Distribution Efficiency Initiative

Market Progress Evaluation Report, No. 1

prepared by

Global Energy Partners, LLC

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Evaluation of the Utility Distribution System Efficiency Initiative (Phase I)

Market Characterization and Assessment

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Northwest Energy Efficiency Alliance

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EXECUTIVE SUMMARY

Traditionally, electric utilities have taken a demand-side approach to energy efficiency and conservation, focusing resources on programs to promote energy-efficient measures and conservation practices for their customers. However, industry experts have long believed that a vast, viable, and largely untapped resource for energy efficiency and peak load reduction may exist in the distribution system practices of many utilities. More specifically, scientific evidence suggests that utilities may be able to achieve dramatic energy and demand savings by lowering service voltages on distribution feeders. However, despite considerable utility research on this subject in the 1970s and 80s, few recent studies have examined this potential, and the means to attain it.

As a more recent continuation of this interest in the energy savings potential of voltage reduction, the Northwest Energy Efficiency Alliance (Alliance) commenced a Distribution Efficiency Initiative (DEI) in 2003, with a goal to identify and support efficiency improvements in utility distribution system design and operation. More specifically, the DEI project is focused on demonstrating the energy savings capability of voltage reduction in the residential and small commercial sectors through a load research study of approximately 500 participating homes and commercial establishments in the Pacific Northwest (PNW) region. The DEI is in the process of demonstrating a variety of voltage regulation strategies to document costs, benefits and successful practices required to achieve efficiency improvements for light commercial and residential consumers. The overall objective of DEI is to transform the distribution system market, supporting distribution engineers and utility management in adopting DEI strategies and technologies when appropriate to their operations.

As part of this DEI, the Alliance engaged Global Energy Partners (Global) to characterize the market for distribution efficiency and voltage regulation practices across the country. Through interviews with utilities and a review of industry literature on the subject, Global found that:

- Conservation voltage reduction is largely not practiced today – only 7.5% of all feeders by one account
- There are some pockets of regional activity in the Northeast, Southeast, California, and the Pacific Northwest. Among all regions, the Pacific Northwest is the leading area of voltage regulation activity, where approximately 15% of substations deliver voltage at less than the allowable upper limit.
- Where it is practiced, voltage reduction has been proven to reduce energy consumption, by an overall factor of 0.8 – meaning that a 1% reduction in voltage results in, on average, a 0.8% reduction in energy consumption. This “CVR Factor,” is defined as the percentage

reduction in load resulting from a 1% reduction in voltage, is the metric most often used to gauge the effectiveness of voltage reduction as a load reduction or energy savings tool.

- Utilities that implement voltage reduction typically have some or all of the following characteristics:
    - Capacity-constrained
    - Expensive to generate or procure peak power
    - Public power companies / cooperatives with demand charges imposed by Generation and Transmission (G&T) companies
    - Serve metro areas with shorter feeders
    - An in-house technical champion (engineer)

- There is still a significant amount of technical skepticism concerning the link between voltage reduction and energy reduction among utility technical staff

- It is difficult for utilities to quantify the economic benefits of voltage reduction vs. the associated costs, including foregone revenue

- Utilities do not share information with each other regarding best practices associated with voltage regulation

Based on a review of the findings, Global recommends the following actions for the Alliance and other interested parties to consider to increase the market penetration of Distribution System Efficiency (DSE) / voltage reduction practices to more utilities across the country.

1. Facilitate a summit meeting of practitioners and champions of voltage regulation from utilities across the country to encourage the sharing of information and development of best practices, and to begin the process of forming a national consortium for voltage regulation. Existing industry conferences, such as the recurring Peak Power Conference, Peak Load Management Alliance (PLMA), EPRI, or American Council for an Energy-Efficient Economy (ACEEE) could be good venues for such a meeting.

2. Investigate the voltage drop from the customer meter to plug in residential and commercial applications to determine whether the widely held assumption of a 4V drop is valid. Based on discussions with numerous utility distribution experts, the actual voltage drop, particularly in new construction, is likely much less, on average. Documentary evidence to this effect could potentially persuade utilities that may be “on the fence” with respect to CVR – out of concern for falling below 114V in service voltage – that the risk of CVR posing problems for customers is minimal.

3. Promote voltage regulation in the context of overall distribution effectiveness. With some planning and calculation, CVR or distribution efficiency can be used as a tool to justify much needed improvements in the distribution infrastructure.

4. Encourage greater dialogue and collaboration between distribution and DSM groups with utilities to uncover energy savings opportunities and funding sources.

Highlights of the Alliance DEI Project

The Alliance has sponsored a large set of tests of CVR to identify and quantify costs and benefits. R. W. Beck was selected in August 2003 as the contractor to implement these tests. This report provides information on the Alliance DEI project through September 2004.

The tests involve:

- Residential tests of 475 homes that will have 15-minute load and voltage meters installed. An on-site voltage regulator (OVR) will be installed in each of these homes to regulate voltage on a 24 hour on and off basis for one year. This test is designed to identify the impacts of lowering voltage as well as isolating the impacts on individual end-uses.

- Additional tests of a group of 50 small commercial buildings to measure the impact of on-site voltage regulation on small commercial loads.

- A group of 11 utilities from Idaho, Oregon and Washington has been recruited to participate in the load metering study, with final installations expected in Q1 of 2005. Preliminary data analysis is expected by the end of 2005.

Table ES-1-1
Utility OVR Commitments

Utility	Total OVRs
Douglas County PUD	50
Eugene W&EB	50
Franklin PUD	25
Hood River Elec Coop	25
Idaho Falls Power	25
Idaho Power	50
PacifiCorp	75
Portland General Electric	50
Puget Sound Energy	50
Skamania PUD	25
Snohomish PUD	50
Total	475

- A set of pilot studies has also been developed to obtain cost, savings and other implementation data on CVR. The Initiative planned to have a series of pilot studies performed that would regulate voltage on residential feeder lines. Through September 2004, nine utilities have agreed to participate.

- Three utilities will be conducting simple CVR pilots involving Line Drop Compensation (LDC) voltage controls at each substation. One utility is also installing end-of-line voltage metering as part of the pilot project.

- Six utilities will be conducting pilots involving Line Drop Compensation voltage controls at each substation combined with the installation of some system improvements. System improvements will include the installation of shunt capacitors, line regulators, end-of-line voltage metering, substation voltage meters, and/or feeder reconductoring. At the time of this report, specific system improvements have not been detailed.

- Two utilities will be installing a PCS UtiliData® AdaptiVolt™ system with end-of-line voltage feedback. In these pilots, each feeder and each phase are independently controlled by the system. The pilot will implement controls on both substation transformers and feeder regulators.

The inputs and results of these studies will be used to develop a series of financial and technical planning tools to assist distribution engineers in the design and development of DSE projects.

One of the principal objectives of this study was to update the CVR supply curves developed by BPA in 1987. A supply curve relates the energy savings of a measure with the cost of implementing the measure. The results from the Alliance and Global models imply that under the current regulatory climate and using currently available technology, only 100 AMW of DSE is achievable in the near term. Additionally, as shown in the report, a limited number of utilities have applied DSE measures and strategies since the BPA study. As a result, the BPA 1987 conclusion that DSE can provide an energy conservation resource of over 200 AMW will be difficult to achieve in the near future.

CONTENTS

LIST OF FIGURES

LIST OF TABLES

1 INTRODUCTION

1.1 Background

Traditionally, electric utilities have taken a demand-side approach to energy efficiency and conservation, focusing resources on programs to promote energy-efficient measures and conservation practices for their customers. However, industry experts have long believed that a vast, viable, and largely untapped resource for energy efficiency may exist in the distribution system practices of many utilities. More specifically, scientific evidence suggests that utilities may be able to achieve dramatic energy and demand savings by lowering service voltages on distribution feeders. However, despite considerable utility research on this subject in the 1970s and 80s, few recent studies have examined this potential, and the means to attain it.

Perhaps the most seminal study of the impact of voltage reduction on energy conservation was a project conducted for the Bonneville Power Administration (BPA) in the mid 80's, as summarized in a 1987 report entitled "Assessment of Conservation Voltage Reduction Applicable in the BPA Service Region" (BPA Report). The BPA Report was one of the most comprehensive assessments of voltage reduction as an energy conservation and distribution efficiency practice ever conducted, and was one of the few that actually estimated impacts to the PNW region. Section 1.3 discusses the BPA Report in more detail.

The Northwest Power Planning Council (NPPC) acted on the BPA Report by incorporating conservation voltage regulation (CVR) into its power plan. The NPPC ascribed CVR with over 200 AMW (average megawatts) of potential savings for the Pacific Northwest (PNW) region.

As a more recent continuation of this interest in the energy savings potential of voltage reduction, the Northwest Energy Efficiency Alliance (Alliance) commenced a Distribution Efficiency Initiative (DEI) in 2003, with the goal of identifying and supporting efficiency improvements in utility distribution system design and operation. More specifically, the DEI project is focused on demonstrating the energy savings capability of voltage reduction in the residential and small commercial sectors through a load research study of approximately 500 participating homes and commercial establishments in the PNW region. The DEI is in the process of demonstrating a variety of voltage regulation strategies to document costs, benefits and successful practices required to achieve efficiency improvements for light commercial and residential consumers. The information gleaned from this work will be used to develop financial and planning tools that will assist the distribution engineering in planning, designing, and implementing DSE projects. The overall objective of DEI is to transform the distribution system market, supporting distribution engineers and utility management in adopting DEI strategies and technologies when appropriate to their operations.

The emphasis of DEI is on cost-effective design, construction and operation decisions that optimize the local distribution service voltage. The project is demonstrating four options for achieving this goal:

1. Simple approach focusing on utility- and contractor-delivered enhancements to substations and feeders including installation of meters, setting controls and calculating line drop compensation.
2. Customized approach for large utilities, including a combination of equipment, engineering modeling, application tools and other solutions that address the unique needs of larger utility systems.
3. Automated system approach that requires SCADA installation and automated controls using end-of-the-line meters to monitor and control system voltage.
4. On-site voltage regulator approach using a device installed at the residential customer's electric meter to raise and lower voltage as needed.

1.2 Purpose and Objectives

Global Energy Partners (Global) was commissioned by the Northwest Energy Efficiency Alliance (Alliance) to:

- Provide a systematic, accurate and timely ***market characterization*** and assessment of the current distribution system efficiency practices in the nation as a whole, and in the PNW region in particular as it relates to the measures being implemented through the DEI. This market characterization is intended to serve as a follow up to the BPA Report, as further explained in Section 1.3.
- Document the activities of Phase 1 of the DEI.

This report serves as Global's deliverable for both tasks.

1.3 BPA Report

One of the objectives of this report is to serve as a follow up to a 1987 report sponsored by Bonneville Power Administration (BPA) entitled "Assessment of Conservation Voltage Reduction Applicable in the BPA Service Region" (BPA Report). The BPA Report was one of the most comprehensive assessments of voltage reduction as an energy conservation and distribution efficiency practices ever conducted, and was one of the few that actually estimated impacts to the PNW region.

1.4 DEI Project Summary

In January 2003, the Alliance Board approved funding for the first phase of a proposed three phase, five year Utility Distribution System Efficiency Initiative ("Initiative") targeted at distribution system efficiency improvements and conservation voltage regulation with electric utilities. Through this initiative, the Alliance intended to collaborate with utilities, vendors, and energy related organizations to acquire cost-effective electric savings from a variety of efficiency strategies. The objective of the Initiative is to determine the costs and savings and other impacts of voltage regulation at the customer side of the meter and on the utility's distribution system.

The Initiative will evaluate a broad selection of residential customer load types to determine the energy and demand savings as a result of improved voltage regulation. As part of this process, R. W. Beck was selected to provide overall project management as well as research, design, and implementation activities. RLW Analytics was selected to conduct customer surveys, evaluate load types, and analyze load impacts. Auriga Corporation will aid in the development of financial and planning tools.

The Initiative will be implemented in three phases:

- **Phase I – Development**: Includes confirmation of costs, benefits, implementation options; and utility decision-making tools;
- **Phase II – Implementation**: Includes communications/marketing, and regional policy implementation, further development of support tools; and
- **Phase III – Transition**: Integration of project actions to market transformation.

Phase I of the Initiative will document actual costs and benefits associated with voltage regulation strategies as well as recommend implementation activities. The intended project result is to confirm the overall value of operating the distribution system with a lower voltage average and within the American National Standards Institute (ANSI) Service Voltage Standard. If the project results are favorable, the project team will present a proposal to the Alliance Board to fund Phase II, which begins the implementation process.

