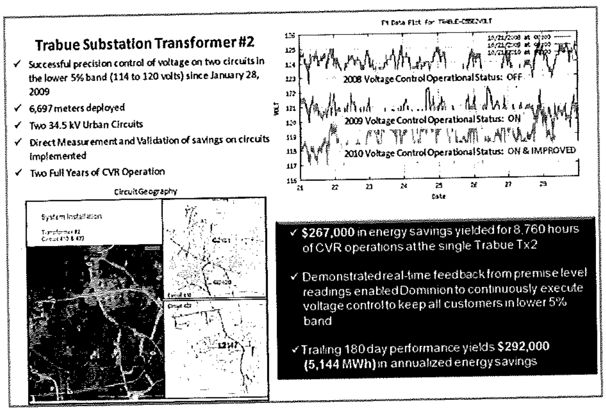


Figure 4 CVR Circuit Example

Conceptual View of Plan, Manage, and Validate

DVI's EDGE® efficiency program uses existing voltage regulation equipment with a more precise set point control that processes AMI data to improve accuracy and provide the adaptive capability. The adaptive voltage control is implemented using AMI technology to collect the needed customer voltage readings, the EDGE® technology to control set point changes, and a Distribution Management System (DMS) or SCADA to control the local substation LTC controller, circuit voltage regulator and/or capacitor. The technology also allows set point control for down-line regulators and capacitor banks through distribution automation systems.

Grid-side Efficiency Planning

Planning the circuit improvements based on the data collected at the customer meter level from AMI is one of the key differences between EDGE® technology and other CVR approaches. Figure 5 displays the value of statistically looking at the customer voltage performance on a targeted circuit. Knowing that the desired band of voltages for efficient operation is a 5% range, the software quickly identifies and lists the customer voltages that do not meet the requirement. Transferring this information to the planning analysis software used by the utility allows the engineer to quickly identify the necessary improvements needed to increase circuit performance. Figure 6 demonstrates one of the differences between the traditional planning process that models primary voltage levels and the EDGE® enhanced planning that allows customer voltages to be mapped from AMI to the utility's existing planning software, giving the planning engineer the ability to manage least cost improvements by identifying granular equipment changes down to the service transformer and service lateral level. This will provide a clear process to manage the voltage drop effectively from the substation to the customer meter. This process links the geographic view of the planning software to the voltage data from AMI, enabling a quick review of the location and potential corrections for voltage problems.

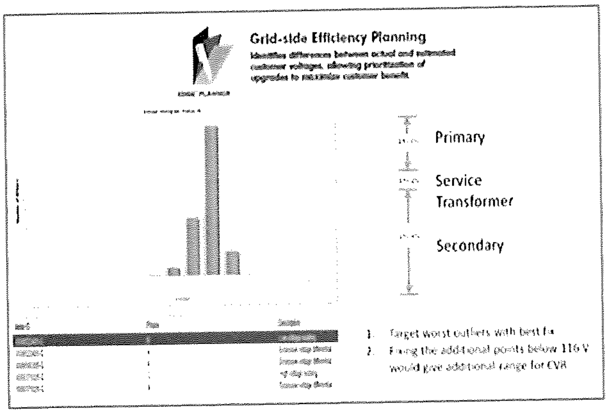


Figure 5 Customer Based Planning

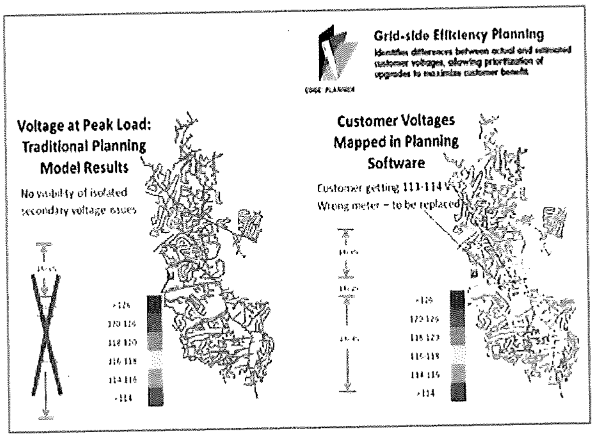


Figure 6 Traditional vs EDGE® Enabled Planning

Controlling Required Distribution System Modifications

One goal of voltage conservation is to minimize the modifications required to the distribution system as this CVR system is deployed, resulting in a fast, efficient deployment of the AMI and adaptive voltage control system. Only a few adjustments for individual customers are needed and rare infrastructure additions, such as capacitor banks and line regulators are anticipated. This is a very cost effective way to deploy the system in a first stage, providing sufficient business case from the voltage conservation savings to justify the full costs of the AMI and adaptive voltage control system.

The key to achieving this goal is to use the granular information from AMI voltage measurement to only improve required infrastructure, such as service transformers or service laterals, instead of more costly improvements such as conductor upgrades or circuit/substation additions. Breaking the process into two steps, with the first step being a plan to operate the voltage conservation system for circuit loads less than 65% of peak, will reduce initial costs. The nature of the typical residential and commercial customer load allows utilities to operate CVR when the load is below 65% of yearly peak but still keep the system within the lower 5% band over 80% of the time, resulting in an energy reduction level of approximately 3% year round. Once this level of performance is met, a second level of upgrades allows operation for the remaining 35% of the load level which occurs 20% of the time. For generation-short utilities that purchase off peak energy from the market, this first level energy savings can provide a strong business case for the AMI and CVR deployment.

EDGE® Manager – Customer Voltage Control

At the substation, an LTC transformer or voltage regulator is used to adjust the feeder voltage. A substation controller manages circuit voltage based on local substation bus voltage sensing and target set point control. The substation control is illustrated in the top left section of Figure 7. The feedback control loop created by this controller and local sensing is fast-responding, able to react within seconds to voltage swings outside the set point. Large changes in voltage at the substation bus will be quickly regulated. This control system is in place today at most substation and circuit regulator sites.

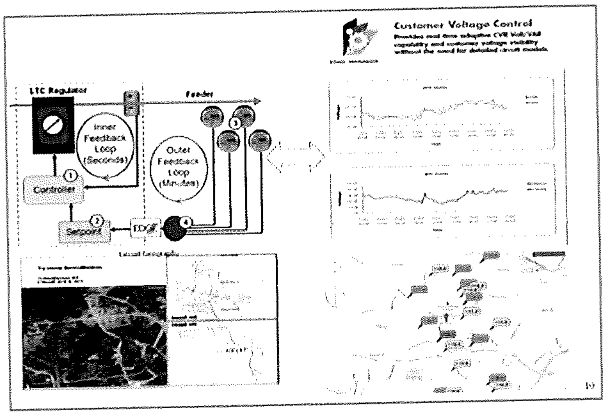


Figure 7 EDGE® Manager

On the feeder, a small number of customer meters are selected as representatives for all the customers. For the moment, consider these as a fixed group, selected as the known worst-case low-voltage points throughout the circuit. There is no upper limit on the number of customer voltages that could be monitored continuously. The decision to identify a smaller select group is a practical one, made primarily to reduce the burden on the communication network. The voltages from these selected meters are collected every 5 to 15 minutes and evaluated. These meters report the circuit bus voltage, the average of the 10 lowest voltages and the lowest voltage of the circuit (one of the 10). EDGE® Manager acquires voltages from the AMI system, evaluates the need to change the set point, and if necessary, changes the set point using the DMS/SCADA system as shown in Figure 7.

EDGE® Manager uses the DMS/SCADA system to control the device set points. It takes the customer voltage readings from the AMI database for the lowest, highest, and low average voltages and adjusts the set point of the substation LTC or voltage regulator. The EDGE® Manager evaluates the voltages and modifies the voltage regulation set points in such a way as to maintain flat customer voltage levels along the feeder within the more precise lower 5% band. The EDGE® Patents cover in detail the unique aspects of this AMI-based CVR control methodology. The top right side of Figure 7 shows EDGE® Manager's graphic plot of real time voltage control on the circuit. The top graph plots the set point value for the regulator (red) and the resulting substation bus voltage (blue). The bottom graph is the plot of the 10 low average voltages (red) and the lowest voltage of the average (blue). The intent of this control is to keep both the upper and lower red and blue plots between the lower voltage band of 114 volts to 120 volts as much as possible. This keeps all customers within the required voltage tolerance while taking advantage of the reduced energy use operating in this band.

The bottom left picture is a circuit view of the 6,600-customer, two-circuit demonstration system and the picture on the left is the plot from EDGE® Manager of the geographic location of the 20 voltages being continuously monitored to maintain the set point control at the substation.

EDGE® Manager – Adaptive Voltage Control

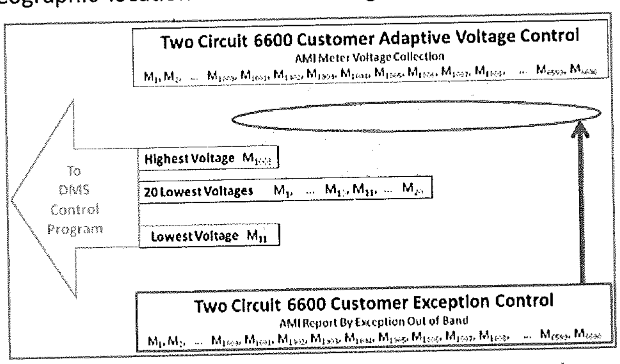


Figure 8 Adaptive Meter Control: 6,600 Meter Example

The initial assumption was that the group of AMI voltages representing the circuit was a fixed group, selected as the known worst-case low-voltage points throughout the circuit along with the bus voltage point on the circuit. To make the circuit adaptive, we remove this assumption from the control system. To implement the adaptive control, EDGE® Manager uses a customer voltage report by exception process from AMI. If the voltage for any customer drops below a set low point level (such as 115) a report by exception process is initiated to software connect the new low voltage location and meter to the EDGE® Manager. EDGE® Manager then compares the existing low voltage monitoring points to the exception value and on a periodic basis re-chooses the best voltages to control the circuit. This process results in continuous voltage set point control using the small number of voltage points but report by exception control for the remainder of the meters on the circuit. See Figure 8.

This ability to adapt to changing circuit conditions provides a powerful improvement to the voltage conservation control process. As an example, most utilities are constantly adding new customers and subtracting others. If a new customer is added to the end of a circuit and becomes the new low voltage point, the adaptive voltage control program automatically incorporates the new control point into the voltage control system without operator intervention. In addition, if an existing customer adds load unknown to the utility and results in low voltage at the customer site the meter voltage will automatically connect the new low voltage to the adaptive voltage control and raise the voltage to the appropriate level. Another more frequent example is seasonal changes. If one part of the circuit uses primarily electric heating, it may be the low voltage limit during the winter season. But if another part of the circuit is heated by an alternate fuel such as gas and cooled by electric air conditioning, it could easily be the new limit for summer operation. This seasonal dynamic change will be easily adapted to by the voltage control scheme.

One of the key problems with previous implementations of CVR schemes is that they are engineered with a very limited number of voltage control points usually at primary voltage level, and as the dynamic nature of distribution circuits changed, they had to be re-engineered to keep customer voltages working in the lower 5% band. EDGE® adaptive control using AMI addresses this key issue and allows near total automatic response to the typical dynamic circuit environment. In addition, the method provides constant verification that the voltage conservation system is not resulting in any customer voltages being served at levels below ANSI C84.1 specifications.

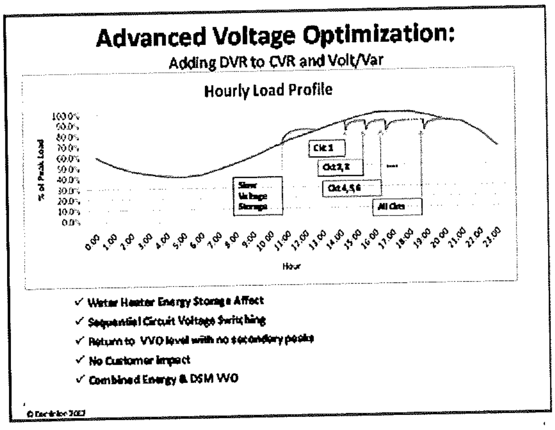


Figure 9 Demand & EE Operation Modes

EDGE® Manager operates in two distinct modes. The first one is a continuous 24 hour operating mode where the algorithm just described is used to optimize the customer voltages across the circuit for combined Volt/Var and CVR operation. This is an energy efficiency operation that precisely controls voltages on the circuit using combined CVR and Volt/Var optimization principles applied at the customer level. Using customer level voltages in combination with primary voltages to control the primary equipment such as LTC's, regulators, and capacitors is the unique patented part of the EDGE® program.

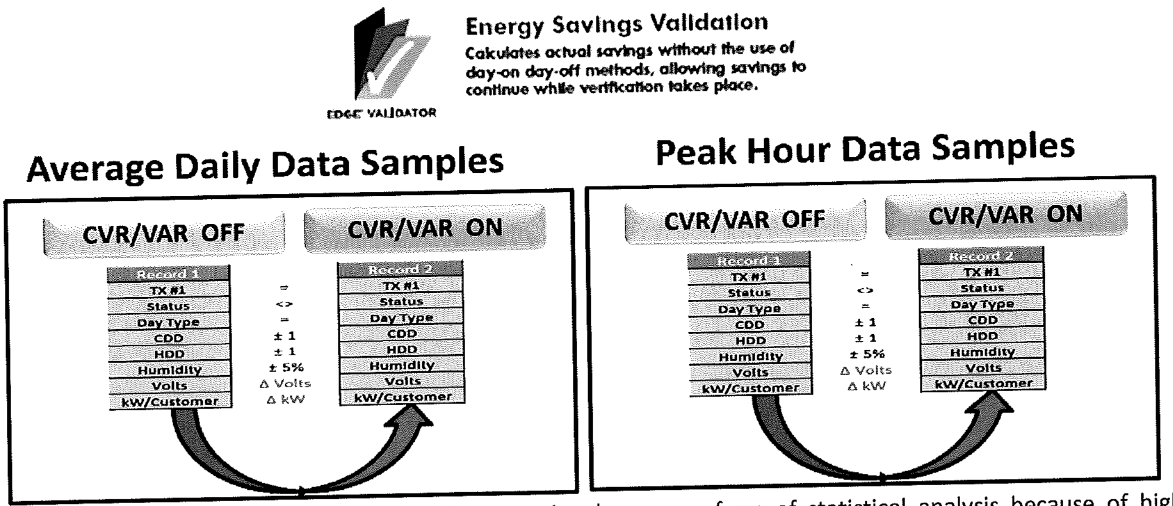
The second operating mode for EDGE® Manager is a targeted reduction for a limited number of hours. This demand management mode uses the same principles previously discussed but adds to them additional savings from reverse CVR energy storage. This effect is best explained using a hot water heater example. The water heater uses a resistor to produce heat for keeping the water at a set temperature. To raise the temperature the resistor is turned on with a set voltage and the heating power going out from the resistor is proportional to the square of the voltage. The amount of energy to raise the water temperature from one level to another is always the same. The higher the voltage the faster the hot water is heated. With this in mind, the demand control will raise the voltages on the circuit prior to the demand control hours. This causes the water to heat faster and "store" energy in the water tank before the demand control is initiated.

Once this is completed, the CVR voltage reduction is initiated, which lowers the hot water charging power for the units that are trying to charge and has "extra stored" energy from the reverse CVR effect just described above. This already stored energy reduces the total number of water heaters turning on as fast as they would have otherwise. These savings will continue until the water heaters lose the "extra energy" diversity from their storage cycle. The effect of this on the energy use is to provide a short time at the beginning of the hour that extra CVR storage effect is combined with normal CVR, creating more demand savings. This effect occurs not just for hot water heaters but also for other processes that are driven by voltage sensitive equipment, such as space heating and other thermal processes.

Figure 9 describes the combined processes. The reverse CVR energy acceleration is shown prior to the peak load target. Once it is completed, the optimized circuit CVR reductions are scheduled to flatten the peak energy use as much as possible. Once the peak period is over, the process is reversed and the circuit by circuit voltage levels are returned to the level chosen for off peak control. EDGE® Manager will allow the customer to choose the mode to operate in at any given time. It can be operated just as an energy efficiency program 24 hours per day, just as a demand management program targeted on a limited number of hours, or both at the same time to reduce energy use 24 hours a day and still target the peak hours using the CVR demand management function.

EDGE® VALIDATOR – Energy Efficiency and Demand Measurement and Verification

The objective of Measurement and Verification is to confirm through verifiable statistical analysis that the expected energy and demand savings by circuit were achieved. DVI uses results of prior industry studies in CVR from EPRI and the Northwest Energy Efficiency Alliance (NEEA), to determine expected values of .6 to 1.2% reduction in energy for every 1% reduction in average voltage. Many of the measurement techniques used for determining the energy savings were based on operating the system "ON" for one day and "OFF" for the next day and doing statistical comparisons between the on and off states to determine the actual CVR-based savings. These are accurate techniques, but using them for widespread continuous measurement requires a sacrifice of 50% of the savings in order to do the measurement. With this in mind, DVI developed a more practical method of statistical measurement to determine the savings.