Global conducted an evaluation of Phase 1 to provide the Alliance with a systematic, accurate and timely characterization and assessment of the current baseline market for distribution system efficiency. This report documents Global's findings and recommendations associated with the market characterization.

Phase I had three major tasks (described in detail in the following sections):

1. **Load research**: Plan and implement a research project to obtain estimates of customer related energy savings as a result of CVR. This project was to involve up to 500 residential homes that would have their energy and voltage metered for one year.
2. **Distribution system efficiency**: R. W. Beck was to research cost-effective design, construction and operation decisions that optimize the reduction of local distribution service voltage (conservation voltage regulation or CVR). Originally, R. W. Beck was to demonstrate four options for achieving this goal:

   a) Simple CVR or CVR "Lite" which includes utility and contractor delivered enhancements to substations and feeders including installation of meters, setting controls, calculating line drop compensation settings, etc.

   b) Large Utility Customized Approach including a combination of equipment, engineering modeling, CVR application tools, and other actions to address the unique needs of larger utility systems;

   c) Automated System Approach which requires SCADA installation and automated controls using end of the line meters to monitor and control system voltage; and

   d) On-site Voltage Regulator Approach using a device installed at the customer's electric meter to raise or lower the voltage as needed.

3. **Tool development**: Software and other tools were to be developed to assist utilities in making distribution system efficiency decisions. Results and information gleaned from the previous two tasks were to be used as inputs into the tools and their development.

For Phase II, The Initiative would apply the lessons learned during Phase I to develop tools for communication/marketing, regional policy implementation, and utility decision-making. For Phase III, The Initiative would integrate all of the lessons, knowledge, and tools developed during the earlier phases to transform the DEI market.

In addition, the Alliance created a number of different opportunities for utilities to participate in the Initiative.

- Technical Advisory Committee – The Alliance formed a seven member advisory committee made up of utility, vendor, and other energy related organizations to help guide the Initiative's technical work and provide recommendations.
- Project Demonstration & Customer Load Research Projects –The Alliance will provide limited funding and assistance to utilities for a selection of DEI pilot demonstration and customer load research projects. These projects are intended to confirm DEI energy savings and to validate several approaches of distribution system efficiency that could be replicated to others in the region.
- Local Utility Project Assistance – The Alliance, through the Initiative, could provide limited consulting support to help utilities enhance utility distribution improvements that they are currently implementing or planning to implement that are designed to increase distribution system efficiency.
- Awareness of Project Activities – The Alliance developed a ListServe to inform interested utilities, vendors, and others about the overall Initiative and ongoing activities.

1.5 Phase I Load Research

The Phase I load research effort is designed to collect information on a sample of randomly selected homes to get whole house equipment and usage data that is representative of the residential homes in region. The load research sample will include detailed information and data on 475 homes and will constitute the baseline information for use in the OVR studies. The Phase I load research effort is comprised of three main tasks:

1. Overall sample design

2. Sample designs for the utilities doing On-site Voltage Regulator (OVR) studies

3. Residential onsite surveys for the homes in the OVR samples.

In March 2004, RLW Analytics presented the sample survey design, data collection methodologies, protocols, and data analysis procedures that will be used to represent the Northwest residential and small commercial loads. In addition, RLW recommended:

- Customer classifications and sectors to be tested with definitions for each item.
- Climate zones to be tested with definitions for each.
- How dry bulb temperature will be derived from Weather Service temperature data.
- Final residential assessment questionnaire.
- Customer contact protocols, processes and agreements between customers and utility.
- Plan for coordinating all load data research customer metering efforts, metering installations, and data collection.
- Data collection procedures
- Data retrieval procedures and data management,
- Data analysis procedures
- Voltage level variations and time interval for each metering site.

RLW is working with EWEB, Snohomish PUD, Avista, and Clatskanie PUD to begin customer selection and on-site surveys. Most of these utilities want to take the lead in customer selection and customer contacts. RLW is planning to offer customers a $25 incentive if needed to participate in the surveys. Puget Sound Energy is limiting its customer selection to King County. EWEB will be doing its own customer selection with assistance from RLW. Inland declined participation in the Load Research project due to complications in their Adaptive Voltage Control project. Table 1-1 provides a summary of the status of the recruitment and on-site survey activities as of September 2004.

Table 1-1
OVR Customer Recruitment Status

Utility/Task	Initial Customer Recruitment	Utility Inspection	Final Recruitment	On-site Survey
Douglas County PUD	92%	92%	92%	92%
Eugene W&EB	Project will begin in 2005			
Franklin PUD	100%	100%	100%	100%
Hood River Elec. Coop	100%	100%	100%	100%
Idaho Falls Power	100%	100%	100%	100%
Idaho Power	Project will begin in 2005			
PacifiCorp	Project will begin in 2005			
Portland General Electric	Project will begin in 2005			
Puget Sound Energy	Project waiting for PSE management approval			
Skamania PUD	100%	100%	100%	100%
Snohomish PUD	100%	100%	98%	98%

The current schedule is to have customers selected in February to early March 2004. In-home surveys started in mid July 2004 and will be completed by March 2005. In addition, a limited on-site assessment of commercial facilities is being considered for about 50 sites at Puget Sound Energy.

1.6 Phase I Distribution System Efficiency Approaches

A broad range of utility options exists to increase efficiency on both the customer and the utility side of the meter. Emphasis for project demonstrations will be placed on cost-effective design, construction and operation decisions that optimize the reduction of local distribution service voltage. The load research program and distribution feeder pilot demonstration projects are designed to quantify the savings for the utility and for the customer for each application.

R.W. Beck began working on options, collecting information from utilities on how they design distribution systems, and performing research in May 2004. Ideally, projects that would involve the following modifications would provide the Alliance with information on DSE implementation issues and results:

- Six (6) low cost medium efficiency demonstration pilot projects (CVR ‘Lite’) consisting of the following improvements:
    - Installation of shunt capacitors to improve power factor on an as needed basis, PF=100 +/-2%
    - Installation of Line Regulators as needed, maintain 4V drop max on feeder between voltage control devices
    - Implementation of Line Drop Compensation (LDC) voltage controls on all regulation equipment.

  - Installation of switched shunt capacitor applications as needed, use fix to maintain base load, then used switched.
  - Installation of end of line voltage metering
  - Installation of feeder load and voltage metering at Substation locations
- Two (2) medium cost high efficiency pilot project (CVR ‘Medium’) consisting of CVR ‘Lite’ plus SCADA adaptive voltage control of substation and line regulators and end of line voltage sensing.
- Two (2) higher cost very high efficiency pilot projects (CVR ‘Heavy’) consisting of a combination of engineering model enhancements, SCADA, OVR, and special metering applications.

R.W. Beck began working with nine utilities for potential pilot demonstration projects involving these modifications. R.W. Beck is looking at each distribution component – Power transformer, load tap changer (LTC) with LDC settings, economic primary conductor sizing, effects of voltage on distribution transformers, distribution transformer loading, and economic secondary conductor sizing and loading. R.W. Beck is developing options that will achieve maximum efficiency by using load flow models to perform alternative scenarios. A summary of the pilot projects is shown in Table 1-2.

Table 1-2
Utility Pilot Projects

Utility	Pilot	Pilot Description
Clark County PUD	CVR “Lite”	Line Drop Compensation voltage controls at one substation. Also conducting a CVR ‘Medium’ pilot on another substation.
Douglas County PUD		Line Drop Compensation voltage controls at substation.
Snohomish PUD		Line Drop Compensation voltage controls at one substation. Also conducting a CVR ‘Medium’ pilot on another substation. Installing end-of-line voltage metering.
Clark County PUD	CVR “Medium”	Line Drop Compensation voltage controls at one substation. Installing some system improvements.
Eugene W&EB		Line Drop Compensation voltage controls at each substation. Installing some system improvements.
Franklin PUD		Line Drop Compensation voltage controls at each substation. Installing some system improvements.
Grant County PUD		Line Drop Compensation voltage controls at each substation. Installing some system improvements.

Utility	Pilot	Pilot Description
Idaho Power		Pending MOU. Line Drop Compensation voltage controls at each substation. Installing some system improvements.
Snohomish PUD		Line Drop Compensation voltage controls at one substation. Installing some system improvements. Also installing end-of-line voltage metering.
Avista	CVR “Heavy”	Installing a PCS UtiliData® AdaptiVolt™ system with end-of-line voltage feedback. Each feeder and each phase are independently controlled
Clatskanie PUD		Installing a PCS UtiliData® AdaptiVolt™ system with end-of-line voltage feedback. Each feeder and each phase are independently controlled

1.6.1 Phase I On-Site Voltage Regulator Approach

In addition to the traditional methods used to control voltage under evaluation, the Phase I effort is also evaluating other voltage control technologies. One new technology is the on-site voltage regulator (OVR). Typically, utilities install voltage regulators on the distribution system to maintain the distribution voltage within the standard. The voltage regulator will increase or decrease the distribution voltage as needed based on the load conditions. In a similar fashion, an on-site voltage regulator stabilizes the facility voltage by either lower or raise incoming voltage to set values. The OVR is a small box that houses a programmable personal computer board that controls a small transformer. This type of equipment can be used in DSE applications by allowing the utility to decrease the distribution voltage without adversely affecting the facility. Currently, the only known manufacturers of an OVR are MicroPlanet and Legend Power Systems. In Phase I, R.W. Beck began recruiting utilities to participate in a demonstration of the OVR technology. The project plan included a one-year demonstration study with 500 participants. The project plan includes:

- Detailed site visit for each facility
- The installation of a 15 minute load and voltage meter
- Voltage switched from OVR control at 115 volts to system voltage on a 24 hour on/off basis
- One year of data will be collected and analyzed to obtain estimates of energy savings associated with voltage reduction.

Some Utilities expressed concern and reservations about installing the OVR at a customer’s home without a UL approval of the unit. Accordingly, the Alliance and the OVR manufacturer proceeded to obtain UL approval of the OVR. The main components of the unit needed to be tested independently. The OVR was put into the UL testing schedule in April 2004, and attained UL approval in November 2004.

The OVR manufacturer is currently updating the existing installation manual. An 11” x 17” installation sheet will be developed after UL approval to be sure the final equipment matches the installation instructions and training. An installation sheet will be developed for selected locations such as Idaho Falls, Idaho Power, Western Washington, and Oregon. As of September 2004, 11 Utilities have made commitments to install 475 OVRs and participate in the Initiative’s load research project. Table 1-3 provides a summary of the participating utilities and their commitments.

Table 1-3
Utility OVR Commitments

Utility	Total OVRs
Douglas County PUD	50
Eugene W&EB	50
Franklin PUD	25
Hood River Elec Coop	25
Idaho Falls Power	25
Idaho Power	50
PacifiCorp	75
Portland General Electric	50
Puget Sound Energy	50
Skamania PUD	25
Snohomish PUD	50
Total	475

1.7 Phase I Tool Development

In addition to the demonstration projects, the Phase I effort includes the development of software and other tools to assist utility staff in making distribution system efficiency decisions. Results and information gleaned from the previous two tasks will be used as inputs into the tools and their development. The following suite of tools is under development:

- Benefits Calculator. Used by utility engineers. Defines load types, region, customer mix, etc... Specific to a substation/feeder area (voltage control unit) or used for the whole utility. It will use data from the DEI analysis. The results will output CVR factor, system improvements, cost of improvements, potential voltage reduction, and energy saved.

- Decision tools. Used by management. Looks at system improvements, costs, expenses and economics analysis to determine the payback/benefit-cost ratio/$ per mils etc… It may contain two or three simple economic models.

- Notebook. – Cook book for how to plan and construct distribution systems by DEI/CVR guidelines. Notebook will give an idea of effectiveness of CVR on each end use. In general terms, the notebook will

    1. Complement RUS design guidelines

    2. Calculators that estimate the percentage change in energy for every percentage change in voltage by broad end use shares.

    3. Include information from the OVR pilot to forecast kWh change and voltage change.

    4. Provide impact estimates dependent on time-of-day or loading on system.

1.8 Phase I Status

The Initiative is running behind schedule, unable to meet the initial target of beginning load studies at the beginning of 2004 due to a variety of factors, including:

- Utilities insisted on a UL listing for the OVR, even though it was not necessary from a technical standpoint. The UL testing procedure is very time-consuming, involving a number of steps with inherent wait times in between for testing and feedback. The resultant needs to develop, test, and redesign an OVR production unit for the UL testing procedure stretched the timeline of the Initiative.

- Many of the utilities had already committed their T&D funding for the following fiscal year and therefore did not have funds available to participate in the pilots.

- Identifying the champion within the utility took time. Although it was important to have the distribution department involved in the development project, the energy efficiency or load research departments are also important in the utility's decision process to participate in the project. In many cases, identifying a person within the utility that was interested in a particular aspect of the project was time consuming.

2 METHODOLOGY AND APPROACH

Chapter 2 describes the methodology employed to collect and analyze data for this study.

2.1 Defining Market Characterization Dimensions

A market can be characterized along many different dimensions. For the purposes of this DEI study, Global and the Alliance agreed to characterize the DEI market along the following dimensions:

- **Market Actors:** Identify the relevant market actor groups and the interrelationships between them. These include utilities, and distinct groups within utilities such as distribution planning & engineering, operations, and executive management, regulators, vendors, and third-party organizations such as the Alliance.
- **Information Channels:** Identify what information sources different market actors rely on and how information is disseminated.
- **Drivers:** Identify the technical and business attributes that motivate or facilitate the implementation of distribution efficiency measures such as systematic voltage reduction.
- **Barriers:** Identify the technical and business attributes that impede the implementation of distribution efficiency measures such as systematic voltage reduction.
- **Market Influence:** Assess how market actors influence one another and how these collective actions shape the market for distribution efficiency practices.
- **Market Trends:** Analyze where the market appears to be headed.
- **Physical Characteristics:** Assess the equipment and techniques that constitute efficient distribution operations through systematic voltage reduction.

2.2 Development of Survey Instrument

An early objective of the project was to develop a survey instrument to administer to utility representatives through telephone interviews. This survey instrument was structured to solicit input on all of market characteristic dimensions outlined in Section 2.1. The survey instrument administered to participants in telephone interviews is provided in Appendix A.

2.3 Interviews with Utilities

Global conducted interviews with 19 utilities across the U.S., outside of the Pacific Northwest region, and Canada. These utilities were identified either by the Alliance, through a literature search, or by other utilities as having some experience in DEI activities, and are listed in Table 2-1:

Table 2-1
List of Non-PNW Utilities Interviewed

Utilities	
BC Hydro	NSTAR
Cobb EMC (Georgia)	New York State Electric and Gas (NYSEG)
Northeast Utilities	Progress Energy - Carolinas
Dominion Virginia Power	Progress Energy – Florida
Duke Power	Seminole Electric – Central Florida
Florida Power & Light	Seminole Electric – Clay Electric
Georgia Power	Seminole Electric – Glades
Hawaiian Electric Company	Seminole Electric – Sumter
JEA (Jacksonville, Florida)	Seminole Electric – TriCounty
Nevada Power	

In addition, to gain a perspective on the baseline market for distribution efficiency in the Pacific Northwest (PNW), Global conducted interviews with all 14 PNW utilities for which the Alliance and R.W. Beck provided contact information. These utilities, and the corresponding individuals we spoke to, are listed in Table 2-2:

Table 2-2
List of PNW Utilities and Individuals Interviewed

Utility	Individual
Avista Utilities	Dan Knutson
Benton County PUD	Nancy Philip
Clark Public Utilities	Larry Bekkedahl
Clatskanie PUD	Art Robare
Eugene Water & Electric	Dean Ahlsten
Grant County PUD	Joe White
Idaho Power	Kip Sikes
Inland Power & Light	Dan Villalobos

Utility	Individual
Pacific Power	Tom Tjoelker
Portland General	Dave Lamb
Puget Sound Energy	Thor Angle
Seattle City Light	Hardev Juj
Snohomish PUD	Bob Fletcher
Tacoma Power	Tuan Tran

Global also sought the perspectives of diverse market actors on CVR, including vendors of CVR-enabling equipment such as PCS UtiliData® and Cooper Power as well consulting firms R.W. Beck and Utility Consulting International (UCI) that help utilities implement CVR.

2.4 Review of Secondary Information

In addition to primary interviews, Global conducted a literature search on distribution efficiency practices, with a focus on voltage regulation, across the country and around the world. Global consulted a wide range of sources, including:

- Key industry reports
  - Bonneville Power Administration (BPA): *Assessment of Conservation Voltage Reduction Applicable in the BPA Service Region* (1987).
  - Portland General Electric (PGE): *Conservation Voltage Regulation Pilot Project Report* (1993).
  - R.W. Beck: *Guidebook of the Recommended Conservation Voltage Reduction Engineering Processes at the Snohomish Public Utility District No. 1.* (2001)
- Utility regulatory filings and news releases
- Regional Transmission Organization (RTOs) regulatory filings and news releases
- State Energy Offices
- Equipment vendor materials (websites, product literature, whitepapers)
- EPRI body of literature
- Standards bodies (e.g. ANSI, IEEE)
- Academic research (universities, national laboratories, etc.)

3 MARKET DEFINITION

Chapter 3 describes the market for distribution system efficiency across the US today, in terms of supply and demand.

3.1 Definition

In the context of our study, Distribution System Efficiency (DSE) refers to a range of electric utility measures designed to modify the voltage delivered to end-use customers to a range lower than or tighter than the American National Standards Institute (ANSI) standard C84.1, which is explained in more detail in Section 3.2. Electric utilities may engage in DSE activities as a standard operating procedure or as a tool during certain system conditions to achieve a number of objectives, such as:

- Shaving peak load to avoid capacity constraints
- Shaving peak load to avoid the generation or procurement of expensive peak power
- Conserving energy
- Increasing operating efficiency
- Increasing reliability
- Reducing response times to outages
- Reducing customer complaints
- Increasing the use of automation to make system operations and management easier
- Lowering operating costs
- Reducing customer energy bills

Other terms commonly used to describe DSE or types of DSE measures, include:

- Conservation Voltage Regulation (CVR)
- Voltage Regulation
- Voltage Control
- Volt-Var Control (VVC)
- Volt-Var Optimization (VVO)

For the purposes of this study, we shall refer to all of these measures collectively as DSE.

DSE broadly refers to efforts to minimize the amount of energy required by a distribution system to meet its customer's end use energy needs for heating, cooling, motive power, lighting, computation, etc. A distribution system is most efficient when it supplies its customers with power at a voltage that allows the most efficient use of their equipment (i.e. the lowest energy use to meet their end use needs), and when the energy losses in the distribution system itself are kept at a minimum.

Real time measurement of distribution system losses is conceptually possible, but not currently economic. As a result, distribution system efficiency must be measured by indirect means. Voltage regulation is the most commonly used indirect measure of distribution system efficiency (i.e. losses cause voltage drop). Voltage regulation is the variation between high and low voltages provided to customers on a system caused by differences in the lengths and conductor sizes of lines serving customers near substations from those at distant locations and by daily and seasonal load changes.   As explained in the next section, industry standards allow a utility to provide a 10% variation (plus or minus 5% from nominal voltage) in the voltages it provides its customers.

3.2 The ANSI Standard

ANSI standard C84.1, “American National Standard for Electric Power Systems and Equipment – Voltage Ratings (60 Hz),” establishes nominal voltage ratings and operating tolerances for 60-Hz AC electric power systems above 100 volts and through 230 kilovolts. For typical, 120 V nominal service voltage (voltage delivered to the customer meter), this standard specifies a preferred range of +/- 5%, or 114 – 126 V. Utilities tend to keep the average voltage above 120V to provide a bigger safety margin during periods of unusually high loads as well as to maximize revenues from electricity sales. Utilities generally regard 114V the lowest acceptable service voltage to customers under normal conditions, since a 4-volt drop is typically assumed from the customer meter to the plug, and most appliances are designed to operate at no less than 110V of delivered voltage. These voltage ranges and tolerances are illustrated in Figure 3-1.

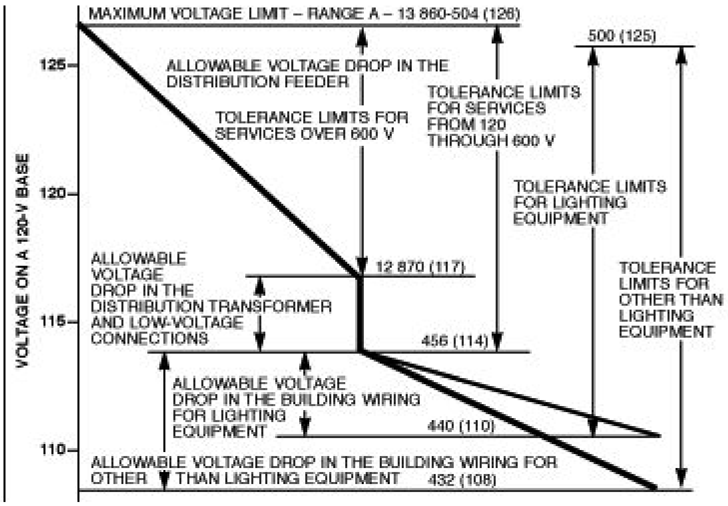

Figure 3-1
Voltage Profile of Limits of ANSI C84-1, Range A

On this basis, we define DSE as practices that lower the high end of the range, either by reducing the nominal voltage from 126 V or by narrowing the tolerance band around the nominal voltage. This concept is illustrated in Figure 3-2.

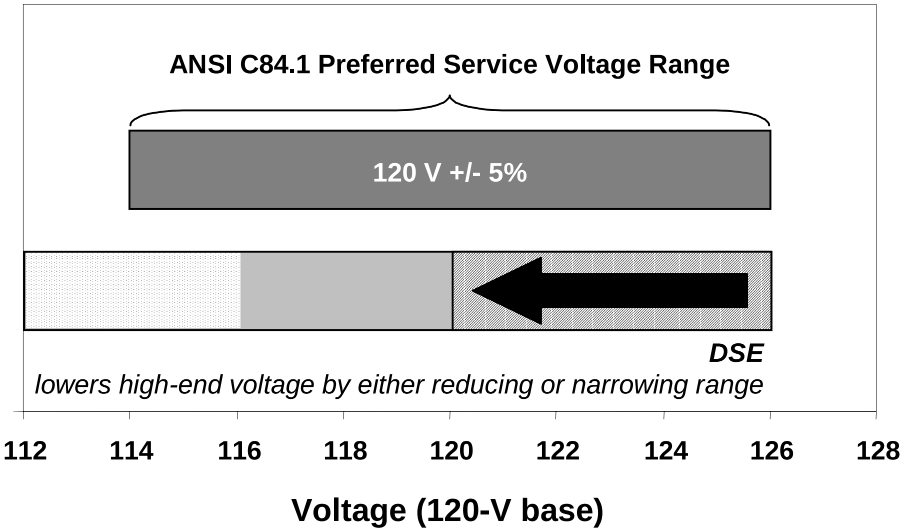

Figure 3-2
DSE in the Context of ANSI C84.1 Preferred Service Voltage Standard for 120-V Systems

The ANSI standard also defines a less stringent voltage range of 110-127 V acceptable on an infrequent basis and only under extenuating circumstances. It is generally accepted that service voltage outside of this range can lead to unsatisfactory performance and even damage of some types of customer equipment, particularly motor loads. As a result, most DSE efforts are constrained by not crossing the 110-V service voltage threshold on the low-end. Figure 3-3 compares these voltage ranges and places them in context of their corresponding utilization voltage ranges (defined as the voltage utilized by end-user loads at the plug).

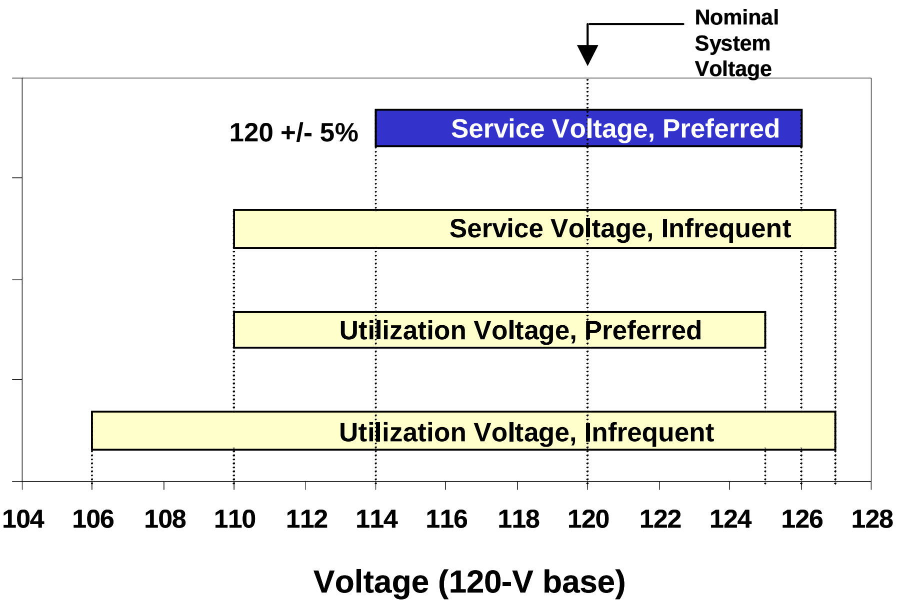

Figure 3-3
ANSI C84.1 Voltage Standards for 120-V Systems

3.3 The Link Between Voltage Regulation and Distribution System Efficiency

Voltage regulation is a good indirect measure of system efficiency for two reasons:

- The large voltage drops associated with less well regulated distribution systems are indicative of high line losses.
- The tighter voltage ranges of well-regulated systems allow utilities to provide systematically lower service voltages to customers while minimizing the risk of causing damage to customer equipment from voltages below the minimum acceptable threshold. Customer equipment generally operates most efficiently when voltages are kept in the lower portion of the national voltage range.