Determining the benefits of a CVR control system involves some form of statistical analysis because of high

Figure 10 Validating the Hourly Demand and Daily Energy Savings per Customer Using Paired t Analysis

variation associated with individual customer usage patterns. As an example, during measurements on residential customer use, variables such as being on vacation, adding new appliances, additions to customer facilities, and many other non-predictable variations not specifically represented in the load model will occur. The basic statistical method of representing this non-predictable variation is to assume this level of variation is "normal" in a statistical sense. EDGE® Validator uses a rigorous statistical method that incorporates a paired t difference test comparing daily/hourly samples of the circuit data ("OFF" condition) to the CVR circuit data ("ON" condition) under matched operating conditions. The CVR "OFF" condition is taken from a six month to one year history period prior to operating CVR. Pairing is done by matching pairs that are from days or hours with the same heating/cooling degree day level, same type of day (weekday/weekend/holiday), and similar humidity levels as shown in Figure 10. By measuring the average kWh/customer, EDGE® Validator is able to eliminate the customer growth effect on the circuit. By statistically measuring the average difference between the energy (demand) use per customer with voltage conservation "OFF" to energy (demand) use per customer with voltage conservation "ON" for the measured samples, the average savings per customer in energy and demand can be calculated. The last calculation that EDGE® Validator does is to compare the measured circuit to a control circuit. This comparison measurement will remove any variables other than voltage that are affecting the change in kWh/customer by subtracting the change in the control circuit sample values from the change in the circuit values with CVR being tested for each paired "ON" to "OFF" sample. The control circuit is chosen to be in the same weather pattern as the CVR circuit and with a similar range and type of customers.

Previous CVR experiments operated in an alternating day-on/day-off fashion and compared differences over a large number of days. In other words, at each test location two circuits were chosen as operating circuits and one would have voltage conservation on for 24 hours and the other would have voltage conservation off for the same 24 hours. The next 24 hours the circuits would be reversed. A third circuit would be operated with no voltage conservation and used as a control circuit for the other two. This method requires approximately one year of operation to measure the average savings for voltage conservation. DVI, however, wanted to keep the system operating continuously once it was brought online but still be able to calculate the average savings per customer by circuit using a method that is more practical to implement.

EDGE® VALIDATOR – Measuring EDGE® Manager Savings Results

Figure 11 demonstrates the EDGE® Validator results from the example circuit of Figure 4. The measurement of energy reduction is based on 115 pairs and a control circuit adjustment for customer growth, overall economic conditions, and other factors. The results are presented graphically in Figure 11. The top graph shows the frequency plot of savings level measured for the paired values corrected with a control circuit. The concentration of high frequency near the average value is typical for this output. The bottom scatter plot puts kWh/customer with CVR "ON" on the vertical axis and the paired or matched day kWh/customer with CVR "OFF" on the horizontal axis. This plot is used only to visualize the data results not to calculate savings. The red line is the point where there is no change in usage per customer before and after CVR is turned "ON" are the same. The fact that 87 of the 115 matches fall below the line demonstrates that savings are being realized. The savings results on the right side of Figure 9 are calculated for Lifetime Usage (since the project started) and for the trailing 30 days. This gives a clear indication of whether the circuit is performing as desired.

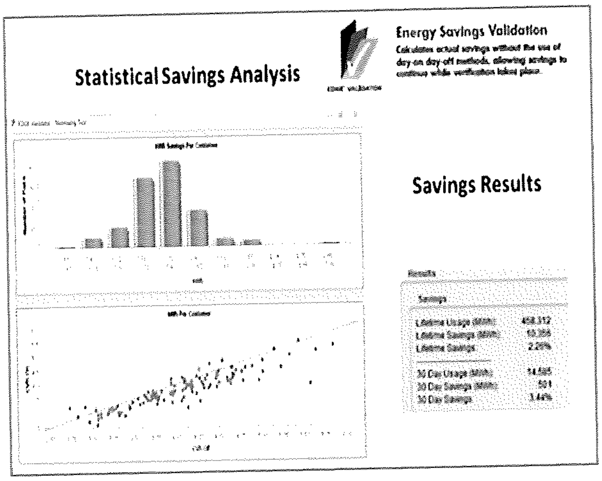


Figure 11 Measuring Results in Energy Use/Customer

EDGE® Validator can also evaluate the "normality" of the statistical data. The Anderson-Darling normality test of the savings difference between the CVR "ON" and CVR "OFF" data calculates whether the characteristics for the data graphed is "normal" measured by a calculated P-Value.

Voltage Optimization: Example of a Strong Business Plan for the Customer & Utility

The EDGE® Platform is designed to implement the process of planning, managing, and validating energy efficiency and demand savings from simultaneously optimized CVR/Volt/Var control. This platform integrates AMI-based customer voltage readings into the planning process as well as integrating into the DMS/SCADA control system to allow precision control of customer level voltages for maximizing energy efficiency and demand reduction from CVR. Because the voltage being controlled is at the customer meter, significant additional accuracy and voltage precision is obtained, enabling increased voltage optimization performance.

The EDGE® Planner Module integrates the AMI-based customer voltages into the utility planning process, identifying areas where granular improvements continue to increase the CVR performance of the circuit creating a continuous improvement process for energy and demand savings. The business case for implementing the EDGE® platform can be significant. Using the example circuit in Figure 4 and scaling it across Dominion Virginia Power's 2.4 million customers in 2008 resulted in the projected cumulative costs and benefits in Figure 12. After paying for the AMI system costs, the net benefit to customers over 10 years was $787 million.

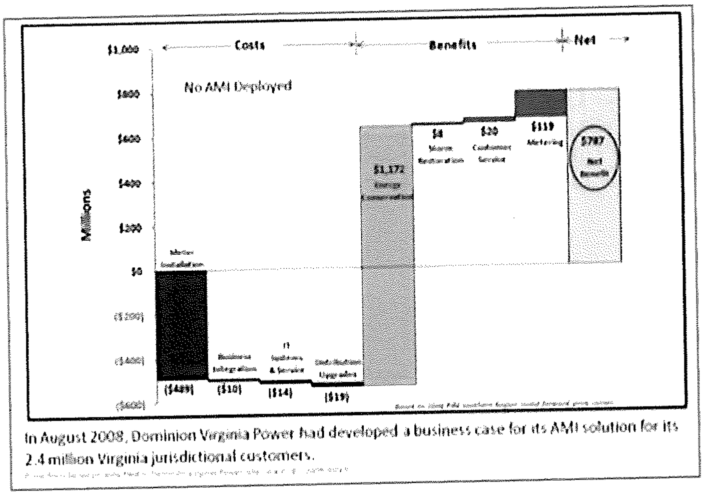


Figure 12 Accumulated Costs and Benefits over 10 Years

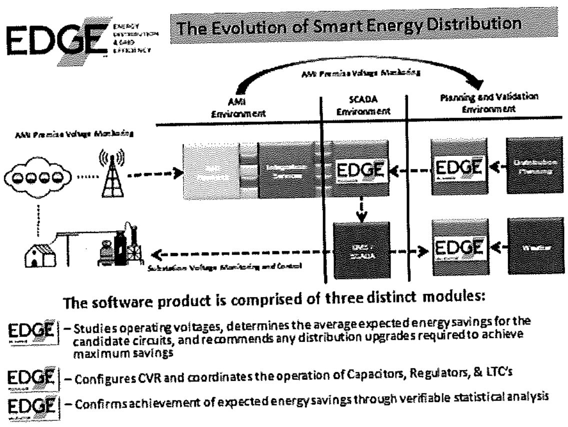


Figure 13 High Level EDGE® Platform

EDGE® Platform

Figure 13 is a high level view of the EDGE® Platform. It contains all three software products integrated tightly into the utility's existing equipment. The AMI platform is pre-integrated into EDGE® Manager and EDGE® Planner. This is done by using an integration server that collects data and then waits for a request of the data from inside the DMS/SCADA security perimeter. This structure allows a highly secure environment for DMS/SCADA while allowing the AMI data to be efficiently collected for use by the EDGE® Manager. The EDGE® Planner and EDGE® Validator are outside of the DMS/SCADA environment, allowing ease of integration to weather data and to the planning software system. The Planner data is collected directly from the AMI environment and does not require an interface through the integration services. In addition, this structure allows all of the direct equipment controls to remain completely under DMS/SCADA control with all of the normal processes and security available to protect them. This structure also supports staged implementation of the Planner, Manager, and Validator software to increase the deployment benefit.

EDGE® Platform Deployment

The process of implementing the EDGE® Platform with AMI-based adaptive CVR is broken into four steps as outlined in Figure 14. The first step is to identify the candidate circuits and collect historical data for use in Planner and Validator. The second step is to install Planner and perform the analysis of the chosen circuits. This information is used to identify any needed improvements, determine the projected savings, and determine the initial meters to be monitored. The third step is to install Manager and complete the integration of the DMS/SCADA to the EDGE® system to implement the input to the device voltage control. If not already completed a second integration is done to allow DMS/SCADA/Distribution Automation to directly control the LTC, regulator, and capacitor voltage setpoints. The fourth and final step is to install Validator and integrate the weather and historian data.

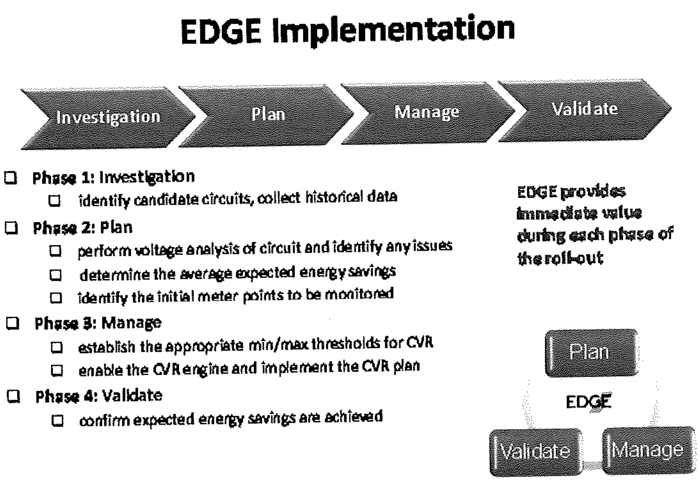


Figure 14 EDGE® Deployment Process

Once the required improvements to the circuits are completed to allow a reasonable range of voltage conservation operation, EDGE® Manager is ready to turn on. The program is initiated with monitoring of lowest voltage, low average voltage, and bus voltage, along with adaptive updating of the voltage monitoring points.

This process of continuous improvement is completed by refining any future cost effective additional upgrades to the circuit, which may aid in better lower band voltage operation for future operation. Load and controls are monitored to make sure small groups of customers are not limiting the performance of large groups of customers. Any situations like this will be evaluated for circuit improvements to eliminate the constraint.

The EDGE® Value Proposition for Utilities

The EDGE® solution allows the utility and its customers to realize the following value:

- Builds upon the investment in an AMI platform and represents another significant step toward enabling a "Smart Grid"
- Enables the utility's customers to benefit from savings with no action required
- Establishes a grid-side efficiency program scalable to the entire service territory
- Evaluates premise-level voltage values from each meter to ensure all customers receive service meeting quality standards, while maintaining operation in the most efficient voltage levels
- Adapts to dynamic changes on the distribution network, creating sustainable savings over time
- Provides a solution that does not require constant updating of detailed circuit models, eliminating maintenance and attention required to support a simulated distribution model
- Provides ease of installation; requires no additional sensors to be installed on the circuits
- Implements CVR by controlling circuit voltage levels with LTC's, Regulators, or Capacitor Banks
- Integrates into existing Planning, DA/DMS/SCADA, and AMI Systems
- Measures efficiency performance improvement without a detailed circuit model
- Enables AMI voltage data to be integrated into the circuit planning process

- Complements existing engineering planning processes to identify circuit improvements that continually increase CVR performance

The EDGE® technology enables a granular continuous improvement process across the distribution delivery system with immediate benefits realized by the customer. There are no known circuits that would need to be excluded or not considered as candidates for CVR. In general, conservation voltage reduction should be considered for all circuits. The DVI EDGE® Solution will be a foundation in preparing a utility's Smart Distribution Grid for future technologies such as microgrids, distributed generation, storage, and load management.

DVI

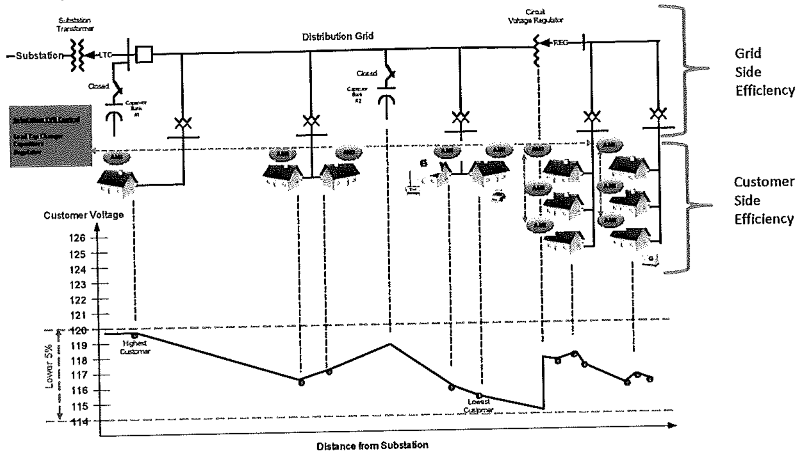
EDGE ENERGY DISTRIBUTION & GRID EFFICIENCY

Every Day It Listens to Your Grid
Every Day It Learns
Every Day Your Grid Gets Smarter and Saves More

CONSERVATION VOLTAGE REDUCTION (CVR):

Customer Efficiency Program or Grid Efficiency Program?

Conservation Voltage Reduction (CVR) has been around the industry for over 30 years and is based on operating electric *customer* voltages in the lower half of the 10% voltage band required by ANSI equipment standards. This energy savings has been tested in numerous field tests over this time period. [1,2,3,4] The results of these studies support an average savings of .8% energy reduction for every 1% average reduction in circuit voltage. One of the unaddressed questions within the industry is whether CVR that results in reductions in consumers' energy consumption should be deemed a customer-based energy efficiency program or a grid efficiency program due to the fact that it is operated through the distribution grid. The implication of how CVR should be classified relative to the efficiency gains is significant as to how the regulatory agencies should evaluate and account for the costs and savings attributable to a CVR program by a distribution utility.



Grid Side Efficiency. Evaluations of more historical CVR practices demonstrate efficiency gains enjoyed by the consumer, which can be improved through advanced voltage optimization technology. Grid side efficiency using either CVR or voltage optimization is executed using the transformer load tap changer, capacitor banks, and regulators to lower the grid losses created when delivering electric energy along the distribution circuit from the substation to the customer meter. Dominion calculates the amount of energy losses each year for the Virginia Commission and for the year 2012 the total annual energy losses due to the distribution grid was determined to be .59%. Using a conservative calculation the savings that the standard CVR practice could attain would be .36% or a total savings of .15% of the total system load going through the distribution grid.

Customer Side Efficiency The best study of customer-efficiency improvements was performed as part of the Distribution System Efficiency Initiative in the Pacific Northwest region of the United States in 2008. In this study, voltage control was placed on the entrances of customer facilities to measure only customer savings from CVR.[3] Comparing these measurements to the combined savings on both the grid-side and customer-side of the meter reveals that the customer portion of the savings conservatively averages approximately 2.9%. This 2.9% value is consistent with both the other major studies in the references and with the independent studies completed by Dominion's Regulated Distribution Business.

Using these conservative efficiency calculations demonstrates that the ***customer efficiency improvement for CVR is greater than 95%*** of the total savings and the ***grid-side efficiency improvement is less than 5%*** of the total energy savings. It is a misnomer to label a CVR programs as a grid-side program merely because of technology placement and not consider it a customer efficiency program. Although the control system that initiates CVR is located on the grid side and the customer is not required to change their energy use patterns, the fact is that once the CVR program is initiated and can control the voltage at the meter at a more efficient voltage band, 95% of the efficiency improvement occurs in the customer equipment and the meter records less energy usage for the same appliance usage resulting in immediate savings for the ***customer***. CVR clearly qualifies as Customer Side Efficiency.

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1 Green Circuit Field Demonstrations. EPRI, Palo Alto, CA: 2009. Report 1016520

2 Conservation Voltage Reduction at Northeast Utilities, D.M. Lauria, IEEE, 1987

3 Utility Distribution System Efficiency Initiative (DEI) Phase 1, Final Market Progress Evaluation Report, No 3, E08-192 (7/2008), E08-192

4 Evaluation of Conservation Voltage Reduction (CVR) on a National Level, PNNL-19596, Prepared for the U.S. Department of Energy under Contract DE-AC05-76RL01830, Pacific Northwest National Lab, July 2010

EXHIBIT 3

1. National Association of Regulatory Utility Commissioners, *EL-2/ERE-3 Resolution Supporting the Rapid Deployment of Voltage Optimization Technologies,* Nov. 14, 2012.

2. American Council for an Energy-Efficient Economy, *Frontiers of Energy Efficiency: Next Generation Programs Reach for High Energy Savings,* January 2013.

3. National Electrical Manufacturer Association, *Volt/VAR Optimization Improves Grid Efficiency.*

4. Carlman, Susan Frick, Naperville Sun, *Naperville launches study of reduced voltage use*, May 30, 2014.

5. Central Lincoln People's Utility District, *Voltage Management at Central Lincoln PUD,* Smart Grid Investment Grant 2014 Report, Project ID 09-0269.

6. Jackson, Jerry, Ph.D., Smart Grid Research Consortium, *Low Cost CVR May Pay for Your AMI System: New Study Turns Traditional Smart Grid Business Case Analysis on its Head,"* Feb. 6, 2014.