Distribution systems that are unable to consistently keep their customer voltages within the ANSI standard 10% range are considered poorly regulated and inefficient. Systems that consistently meet this ANSI standard would be considered fair. A system with “good” voltage regulation would be able to keep its voltage within a tighter band of 5%. Distribution systems that are able to consistently keep their customers within a 5% range and in the lower half of the ANSI standard range are considered to have both outstanding voltage regulation and system efficiency.

Power factor is another indirect measure of distribution system efficiency, although it is more expensive to monitor than voltage and is much less frequently monitored directly. Customer load power factors typically range from 80% to 90% so a system power factor of 80-85% would be completely uncorrected and would be considered poor. A system that uses a combination of switched and fixed capacitor banks to consistently correct its power factor to 98%-100% without overcorrecting would be considered great. A power factor of 100%, referred to as “unity power factor,” corresponds to the lowest possible losses for a given configuration of conductors and transformers. A fair power factor range might be 90%-100% and good might be 95%-100%.

3.4 The Link Between Voltage Regulation and Energy Savings

Generally speaking, lowering voltage lowers load, and thereby saves energy. “CVR Factor,” is defined as the percentage reduction in power resulting from a 1% reduction in voltage, is the metric most often used to gauge the effectiveness of voltage reduction as a load reduction or energy savings tool. CVR Factor will differ from utility to utility and circuit-to-circuit based on each circuit’s unique load characteristics. Empirical data from utilities across the country suggests CVR Factors can range from 0.4 to 1.0, and in some cases may even slightly exceed 1.0. One key characteristic that determines the effectiveness of voltage regulation for load reduction is the nature of resistive vs. reactive load in a given circuit.

Resistive loads such as electric resistance space and water heaters and incandescent lamps act as resistors and predominantly draw real power. As a result, resistive loads respond directly with voltage changes – lower voltages result in reduced power consumption. In fact, power use in an individual resistive load is proportional to the square of the voltage, meaning that the CVR Factor will be greater than 1.0 as long as the load is on. However, automatic controls on resistive loads such as space and water heaters usually reduce this impact, in aggregate, over a large number of loads by keeping heater elements “on” for longer periods to maintain temperatures. Despite this phenomenon, power use will still vary directly with the voltage for resistive loads.

Reactive loads, also known as inductive loads, are the common utility terms used for loads such as motors, pumps, and compressors, which draw both real and inductive-reactive power. Reducing voltages to these loads does not always reduce power consumption and can even have the opposite effect, especially if customer equipment voltages fall below industry guidelines. This effect is most pronounced for industrial customers with large induction motor loads.

3.5 Physical Characteristics of Distribution Efficiency / Voltage Reduction

Utilities can reduce their voltage regulation band, and thereby improve their efficiency, by adding certain equipment to the distribution system and improving equipment control schemes. These equipment and practices are best viewed in the larger context of what constitutes a distribution system.

The following diagram, Figure 3-4, illustrates a conceptual electricity transmission and distribution system, and identifies key equipment used at critical stages to convey and transform electricity from a generation source to the end-use appliances of a home.

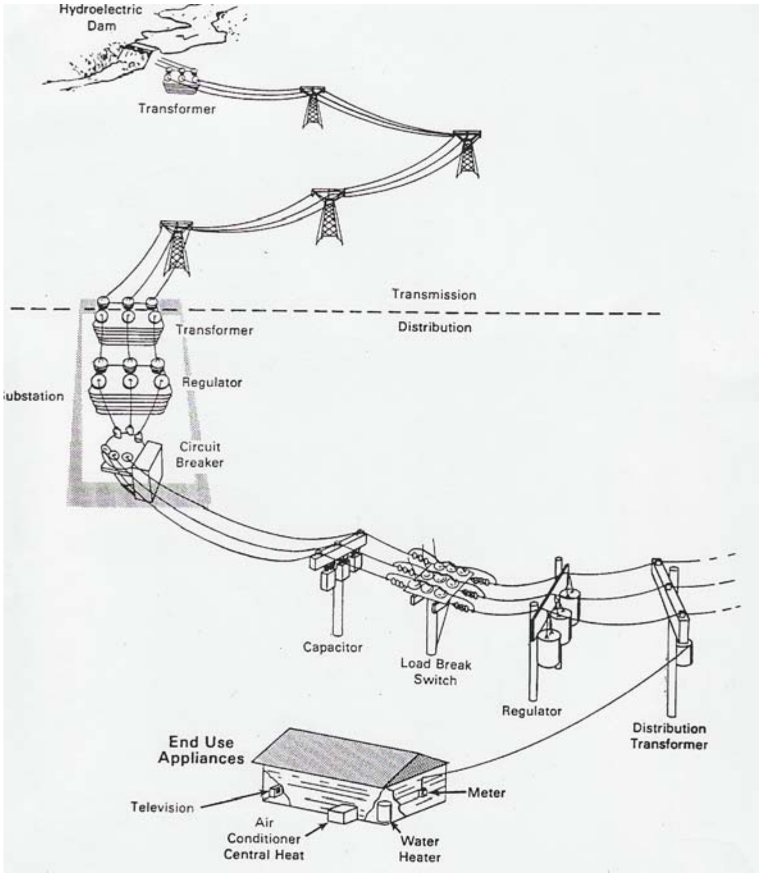

Figure 3-4
Stages of Electricity Transmission and Distribution

Reproduced from BPA Report (1987)

There are a number of methods that utilities can implement to achieve systematic voltage reduction. The more prevalent methods are identified in Figure 3-5 and ordered by cost.

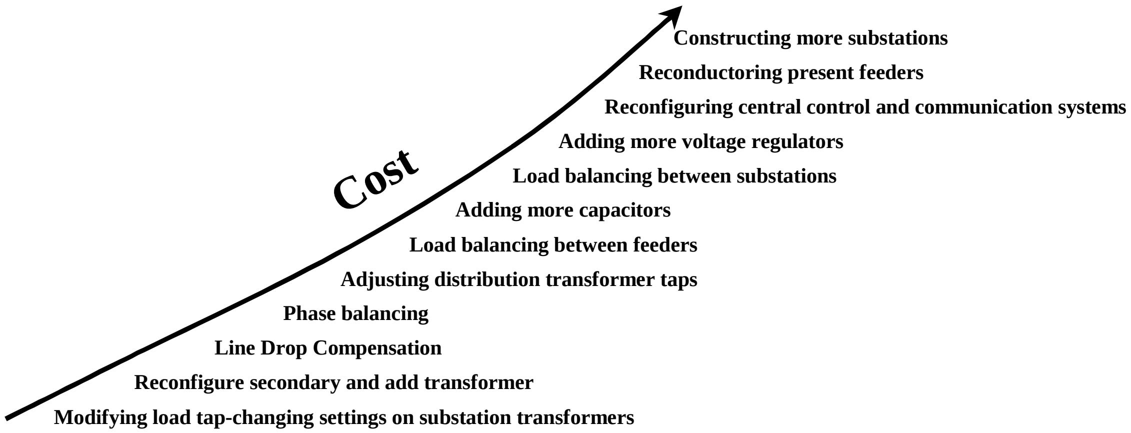

Figure 3-5
Methods of Systematic Voltage Reduction, Ordered by Cost

The slope of the curve in Figure 3-5 is purely conceptual, and is merely intended to illustrate how the various methods may be ordered from low to high cost for most utilities.

Each of these methods is described in further detail below. It is important to note that the relative cost of each of these methods to a utility depends on the nature of that utility's existing distribution infrastructure. For example, if a utility already has a sophisticated SCADA system that enables remote monitoring and control of distribution equipment elements then the relative cost of Line Drop Compensation or Reconfiguring Central Control and Communication System would be less that what may be indicated in Figure 3-5.

- **Modifying load tap-changing settings on substation transformers:** Utilities control the voltage at substations, which typically drop the transmission voltage from 115 kV to about 12 kV, by changing taps on the secondary (12 kV) winding of the transformer. The taps are changed under load without interruption of service. Some substations' taps must be manually changed at the substation, while many are remotely controlled. The same personnel and communication system used for rolling blackouts would be used to implement CVR.

  A substation transformer load tap changer (LTC) allows the voltage at a substation to be adjusted over some range, usually +/- 10%. Since the voltage at the transformer is being modified, all circuits served by the transformer will receive the same voltage. A substation LTC can be controlled manually at the substation by an operator or from a remote location if appropriate telecommunication equipment is installed. In some cases, an automatic control can be put on a LTC and it can operate similar to a regulator, as described later.

  A manual voltage adjustment at a manned substation could involve a substation operator in a control room walking to a control panel and moving a rotary dial. However, this manual technique has generally become outmoded, with computer-based remote control becoming predominant over the past 20 years. LTC settings are typically modified as part of a preset 'voltage schedule'. An operator may perform LTC adjustments several times a day in accordance with a seasonal or weekly schedule to provide a substation voltage that generally supports customer service voltages during typical daily variations in loads.

  Supervisory control and data acquisition (SCADA) installs enough telecommunications and control equipment so that an operator can perform all non-maintenance substation system monitoring and equipment operation functions remotely using a computer terminal. A complete SCADA system is not necessary if the only requirement is to allow operators to control remote LTCs. However, the economics of modifying substations frequently make SCADA a good choice when installing any new remote control features in a substation.

- **Adjusting distribution transformer settings:** Distribution transformers (DTs) transform the high voltages (and low currents) of primary distribution circuits into the lower voltages and higher currents used by customer equipment.

Figure 3-6
Pictures of Distribution Transformers

Most DTs are supplied with a mechanism that allows at least a one-time voltage adjustment when they are installed, such that customers throughout the feed receive the same delivered voltage. If used, this allows a customer at the end of the feeder line to be given a boosted average voltage and a customer at the beginning of the feeder line to be given a lowered average voltage. This concept is illustrated in Figure 3-7 below.

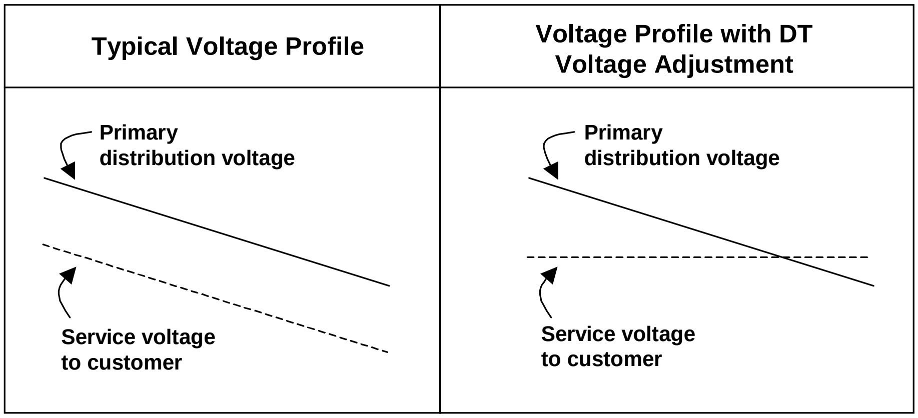

Figure 3-7
Voltage Profiles with and without DT Voltage Adjustment

Proper setting of these ‘transformer tap’ devices for transformers at the beginning and end of a distribution line can allow the automatic voltage control devices (regulators and/or switched capacitor banks) to operate in a narrower voltage range, improving voltage regulation and system efficiency.

- **Adding more capacitors:** To further reduce voltage from the substation, utilities typically have to invest in additional capacitors to flatten out the voltage profile, especially on long feeders – enough to permit voltage reduction at the feeder source and still allow the last customer on the feeder line to have at least the minimum acceptable voltage.

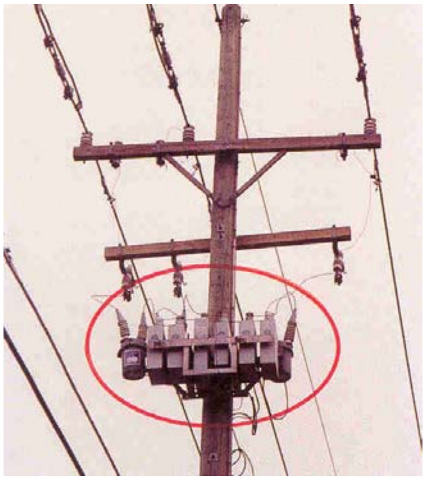

Figure 3-8
Picture of Capacitors

All customer equipment requires electric power (measured in watts) to operate but most equipment also requires a form of energy called reactive power (measured in vars) for operation. Utilities traditionally do not measure or bill for this reactive power, except for their largest customers, but still must supply it by putting capacitors on their system, and loading these costs into their average kilowatt-hour charges.

Customer requirements for reactive power typically rise and fall on a daily and seasonal basis along with the rising and falling demand for measured kW power. Utilities typically install fixed capacitors to meet the minimum annual demand for reactive power and then add switched capacitors to serve the reactive power demands up to the annual peak. Utilities generally install enough capacitors to serve the entire reactive demand. The only alternative for providing reactive power is using generators, which are much more expensive than capacitors, increase system losses, and create additional voltage drop.

Utility capacitors can also serve a voltage control function. When capacitors are connected onto a utility circuit they raise the line voltage. Capacitors can have automatic controls installed similar to regulator controls and can be switched on or off as required by varying load conditions for var control and voltage control. This dual ability frequently makes switched distribution line capacitor banks the most economical distribution equipment to perform the dual functions of reactive power supply and voltage regulation. Utilities that keep all of their capacitor banks in substations and rely only on regulators for distribution voltage regulation forgo this potential benefit of capacitor application on distribution lines.

Unlike regulators, switched capacitors cannot be used to actively reduce voltages. Most utilities that rely mainly on switched capacitor banks for voltage control also make some use of regulators or LTC voltage schedules to adequately regulate system voltages.

The most efficient placement of distribution capacitors is as near as possible to customer loads. The reactive power requirements of customers must flow over the utility lines from the capacitor to the customer load and the shorter the distance of these flows the lower the system losses. The addition of capacitors at critical points on a distribution system close to their loads also provides the distribution lines with a voltage increase precisely where it is most useful to improve voltage regulation.

- **Adding more voltage regulators:** A voltage regulator is a device that allows voltage to be adjusted on a distribution line, usually packaged with an automatic control system. They are often installed on individual circuits in substations but can also be installed as "line regulators" on poles or pads or in vaults. Regulators on individual feeders provide more control over circuit voltages than substation bank LTCs because they allow voltages on heavily loaded circuits in a substation to be controlled separately from circuits that may be lightly loaded at any given time. They have automated controls, such that no substation operator intervention is required for them to do their job. They require no telecommunication links to work, although communication capabilities may lead to more efficient operation. However, effective operation of their automatic controls does require an individual study of the loads and circuits they will serve by an engineer or technical specialist.

  Regulators automatically control the voltage at their location as daily and seasonal loads vary. However, remote loads beyond the regulator may have considerably lower voltages during peak load conditions, especially if they are at the end of long lines of small conductors. Adding a line regulator at the remote location, or at a new substation for large and growing loads with circuit regulators, are ways of more tightly controlling the voltages to these customers.

- **Line Drop Compensation:** On lines operating with CVR, voltage is often regulated with a technique called Line (or Load) Drop Compensation (LDC), which enables the voltage at the distribution transformer to fluctuate so as to maintain a minimum voltage to the home at the end of the line of at least 114V. A distribution transformer with LDC will emanate a lower average voltage over time.

  The simplest and default setting of a regulator's automatic control is to maintain a constant voltage. An installer sets the voltage high enough that the most distant customer will have adequate voltage during peak load conditions. However, peak conditions last only a few hours each year and this setting keeps the circuit voltages at the upper end of their range throughout most of the year. This high voltage causes customer equipment to operate inefficiently and reduces overall system efficiency.

  Regulators also provide a LDC control. An engineer or technical specialist can review circuit maps showing conductor sizes and load information, and input this information into the regulator's automatic control. As loads vary throughout the year, the control performs an internal calculation and keeps voltages only as high as necessary to maintain adequate (calculated) voltages, yielding lower average annual voltages and better efficiency than the default settings.

Computerized controls can also be purchased that communicate through telecommunication with remote voltage sensors or other voltage control equipment. These controls are more expensive and require more engineering time to design but can provide even better annual voltage regulation.

- **Reconfiguring the utility's central control and communication systems:** May involve deployment of a new SCADA system or integration with an existing SCADA system.

  The benefits of adding improved controls and remote sensor and equipment operation features to voltage regulation equipment can often best be described with examples. Suppose you have a distribution circuit that starts in a rural town and then continues out to a farm with a seasonal water-pumping load at the end of the line.

  If the circuit is fed from a substation regulator set to a constant voltage, the voltage setting will need to be high enough to provide adequate voltage at the farm pumps during peak conditions. Most of the customer equipment on the circuit will operate at inefficiently high voltages during the year except when the pumps turn on.

  If the circuit is fed from a LDC controlled regulator, the regulator will reduce average voltage during low loads but must still increase voltages anytime any circuit loads increase in case part of the load is coming from the pumps.

  If a switched capacitor bank with automatic voltage control is added to the circuit near the farm, pump operation will usually reduce the local voltage enough to switch on the capacitor, increasing farm voltage and decreasing circuit load enough to allow the regulator to reduce its voltage somewhat to the customers in town. This reduced town voltage will allow its residential load equipment to operate more efficiently.

  If telecommunications is established between the substation regulator and the capacitor bank, and the capacitor control has both current and voltage sensing, the farm and town voltages can be controlled almost independently. The current sensing at the farm’s capacitor bank will allow the control scheme to know when the pumps are on and to always switch on the capacitor. Town voltage will only be increased if town loads increase or if the voltage sensor at the capacitor shows the farm actually needs voltage support.

  The economics of installing limited telecommunication systems in substations to serve distribution controls often lead utilities to take the next step and fully automate the substation with a SCADA system. SCADA systems provide many other benefits in addition to improved voltage regulation, such as reduced cost to operate substations and improved ability to restore service to customers during emergency conditions. But the cost of complete SCADA systems are not required to gain the benefits of establishing telecommunications links between distribution system voltage regulation equipment.

- **Reconductoring present feeders:** When utilities replace an existing run of line conductor (wire or cable) with a larger size, this action is referred to as line reconductoring. A utility reconductors a line in response to increased loads or to reduce the voltage drop from the beginning of the line to its end (i.e. improve voltage regulation). Reconductoring can be an expensive proposition, approximately $100,000 per linear mile.

Reconductoring a feeder improves system efficiency in two ways:

1. A larger conductor will have lower losses while serving the load than the smaller size it replaces; and
2. The larger conductor will have lower voltage drop that will improve the voltage regulation on the circuit. System efficiency will be improved if the utility responds to this improved regulation by lowering the average circuit voltage, allowing customer equipment to operate more efficiently.

- **Constructing more substations:** Adding distribution substations to a system can improve system efficiency in two ways:

Figure 3-9
Picture of Distribution Substation

1. It allows shorter distribution circuits, which reduces their voltage regulation ranges and their losses, while moving more power on sub-transmission networks which tend to have lower losses; and
2. Substations provide good locations for such voltage control measures such as regulators and switched capacitor banks with their sensors and controls.

3.6 Business Considerations of Distribution Efficiency / Voltage Reduction

The economics of systematic voltage reduction, whether as a standard procedure or a peak demand measure, will vary from utility to utility as a function of each utility's:

- Existing infrastructure
- Load characteristics
- Capacity margin
- Operational efficiencies

- Ability to re-sell excess capacity
- Past and existing planning standards (allowable voltage drop on primary and secondary systems)

Existing Infrastructure

The more advanced a utility's existing distribution infrastructure the less costly it is to regulate voltage for distribution system efficiency and energy conservation. A utility with an existing SCADA system, for example, may already have the capability to remotely and automatically adjust settings of substation transformers, capacitor banks, and voltage regulators. Such a utility would not have to resort to dispatching operators to manually perform these adjustments, and would also be able to employ line drop compensation without having to invest in additional equipment. Conversely, a utility without a sophisticated SCADA system or with antiquated equipment and controls would likely have to outlay capital to invest in infrastructure improvements to enable systematic voltage reduction.

Load Characteristics

As discussed in Section 3.4, the load profile of a given circuit, as defined by the mix of resistive vs. reactive loads, is a key determinant of the effectiveness of voltage reduction in yielding load reduction. Each utility regards its service territory and constituent circuits as unique. As a result, many utilities feel that another utility's voltage regulation results are not necessarily transferable to their own service territory. However, a utility should be able to identify the circuits in its territory that would be the best candidates for voltage regulation for distribution efficiency and load reduction. Ideal circuits would feature highly resistive loads.

Another consideration in the implementation of voltage reduction is whether to do so during peak or off-peak (i.e. light load) periods. The motivation is distinct in each case. The motivation for voltage reduction during peak periods is peak demand reduction. On the other hand, there are two primary motivations for voltage reduction during off-peak, light load periods. The first is to reduce energy requirements and save money for the utility and the customer. The other motivation is to prevent high voltage conditions and associated power quality issues for customers and utility equipment.

A pilot project on CVR conducted by Portland General Electric in 1993 indicated that CVR was more effective in reducing demand and energy during off-peak periods than during on-peak periods.

Figure 3-10 identifies a utility's significant costs and benefits associated with a voltage reduction. The calculation of each cost and benefit, based on each utility's unique characteristics as outlined above, will determine to which side the proverbial scales will tip. Each cost and benefit element is discussed below the figure on the following page.

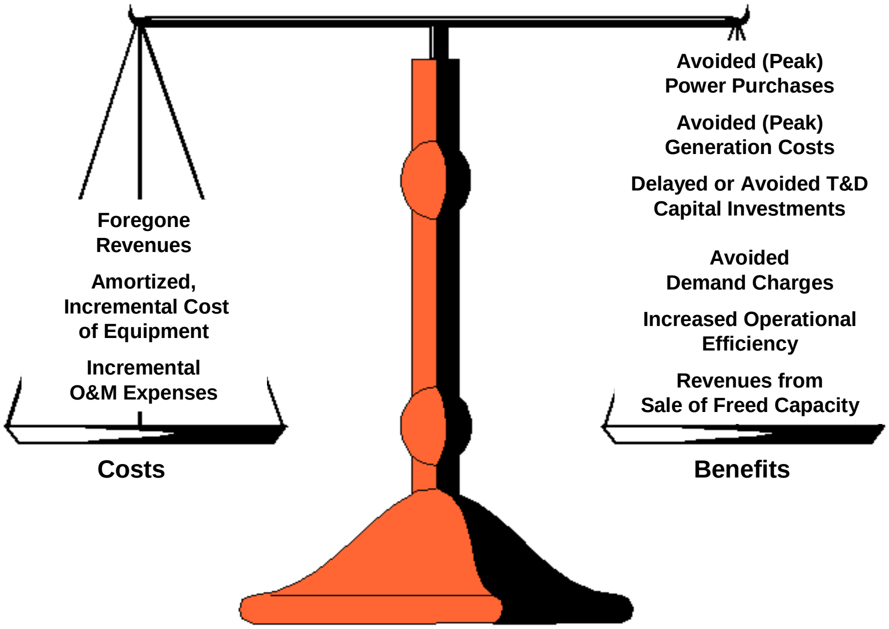

Figure 3-10
Utility Economic Considerations for Implementing Voltage Reduction

COSTS

Foregone Revenues: By lowering voltage for sustained periods to reduce load, a utility foregoes some revenue from lowered kWh sales that it would have otherwise taken in if voltage had been maintaining at normal levels.

Amortized Incremental Cost of Equipment: A utility's existing level of distribution infrastructure determines the extent to which new equipment needs to be purchased to implement voltage reduction. For example, a utility with an existing SCADA system and a sufficient number of switched capacitors throughout its system might be able to implement voltage reduction with minimal investment in additional equipment. Conversely, a utility without a high level of existing infrastructure might have to invest a significant amount of capital in new equipment. The incremental cost of equipment needed to implement voltage reduction, which would have to include installation cost, should be amortized over its expected useful life to be reflected in an overall economic calculation of the benefit of such an implementation.