EL-2/ERE-3Resolution Supporting the Rapid Deployment of Voltage Optimization Technologies

WHEREAS, Adequate and reliable electric power is critical; *and*

WHEREAS, Each electric utility system is unique and States are in the best position to determine the appropriate activities to be employed in modernizing the distribution of electric power by electric utilities under their jurisdiction; *and*

WHEREAS, Some electric utilities, under State legislative guidance and regulatory oversight, have instituted initiatives designed to modernize the electric power grid to make it more efficient, more responsive and more secure; *and*

WHEREAS, Volt Var Optimization (VVO) technology deployment can be used as an important component of electric power grid modernization; *and*

WHEREAS, VVO technology has been proven through in-field deployments to deliver energy and demand reduction benefits, and these benefits have been independently verified; *and*

WHEREAS, These energy efficiency and demand reduction gains from VVO deployment are immediate, predictable, and measureable; *and*

WHEREAS, Since the VVO technology is typically installed on the utility side of the meter through an investment by the utility, with the possibility for rate base treatment, VVO benefits typically require no change in the consumer's home or business building structures, equipment purchases or uses, or behavior modification; *and*

WHEREAS, VVO technology deployment improves efficient delivery of energy and demand and these improvements are immediately reflected on consumers electric meters and reduce their electric bills; *and*

WHEREAS, The benefit-cost analytical results typically demonstrate that VVO technology investment is cost-effective from a ratepayer perspective; *and*

WHEREAS, Many States have legislative or regulatory Energy Efficiency Resource Standards (EERS) or regulatory expectations for electric utilities to provide for increasing amounts of energy and demand reductions; *and*

WHEREAS, Similar to traditional energy efficiency programs, VVO technology deployment can result in reductions of electric utility revenues, specifically revenues that are relied upon by electric utilities to cover fixed costs of investment and operations; *and*

WHEREAS, The impact of lost electric utility revenues can also be mitigated with the development and application of appropriate cost of service and rate designs, identifying the fixed costs of investment and operations which should not be recovered on the basis of customer consumption, but instead recovered through more appropriate means; *and*

Exh. 3-1

WHEREAS, The energy efficiency impacts of VVO eliminate air emissions associated with the forgone energy production, and therefore provide an important tool to help States and electric utilities in meeting environmental compliance requirements; *and*

WHEREAS, Deployment of VVO technology serves as a platform for potential future grid modernization initiatives that can deliver operational visibility, efficiency, and control of the electric distribution grid, improving reliability and customer service for a relatively small incremental investment; *and*

WHEREAS, Investment in VVO can create new employment opportunities related to the manufacturing of equipment and construction jobs associated with deployment, as well as utility-sector jobs associated with the operation of the VVO technology; *and*

WHEREAS, VVO technology can be deployed incrementally as determined cost effective and as financial conditions and fiscal prudency allow, *now, therefore be it*

RESOLVED, That the National Association of Regulatory Utility Commissioners (NARUC) convened at its 2012 Annual Meeting in Baltimore, Maryland and encourages State public service commissions to evaluate the energy efficiency and demand reduction opportunities that can be achieved with the deployment of Volt-Var Optimization (VVO) technologies and other electric utility grid modernization technologies and activities, and use of appropriate measurement and verification tools to ensure that such technologies provide the projected savings; *and be it further*

RESOLVED, That State evaluation is a preferable course to the establishment of federal standards or guidelines that may not reflect the fact that each utility system is unique and the States are in the best position to determine the appropriate activities to be employed in modernizing the distribution of electric power by electric utilities under their jurisdiction; *and be it further*

RESOLVED, That NARUC encourages State public service commissions to work with State legislatures, State energy offices, governors' offices, other State agencies, and Regional Transmission Organization (RTO'S)/Independent System Operator(ISO's) as needed, to certify energy efficiency and demand reductions associated with utility grid modernization efforts, including, but not limited to, the deployment of VVO technologies, as qualified resources in meeting legislative or regulatory Energy Efficiency Resource Standards (EERS) and/or regulatory expectations and orders to achieve prescribed levels of energy and demand reductions; *and be it further*

RESOLVED, That NARUC encourages State public service commissions to consider appropriate regulatory cost recovery mechanisms as appropriate in their respective States to ensure that electric utilities can reduce the reliance on customers' consumption to recover costs, and so that utilities and customers are not financially burdened as a result of achieving the benefits from the energy and demand reductions while experiencing reduced contributions to costs associated with the energy sales reductions produced by the VVO technology deployment; *and be it further*

RESOLVED, That NARUC encourages State public service commissions to avoid implementing policies that result in unnecessary barriers to the deployment of VVO technologies.

Sponsored by the Committee on Electricity and the Committee on Energy Resources and the Environment
Adopted by the Board of Directors, November 13, 2012
Adopted by the NARUC Committee of the Whole, November 14, 2012

Frontiers of Energy Efficiency: Next Generation Programs Reach for High Energy Savings

Dan York, Maggie Molina, Max Neubauer, Seth Nowak, Steven Nadel, Anna Chittum, Neal Elliott, Kate Farley, Ben Foster, Harvey Sachs, and Patti Witte

January 2013

Report Number

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Distribution System Efficiency Improvements

Synopsis

There are significant opportunities to improve the efficiency of distribution systems. In this section we focus on two such opportunities—voltage optimization and amorphous core transformers. A variety of studies find average savings from voltage optimization of just over 2% on appropriate circuits. Amorphous core transformers can reduce transformer losses by 25-40% relative to proposed new federal minimum efficiency standards and will often be cost-effective when transformers need to be purchased. Examples of utilities pursuing these opportunities are provided.

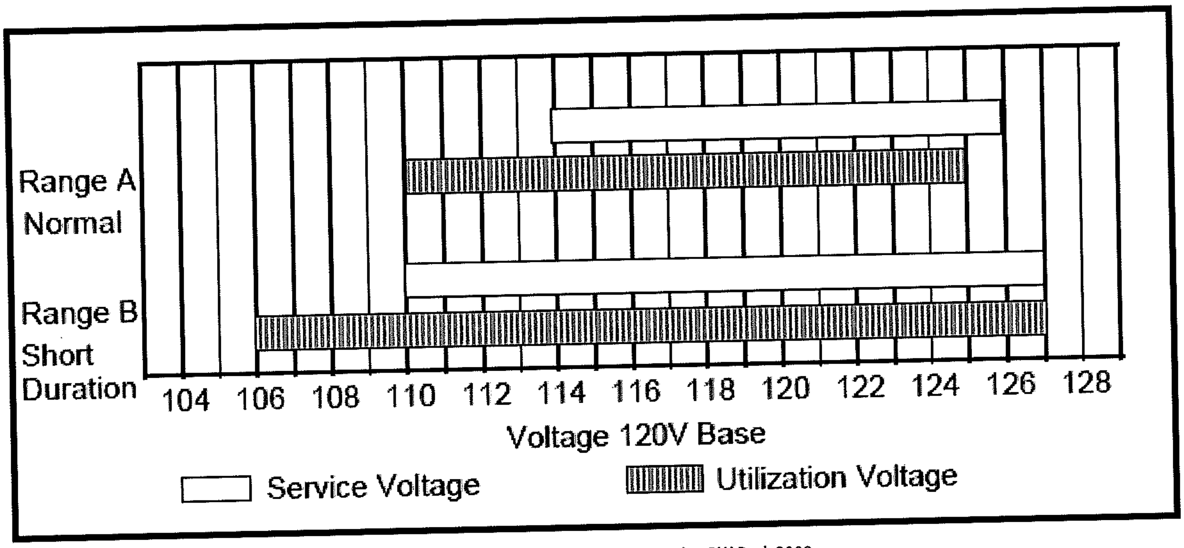
Exh 3-2

Background

In the United States, roughly 7% of electricity generated is lost in the transmission and distribution system[89] (EIA 2012), although this is lower in some areas and higher in others (e.g., most rural areas). This section concentrates on ways to reduce distribution system losses, which are roughly two-thirds[90] of these losses. We discuss two opportunities for improving distribution system efficiency—voltage optimization and high-efficiency transformers.

In the United States, electricity is supplied to residential and small commercial users at 120 volts nominal. However, under American National Standards Institute (ANSI) standards, voltage at the meter can range between 114 and 125 volts at all times and between 106 and 127 volts for brief periods (see Figure 2). The minimum ANSI voltage for some industrial uses is slightly higher—117 volts (RW Beck 2008).

Figure 2. ANSI Voltage Ranges



Source: ANSI C84.1 standard as excerpted in RW Beck 2008.

Voltage Optimization (VO) involves carefully analyzing voltages on distribution feeders in order to find ways to reduce voltages while still maintaining service requirements (including voltage levels and phase balance) at levels that allows equipment to operate without problems. Voltage Optimization is sometimes called Conservation Voltage Reduction (CVR). Lower voltages can improve end-use equipment efficiency and reduce line losses on both the customer and utility side of the meter. Voltage optimization can also improve the effective capacity (kW and help with reactive power management (NWPCC 2009). Voltage can be regulated using either voltage regulators or Load Tap Changers at the substation. Controlling the distribution voltage level from the transmission system or

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[89] Losses during critical times such as on hot days when systems peak can be twice average losses

[90] ACEEE estimate based on a review of data at http://www.ercot.com/mktinfo/metering/dlfmethodology/ .

using switched capacitors are less common methods. Voltage control needs to be automatic and can be done via Line Drop Compensation settings, switched capacitor banks, excitation on the generator, or voltage feedback signals from the extremities of the distribution system (RW Beck 2008). At times, distribution system improvements will be needed on some circuits in order to optimize voltages across the circuit. Best methods for voltage control will often vary from circuit to circuit—there is not a one size fits all approach. Additional plain English information on this opportunity can be found in a Regulatory Assistance Project report (Schwartz 2010).

Distribution transformers are ubiquitous on distribution systems and are used to step-down voltage from primary to secondary to the voltages used by customers. The U.S. Department of Energy estimates that more than 700,000 liquid-immersed distribution transformers (the type that are primarily used by utilities) are sold each year and that these transformers have an average service life of 32 years. This implies that there are more than 20 million transformers in utility distribution systems (DOE 2012a). New federal minimum efficiency standards took effect for these transformers in 2010 that result in more than a 20% reduction in losses relative to typical transformers being sold when the standard was set in 2007 (Sampat 2012).

Drivers for Change

Recent work on VO began in the Pacific Northwest with a major project by the Northwest Energy Efficiency Alliance (NEEA). The NEEA project involved pilot demonstrations involving six utilities, 10 substations and 31 feeders (NWPCC 2009). Voltage was controlled one day, off the next day, controlled the following day, etc. for multi-month [check] periods. In this way the impacts of voltage control could be separated from non-control under a wide range of operating conditions. The NEEA project found average energy savings from voltage control of 2.07% of the consumption on the circuit, with savings higher in summer and lower in winter (seasonal variation is discussed further below) (NWPCC 2009). As long as voltage is being carefully controlled to be above minimum thresholds, pilot programs have found that most customers will not notice any difference.

Interest in Voltage Optimization is growing. VO can save energy in ways that are fully under utility control, unlike some other approaches that have major unknowns such as customer response. VO can lead to known savings that can help meet resource needs and meet energy-saving goals. VO can also have other benefits such as reactive power management (specific data are discussed below). And one company markets its voltage optimization tools by saying they help to prevent under-voltage that can violate service quality requirements.

Building on the initial pilot in the Northwest, the Bonneville Power Administration is now implementing a full-scale Voltage Optimization program, providing a possible template for others. Some information on this program is provided below. Furthermore, the Electric Power Research Institute (EPRI) sponsored a major project, called Green Circuits, which working with more than 24 utilities to characterize 85 circuits across 33 states and four countries, identify existing circuit losses and prioritize potential options for efficiency improvement.[91] This project is exposing the 24 participating utilities to distribution efficiency opportunities and also is helping to validate these opportunities across many different applications.

In addition, new software and new technologies are making voltage optimization easier. Some of these developments are discussed in the next section.

Regarding distribution transformers, DOE will publish a new standard in late 2012, to take effect in 2016, that is likely to result in modest further reductions in losses (e.g., a 4-10% average reduction in losses for the draft 2016 standard relative to the 2010 standard). DOE has indicated that this standard will be set at levels that can be met with silicon steel cores (DOE 2012b). Utilities can avoid more losses by upgrading to amorphous core transformers. For example, relative to the draft standard DOE published in early 2012, amorphous core transformers that result in minimum lifecycle costs will reduce transformer losses by 25-40% (DOE 2012a). Specific numbers are provided later in this description under Savings Potential.

Emerging Trends and Recommendations

In this section we review emerging trends regarding distribution system efficiency and then discuss potential elements of a distribution efficiency program and potential savings from such a program.

Technologies

Several recent technology developments can contribute to distribution system efficiency. There are improved ways to optimize voltage. For example, several companies (General Electric, Cooper, Utilidata) are now marketing Integrated Volt-VAR Controls (IVVC) that provide automated adjustment of substation-level voltage based on end-of-line voltage and predictive algorithms. And some of these products can also control switchable capacitor banks to regulate reactive power compensation.

Second, smart meters with two-way communication being installed in many areas can provide utilities with a way to measure service voltage at each home. These data can provide aid in voltage control. For example, Dominion Voltage (a subsidiary of the utility Dominion Energy) has a set of three software products that use this smart meter data for customer voltage control as well as grid-planning, and energy savings validation.[92]

Third, as discussed above, amorphous core transformers reduce core losses relative to silicon steel transformers, even transformers with low-loss steel. Amorphous steel is a solid metallic material with a disordered atomic-scale structure. Amorphous metals are non-crystalline, and thus are classified as

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[91] http://tdworld.com/overhead_distribution/epri-green-circuits-project/ .
[92] https://www.dom.com/business/dominion-voltage/edge-overview.jsp .

glasses. But unlike the usual glasses, such as window-glass, which are insulators, amorphous metals have very good electrical conductivity, reducing losses in transformer cores. Amorphous steel was first developed by Allied Signal in the 1980s which was bought by Honeywell and ultimately MetGlas, a subsidiary of Hitachi. They have a plant in Conway, SC that produces the amorphous material for transformer manufacturers such as Howard and General Electric. Amorphous metal is also produced in China and Posco in Korea recently announced they will start production.

Interestingly, China and India have been quicker to embrace amorphous core transformers than American utilities. China requires that utilities purchase a certain percentage of their transformers at efficiency levels which can only be met by amorphous metal. A forthcoming specification will increase this percentage. In India, utility specifications require amorphous level performance. As a result, China is installing roughly five times the volume of amorphous transformers and India twice the volume as the U.S. (Millure 2012).

Program Design

For the most part this is an effort that utilities would implement themselves for their own systems. A plan for voltage optimization would need to be developed identifying which circuits to address first and specifying the period for overall implementation. Voltage optimization experts suggest that circuits that are primarily residential tend to be the easiest, followed by circuits with many small commercial customers. For circuits with very large commercial and industrial customers, more detailed circuit analysis will be needed to make sure that any changes do not have adverse impacts for these key large customers. Large customers may also have opportunities to optimize voltages on their side of the utility meter but we are not aware of any utilities offering programs in this area.

For transformers, the likely approach is to change purchasing practices so that when new transformers are purchased, generally these purchases are amorphous. We suggest "generally" because most utilities conduct a simple economic analysis on each transformer purchase and there will be some applications where amorphous transformers have higher lifecycle costs. Typically utilities examine transformer economics using so-called A and B values. These should be set to minimize lifecycle costs over the entire life of a transformer. "Bands of equivalence" should not be used as these override long-term life-cycle cost savings in favor of minimizing initial costs. As a rough approximation, Table 6 provides DOE's estimates of the mean lifecycle savings and median simple payback for use of amorphous core liquid immersed transformers relative to transformers meeting today's federal minimum efficiency standards.

Table 6. DOE Estimates of the Economics for Representative Amophous Core Transformers

Transformer Size and Type	Mean Lifecycle Cost Savings	Median Simple Payback Period (years)
50 kVA, single phase, rectangular tank	$641	7.9
25 kVA, single phase, round tank	$338	8.0
500 kVA, single phase	$5591	4.7
150 kVA, three phase	$3356	4.1
1500 kVA, three phase	$12,513	6.3

Source: DOE 2012b. Values shown are for Trial Standard Level 4

Target Market

This program would generally be operated by distribution utilities working on their own circuits. In the case of small utilities, a wholesale power provider could offer a program, just as the Bonneville Power Authority is offering a program for their utility customers (discussed further under Examples).

Marketing

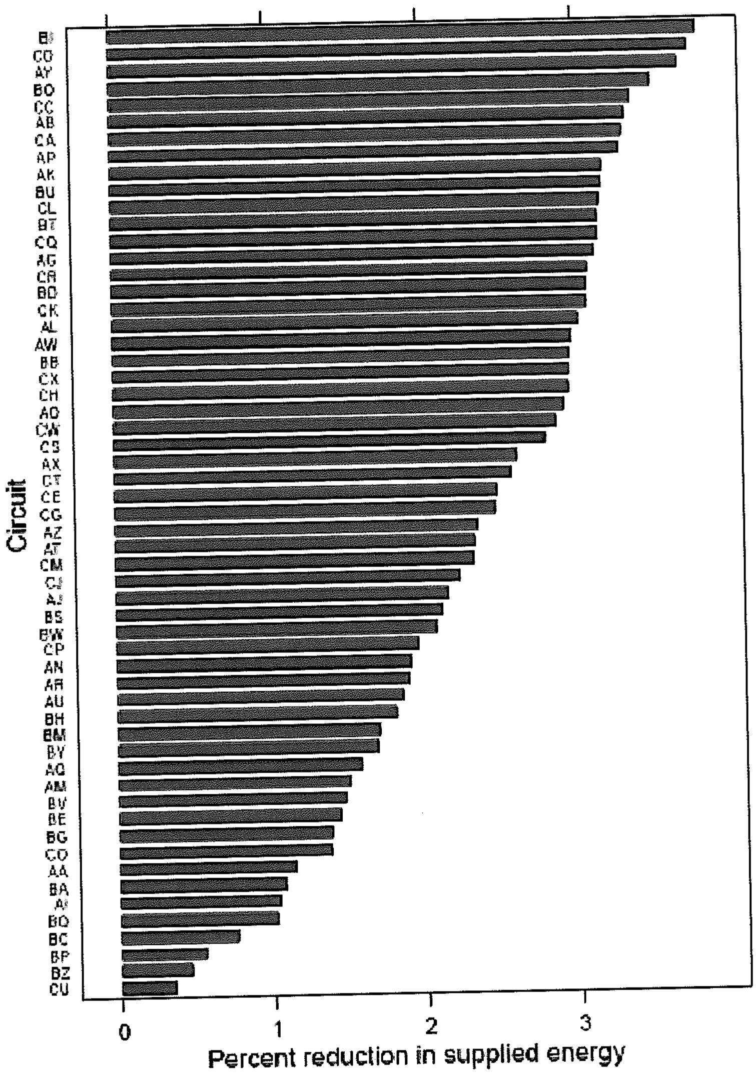
Unlike other energy efficiency programs the primary "marketing" is for a utility to decide internally to proceed. Utility management needs to be convinced that the savings are real and that there will not be adverse impacts on customers. All of the benefits should be examined together—customer energy savings, line loss reductions on the utility side of the meter, and reactive power management. One utility representative we talked to also suggested that decoupling or lost revenue recovery can be important, as voltage optimization clearly reduces sales, and utility management can be concerned about the lost revenue.