Incremental O&M Expenses: To the extent that implementing voltage reduction requires incremental operations and maintenance expenses, these costs should also be taken into account. For example, a utility might have to dispatch a crew to periodically modify load tap changer settings for voltage reduction, which it would not otherwise have to do.

BENEFITS

Avoided (Peak) Power Purchases and/or Generation Costs: By reducing load through voltage reduction, particularly during peak periods, a utility reduces its requirement to procure or generate peak power. For many utilities, procuring or generating power for peak periods is costly and unprofitable on the margin. For some utilities, these avoided costs alone can compensate for foregone revenue during peak periods.

Delayed or Avoided Capital Investments: Voltage reduction can alleviate distribution bottlenecks and reduce strain on overloaded circuits and distribution transformers, thereby providing distribution utilities with a hedge to delay or even avoid capital investments on constrained feeder lines. From a Net Present Value perspective, forestalling such costly capital investments is economically beneficial to distribution utilities, since costs in future years are discounted by a utility's cost of capital.

Avoided Demand Charges: Many rural power distributors belong to G&T cooperatives that supply most or all of their generation. Many G&T cooperatives assess high demand charges to their member power distributors during monthly peak demand periods to reflect the higher cost of peak power and motivate load reduction measure. By reducing voltage during these peak periods, rural power distributors or other utilities in a similar situation can reduce these demand charges. The members of the Seminole Electric Cooperative in Florida, for example, routinely implement voltage reduction in this manner with great success. Interviews with a number of these members, as noted in Chapter 4, indicate that voltage reduction is preferred over direct load control as the measure of choice to avoid demand charges, due to its effectiveness and lack of disruption to customers.

The presence of external G&T demand charges provides a direct incentive for utilities to implement load control measures such as voltage reduction, as well as a means to quantify the resultant savings.

Increased Operational Efficiency: In the course of implementing voltage reduction, a utility will typically decrease the voltage drop along its distribution feeders, which reduces system line and transformer losses. Such gains in operational efficiency enhance the economics of a voltage reduction program.

Revenues from Sales of "Freed" Capacity: By reducing load through voltage reduction, a utility increases its capacity margin, and therefore, its increases the amount of power it can re-sell on the open market. The flexibility to sell excess capacity on the open market can represent the deciding factor that can "tip the scales" in favor of implementing voltage reduction. Depending upon the nature of a utility (i.e. investor owned utility, municipality, cooperative, etc.), its regulatory status and its obligations to its power generators, it may or may not be able to resell its excess capacity on the wholesale market. For example, some utilities that receive their power from federal power marketing agencies such as Bonneville Power Administration (BPA) or Tennessee Valley Authority (TVA) are obligated to procure what it consumes, leaving no margin available for re-sale.

4 CURRENT STATUS OF VOLTAGE REDUCTION

Chapter 4 presents summarizes the findings from our interviews with utilities across the country and in Canada regarding the current status of distribution efficiency practices.

4.1 National / North American Perspective

National Perspective

Since the advent of the voltage reduction concept in the 1970s, most U.S. utilities have at least tested some form of voltage reduction on parts of their systems and for widely varying lengths of time. In general they have successfully reduced the average voltage supplied to residential and some commercial customers about 4%, to about 117.5V from the average 122.5V. Yet voltage reduction is currently applied nationwide to less than 7.5% of all feeders, of which approximately 3% are in California where, until recently, voltage reduction was mandated.[1]

Table 4-1 summarizes the key findings from our surveys of utilities across the country identified as having some exposure to voltage reduction.

Table 4-1
Highlights of National/North American Survey Findings

Highlights of Key National Findings From Interviews
DISTRIBUTION EFFICIENCY INITIATIVES
• CVR has been largely "abandoned" nationwide o Applied to approximately 7.5% of all feeders nationally o Apart from some regional pockets of voltage reduction activity in the northeast, southeast (Florida and Georgia), California, Pacific NW, and Wisconsin, voltage reduction is virtually non-existent elsewhere
• Barriers to CVR implementation: o Still a high degree of skepticism over the effectiveness of voltage reduction on load • Highly dependent on the nature of a utility's load profile (resistive vs. reactive) by circuit • One utility's CVR test results do not necessarily apply to another utility. Not much sharing of information among utilities on lessons learned. o Most of the country is not capacity constrained o Lost revenue from lower service voltages • If lost revenue > cost of procuring or generating peak power, a utility will not consider voltage

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[1] Global Energy Partners estimate, based on literature review and interviews with utilities. Voltage reduction in residential (and small commercial) circuits among California's three investor owned utilities represents 25% of California consumption; multiplied by California as 12% of total = 3%, used as proxy for percentage of feeders. Additional voltage reduction activity in Northeast states, New York, Georgia, Florida, and Pacific Northwest adds up to estimate of 7.5% of national feeders.

Highlights of Key National Findings From Interviews

reduction

  - Fear of customer complaints
  - Perception of “takeback” phenomenon that would mitigate or defeat real energy savings
      - E.g. lower voltage → dimmer lights → consumer buys higher watt bulb
  - Problematic in rural areas with long feeders
    - End-of-line voltage can drop out of range
      - Requires additional capital (i.e. more equipment and engineering)

DISTRIBUTION VOLTAGE REDUCTION FOR CAPACITY MANAGEMENT

- Utilities reduce voltage primarily on an “as-needed” basis for peak demand reduction rather than a standard operating procedure for energy conservation
- Most utilities include voltage reduction in their basket of emergency measures to reduce load during peak conditions or when a circuit might be overloaded.

- Utilities that implement voltage reduction typically have some or all of the following characteristics:
  - Capacity-constrained
  - Expensive to generate or procure peak power
  - Utilities with demand charges imposed by G&Ts
  - Serve metro areas with shorter feeders
  - An in-house technical champion (engineer)

NORMAL DISTRIBUTION ENGINEERING & OPERATIONS FUNCTIONS

- Volt-VAR Control/Optimization is more in vogue
  - Goals: (a) Flatten voltage bandwidth, (b) improve system efficiencies, (c) reduce system losses
  - No net demand reduction or energy savings

Apart from some regional pockets of activity, which are discussed in the remainder of this section, utilities have largely abandoned voltage reduction as a means of energy conservation.

There are several key barriers to the consideration and adoption of voltage reduction, the most fundamental of which is technical skepticism over the link between voltage reduction and load reduction. Some utility engineers believe that certain loads draw more current at lower voltage levels, and that therefore lower voltage does not necessarily result in reduced loads. However, while this inverse relationship may hold true for certain types of loads, data from many utilities clearly prove that most loads do consume less power at lower voltages.

Another aspect of technical skepticism is belief in the “takeback effect.” According to this hypothesis, the energy savings from voltage reduction will only be temporary and will not live up to estimates because customers will adjust their usage based on perceived changes to their end-uses. For example, this hypothesis contends that if lower voltages result in perceptibly dimmer lights, some customers will therefore change to higher wattage bulbs, thereby negating the intended energy savings. There is no known study that verifies this hypothesis. Moreover, most evidence from utilities suggests a net energy savings associated with voltage reduction.

Another technical challenge to voltage reduction is maintaining a minimum acceptable end of line voltage along long feeder lines, which typically serve rural areas, as well as for even short feeder lines where a number of customers have long secondary feeders with large perceived voltage drops. For example, NYSEG was unable to continue a voltage reduction program in upstate New York because voltage levels for rural customers at the end of long feeder lines would periodically drop below the 114V threshold level, and therefore resulted in complaints from customers. To reduce the voltage drop along long feeder lines, utilities have to invest in additional equipment such as capacitors or rework secondary systems to shorten the secondary conductors.

In addition, each utility tends to regard its service territory and load characteristics as unique. This poses another barrier, since a given utility may not be influenced by another utility's positive experience with voltage regulation. Not surprisingly, utilities tend not to share information about distribution voltage practices. Moreover, the mix of resistive to reactive load from circuit to circuit determines the effectiveness of voltage reduction in achieving load reduction.

Another barrier to more widespread application of voltage reduction is that most of the country is not presently capacity constrained. Many utilities have provisions in their emergency plans to resort to temporary voltage reductions during system emergencies or for only a few peak days in a given year. In areas that are capacity constrained or have experienced capacity crises, voltage reduction has been applied successfully. For example, during the energy crisis of 2001 that affected western states, utilities in the PNW region and in California reduced voltages to avoid rolling blackouts.

The forgone revenue from reduced power consumption associated with voltage regulation is another significant economic barrier for utilities. As explained in Section 3.6, utility engineering personnel are challenged to quantify the net economic impact of voltage regulation to their senior management. For utilities that have to either procure peak power at high rates or engage their own costly peaker plants, the marginal economic impact of reducing voltage to reduce load can be positive. However, utilities that do not face peak capacity constraints or who are unable to resell capacity on the wholesale market are particularly hard-pressed to justify the economics of voltage regulation.

California

During the `70s and early `80s, California was among several states across the country that recognized the opportunity for energy savings from voltage reduction. For example, in 1976 the California Public Utilities Commission (CPUC) mandated that California Investor-owned utilities (IOUs) limit delivery voltage to residential and commercial customers to the range of 114-120 volts, effectively reducing the voltage bandwidth by half. The utilities complied and, through the end of 1978 it was estimated that more than 1 billion kWh were conserved through this practice.[2] Measurements as recent as 2002 indicate that the average voltage delivered to the meters of California customers is about 118V. Tests conducted by the California IOUs showed a

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[2] California Public Utilities Commission. Rulemaking 00-10-002, Phase 2 Voltage Reduction. Decision 02-03-024. March 6, 2002.

typical house having a 6% reduction in power for an 8% reduction in voltage, for a CVR factor of 0.75.[3]

Due to the California energy crisis of 2001, Governor Gray Davis asked the CPUC on July 3, 2001 to instruct the IOUs to further reduce distribution system voltage in order to reduce peak demand and help alleviate the need for rolling blackouts. In response, Pacific Gas & Electric (PG&E) implemented a plan from July through October 2001 to review and modify over 2,000 voltage regulators at substation banks and feeders such that it could further reduce distribution system voltage by 2.5% on an emergency basis. PG&E estimates that its upgrades allow substation voltage of 117V, which can reduce peak demand by up to 50 MW when activated system-wide.

Today, the CPUC no longer mandates an upper limit service voltage of 120V for IOUs. Despite the absence of a regulatory mandate, however, all three IOUs still typically provide voltage to residential and small commercial circuits at a voltage range of 114-120V. This sustained voltage reduction activity does not appear to be motivated by any explicit energy conservation or peak reduction goal, but rather represents a continuation of operations that have become the norm. The lesson from California is that once DSE activities such as voltage regulation/reduction are implemented, even if originally driven by regulatory fiat, they are eventually accepted as normative operations by Distribution Operations staff. These activities can continue even when a regulatory mandate is lifted, provided that they do not trigger tangible increases in customer complaints.

Northeast

In the 1980's, the public utilities commissions of Massachusetts and Connecticut mandated CVR practices, which continue to this day. The Connecticut PUC mandated utilities to reduce the maximum allowable service voltage from 126V to 123.6V, for a service voltage range of 120V +3%/-5% for all circuits. Northeast Utilities estimates that it took 3 to 4 years from the time of the mandate to implement CVR on all of its circuits in Connecticut.

The Massachusetts PUC[4] does not require utilities to deviate from the ANSI standard range of 120V +5%/-5%. However, for a limited time it did provide financial incentives for utilities to lower voltage during *light load* periods in order to save ratepayers money through the associated reduction in load. The light load period was selected to minimize the risk of voltage falling below the minimum threshold of 114V, since voltage drops along a feeder increase with higher loads. The financial incentive takes the form of rate recovery relief to compensate utilities like NSTAR for the revenue foregone by reducing voltage. The Massachusetts PUC offers this incentive to all public utilities and IOUs for which they determine rates, which excludes municipalities.

In practice, utilities in Massachusetts lower the service voltage on their distribution transformers to less than 125V during daily off-peak periods and up to 125V during peak periods. This

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[3] Steve Greenberg. "Quick fix for peak power woes? - Utilities - conservation voltage regulation in California to reduce energy consumption." Home Energy. Jan

[4] Current name is Massachusetts Department of Telecom and Energy

mandate currently remains in place. In the early 1990's, the Connecticut PUC adopted the Massachusetts off-peak voltage reduction requirement, and mandated its utilities to further reduce voltages on some circuits during off-peak periods above and beyond the everyday CVR operation of 120V +3%/-5%.