Utility commissions also have a role. They need to approve expenditures for distribution system improvements and they can encourage utilities to undertake any such improvements that reduce customer lifecycle costs. Voltage optimization in particular can reduce customer cost, because, as discussed below, most of the savings are on the customer side of the meter.

Savings Potential

Voltage Optimization. As discussed above, the NEEA project in the northwest found average savings of 2.07% across the 31 feeders that were included in their pilot study. Results from the EPRI green circuits program have found similar savings. For example, computer modeling of 66 circuits across multiple participating utilities found average kWh savings of 2.3%. These circuits were not randomly selected but instead were selected by participating utilities for a wide variety of reasons. Savings ranged significantly from circuit to circuit, as shown in Figure 3 (Arritt, Short and Brooks 2012). Tom Short (2012) of the EPRI green circuits team reports that achieving savings is generally easier and more cost-effective on shorter circuits, as on long circuits, voltage drops over the entire length of the line are greater and therefore, to avoid violating voltage limits, either voltage can be reduced less or more monitoring points and regulator banks must be installed, which increases costs.

Figure 3. Modeled Saving from Voltage Optimization of 66 Circuits



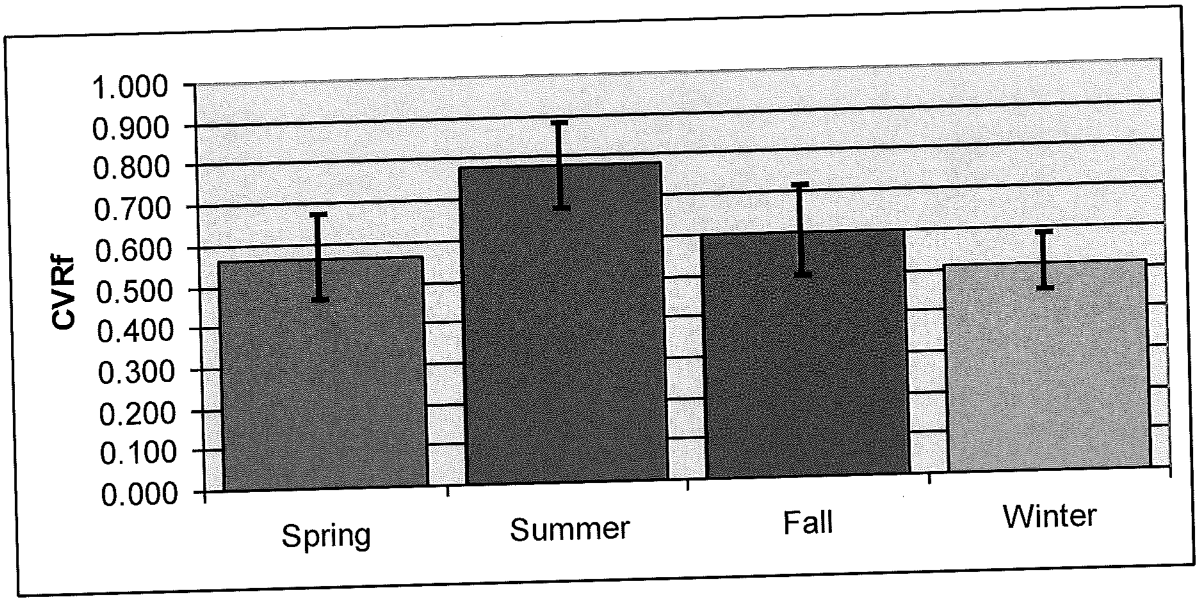
Source: Arritt, Short and Brooks. 2012.

Actual field measurements for nine circuits that were optimized as part of green circuits found savings ranging from 0.23-2.40% with a median of 2.01% energy savings. Reasons for the outlier are unclear but instrumentation accuracy may be involved (Short and Mee 2012). Reactive power was also measured on two of these circuits and very positive improvements in reactive power were obtained. Among these nine circuits for the most part, there were no complaints on circuits operating at reduced voltage. There were initial complaints on two circuits, but these were resolved by less aggressive voltage reduction.

Schwartz (2010), based on her review of data available as of 2010, estimates that voltage optimization can reduce energy consumption by 1-3%, peak demand by 1-4%, and reduce reactive power requirements by 5-10%.

There are two other interesting findings regarding energy savings First, savings tend to be higher in the summer when air conditioners are running and lower in the winter on circuits with substantial electric resistance heat. With electric resistance heat, when voltage is reduced, the amount of heat is also reduced and equipment needs to run a little longer. This is illustrated in Figure 4, which shows results from the NEEA study.

Figure 4. Energy Savings per Percent Voltage Reduction by Season in Northwest Pilot



Note: CVRf is the conservation voltage reduction factor. It is the percent reduction in energy use divided by the percent reduction in voltage.
Source: NWPCC 2009

Second, the majority of savings from customer optimization are on the customer side of the meter. Schwartz (2010) suggests "perhaps 80%." One utility we talked to suggested it might be as high as 95%.

In addition, it is not yet clear what proportion of circuits these savings apply to. The most work has been done on circuits that are primarily residential and secondarily on circuits with significant commercial loads. But little work has been done on circuits with large commercial and industrial customers. Experts we consulted expect lower savings on these circuits.

Amorphous core transformers. DOE, as part of their draft standard for distribution transformers estimates that on a national basis, by 2035, use of transformers that minimize lifecycle costs (primarily but not exclusively amorphous core) will reduce national electricity use by about 7,300 GWh. Savings will gradually ramp-in starting when the standard takes effect in 2015 and will gradually increase until all transformers are upgraded by about 2048 (2015 + 32 year average transformer life). Extrapolating, the savings in 2048 will be approximately 11,700 GWh. The 2035 savings amount to an estimated 0.2% of national electricity use in that year.

Potential Energy Savings Summary

Distribution Efficiency System Improvements	Electricity	Notes
	TWh	
National energy use affected	4514	Total electric use from AEO 2012
Average percent savings	2.2%	2.07% for voltage optimization from NW plus 0.15% for transformers
Ultimate participation rate	75%	Estimate of appropriate percentage of circuits and transformers
Potential long-term savings	75	

Examples

Voltage Optimization

Bonneville Power Administration (BPA). Based on the results of the northwest pilot project, BPA decided to go to full-scale implementation of voltage optimization and supporting system improvements. BPA is a wholesale power provider and utilities that purchase power from them can receive incentives for VO projects. BPA requires that a study estimating savings be conducted and BPA pays incentives based on the estimated savings achieved. Details can be found in their Implementation Manual (BPA 2012). The Northwest Regional Technical Forum has adopted two measurement and verification protocols for savings verification—one for simple approaches, one for sophisticated systems.[93]

PacifiCorp. PacifiCorp serves portions of six states and has begun to pursue voltage optimization in three of these. Work began in Washington where the utility commission has explicitly authorized cost recovery for voltage optimization.[94] In Washington PacifiCorp conducted a "tier 1" study of its circuits which identified some circuits for immediate work and other circuits for a further "tier 2" study. Some of the immediate projects are now being implemented and the tier 2 study is underway. In Oregon, an initial high-level tier 1 study is planned for 2012. In Utah, PacifiCorp originally proposed a similar process but the utility commission instead asked them to incorporate voltage optimization as part of their normal transmission and distribution business. PacifiCorp conducts a planning exercise on each circuit every five years, with about 20% of circuits reviewed each year. Voltage optimization is now being incorporated into this process. In Idaho and Wyoming, PacifiCorp serves extensive industrial loads and is not pursuing voltage optimization at this time (Jones 2012).

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[93] http://www.nwcouncil.org/energy/rtf/protocols/Default.asp .

[94] http://apps.leg.wa.gov/wac/default.aspx?cite=194-37-090 .

Green Mountain Power (GMP). Like most utilities, GMP conducts an economic analysis on each transformer purchase. GMP uses criteria that emphasizes life-cycle cost effectiveness with the result that since 2011, about half of their transformer purchases are now amorphous. The change happened in 2011 when their main supplier began providing amorphous core transformers at competitive prices. GMP notes that their economic analyses indicate they should purchase amorphous cores in more than half the cases, but lead times for amorphous transformers from their current supplier are long and sometimes they cannot wait (Litkovitz 2012).

Recommendations

Based on these findings, we recommend that utilities conduct voltage optimization studies on their circuits, beginning with primarily residential circuits and proceeding over time to circuits with substantial commercial and industrial loads. Such studies can occur in blocks, as PacifiCorp is doing in Washington, or as part of regular planning processes, as PacifiCorp is doing in Utah. In addition, utilities should review their transformer purchase policies to make sure they minimize life-cycle costs at the utility's cost of capital. Using such criteria, utilities should consider amorphous core transformers whenever new transformers are purchased. For both of these savings opportunities, we recommend that utilities receive credit for the savings as part of efforts to reach savings goals and to earn incentives if they meet their goals.

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Additional Program Concepts

In addition to the full program write-ups in the previous chapters, there are several other promising program concepts where field experience is still limited. In this chapter, we discuss two of them with a briefer write-up than for programs with substantial experience; these are for *Miscellaneous Energy Use in Commercial Buildings* and for *Commercial-Sector Behavior Programs.*

MISCELLANEOUS ENERGY USE IN COMMERCIAL BUILDINGS

Synopsis

Projections show that miscellaneous energy use will account for nearly half of commercial sector energy use by 2035. Available data and programs are limited and there is a need for continued data collection and program experimentation. The New Buildings Institute has just issued a guide to reducing plug loads in offices, which might provide enough information to support pilot programs.

Many program operators already address data centers in their programs but these efforts generally target large dedicated data centers. Program implementers should consider expanding this work to servers that are not in data center. Further work is needed to understand miscellaneous energy use and program strategies for addressing this use. This program area has larger potential energy savings than any other program area profiled in this report.

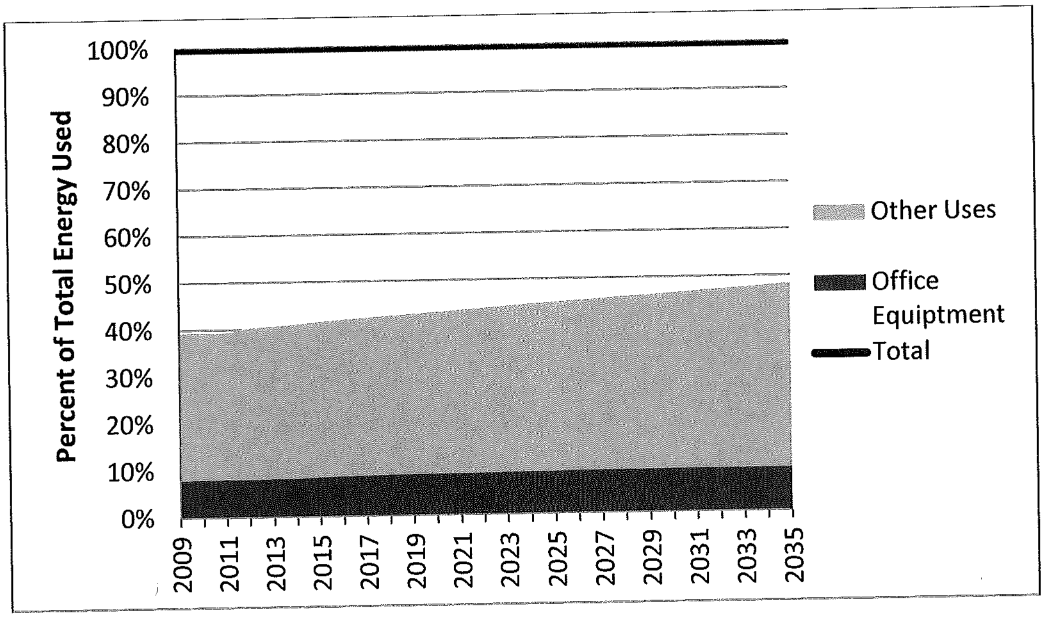
Background and Drivers for Change

Historically the vast majority of energy used in commercial buildings has been for space and water heating, cooling, ventilation, lighting and refrigeration. In recent decades, efficiency in these major end uses has improved yet simultaneously the number of "other" energy uses has grown (computers, peripherals, servers, data centers), increasing their proportion of the total load. The Energy Information Administration is now projecting that by 2035, almost half of energy use in commercial buildings will be for office equipment, and "other" energy uses (see Figure 5). In absolute terms, EIA projects this use will grow from about 7 to about 11 quadrillion Btus per year (see Figure 6). Other estimates of miscellaneous energy use are somewhat smaller,[95] but all agree that these loads account for a steadily growing share of commercial building energy use.

The range of end-uses in buildings and their contribution to total energy use is illustrated by metered data from a single building, as shown in Figure 3.

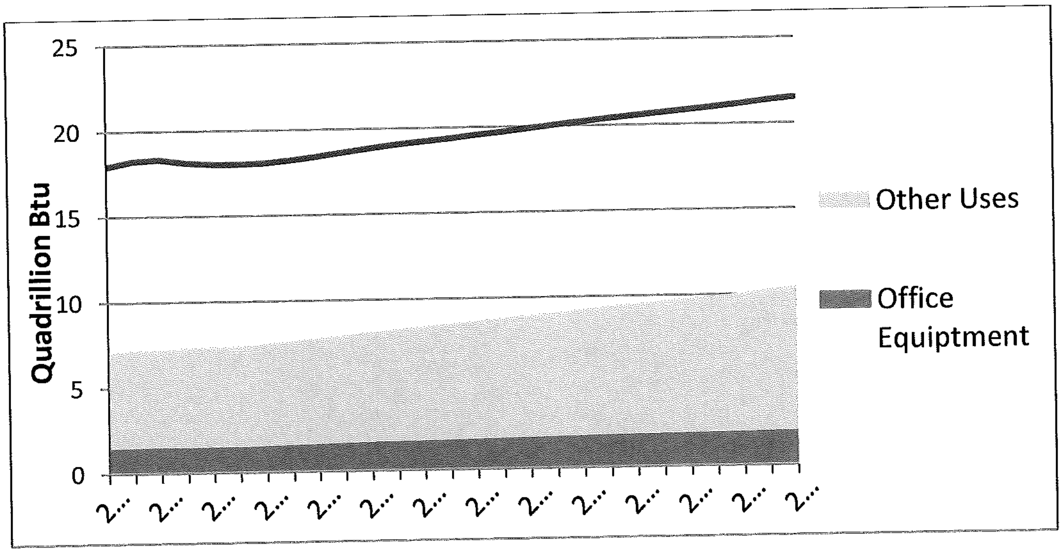
[95] ACEEE will be releasing a report summarizing available data in early 2013.