Northeast Utilities

Northeast Utilities, which operates Connecticut Power & Light and Western Massachusetts Electric Power, employs line drop compensation (LDC) to maintain a voltage of 114V at the end of its distribution feeders in Connecticut. Northeast Utilities meters voltage levels at the end of its distribution feeders on its most heavily loaded circuits to ensure that end of line voltage remains at or above 114V. To help reduce voltage drops along its feeders, Northeast Utilities has taken measures such as adding capacitors and reconductoring.

Northeast Utilities has observed an average load reduction of 0.5% per 1% voltage reduction, for a CVR factor of 0.5. The utility notes that this CVR factor varies by season and by the nature of the load on a given circuit.

Despite internal concerns at Northeast Utilities over the potential for customer complains due to problems associated with lower voltages, Northeast Utilities claims that there has not been any perceptible increase in customer complaints since the inception of its CVR practices in Connecticut and Massachusetts.

Northeast Utilities has not performed an economic analysis to determine the financial impact of CVR net of foregone revenues. Any infrastructure investments made to implement CVR have been rate-based capital expenditures, with no special treatment from other infrastructure upgrades.

NSTAR

NSTAR[5], which serves Massachusetts, follows the Massachusetts guideline of lowering voltages during light load conditions to save ratepayers money on their bills. NSTAR employs LDC to reduce voltage by 2-3% during light load periods on 15 to 20 of its substations, out of 80 substations in its system. The designated substations serve predominantly residential and commercial customers.

It took NSTAR six months to install the additional metering and implement new internal software to facilitate the rollout of the light load voltage reduction plan on 15 to 20 substations. NSTAR cites its pre-existing SCADA system as essential to the implementation and operation of its light load voltage reduction plan. Using SCADA, NSTAR remotely controls selected load tap changers (LTCs) based on circuit loading. NSTAR reports that it has not observed any customer complaints related to the light load voltage reduction practice.

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[5] NSTAR is comprised of the former utilities Commonwealth Electric, Boston Edison, and Cambridge Electric

Because the Massachusetts PUC has recently discontinued offering financial incentives, NSTAR has not expanded its light load voltage reduction operations to additional substations.

New York State Electric and Gas (NYSEG)

In the 1980s, the New York State Public Service Commission ordered IOUs and other utilities serving the state to lower voltage as a general practice to conserve energy and save customers money. For approximately five years, the maximum allowable service voltage was reduced from 126V to 122V, for an effective service voltage bandwidth of 122-114V. However, the Public Service Commission dropped its mandate for voltage reduction due to unacceptably low voltage drops, especially along longer feeder lines in the rural areas of update New York.

During the years of implementation, NYSEG determined that a 5% voltage drop led to a 3% reduction in load, for a CVR factor of 0.6.

Voltage Reduction as an Emergency Measure

As in other parts of the country, utilities in the Northeast region are mandated by their Independent System Operator (ISO) to employ voltage reduction as a measure during emergency or extreme peak conditions. For example, ISO New England mandates that utilities have the capability to implement a 5% voltage reduction at their substations on a 10-minute notice. In practice, ISO New England only makes such a call for a few summer peaking days per year, if at all, and only for a few hours on the affected days. A 5% voltage reduction reduces the service range from 126-114V to approximately 120-108V. Some utilities regard reducing voltage in this manner as a more acceptable short-term alternative to curtailments or rolling blackouts. The utilities that we spoke to in the Northeast stated that implementing an across the board voltage reduction at the substation level on an emergency basis is far less complicated than tailoring a voltage reduction program at the regulator and distribution transformer level as a standard operating procedure.

Southeast

The Southeast is another regional pocket of CVR activity, particularly in Florida and Georgia. Utilities in the region cite the large installed base of resistance load as a favorable factor for CVR as a demand-reducing measure, since resistive load decreases predictably with reduced voltage. From a business standpoint, a number of rural power distributors successfully employ CVR selectively on a monthly basis to avoid costly demand charges imposed by their G&T cooperative. Perhaps the leading example of this practice is seen among the member utilities of Seminole Electric Cooperative in Florida, who are highlighted below.

Seminole Electric Cooperative

The member utilities of Seminole Electric Cooperative, a G&T cooperative based in Tampa, Florida, are assessed monthly peak demand charges by Seminole. To avoid these expensive demand charges, most of the members reduce voltage during peak loads or when requested by Seminole.

Central Florida Electric Cooperative, for example, resorts to voltage reduction as its first measure to reduce peak demand and lower demand charges. Central Florida reduces the 125V nominal voltage at selected distribution transformers by 1.5% to 3%, and adjusts its voltage regulator controls through its SCADA system to allow for this reduced voltage. Of Central Florida's 14 substations, 7 are enabled with this voltage reduction capability, which consist of largely residential and commercial circuits. Because Central Florida already had a SCADA system in place at its substations and could also adjust regulator controls remotely, it did not need to procure or install any additional equipment to implement its voltage reduction practice. It only had to perform some new wiring and relays, which took a 2-man crew 1 day per substation to complete.

By implementing voltage reductions of 1.5% to 3%, Central Florida claims that is has been able to reduce its monthly peak demand rates by up to 20%.[6]

Tests on the first substation to implement this voltage reduction revealed a 0.5% reduction in load for every 1% reduction in voltage (for a CVR factor of 0.5) during the summer and 0.75% load reduction in the winter. Central Florida notes that its voltage reduction activity is most effective during its winter peaks due to the high presence of resistive heating in its region.

Clay Electric Cooperative has employed voltage reduction as a peak demand reduction tool on its ten substations for over 10 years. Clay reduces its substation voltages by 1.7%, from 126V down to 123.86V to avoid monthly peak demand charges. Clay observes a 1% load reduction per 1% voltage reduction, for a CVR factor of 1.0.[7]

Since 1983, Sumter Electric Cooperative has employed voltage reduction about three times per month, in conjunction with Seminole load management requests, on 10 of its 40 substations. Sumter implements a 2% voltage reduction at its substations for a duration of up to two-hours corresponding to its system peak. From the time that Seminole calls in the request, Sumter can implement the 2% voltage reduction through its SCADA system within 5 minutes. Sumter sends a signal to its SCADA-compatible QEI regulator controls to "trick" the regulator into thinking that the incoming voltage is greater than it really is. Sumter was able to implement its voltage reduction program without procuring any additional equipment. The only incremental investment was some SCADA programming and training, which it provided in house. The 10 substations selected for this measure are all newer 25 MVA stations serving residential and commercial customers on typically shorter feeders for which the normal end-of-line voltage is no less than 118V or greater.

Sumter had experimented in the past with 4% voltage reductions during peak periods, but discontinued the practice due to concerns over crossing the minimum acceptable threshold to end of line customers of 114V.

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[6] Interview with Mike High, Director of Engineering, Central Florida Electric Cooperative. October 27, 2003.

[7] Interview with Maurice Snay, Clay Electric Cooperative. October 9, 2003.

Perhaps cooperatives with distinct demand charges can more easily quantify benefits of peak demand reduction through CVR. In integrated utilities, demand charges may be internal pass-through costs that are hard to identify. It would be more difficult to determine CVR cost-effectiveness without this type of cost data.

Each of the members of the Seminole G&T system have shared notes over the years on best practices for voltage reduction, which has helped all of the members improve the effectiveness of their efforts. The Seminole Cooperative hosts periodic "Load Management Working Group" meetings that provide a forum for member cooperatives to exchange ideas. Several members, including Central Florida and Sumter, have determined voltage reduction to be a more effective demand reduction tool than direct load control. These utilities also prefer voltage reduction to direct load control because it generates fewer complains; many have even dropped existing load control programs altogether.

Florida Power & Light

For over 30 years, Florida Power & Light (FP&L) has been operating within a tighter voltage bandwidth than the ANSI standard for most of its substations[8]. FP&L operates at 120V +/- 2.5%, or a range of 123-117V. FP&L claims that the driver for this practice is the prevention of customer power quality complaints, rather than objectives such as energy conservation, demand reduction, or regulatory compliance. In fact, because this operating at this voltage has been FP&L's standard practice for over 30 years they have not attempted to quantify the energy and demand they are likely saving through this practice compared to operating at the ANSI Standard.

Furthermore, under certain peak conditions the nominal voltage is reduced by a factor of 2.5%, for a modified voltage range of 120 –114 V (i.e. 117V +/- 2.5%)[9]. FP&L claims that that it can shave 200 MW off its system peak through the application of this 2.5% emergency voltage reduction throughout its system.

To accomplish its voltage regulation, FP&L uses SCADA-compatible software to control regulators on its system on an individual, group, or aggregate basis. FP&L is capable of automatically adjusting the nominal voltage and voltage bandwidth on its regulators without the need to dispatch operations or maintenance personnel to specific sites.

Progress Energy – Florida

Progress Energy – Florida implements a 2.5% voltage reduction only as an emergency demand reduction measure. Through internal studies, it has determined a 1% load reduction per 1% voltage reduction, for a CVR factor of 1.0.[10]

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[8] The only exceptions are a few rural circuits, which operate at the normal ANSI Standard of 120V +/-5%.

[9] In practice, FP&L operates at all times to maintain a minimum end of line service voltage of 115V.

[10] Interview with Jason Handley, Manager of Power Quality and Reliability, Progress Energy – Florida. October 29-30, 2003.

JEA

JEA in Jacksonville, Florida realized a significant decrease in load using voltage reduction during its highest summer peak of 3,166 MW in 2003. By implementing a 5% reduction in voltage, which was enabled by a distribution automation system implementing in 1999, JEA reduced load by more than 65 MW. JEA also reported no customer complaints during this voltage reduction event, which allowed all customers to receive electric service and averted rolling blackouts during JEAs unprecedented peak.[11]

Georgia Power

In 1998, motivated to lower peak demand while cost-effectively maintaining reliable customer service, Georgia Power began implementation of its Distribution Efficiency Program (DEP), which involved the installation of switched capacitors at strategic points on its distribution system to provide a near-uniform voltage profile from the substation to the end of line. The cost of implementation was $15.5 million over two years to purchase and install switched capacitor banks and controllers, substation equipment and controllers, and communications equipment.[12]

By reducing the voltage drop from the substation to the end of line customer meter, Georgia Power reduced transmission and distribution system losses and gained additional margin to implement voltage reduction to reduce peak demand. On most of its circuits, Georgia Power typically holds service voltage at 123V from the substation through the end of a given feeder line, as opposed to previously operating its substations at 126V. Having rolled out DEP to additional substations from 1998 through 2001, Georgia Power claims that the efficiencies provided by DEP reduce peak load by 264 MW system-wide.[13] Georgia Power further estimates that DEP saved the utility $4.6 million in avoided peak power purchases during implementation in the summers of 1999 and 2000.[14]

Georgia Power continues to implement DEP during summer peaking periods, and plans to continue to expand the program as load grows.

Cobb EMC (Georgia)

For the past two years, Cobb EMC in Georgia has been implementing voltage reduction on an emergency basis on six circuits. Under certain peak conditions, Cobb lowers source voltage to 120V, while maintaining a minimum end-of-line voltage of 114V. In 2003, Cobb implemented this practice on four days of its summer peak for approximately 2.5 hours each day. Cobb calculates an average 0.75% load reduction per 1% voltage reduction, for a CVR factor of 0.75.

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[11] Gilbert, Donald C. “After a Major Automation Rollout, the Benefits Roll In.” Transmission & Distribution World. June 1, 2004.

[12] Ivester, Carroll and Bright, Jim. “Georgia Power Combats Price Spikes.” Transmission & Distribution World. May 1, 1999.

[13] “Georgia Power Uses UtiliNet in its Distribution Efficiency Program (DEP).” Schlumberger Energy & Utilities. 2002.

[14] Ibid.

Midwest and West

There is minimal to no voltage reduction activity through most of the Midwest, plains states, and western U.S. (apart from California and the Pacific Northwest). This may be due to several factors, including:

- Presence of sufficient generating capacity to obviate the need for emergency / peak demand reduction
- Lack of regulatory pressure
- Concern for foregone revenues from lowering voltage
- Lack of recent tests on voltage reduction impacts in the region

Canada (BC Hydro)

The Canadian service voltage standard is 110-126V under normal operating conditions, as defined by the standard code CAN 3-CT35.

An interview with BC Hydro confirmed conformance to CAN 3-CT35 on 100% of its circuits. In addition, under emergency conditions, the BC Hydro allows the voltage range to expand to 106-127V. On Vancouver Island, for example, BC Hydro implements this “emergency” mode of voltage bandwidth on a daily basis to reduce daily peak demand – allowing service voltage to drop as low as 106V (107V average service voltage +/- 2%). Apart from this measure, BC Hydro also has a single push button control system to lower voltages for up to 15 subsystems on an emergency basis.