Figure 5. Projected Energy Use for Office Equipment and "Other" Uses in the Commercial Sector as a Percent of Total Commercial Energy Use



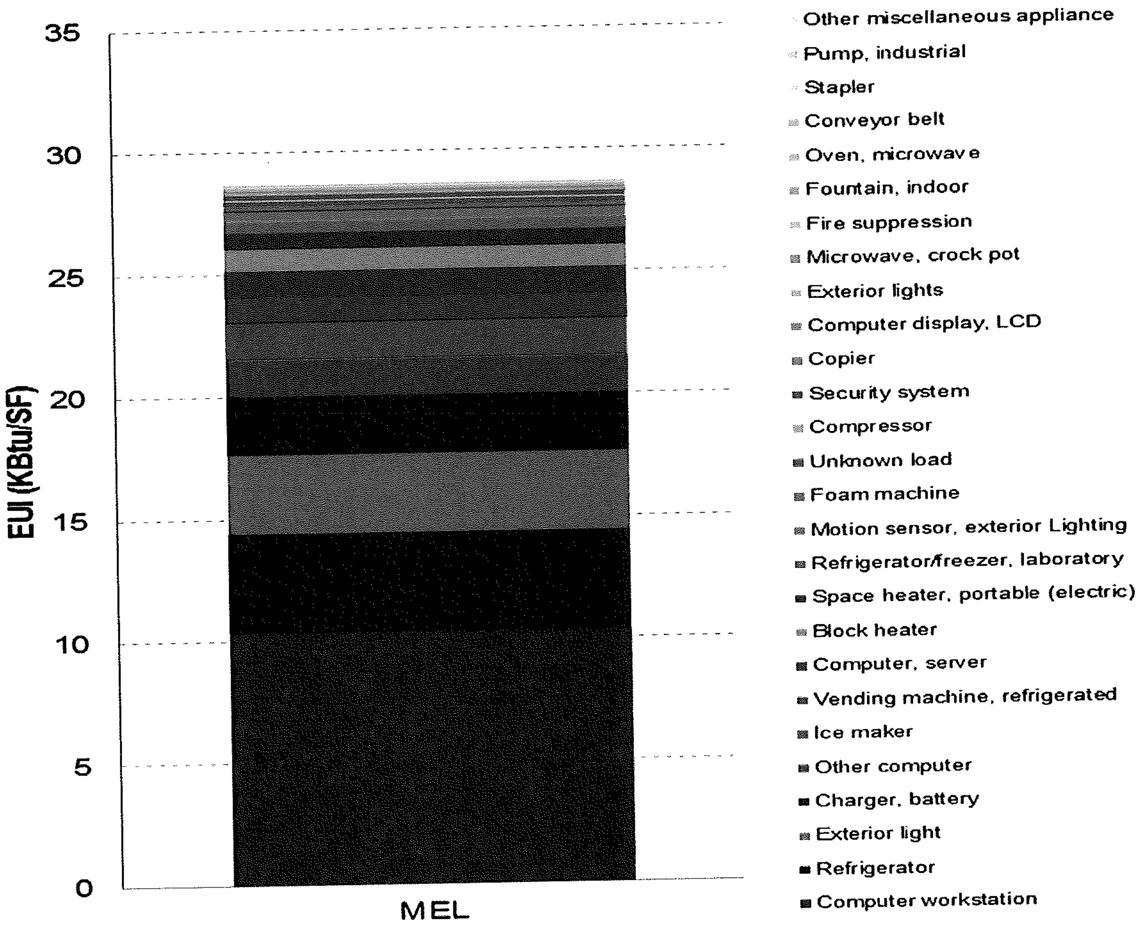
Source: EIA AEO 2012

Figure 6. Projected Electricity Use for Office Equipment and "Other" Uses in the Commercial Sector in GWh



Source: EIA AEO 2012

Figure 7. Metered Miscellaneous Electric Loads in a Warehouse



Source: Dirks and Rauch 2012

Emerging Trends

Given the trends discussed above, researchers and program administrators are paying more attention to miscellaneous energy uses in the commercial sector, with a primary focus on office equipment, servers and data centers. While this work is not as advanced as is comparable work on miscellaneous uses in the residential sector, the savings opportunities may ultimately be greater.

For these end-uses, energy savings opportunities fall into two general categories:

1. Promote more efficient technologies such as improved personal computers, monitors, printers, copiers and servers.
2. Promote management and control of these devices power management of personal computers, virtualization of data centers that allow computing to be accomplished with fewer actual computers (hardware) running, and improving distribution of heated air and light distribution in buildings so fewer personal space heaters and lamps are needed.

In addition, there are major energy users in the commercial sector that might merit attention. For example, a report by TIAX (2006) for the Energy Information Administration finds significant electricity use for water distribution, water treatment, elevators, X-ray machines, non-road electric vehicles and coffee makers. Some program administrators have targeted water distribution and treatment for many years, but others have not. And few utility-sector programs have addressed these other end-uses.

Examples

New Buildings Institute (NBI) has recently (August 2012) released a *Plug Loads Best Practices Guide* that outlines steps that an office can take to examine and reduce plug load energy use. Previous research by NBI (Mercier and Moorefield 2011) that examined plug loads in an office and a library, collecting baseline data and then instituting a variety of operational improvements as well as replacing some old equipment. These changes resulted in 48% plug load savings in the office and 17% in the library.

Data Centers. According to McDonald (2011), many utilities have offered custom incentives to data centers to help improve cooling system performance, for more efficient equipment, for virtualization/consolidation, airflow control systems, high efficiency uninterrupted power supply systems, efficient distribution systems and efficient power supplies and monitors. Leaders including Pacific Gas & Electric, Austin Energy, and BC Hydro, are also incenting efficient data storage technology, thin and zero client systems, PC management software, and remote monitoring. Some of these measures apply beyond data centers, for example, many of these can apply to server systems outside of data centers.

Savings Potential

More systematic work to estimate the savings potential is needed, however here we provide a rough initial estimate.

Miscellaneous Energy Use in Commercial Buildings	Electricity	Natural Gas	Notes
	TWh	TBtu	
National energy use affected	782	1360	From AEO 2012 for "other, office equipment & cooking" in 2030
Average percent savings	30%	10%	Based on midpoint of NBI study for electric; ACEEE estimates 10% for natural gas savings
Ultimate participation rate	75%	50%	
Potential long-term savings	176	68	

Volt/VAR Optimization Improves Grid Efficiency

Introduction

Traditional Voltage/ VAR management[1] technologies have been used by the power industry for over 30 years to reduce electric line losses and increase grid efficiency. Today those technologies have advanced to include Volt/Volt-Ampere Reactive Optimization (VVO) sensors, equipment and software capable of reducing overall distribution line losses by 2%–5% through tight control of voltage and current fluctuations.

Despite their ability to significantly improve power quality, lower line losses and reduce peak demand compared to traditional methods, VVO systems have not been widely deployed in the United States because traditional utility fee structures fail to provide revenue recovery or ROI to pay for the needed investments.

In November 2012, the National Association of Regulatory Utility Commissioners, representing the public utility commissions of all fifty states and our territories, recognized the need for change through its resolution of support for the adoption and rapid deployment of voltage optimization technologies, stating:

> *"(NARUC) encourages State public service commissions to evaluate the energy efficiency and demand reduction opportunities that can be achieved with the deployment of Volt-Var Optimization (VVO) technologies…and encourages State public service commissions to consider appropriate regulatory cost recovery mechanisms."* [2]

NEMA supports the NARUC position and further recognizes an appropriate role for federal support in expediting state adoption of VVO technologies. Federal legislation to improve energy efficiency and advance the electric grid must include incentives to encourage the deployment of voltage management technology and should include incentives for the adoption of State Energy Efficiency Resource Standards, electric utility rate incentives, and/or the establishment of a grid optimization fund to finance necessary upgrades.

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[1] VAR or Volt-Amphere Reactive is a unit used to measure reactive power in alternating current

[2] http://www.naruc.org/Resolutions/Resolution%20Supporting%20the%20Rapid%20Deployment%20of%20Voltage%20Optimization%20Technologies.pdf

Exh 3-3

Background

The concept of Voltage/VAR management or control is essential to electrical utilities' ability to deliver power within appropriate voltage limits so that consumers' equipment operates properly, and to deliver power at an optimal power factor to minimize losses. These concepts are affected by a variety of factors throughout the distribution network including: substation bus voltages; length of feeders; conductor sizing; type, size, and location of different loads (resistive, capacitive, inductive, or a combination of these); and the type, size, and location of distributed energy resources (photovoltaics, distributed wind, various storage technologies, etc.); among others.

The complexity and dynamic nature of these characteristics make the task of managing electrical distribution networks challenging. While voltage regulation and VAR regulation are often referenced in combination (i.e. Volt/VAR control), they are perhaps easier to understand if described as two separate, but interrelated concepts.

Voltage Regulation. Feeder voltage regulation refers to the management of voltages on a feeder with varying load conditions. Regardless of nominal operating voltage, a utility distribution system is designed to deliver power to consumers within a predefined voltage range. Under normal conditions, the service and utilization voltages must remain within ANSI standard C84.1-2011 limits, defined as Range A. On a 120V base, this service range is defined as 114–126V and utilization range is 110-126V. During high load conditions, the source voltage at the substation is at the higher end of this range and the service voltages at the end of the feeder are at the lower end of the range.

VAR Regulation. Nearly all power system loads require a combination of real power (watts) and reactive power (VARs). Real power must be supplied by a remote generator while reactive power can be supplied either by a remote generator or a local VAR supply, such as a capacitor. Delivery of reactive power from a remote VAR supply results in additional feeder voltage drop and losses due to increased current flow, so utilities prefer to deliver reactive power from a local source. Since demand for reactive power is higher during heavy load conditions than light load conditions, VAR supply on a distribution feeder is regulated or controlled by switching capacitors on during periods of high demand and off during periods of low demand. As with voltage control, there are both feeder design considerations (to minimize capital costs) and operating considerations.

Volt/VAR Regulation. Supplying VARs when and where demanded is inherent to operating an electric power system. But the flow of reactive power affects power system voltages just as the flow of real power does. The effects of real power flow nearly always have negative effects on voltage while the effects of reactive power flows are sometimes positive and sometimes negative. Experience has proven that overall costs and performance of operating a power system can be best managed if voltage control and reactive power control are well integrated.

A number of technologies have been employed by utility companies to monitor and adjust voltage and/or VAR levels on their electrical networks. In substations, these include capacitor banks, voltage regulators and power transformers with on-load tap changers (OLTC). Of course by being located in the substation, these devices manipulate electrical parameters at the substation bus level. While they take into account down line feeder conditions, they are utilized primarily for gross adjustments and were designed initially for radial distribution networks. Down-line feeder technologies including fixed and switched capacitor banks and voltage regulators are also utilized to help adjust system parameters along the length of a feeder.

With the development of microprocessor-based controls and computing platforms, pervasive, high performance communications technologies, widely deployed sensor technology including AMI systems and advanced software algorithms, it is now possible to coordinate these devices to optimize the broader electrical system at the feeder, substation or utility level with VVO systems. With these integrated systems in place, utilities can optimize voltage profiles and VAR flow to achieve a variety of objectives, including: reducing peak demand, targeting power factor levels to minimize energy losses, or implementing Conservation Voltage Reduction (CVR). CVR controls feeder and substation equipment to lower distribution line voltage within approved standard ranges. The result is a significant reduction of losses and energy demand. They can also change target objectives at different times of the day/week/month/year to meet performance goals.

Benefits

There are a number of benefits associated with implementing VVO technologies. For utility operations, VVO solutions provide a higher level of visibility into system operating parameters and a greater degree of control to optimize energy efficient and reliable electricity delivery. VVO technologies help utilities move from flying blind to operating with end-to-end instrumentation on feeders and automated optimization. Utilities are facing a dynamic operating landscape, a landscape that wasn't envisioned when most electrical networks were designed. The increasing penetration of intermittent renewable generation sources, the increasing diversity and variability of loads are driving this volatility. Utilities are also running closer to the operating limits of these systems than ever before, making the ability to optimize within operating parameters extremely important.

In the case of a vertically integrated utility, being able to optimize a power factor means that the utility has to generate less power to satisfy the demand of its customers. In simple terms, certain power factor conditions require utilities to generate more real power than is actually needed by its consumers. This excess real power is wasted in the form of thermal losses. The ability to optimize power factor is a key driver in a utility's ability to minimize losses. This particular benefit also serves the environment; if a utility has to generate less power to serve the same demand then in turn they burn less coal or natural gas and therefore emit less CO^2. Similarly, utilities that purchase power from transmission companies or independent power producers usually have contractual, financial incentives including steep penalties for operating outside of specified power factor limits.

Strategies such as Conservation Voltage Reduction (CVR) have numerous potential benefits. This type of VVO solution can be used to flatten voltage profiles and then lower overall system voltage while staying within the specified ANSI voltage limits. In short, doing this reduces overall system demand by a factor of 0.7-1.0% for every 1% reduction in voltage. From a consumer perspective, this reduces the energy they consume. From a utility perspective it reduces the amount of power they need to generate or purchase from a generator. There is a cost benefit associated with reduced operating costs, but to the extent these strategies can be implemented to defer investment in new generation capacity or to address reduced capacity due to old generating assets being taken offline, the benefits can be enormous especially when load growth is small.

Examples of results from utility studies and pilot projects on CVR include:

- A 1987 study at Northeast Utilities showed a 1% energy savings for each 1% voltage reduction.
- A distribution efficiency initiative was commenced in 2003 by the Northwest Energy Efficiency Alliance and completed in 2005 - 13 utilities showed an average of 0.8% energy savings for each 1% voltage reduction.
- Results of a recent EPRI study of 6 distribution feeders over a one year period showed energy savings ranging from 0.66% to 0.92% for each 1% voltage reduction.
- Recent pilot studies conducted by Dominion Virginia Power showed a 0.8% energy savings for each 1% voltage reduction study.

Challenges

There are several challenges facing utilities who are interested in deploying VVO technologies, which range from financial hurdles to technical hurdles. Each must be considered in determining how to best fund these deployments and maintain and manage them long term.

The primary technical hurdles typically involve how best to deploy the solution across the distribution feeders. The main hurdles determining the communication technology that can best fit the deployment needs as well as the optimal sensing solutions to provide real-time voltage measurements to the VVO system. Utilities have used communication systems ranging from public wireless technologies, such as 4G/3G, to private wireless mesh technologies, including Advanced Metering Infrastructure (AMI) networks. In terms of the sensing solutions, they have used devices such as stand-alone voltage and current sensors to AMI meters as well as integrated sensing in devices such as capacitor controls. Tied to these technical hurdles is the cost to deploy these communications and sensor technologies along with the VVO system.

The financial hurdles to the deployment of VVO technologies are particularly acute for regulated investor-owned utilities operating as transmission and distribution wires companies. Utilities which are paid for the volume of electricity delivered have limited incentive to implement energy savings technologies. Revenue-reducing technologies like VVO face greater obstacles due to the rate structures currently in place which were applied to recover investment and upgrade costs based on kWhs delivered. The long term benefits enabled by VVO, such as reduced generation requirements through deferral of new infrastructure, the ability to burn fewer fossil fuels, and the improvement to both system operations and the quality of power delivered to consumers, fail to offset the revenue impact of the rate structure for wires companies. The benefits do not compete with the immediate need for investor returns and impact the returns of previous investments without some financial recovery incentive for the utility.

VVO technologies also suffer when compared to utility and regulatory funding for energy efficiency programs. For most utilities seeking to enable energy efficiency, there is typically ample funding for programs such as customer demand response and load control, which require the utility to install controls within the customer premise to enable demand and energy reduction. However, these same programs fail to account for the ability of VVO to provide similar results for demand and energy reduction without the need for customer involvement. All of the energy efficiency technologies should therefore be treated equally in terms of their ability to enable energy efficiency through the electric distribution system.

There are similar financial hurdles for utilities that buy power from entities such as regional generation and transmission companies. These utilities typically deploy VVO for peak demand reduction as they are charged a higher rate from the G&T for their monthly peak demand. However, they usually will not use the VVO technology during off peak periods as it decreases their revenue, which is needed to offset their traditional operational costs.

Conclusion

Volt/VAR Optimization has been successfully used to increase power system efficiency by all types of utilities for many years. This record of success and today's smart grid advances have led industry experts like NARUC to recognize the significant energy savings and reliability benefits available through use of VVO, and the need for incentives to drive their adoption.

Absent new rate structures or financial compensation to address the cost of deploying VVO technologies, these valuable tools will languish. Therefore, NEMA urges policymakers to support the widespread deployment of these important control systems through appropriate investment incentives, recovery rate structures and tax policy.

Case Studies

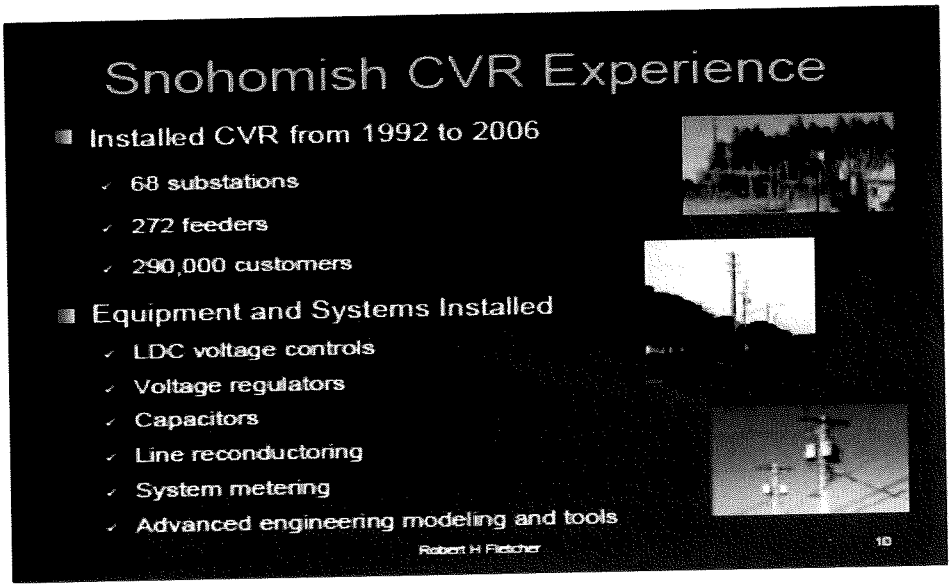
What follows are some case studies that provide compelling cost/benefit examples of voltage management implementation.

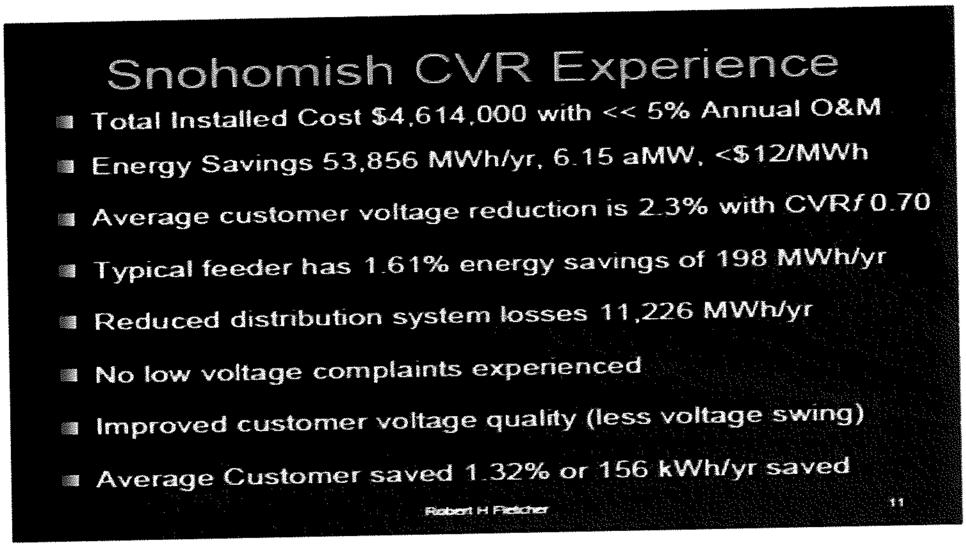
- **The Snohomish County PUD** installed a Conservation Voltage Reduction system to improve system throughput and improve power quality. Their investment of under $5 million has resulted in energy savings of 53,856 MWh/yr, including reduced distribution system losses by 11,226 MWh/yr while providing better voltage quality (less voltage swing) to end-use customers.

- **The Northwest Energy Efficiency Alliance** studied 13 utilities for the impact of lower voltage on consumers. Their work showed voltage reductions of 2.5% resulted in energy savings of 2.07% without impact on consumer power quality.

- **The Clinton Utilities Board** is using state-of-the-art voltage regulation technologies to power 3,000 homes solely through energy savings. Utilizing Dispatchable Voltage Regulation to safely and automatically adjust end-use voltages to meet peak demand needs, Clinton has harnessed a virtual power plant by capturing otherwise lost energy to meet service needs.

- **Oklahoma Gas & Electric** (OG&E) is in the process of implementing volt/VAR optimization (VVO) across 400 feeder circuits to achieve a 75-megawatt load reduction within the next eight years. Advanced model-based VVO allows OG&E to maximize the performance and reliability of its distribution systems while significantly reducing peak demand, minimizing power losses and lowering overall operating costs.





Utility Energy Efficiency Summit, March 17-18, 2009, Robert Fletcher, PHD, P.E.[3]

3 http://www.bpa.gov/Energy/N/Utilities_Sharing_EE/Utility_Summit/Workshop2009/pdf/BobFletcherSnohomishPUD.pdf

NEEA DEI Study

The NEEA DEI Study (2002-2007) involved 13 Northwest Utilities to study the impacts of lower voltage at the customer.

	Pilot
– Avista	Load Research & Pilot
– Clark Public Utilities	Load Research & Pilot
– Douglas PUD	Load Research
– Eugene W & EB	Load Research
– Franklin PUD	Load Research
– Hood River	Load Research
– Idaho Falls Power	Load Research & Pilot
– Idaho Power	Load Research
– PacificCorp	Load Research
– Portland Gen Elec	Load Research & Pilot
– Puget Sound Energy	Load Research
– Skamania PUD	Load Research & Pilot
– Snohomish PUD	

Contractor was R.W. Beck, RLW Analytics, Auriga, and Hunt Power

Robert H Fletcher 12

NEEA DEI Study Results

- Pilot Demonstrations – 2.5 years of data
  - ✓ 10 Distribution Substations – 6 utilities
  - ✓ 30,000 customers involved in tests
  - ✓ Average voltage reduction 3.03 V (2.5%)
  - ✓ Average energy saved 2.07%
  - ✓ kWh CVR*f* = 0.690
  - ✓ kW CVR*f* = 0.780
  - ✓ kVAr CVR*f* = 3.850

Robert H Fletcher 14

Utility Energy Efficiency Summit, March 17-18, 2009, Robert Fletcher, PHD, P.E.[4]

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[4] *Id.*

Clinton Utilities Board Partners with TVA on new Energy Saving Program[5]
Oct. 22, 2012

Imagine a power plant that generates zero emissions, power for 3,000 homes, and saves ratepayers hundreds of thousands of dollars. And by the way ... this power plant is *invisible.* Clinton Utilities Board has created exactly that. They're one of the first power companies in the Tennessee Valley Authority's seven-state service region to build their own "virtual power plant." Instead of bricks, mortar and generators, CUB is using state-of-the-art technology called Dispatchable Voltage Regulation which automatically adjusts end-use voltages across their service area.

The virtual power plant enables CUB to make carefully monitored voltage reductions in its distribution system when requested by TVA. When CUB activates its demand reduction technology, less power is used throughout CUB's service territory, enabling TVA to use that power to supply other customers. "We have always strived to use cutting-edge technology and forward-thinking to design and implement projects such as this demand reduction technology. Said Greg Fay, CUB General Manager. "Our ability to leverage this technology has reduced our wholesale power costs, thereby saving our local ratepayers over $800,000 to date and will help lower utility bills throughout the TVA service area."

"CUB is pleased to partner with TVA in this pilot effort to reduce peak power demands" said Ernie Bowles, CUB's Assistant General Manager. "When we get a request from TVA for demand reduction, it occurs within seconds and its effects are invisible to our customers. This will help lower utility bills throughout the TVA service area." Earlier this summer, when temperatures topped 100 degrees across the Tennessee Valley, CUB used its virtual power plant to help TVA supply power to the region. TVA has asked CUB to engage their Virtual Power Plant on five different dates this summer. Each time, the project has been successful in utilizing its technology to aid TVA in meeting the power requirements of the valley. "We applaud CUB for being the first local power company in the valley to join us in this new initiative," said John G. Trawick, TVA's senior vice president of Power Supply and Fuels. "Utilities have known for some time that voltage reduction held great promise for reducing peak power demand and lowering emissions, but until recently the technology was out of reach and demand and energy wholesale rates were not in place to use the technology effectively. CUB is helping us lower the cost of providing electricity at those times when power usage and costs are the highest." The virtual power plant is headquartered in a brand new high-tech control room, with big screen monitors showing real-time data from smart meters across the entire service area. It's all part of a TVA Smart Grid Pilot program to cut energy use during peak periods.

Clinton Utilities Board was founded in 1939. When the town acquired the system, it served only 1,877 customers. Today CUB distributes electric service to about 30,000 customers in six counties (Anderson, Campbell, Knox, Morgan, Roane and Union) and four municipalities (Clinton, Lake City, Norris and Oliver Springs). CUB purchases wholesale power from TVA. CUB provides the necessary facilities to distribute electric service over approximately 1,400 miles of high voltage circuitry to our customers.

The Tennessee Valley Authority, a corporation owned by the U.S. government, provides electricity for business customers and distribution utilities that serve 9 million people in parts of seven southeastern states at prices below the national average. TVA, which receives no taxpayer money and makes no profits, also provides flood control, navigation and land management for the Tennessee River system and assists utilities and state and local governments with economic development.

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[5] http://www.clintonutilities.com/TVA%20Press%20Release-CUB%20Virtual%20Power%20Plant.pdf

- Decoupling of sales from revenue and Revenue Recovery. The following example of Entergy's CVR installation shows the significance of this challenge.

Entergy.

THE POWER OF PEOPLE®

Entergy Tests AMI Voltage Optimization

What else can the smart meters do?

Katherine Tweed: January 27, 2012

Many people working in smart grid argue that the smart meter, which got so much attention (and stimulus funds) in recent years, is just an endpoint. Real smart grid is on the grid itself, providing two-way communication and more efficient power flow across the distribution system.

But what if the meter can help with some of that? Following in the footsteps of Dominion Virginia Power, Entergy is using its Elster smart meter system to understand, and adjust, voltage conditions at the end of the line.

Entergy has been testing two residential feeders, one with about 70 meters on the end and the other with about 30. The utility is seeing a consistent 4 percent to 6 percent savings in energy consumed.

The project, which also involves ABB and Survalent Technology, will next move into a controlled pilot to figure out the business case to bring to the public utility commission. If all goes well, it could then be expanded to many feeders throughout Entergy's territory.

That's a big if, however. Voltage reduction seems like a win-win. A recent GTM Research report, Distribution Automation: 2012-2016: Technologies and Strategies for Grid Optimization, noted that "VVO is poised for an explosion of acceptance among utilities looking to reduce peak load and defer capital expenditures through CVR or increase control of voltage and reactive power levels on the distribution grid."

However, that's only if the utilities are incentivized to shave peak load through decoupling or other methods that ensure that the utility won't be losing money if they sell less power. "The challenge is to make sure we have the right regulatory recovery mechanism," said Paul D. Olivier, Director of Smart Grid at Entergy.

For investor-owned utilities that already have something in place that allows them to increase efficiency without sacrificing profits (or for Munis and Co-Ops, that are seeking the lowest rates for their customers), David Green of Elster argued that voltage conservation and transformer management using advanced metering can boost the business case by squeezing more value out of the system. "Beyond radial feeders, networked systems will also provide a quick payback for utilities interested in VVO, as they consist of shorter, heavily loaded lines," wrote Ben Kellison, author of GTM Research's latest DA report.

To reduce the voltage, Entergy is adjusting capacitor banks and adjusting setting for load tap changers at the substation. "Some of the secret sauce in the software is creating optimal settings so you're not creating feedback loops," said Olivier.

To support the findings of the Entergy pilot in Louisiana, Elster formed the Smart Grid Voltage Conservation Alliance in August 2011. If the pilot is successful, Elster hopes to expand it to other utilities. For now, the alliance is comprised of just the companies involved in the Entergy pilot -- hardly an industry consortium so far.

For ABB, which has a clear stake in conservation voltage reduction hardware, the project has allowed the company to learn more about voltage across the feeders and down the end point, according to Jon Rennie, vice president and general manager for ABB Distribution Components. Although metering can provide insight into what's happening down the feeder, it can't provide the switching that's needed back at the substation or on the line to reduce the voltage.

In Louisiana, Entergy is adjusting capacitor banks or adjusting settings for load tap changers at the substation to achieve the reduction. The hard part is finding just the right balance so that two devices aren't fighting each other to get the reduction, Olivier said.

But even more difficult than achieving the right balance using the AMI system and just the right devices is getting regulators on board. "Our challenge is to get CVR to be included in energy efficiency for recovering lost revenue," Olivier said. "The good news is, I don't think these are insurmountable hurdles."[6]

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6 Entergy Tests AMI Voltage Optimization Greentech Media.mht

NY utilities: Transmission solutions far less costly than repowering 2 plants
May 23, 2013 Thursday
SNL Power Daily with Market Report
Kerry Bleskan

Utilities that will be affected if two New York power plants are shut down permanently say transmission upgrades fix the problems more cheaply than repowering the units.

The coal-fired Dunkirk and Cayuga plants were slated to be closed and are currently running under agreements with National Grid USA and New York State Electric & Gas Corp. The New York Public Service Commission ordered the utilities to examine the relative costs and benefits of transmission solutions versus repowering the plants to run on natural gas. National Grid and NYSEG submitted their reports on May 17.

National Grid and the Dunkirk plant

The western New York system is vulnerable to low voltages during transmission outages with or without Dunkirk, National Grid said, but the problem is worse when Dunkirk is out. By National Grid's calculations, transmission solutions to maintaining reliability in southwestern New York state would be three to seven times less expensive than repowering the Dunkirk plant, which is owned by NRG Energy Inc. NRG submitted a plan in March to replace the existing 1950s-era Dunkirk units with a 440-MW combined cycle gas plant, online in 2017.

The report from National Grid, known legally in New York as Niagara Mohawk Power Corp., found a number factors to be equal between the generation and transmission options, including job creation and environmental and reliability benefits, so it based its recommendations on cost. "The company does not oppose generation repowering in principle; however, repowering at the Dunkirk facility is not in the best interest of customers," National Grid said. "In addition, repowering under the commercial structure proposed by NRG would shift significant risk back to customers and away from the competitive market."

National Grid evaluated NRG's repowering Option 1 as a new 422-MW combined cycle gas turbine located on the 230-kV network and online in 2017 plus refueling Dunkirk Unit 2 as a 75-MW gas unit on the 115-kV system, complete by 2015. Option 2 would add natural gas firing capability to Dunkirk units 2, 3 and 4 for 455 MW of generation capacity. Option 3 is 285 MW of new gas peaking units. Repowering Option 3 is insufficient to meet reliability needs, National Grid said, so it was dropped from consideration.

The $63 million transmission option includes a series of upgrades that would be in service by June 2015 and which would eliminate the need for the existing reliability agreement with the Dunkirk plant, and two longer-term reliability projects to be completed later, by 2018 at the latest.

The first repowering option created the most jobs during construction compared to the transmission option and the other repowering option. "However, the costs and resulting rate impacts of Repowering Option 1 would result in the highest number of job losses during the study period," National Grid said.

"Based on the analysis summarized in this report, the company recommends the commission support the transmission upgrades to address the reliability needs at the lowest overall cost, least risk to customers, and with minimum impact on competitive markets," National Grid said. "The regulated nature of the transmission upgrades also provides for greater transparency of and scrutiny over the investments that are being made for the benefit of customers."

National Grid estimated that transmission upgrades will cost customers about $10.5 million per year, a net present value of $70.5 million over the study period. Repowering Option 1 would cost $375 million over 10 years, and Option 2 would cost $218 million over 10 years. The projects' net costs in 2018 were redacted. Translating those numbers to delivery cost increases to customers, the transmission option would raise delivery costs by 0.5% for residential customers and 1.3% for the largest customers. The first repowering option would raise costs by 3.5% to 9.5%, and the second repowering option would raise costs by 5.3% to 13.9%, depending on customer class.

NYSEG on the Cayuga plan

Iberdrola SA subsidiary New York State Electric & Gas also recommended a transmission reinforcement solution over repowering, regarding Cayuga Operating Co. LLC's 309-MW, two-unit Cayuga coal plant, which dates from 1955.

NYSEG conducted reliability analyses of its system with a mothballed Cayuga plant and found issues would start cropping up at 65% of projected peak summer loads. The company has already proposed an Auburn-area transmission reinforcement of one new 14.5-mile, 115-kV line. Should the plant be retired permanently, NYSEG proposed to rebuild another 14.5-mile, 115-kV line, although a less expensive National Grid capacity-upgrade project will eliminate the same problems.

Cayuga presented NYSEG with four repowering options, each of which requires a new natural gas pipeline to the Cayuga Generating Facility site and relies on a levelized revenue stream from NYSEG customers over a certain, confidential number of years. Option 1 is a repowering of the two existing coal-fired boilers and would have a maximum output of 300 MW. Option 2 would achieve a similar maximum output, 294 MW, with three new simple-cycle combustion turbines.

Option 3, maximum output 300 MW, would repower Cayuga unit 2 with a combined-cycle turbine generator, a heat recovery steam generator and a condensing cycle steam turbine generator. Option 3 is described as a hybrid of Options 1 and 4, and additionally raises the possibility to fuel-switch Cayuga unit 1 to natural gas.

Option 4 uses the same combination of equipment as Option 3 but has a maximum output of 326 MW due to two new combined-cycle combustion turbine generator trains. Option 4 would provide the most flexibility and reliability, NYSEG summarized, "but at an added cost."

NYSEG said that the repowering options are riskier than transmission options in several different ways. Cayuga's proposal places the full market risk on NYSEG customers, the utility said, because NYSEG would make a fixed payment to Cayuga and the offsetting market price revenues will fluctuate.

Additionally, NYSEG was unable to duplicate Cayuga's forecasted level of revenues and worries that Cayuga may have overstated the revenue potential of a repowering option. "NYSEG is concerned about its customers assuming the market price risk associated with the Cayuga repowering option," the utility said. "If this market risk is removed and no market revenues are assumed, the transmission option is the least cost option."

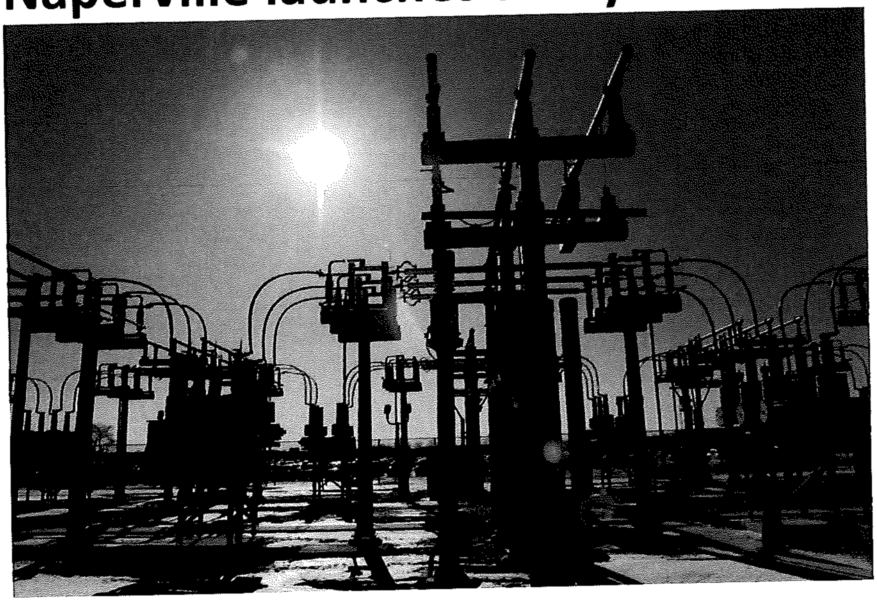
NYSEG also argued that transmission options are better for the environment and for competitiveness in the electricity market. "By definition, Cayuga [out of merit] operation reduces economic efficiency and increases costs for customers in the sub-zone," NYSEG said.

Even if a generation option is chosen, NYSEG said, transmission planning for risk mitigation should continue until the generation is online, "given the uncertainty inherent in a generation option." The utility asked regulators to allow it to move ahead with planning and approvals in case a generation option falls through. "The company's customers cannot wait for three years for a repowering project to be completed, only to find out that Cayuga (or another developer) cannot or will not be able to bring on line the generation necessary for reliability," NYSEG said.

Details provided by Cayuga were redacted from NYSEG report, including the maximum heat rate and development timelines and cost recovery proposals for the several repowering options. "The recommendations are necessarily preliminary given the unverified nature of the information underlying the four repowering options proposed by Cayuga Operating Company LLC," NYSEG said, noting other future uncertainties including the price of natural gas.

NapervilleSun
A CHICAGO SUN-TIMES.com publication

Naperville launches study of reduced voltage use



Transformers and circuit breakers make up the majority of the switch yard at the City of Naperville's Jefferson Substation | Jonathan Miano/Staff Photographer

Susan Frick Carlman
scarlman@stmedianetwork.com | @scarlman
May 30 9:30 a.m.

Naperville is aiming to work out any bugs in the electric utility's smart grid distribution network well in advance of its full launch. A pilot program begun earlier this month is part of that preemptive approach.

The Conservation Voltage Reduction undertaking is designed to spotlight potential savings to be realized through paring back, when feasible, the energy circulated through the city-owned system. The goal is to bring down the city's bulk power purchase expense while delivering the ideal electricity levels to the utility's customers, to keep them from overpaying for the energy.

The process taps data generated by the smart grid to reduce voltage when it makes sense, boosting efficiency.

"CVR optimizes the utility's understanding of how power travels from start to finish from its substations through its wires to homes and businesses and allows the utility to reduce line loss, also known as wasted power or energy," electric utility Director Mark Curran wrote in a recent memo to the City Council.

The program is expected to save the city $2 million annually, which represents 42 percent of the projected savings to be yielded by the smart grid. The CVR software, purchased last year, cost $771,575.

The pilot program began earlier this month at the Meadows Substation on 75th Street. Analysis of the data generated from the readings will begin June 30.

"Staff will be examining how the electric load out of the Meadows Substation reacts to a conservative reduction in voltage, which will help answer the question of how many dollars can be saved through CVR," Curran said.

Also during June, staff will study other substations to gauge any work they need before the pilot is expanded to the 15 remaining locations.

Part of the aim of the pilot is to enable utility staff to study the reductions under controlled conditions and address issues that arise before they crop up on the citywide level.

"Realizing that this program will provide potential savings to utility customers, staff has implemented a more aggressive timeline for full CVR rollout and anticipates completion in mid 2015," Curran said.

Exh. 3-4

CENTRAL LINCOLN
A PUBLICLY-OWNED ELECTRIC UTILITY

Project ID 09-0269

Voltage Management at Central Lincoln PUD

Summary

Central Lincoln People's Utility District (Central Lincoln) has implemented a unique approach for voltage optimization utilizing near real-time premise level voltages with supervisory control and data acquisition (SCADA) control to drive significant customer savings as well as utility benefits. Conservation voltage regulation (CVR) has been practiced for more than thirty years; however, with recent innovations in advanced metering infrastructure (AMI) technology and communications, significant improvements are possible. Central Lincoln's CVR program combines the latest in radio frequency (RF) AMI technology with adaptive control algorithms that continually scan voltages while having a negligible impact on the AMI communications network. The program combines distribution planning analytics, real-time management and control, and an approved measurement and verification methodology.

Table 1: Key Results

CVR Pilot Project Key Results	
Customer Benefits	• Energy savings without a change in behavior • Enhanced reliability • Stable voltage levels at the premise
Operational Improvements	• Higher system reliability • Improved asset management • More information about infrastructure • Proactive approach to service issues • Less truck rolls • Application of existing AMI load profile data
Lessons Learned	• LTC not exercised any more than without CVR • Minimizes customer voltage excursion risk • Minimal impact on communications network • Designed to turn off when bypassing a circuit switch or breaker • Reconnaissance to the voltage levels at the customer site • No power quality complaints during the pilot
Investment Plan	• District-wide deployment of CVR

Exh 3-5

Background

In October 2009, Central Lincoln was awarded an American Recovery and Investment Act Smart Grid Investment Grant from the U.S. Department of Energy for $9,936,950. The grant to implement the District's TEAM 2020 Smart Grid plan comprised of a variety of grid modernization projects including the deployment of a district-wide AMI system, meter data management system, customer energy management web portal, fiber network buildout, installation of distribution automation devices and an upgraded SCADA/outage management system (OMS). The TEAM 2020 Smart Grid plan also included a demonstration project for CVR.

In 2011, Central Lincoln began discussions with the District's AMI vendor, Landis+Gyr, and energy solutions partner, Dominion Voltage, Inc. (DVI) exploring the development of a CVR pilot project that would leverage the meter data from the newly deployed AMI system. Central Lincoln's robust AMI system utilizes RF communication and has a read rate of 99% for customer billing and load profile. DVI had recently developed a patented voltage control methodology called EDGE which uses AMI data and encompasses planning, operation and validation functions. The discussions led to a six-month CVR pilot project that included one substation, two feeders and 1,400 meters and was implemented in partnership with the Bonneville Power Administration (BPA) Energy Conservation and Incentives Program.

Pilot Project

Central Lincoln implemented a substation-level pilot project of the EDGE program at the Lincoln Beach substation. DVI's EDGE software is a dynamic voltage management application that serves as a practical method for using the Landis+Gyr Gridstream advanced metering solution to measure circuit voltages and allow more precise control of the customer premise voltage. The application does this by using a common voltage control device such as a substation transformer load tap changer (LTC) while maintaining quality service voltage levels to customers.

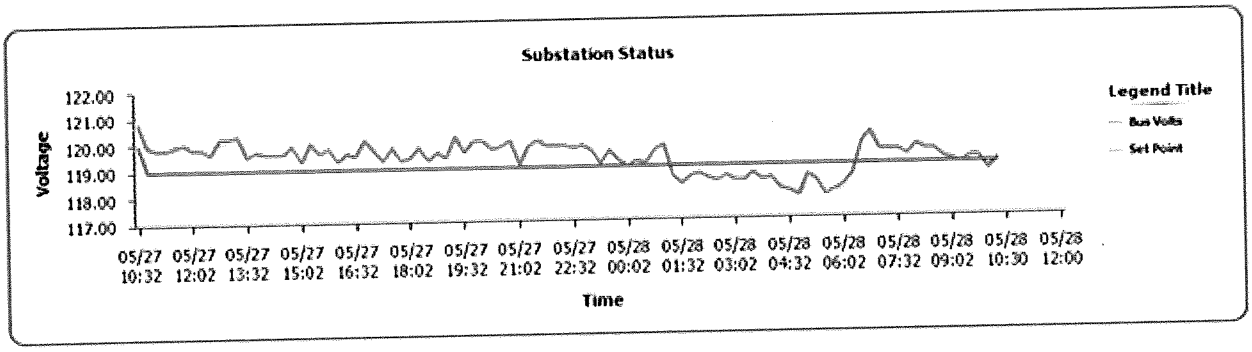
The DVI application takes advantage of the emerging smart grid technologies that provide near real-time monitoring and feedback from every energy user on a distribution system. The ability to measure and maintain voltage through continuous voltage control in an optimum range has the potential to provide significant energy savings. Using information provided by advanced meters, the voltage management application relies on up-to-date information from the customer site to adjust voltage levels automatically from the substation LTC controller. The EDGE pilot project required three stages: Plan, Manage, and Validate.

1. <u>Plan</u>

The Plan phase began in March 2013 with a voltage study performed in EDGE Planner. This study analyzed the voltage for all customers served by the Lincoln Beach substation by looking at historic 15-minute interval data for a given month. Central Lincoln collects 15-minute data on all meters as part of the AMI load profile feature. Voltage outliers identified through EDGE Planner were visited in the field and service issues were proactively resolved by Central Lincoln personnel. Once voltage issues were addressed, EDGE Planner was used to select 20 meters with the lowest voltage which would serve as the bellwether set for EDGE Manager. The bellwether set is used to minimize impact on the communication bandwidth by reading only the lowest-voltage meters.

2. <u>Manage</u>

The Manage phase began in May 2013 when EDGE Manager was enabled to run CVR. EDGE Manager is integrated with two existing utility systems; the Survalent SCADA system for substation data and the Landis+Gyr AMI system for customer voltage data. Every 15 minutes, EDGE Manager analyzes AMI load profile data. If AMI voltages are outside the target range, EDGE Manager sends a SCADA command to raise or lower the source voltage at the substation. EDGE also monitors incoming voltage sag alerts from the entire population of meters served by Lincoln Beach. Meters experiencing voltage sags are added to the bellwether set on a trial basis; after 24 hours those meters with the highest voltage are removed to return the bellwether set to a total of 20 meters. This adaptive bellwether set is a patented feature of EDGE that ensures all customers' voltage is monitored and adequate protection is put in place.



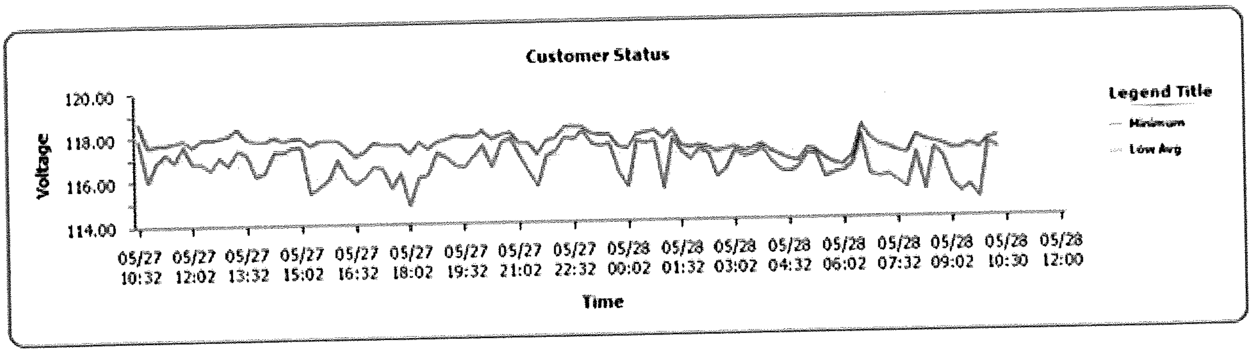


Figure 1: EDGE Manager Dashboard enables staff to monitor voltages in real time.

3. Validate

The Validate phase began in January 2014 after sufficient summer and winter operating data were collected. EDGE Validator was used to find pairs of hours with similar weather conditions; one side of the hour pair had CVR turned on and the other side had CVR turned off (including data during or prior to the pilot). For each pair of hours, the percent change in load was divided by the percent change in voltage to calculate the CVR factor for that pair. The entire group of CVR factors was statistically analyzed to determine the overall CVR factor. From that, the overall change in voltage was used to calculate the total energy savings.

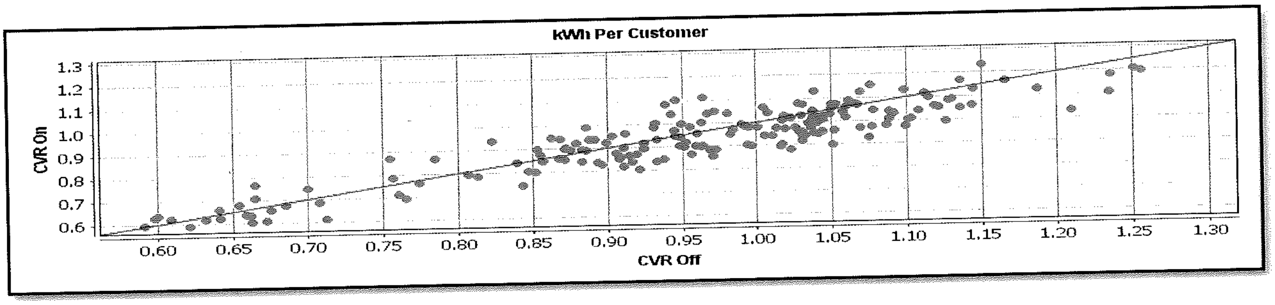


Figure 2: Each dot represents a pair of data and corresponding energy usage. The dots below the red line indicate a positive CVR factor and the dots above the line indicate a negative CVR factor.

Results

During the six-month pilot period, the Lincoln Beach substation LTC voltage set point was reduced from 123.5V to approximately 119.5V while maintaining required minimum ANSI voltage standards to all customers. Based on the monitoring and verification procedure approved by BPA, the CVR pilot reduced voltage by 2.60 percent and provided a 2.15 percent energy savings. This translates to an annualized savings of 325 megawatt-hours from a single substation transformer.

Table 2: Customer Savings

Lincoln Beach	**Voltage Reduction**	**CVR Factor**	**Energy Savings**
Summer	3.09%	.43	1.49%
Winter	2.35%	1.05	2.49%

While CVR is not a new technology, coupling it with real time voltage measurements provided by AMI meters and dynamically controlled substation bus regulation, a higher level of savings is possible while maintaining appropriate customer level safeguards. Based on the pilot project operation, the DVI EDGE product provides the appropriate controls that minimize customer voltage excursion risk while providing cost savings to the customer.

The principle benefit of the CVR project occurs on the customer premise with the lowered utilization voltage providing a 2.04 percent bill reduction. With the conservative approach adopted by the EDGE product, the customer does not see an impact in power quality and is not required to engage in active energy efficiency management.

Conclusion

Central Lincoln identified unforeseen benefits including improved asset management, increased information about the health and functionality of our infrastructure and higher system reliability. The District was able to observe and remedy customer power quality issues such as poor secondary connections, inadequate service design, and overloaded and failing transformers. Further, the LTC was not exercised beyond our historical norm during the pilot and the CVR implementation did not translate to higher maintenance cost of the LTC. A full CVR deployment would provide a superior tool to proactively assess service problems, quantify the requirements for repair and remedy issues before customer outages occur.

The energy efficiency and cost savings benefits for the customers occurred without any active customer participation. All socioeconomic groups benefit as the 2% customer savings occurred without regard to homeowner or renter status. For the future, the results of the pilot project were so impressive that Central Lincoln is undergoing plans for a full system wide implementation.

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Low-Cost CVR May Pay for Your AMI System

New Study Turns Traditional Smart Grid Business Case Analysis on its Head

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February 6, 2014

Summary

A recently-completed Smart Grid Research Consortium (SGRC) study identifies a new smart grid investment strategy that can transform a poor AMI business case into an attractive investment. Many electric cooperatives and public utilities have rejected AMI systems because expected meter-related benefits are not compelling enough to outweigh costs. Adding demand response savings boosts benefit-cost ratios; however, the uncertainty and long lead times surrounding these customer engagement programs add more risk. Adding distribution automation (DA) benefits and costs including customer valuations of improved reliability provide added costs and benefits but leaves utility decision-makers skeptical.

This new SGRC study shows that the combination of AMI and low-cost conservation voltage reduction enabled with smart meters can provide a compelling business case for many of these utilities with little risk.

This study turns the traditional smart grid business case analysis approach on its head: instead of viewing AMI as the foundation, then adding demand response and then distribution automation benefits and costs, the analysis started with a joint AMI/low-cost conservation voltage reduction (CVR) strategy as the foundation for the business case. The low-cost CVR provides significant benefits and, because it is enabled with smart meter data, more than makes up shortcomings in the stand-alone AMI business case for many utilities without going on to more speculative smart grid benefits.

A significant advantage of this new strategic approach is that costs and benefits of individual AMI and CVR elements can be determined with considerable certainty prior to initiating the project. In addition, the low-cost CVR component can be developed simultaneously with the AMI implementation avoiding the long delays that many utilities are experiencing with customer engagement infrastructure development. The CVR strategy requires utility distribution information including some voltage-demand experiments; however, this information is inexpensive to collect and analyze with our Smart Grid Investment Model."

The CVR strategy considered here is low cost, averaging about $15,000 per feeder for controls, communications and installation with no new investments voltage regulators or capacitor banks. This CVR strategy uses smart meters for voltage metering, retrofitted controls and communications to existing feeder equipment, where appropriate, and lowers and " tightens" grid voltage control at

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during peak periods.

This study and its implications for utilities are noteworthy for six reasons:

- The AMI/low-cost CVR strategy reflects a new paradigm for smart grid business case analysis
- The analysis quantifies an often omitted contribution of smart meter data,
- Results illustrate the incremental financial value of limited, low-costs CVR grid improvements enabled by smart meter data,
- The financial value of this strategy is easy to verify beforehand,
- The CVR portion can be implemented simultaneously with the AMI implementation, and
- Contributions of smart meter-enabled CVR can turn a negative AMI business case positive

Study analysis is based on results from a recently completed SGRC CVR study conducted for an electric cooperative utility and data on electric coops and municipal utilities drawn from existing CVR, and other smart grid pilot studies and implementations.

This paper includes summary results of the new study for a generic electric cooperative utilizing the Consortium's Smart Grid Investment Model along with a description of the Consortium's AMI/low-cost CVR applications assessment and implement services.

Why Some AMI Business Cases Fail

AMI/smart meter business cases do not meet investment requirements at some electric cooperatives and municipal utilities for two primary reasons:

1. Utilities who previously installed AMR systems are already achieving much of the AMI meter-reading benefit. While these systems have reduced meter-related costs, many do not provide the bandwidth required to support many modern AMI systems valued-added benefits that enhance outage
2. Distribution system characteristics, operating structure, wage levels, and customer characteristics at some utilities are such that AMI meter-related savings estimates are not sufficient to provide an attractive business case.

Conservation Voltage Reduction

Conservation voltage reduction (CVR) reduces voltage during peak period times reducing peak kW demand. CVR reduces the monthly demand charge for utility wholesale power purchases or, for utilities that self-generate, provides excess power to sell at peak prices on the wholesale market. CVR has received new attention in recent years as metering, communications and control technologies have advanced.

CVR strategies attempt (among other objectives) to provide voltage at the meter as close to 114 volts as practicably possible. ANSI standards require voltage between 114 and 126 volts. Voltage declines from the head end of a feeder at the substation depending on the length of the feeder, loads along the feeder and other variables like conductor size, temperature and placement of voltage regulators and capacitor banks. Voltage along the feeder varies from day to day and hour to hour. Determining the appropriate substation voltage to maintain minimum voltage at the meter is not an easy matter.

A variety of voltage drop calculation approaches are used to determine desired substation feeder voltage and to estimate meter-level voltage. Most utilities set head end voltage at considerably higher levels than necessary to reduce the possibility of low-voltage situations at the meter. This is a prudent approach since meter –level voltage is an estimated value with a large confidence interval.

The Consortium's work with utilities in 20 Smart Grid Investment Model projects and a review of case study reports indicate that typical head end voltage is typically 122 – 125 volts with meter-level voltage in the 118 – 120 range.

Low-Cost CVR

The low-cost CVR strategy considered here includes developing and processing feeder-level information from smart meter data to reduce end-of-line voltage closer to the 114 minimum. Costs are estimated to be $15,000 per feeder which includes controls, communications and labor costs. Voltage information is provided by smart meters. Substation costs for a substation a single substation transformer and three feeders would be $45,000 in this example.

This cost is "low" at 6-10 percent of the cost of comprehensive volt/VAR control and optimization that add voltage regulators, capacitor banks, metering, communication and control, and other technologies/strategies. The low-cost CVR strategy achieves load flattening where possible with existing voltage regulators and capacitor banks using meter-level data to adjust settings of voltage regulators and capacitor banks and adding control/communications capabilities as appropriate to equipment tht already exists along feeders.

A relatively small number of utilities already apply no-cost CVR by lowering substation voltage by small amounts during peak period times. These strategies tend to be quite conservative because of the uncertainty of meter-level voltage that occurs with this voltage drop during peak period times. These utilities can also benefit from the low-cost CVR strategy described in this paper.

The AMI Business Case

The objective of this paper is to examine the potential impact of including low-cost CVR benefits in a joint AMI/low-cost CVR business case when the AMI business case alone fails. This low-cost CVR benefits would not be available without AMI data.

As indicated in a previous section, the CVR program considered here results only in a "tightening-up" of voltage control with no addition of voltage regulators, capacitor banks and other investments that would be applied in more comprehensive voltage/VAR and CVR initiatives.

Every utility presents a unique AMI/ low-cost CVR business case depending on current meter-related costs, distribution infrastructure, system peak period hourly load profiles and avoided cost structures. The representative utility used for this analysis has about 60,000 customers with system load shapes consistent with a moderately hot and humid climate reflecting about 85 percent residential, 10 percent commercial and 5 percent industrial loads. The utility purchases its power and faces a peak demand charge of $12.00/kW with a one year ratchet that applies the previous year's average 4-month summer peak to each month of the current year.

The utility has an AMR system that was installed a decade ago providing automated meter reading but does not have the ability to connect and discounted remotely and does not have bandwidth and latency to provide many AMI functions.

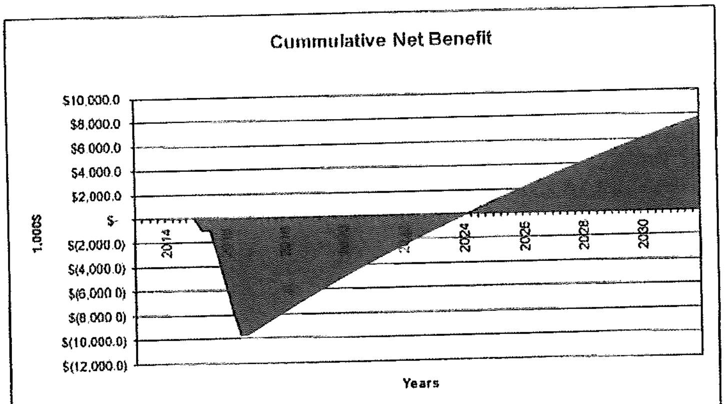
If instead of its dated AMR system, this utility reflected a typical electro-mechanical metering-based utility, its AMI business case would look something like that shown in the following figure. The internal rate of return (IRR) reflects the return on the investment. An IRR greater than the cost of capital (i.e., the interest rate on utility bonds) is considered an attractive investment. The undiscounted breakeven period is the payback period and the discounted breakeven period is the discounted payback period, that is, the payback period when financial values are discounted to reflect current financial values. The net present value is the discounted benefits minus discounted costs. The benefit cost ratio is calculated as discounted benefits divided by discounted costs (see the note at the end of this paper for more information on present value and discounting).

The cumulative net benefit chart shows discounted benefits minus discounted costs in each quarter of the analysis period. The point where the line crosses the X-axis is the discounted breakeven period. The distance from the X-axis to the line is the net present value at that time period.

Figure 1. Representative AMI Business Case for a Utility With Electromechanical Meters

Representative AMI Business Case (Existing electromechanical meters)

Internal Rate of Return (%)	9%
Undiscounted Breakeven Period	7.5 Years
Discounted Breakeven Period	9 Years
Net Present Value (NPV, $mill)	7.583
Benefit/Cost Ratio	1.62

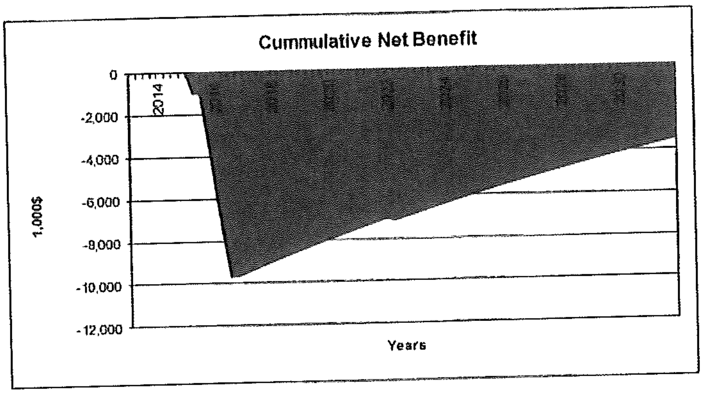


This business case would probably be sufficient for the utility to move forward with an AMI upgrade.

However, our example utility's AMR system already captures about 2/3 of the benefits of an electromechanical- to-AMI system upgrade reducing per-meter benefits of about $12/meter. Consequently, the AMI business case of the example utility looks like the following – clearly not an attractive investment with a benefit cost ratio of 0.7.

Figure 2. Representative AMI Business Case for a Utility With an Existing AMR System

Representative AMI Business Case (Existing AMR meters)	
Internal Rate of Return (%)	*
Undiscounted Breakeven Period	*
Discounted Breakeven Period	*
Net Present Value (NPV, $mill)	*
Benefit/Cost Ratio	0.70



Evaluating the Joint AMI/Low-Cost CVR Business Case

As indicated above, uncertainty over meter-level voltages results in voltages that typically are anywhere from 4 to 6 volts above the minimum of 114. However information from a strategically selected sample of smart meters can provide near-real time information on meter-level voltages along each feeder. Analysis of this data, including voltage experiments to estimate feeder conservation voltage reduction factors (CVRf) can provide a low-cost CVR strategy that at most requires a limited investment in communications and control technologies. This analysis assumes an investment cost of $15,000 per feeder or $45,000 for the two-transformer, 3-feeder substation mentioned above. Our analysis indicates that the added information provided by smart meters permits the typical utility to reduce its voltage by 2 to 3 volts during peak period. A typical conservation voltage reduction factor (CVRf) of 0.75 reduces peak demand by about 1.3 to 2.25 percent for feeders for which CVR is attractive (typically about ½ the total number of feeders).

The impacts of voltage reductions of 2 and 3 percent are presented below for a joint AMI/low-cost CVR strategy applied to the example utility with avoided power costs of $12/kW. These Figures should be compared to Figure 2 that shows the AMI case without low-cost CVR benefits.

Figure 3. AMI-Low Cost CVR Business Case, Existing AMR System, 2 % Voltage Reduction, $12/KW

AMI With Low-Cost CVR Savings (Existing AMR meters, 2% voltage reduction)	
Internal Rate of Return (%)	11.8%
Undiscounted Breakeven Period	7 Years
Discounted Breakeven Period	8.25 Years
Net Present Value (NPV, $mill)	8,849
Benefit/Cost Ratio	1.76

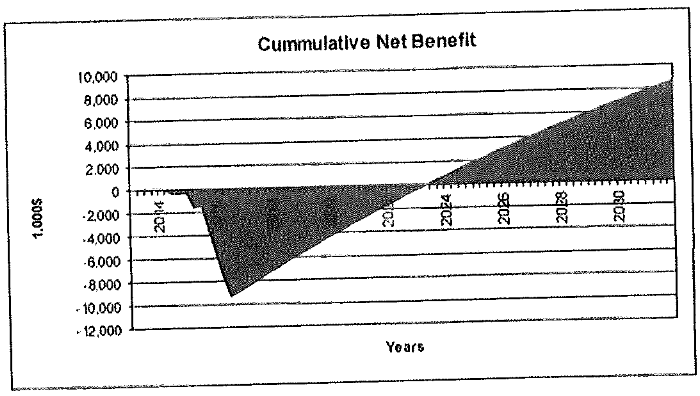
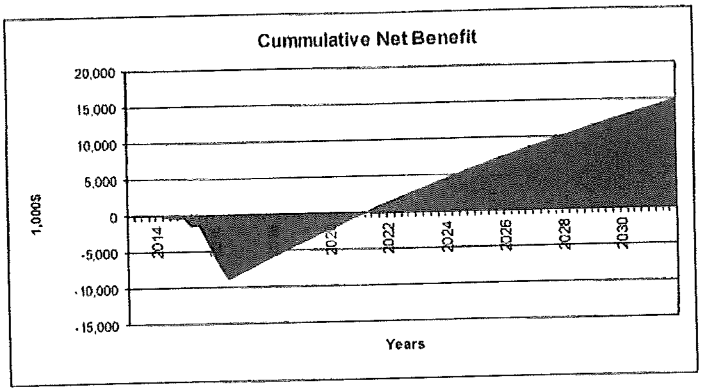


Figure 4. AMI-Low Cost CVR Business Case, Existing AMR System, 3 % Voltage Reduction, $12/KW

AMI With Low-Cost CVR Savings
(Existing AMR meters, 3% voltage reduction)

Internal Rate of Return (%)	20.8%
Undiscounted Breakeven Period	5.5 Years
Discounted Breakeven Period	6.25 Years
Net Present Value (NPV, $mill)	15.049
Benefit/Cost Ratio	2.30



Both of the business case outcomes above provide a positive with paybacks in 5.5 and 7 years for 2 and 3 percent voltage reductions, respectively. The benefit cost ratio has increased from 0.7 for the AMI case alone to 1.76 and 2.30 for the two joint AMI/low-cost CVR.

It is important to reemphasize that the low-cost CVR benefits are a result of additional information derived from the smart meters and not from a traditional CVR initiative which would include, among other things, addition of voltage regulators and capacitor banks. That is, the low-cost CVR benefits are a side benefit of the smart meters in this analysis.

Low-cost CVR benefits are substantial enough to provide a positive business case even where peak demand charges are as low as $6/kW as shown in figure 5. Figure 6 shows results with avoided power costs of $9/kW

Figure 5. AMI-Low Cost CVR Business Case, Existing AMR System, 3 % Voltage Reduction, $6/kW

AMI With Low-Cost CVR Savings
(Existing AMR meters, 2% voltage reduction)

Internal Rate of Return (%)	7.6%
Undiscounted Breakeven Period	8.25 Years
Discounted Breakeven Period	10 Years
Net Present Value (NPV, $mill)	5.934
Benefit/Cost Ratio	1.51

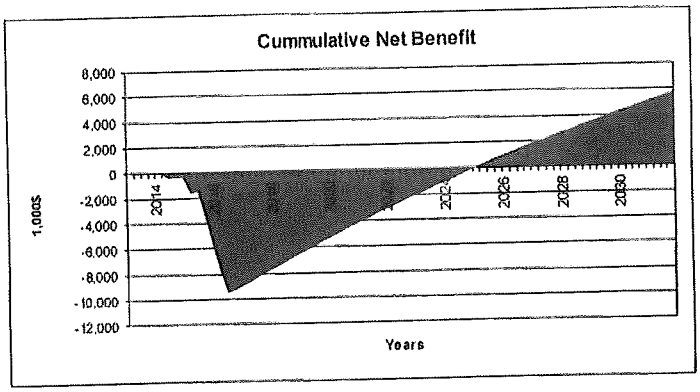
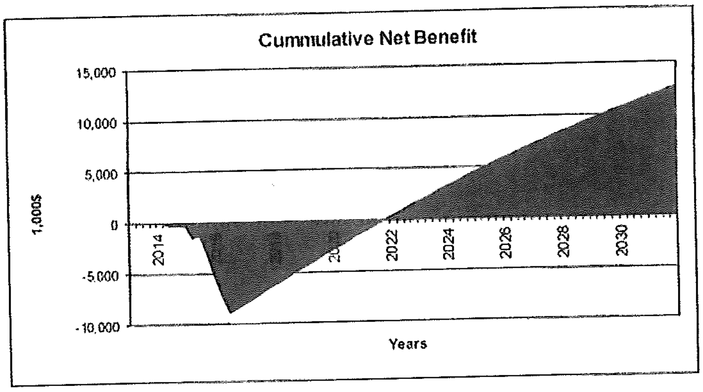


Figure 6. AMI-Low Cost CVR Business Case, Existing AMR System, 3 % Voltage Reduction, $9/kW

AMI With Low-Cost CVR Savings
(Existing AMR meters, 3% voltage reduction)

Internal Rate of Return (%)	17.8%
Undiscounted Breakeven Period	6 Years
Discounted Breakeven Period	6.75 Years
Net Present Value (NPV, $mill)	12.863
Benefit/Cost Ratio	2.11



Consortium AMI/Low-Cost Analysis for Coops and Public Utilities

The Consortium works with client utilities to evaluate AMI, customer engagement, DA, CVR, Volt/VAR optimization and the topic of this paper: AMI/low-cost CVR with smart meter data. The Consortium's analysis process when working with utilities to assess AMI/low-cost CVR applications includes:

- Evaluating the AMI business case utilizing utility data and the Smart Grid Investment Model (SGIM)
- Analyzing feeder-level data to estimate current end-of-line voltages
- Estimating conservation voltage reduction factors for each feeder using historical transformer or feeder demand data and voltage experiments,
- Incorporating feeder level CVR-related data and avoided peak period power costs in the SGIM,
- Analyzing various CVR strategies and assessing joint AMI/low-cost CVR strategies
- Developing a strategy and milestones for implementing the AMI/CVR system
- Working with utility staff and vendors to develop vendor cost bids in the analysis
- Working with utility staff to assess post investment CVR peak-period benefits

Conclusions

A new study by the Smart Grid Research Consortium finds that many utilities can achieve large returns with an integrated AMI/low-cost conservation voltage reduction (CVR)- strategy that utilizes smart meter voltage data to achieve peak period voltage reductions - even if the AMI portion doesn't meet financial targets on its own. For utilities that already have an AMI system, this low-cost CVR strategy can boost returns and significantly shorten payback periods.

The low-cost CVR strategy differs from comprehensive Volt/VAR and CVR initiatives in that no new voltage regulators or capacitor banks are installed on feeders while voltage information from smart meters and low-cost communication/control technologies are used to "tighten" up voltage delivery, eliminating the extra margin traditionally used to ensure sufficient voltage delivery at the meter.

The added benefit of smart meter data in a voltage control application is quantitatively isolated in this study with the Smart Grid Investment Model – that is, the voltage reduction achieved is a result only of more accurate information and more precise control provided by data from smart meters.

This strategy is especially important for utilities with existing AMR systems and other utilities that do not see a positive AMI business case.

This study and its implications for utilities are noteworthy for six reasons:

- The AMI/low-cost CVR strategy reflects a new paradigm for smart grid business case analysis
- The analysis quantifies an often omitted contribution of smart meter data,
- Results illustrate the incremental financial value of limited, low-costs CVR grid improvements enabled by smart meter data,
- The financial value of this strategy is easy to verify beforehand,
- CVR portion can be implemented simultaneously with the AMI implementation, and
- Contributions of smart meter-enabled CVR can turn a negative AMI business case positive.

The take-away from this analysis is that utilities who have considered AMI investments and found the business case lacking should reconsider a combination AMI/low-cost CVR business case.

The Smart Grid Research Consortium provides business case analysis, investment strategy development and implementation planning and support for AMI/low-cost CVR and other smart grid projects designed to maximize utility benefits and investment returns.

About the Consortium and Author

The Smart Grid Research Consortium (SGRC) (www.smartgridresearchconsortium.org) is an independent, objective research and consulting firm with headquarters in Orlando, Florida. The SGRC was established in 2010 and is currently completing its twentieth smart grid investment analysis project.

The SGRC is managed and its research is led by Dr. Jackson, an energy economist with more than thirty years' experience in new energy technology market analysis, financial model development, utility program development and project management. He was previously a professor at Texas A&M University, chief of the Applied Research Division at Georgia Tech Research Institute, and president of a consulting firm where he has worked with utilities, state regulatory agencies, equipment manufactures and others in addressing energy industry issues. Dr. Jackson can be reached at Smart Grid Research Consortium, 37 N Orange Ave, Suite 500, Orlando, FL 32801, 979-204-7821 or by email at jjackson@smargridresearchconsortium.org.