BC Hydro believes that its voltage reduction practices have been effective, estimating that they are able to reduce peak demand by 2-3% on Vancouver Island by reducing average voltage from 118 V to 107 V.

National Perspective on Using Voltage Reduction as an Emergency Measure

The North American Electric Reliability Council (NERC) includes voltage reduction as a measure to respond to emergency demand conditions. NERC defines a Stage 2 Alert, an intermediate emergency level, as a condition whereby forecasts indicate that firm loads can only be met after the adoption of actions such as voltage reduction, as well as public appeals to reduce demand, implementation of interruptible and curtailable programs and direct load control programs.

Regional Transmission Organizations (RTOs), also referred to as Independent System Operators (ISOs), have guidelines in place for dealing with emergency demand conditions that call for voltage reduction at various stages. For example, the PJM Interconnection, which serves the Mid-Atlantic and portions of the Midwest, urged customers to reduce on-peak consumption during a heat wave in August 2001 to avoid having to implement widespread voltage reduction. PJM Interconnection favored demand-side measures such as direct load control (e.g. AC cycling) to voltage reduction, which was regarded as a last resort measure short of curtailments and rolling blackouts.

Wisconsin Public Power Inc. (WPPI), an organization of public power companies serving Wisconsin, allows for voltage reduction as one of its Level 1 emergency measures, along with activation of curtailable and interruptible loads and direct load control programs.

Examples of Utilities or RTOs/ISOs that have implemented voltage reduction as an emergency measure:

- (Dominion) Virginia Power (July 1999, 5% reduction)
- Independent Electricity Market Operator (Ontario, Canada, June 2003)

4.2 Pacific Northwest Perspective

Utilities Currently Piloting Distribution Efficiency Projects

Three utilities – Avista Utilities, Clatskanie PUD, and Inland Power & Light – are currently conducting pilot tests of the PCS UtiliData® AdaptiVolt™ system at selected substations under the sponsorship of the Alliance and BPA.

- **Avista Utilities**, as part of the Alliance DEI, commissioned a $380,000 pilot test of the PCS UtiliData® AdaptiVolt™ system in February 2004 at its Francis and Cedar substation, which serves a heavily loaded urban area. The AdaptiVolt™ system integrates with Avista's SCADA system to automatically regulate substation voltage in order to maintain a fixed end of line voltage. No additional distribution regulation equipment or capacitors have been assigned for this pilot apart from the AdaptiVolt™ equipment.

  Test results indicate that on distribution feeders where AdaptiVolt™ reduces the average voltage from 121.6 V to 118.8 V (a 2.3% voltage reduction), a maximum energy savings of up to 2.5% is realized for a short period of time.[15] This equates to a CVR factor of 1.09, or a 1.09% reduction in load for every 1% in voltage reduction. In addition, PCS UtiliData® reports a 3.8% reduction in peak demand on feeders using the AdaptiVolt™ system.[16]

  Moreover, PCS UtiliData® reports a reduction in reactive power and a reduced need for capacitors as additional effects of the AdaptiVolt™ system.

  PCS UtiliData® estimates that an AdaptiVolt™ installation at a substation with six feeders carries a payback of less than two years and would save 8.5 million kilowatt-hours of electricity a year (nearly 1 average megawatt), or about $299,000 in energy savings, compared to a total installed cost of some $418,000.[17]

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[15] *Northwest Utilities Seek Voltage Sweet Spot for Energy Savings.* Pacific Northwest Energy Conservation and Renewable Energy Newsletter, CWEB.102. June 30, 2004.

[16] Ibid.

[17] Ibid.

- **Clatskanie PUD** has been piloting the PCS UtiliData® AdaptiVolt™ system since February 2003 on three substations (Wauna, Clatskanie, and Delena), which together serve 6 feeders. BPA has funded this $400,000 implementation project.[18] Using radio communications, AdaptiVolt™ automatically regulates the substation load tap changer in order to maintain an end-of-line voltage range of 118V-116V. Clatskanie claims that substation voltages are being reduced by an average of 2.25%, which is resulting in energy savings of 3.2%. Clatskanie claims an average 1.15 % reduction in load for every 1% reduction in voltage, or an average CVR factor of 1.15. Segmented by sector, the average CVR factor for residential customers was 1.4 and 0.9 for commercial customers.[19] The project was scheduled to operate on a one-day-on / one-day-off basis through December 2004, with final results expected by the end of January 2005.
- **Inland Power & Light** has been piloting the PCS UtiliData® AdaptiVolt™ system on its Half Moon substation since April 2002. The AdaptiVolt™ system, whose $220,000 cost was shared between Inland and BPA, automatically regulates the substation load tap changer in order to maintain an end-of-line voltage of 117.5V.[20] PCS UtiliData® estimates that the AdaptiVolt™ system saved 1,262,000 kWh from November 2002 to November 2003, accounting for 3.4% of total load served by the 8MW peak load rated Half Moon substation. PCS UtiliData® quantified a CVR Factor of 0.953 for the 2002 testing period and 0.914 for the 2003 testing period, for an average CVR Factor of approximately 0.93.[21] The project was scheduled to operate on a one-day-on / one-day-off basis through February 2004, but was shut down due to operational and technical problems.

Figure 4-1
Inland Power & Light Half Moon Substation
Note: Photograph from PCS UtiliData®

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[18] Nelly Leap, Electrical Engineer, BPA, January 2005. Clatskanie PUD project with PCS Utilidata® was funded by BPA as part of its C&RD program as an RD&D project.

[19] Ibid.

[20] *PCS UtiliData Looks to Tap Conservation Demand*. Spokane Journal of Business. January 31, 2003.

[21] *Verification Protocol for Automated Conservation Voltage Regulation Systems.* PCS Utilidata®. Presentation to Northwest Power Planning Council, April 10, 2004.

Utilities Experienced in Voltage Reduction: Snohomish PUD & Idaho Power

- **Snohomish PUD** has been practicing distribution efficiency since 1991, operating substations at voltage levels necessary to maintain end of line voltages at 114V through line drop compensation (LDC). Typically, Snohomish has found that a voltage range of 124V-119V at the substation (average of 123V-122V) is sufficient to maintain the minimum acceptable end of line voltage, which conserves energy compared to operating the substations at up to 126V. Snohomish has, on average, observed a 0.65% reduction in load for every 1% reduction in voltage on its system. Snohomish estimates that it saves 40,000 MWh per year due to its voltage regulation practices. In addition, Snohomish resells approximately half of its saved power on the open market for a profitable return. Snohomish estimates that its distribution efficiency practices result in a societal savings of $15 per customer per year. Applied to its base of over 300,000 customers, this yields an annual savings of $4.5 million. Snohomish intends to continue its present voltage regulation practices, and may consider reducing voltage further going forward.

- **Idaho Power** similarly applies LDC on its feeder lines to maintain end of line voltages at 114V. Idaho Power makes use of additional regulators and capacitors to support voltage and power factor along feeder lines, since the system characteristics of its long feeders in rural areas require extensive voltage regulation. Moreover, most of Idaho Power's system levels and locations are capacity constrained at peak, either voltage-limited or current-limited. Idaho Power estimates that its voltage regulation practices result in annual savings of 30 MW and 157,000 MWh.

  Since Idaho Power is a net importer of generation, the energy it saves through practices such as voltage reduction or other energy efficiency programs, reduces its purchase obligations. In addition, Idaho has in place a pass-through expense for energy procurement, such that any achieved energy savings are passed directly on to customers in the form of lower bills. From strictly an economic perspective, Idaho has no direct incentive to continue or expand its voltage reduction program. However, Idaho is exploring the possibility of funding a continuation of this program through budget from a rider (conservation) program.

Highlights of Other PNW Utilities' Present Voltage Regulation Practices

Most utilities operate within the ANSI standard voltage range of 120V +/-5% (i.e. 126V max. at the substation to 114V min. at the end of a feeder) and do not practice voltage reduction.

- **Benton County PUD** operates its substations at an average of 124V, fluctuating up to 126V depending upon loading conditions. Its goal is to maintain system voltage above a minimum of 118V at the end of line. After declining to participate in the Alliance DEI, Benton's Power Management group conducted a one-week test in November 2003 on the effectiveness of voltage reduction in reducing peak demand at one substation. The results of this test were inconclusive, with little observed change in peak demand. Coupled with projected flat load growth rate, Benton is unlikely to reconsider voltage reduction in the near future.

- **Seattle City Light** has operated at 127V-115V for over 30 years because the Seattle metro area that its serves is heavily loaded. Seattle piloted a voltage reduction study between 1983 and 1985, in which it lowered substation voltage to 118V. The pilot project resulted in only a 0.13% load reduction for every 1% reduction in voltage, and apparently caused many customer complaints. Seattle believes that the low energy savings from the project are due to the highly reactive motor and air conditioning loads that contribute to its peaks. Since Seattle did not employ load tap changers, it had to manually (rather than automatically) adjust set-points capacitors, regulators and distribution transformers, which increased the cost of implementation. Moreover, Seattle controlled distribution voltage by adjusting transmission voltage, resulting in system-wide voltage reductions that were a challenge to manage. Based on this test, Seattle concluded that voltage reduction is ineffective in reducing its load. Seattle is highly unlikely to pursue a distribution efficiency project in the near future, due to its test results and its budget constraints.

- **Puget Sound Energy** operates its substations at 125V, on average. It conducted an internal study in 1983 on the potential for energy savings from lowering substation voltage through techniques such as LDC. This internal study determined that lowering substation voltage could result in an annual savings of 43,673 MWh, based on a calculated 0.6% load reduction for every 1% reduction in voltage. However, no voltage reduction project was ever implemented, because of the perception that low voltage complaints that might result. Currently, Puget Sound is studying distribution efficiency options at two substations as part of the Alliance’s DEI.

- **Portland General Electric** conducted a pilot project on voltage regulation in 1993, which led to mixed results. For example, while voltage reduction led to load reduction during summer off-peak periods, increased load was measured during winter peaking periods. The study concluded that implementing such a program would not be cost-effective. Hence, Portland General does not deviate from the ANSI standard bandwidth, although it does employ LDC on circuits. However, Portland is open to revisiting the concept based on the results of the Alliance’s DEI.

- **Pacific Power** has not considered voltage reduction since an internal test conducted 20 years ago. While that test suggested that voltage reduction could lead to load reduction on its system, the idea was dismissed because it was deemed impractical given its large number of long, rural feeder lines. In addition, distribution engineering remains somewhat apprehensive about the ability of voltage reduction to provide load reduction responsively enough to meet changing system requirements.

A few utilities consistently operate their distribution substations at an average voltage less than the ANSI maximum of 126V. Through these utilities may be practicing voltage reduction and distribution efficiency, they do not label it as such because it is simply their standard practice.

- **Clark Public Utilities** has operated its substation voltages at 120V-121V for over 30 years. Clark employs LDC to maintain an average voltage at the distribution transformer of 117V. Clark has not quantified its energy savings from a more typical voltage baseline.

- **Grant County PUD** has been operating its substations at an average of 122V (+/- 1V) as its standard practice for over ten years. Grant has explored the possibility of lowering substation voltage even further, from an average of 122V to 120V, on six residential substations. Despite its estimate of 19 AMW in potential savings (based 0.7% load reduction for 1% voltage reduction), Grant has decided not to pursue this further voltage reduction due to the lack of a clear economic benefit. The terms of Grant's fractional ownership of a hydro dam stipulate that it can only purchase capacity up to the level of its demand. This stipulation renders Grant unable to resell excess capacity on the open market as a means to recoup lost revenue from lower voltage. If it could sell capacity in the open market the economics of further voltage reduction might be favorable.

- **Tacoma Power** has operated its substations at an average voltage of 122V (within a range of 124V-118V) for the past 10 years. Tacoma Power's minimum voltage is 114V, for an effective range of 124V-114V on the distribution system. During the energy crisis of 2001, Tacoma Power lowered its average substation voltage to 120V during peak periods over several months until the crisis had abated. Since the cost of procuring peak power on the market during the energy crisis far outweighed the foregone revenue from reducing voltage, the economics were favorable. However, Tacoma Power has since reverted back to a 122V average at the substation, rather than 120V, to retain system flexibility. Tacoma remains open to DEI going forward.
- **Eugene Water and Electric Board** fixes its set-point voltage at the substation at 124V, and does not employ LDC. Eugene is not currently inclined to voltage reduction. However, it considers itself a conservation-minded utility and would be open to the concept, pending the Alliance's DEI results.

PNW Perspective on Using Voltage Reduction as an Emergency Measure

Compared to the rest of the country, proportionately fewer PNW utilities retain voltage reduction as a possible response to extraordinary peak demand or other emergency conditions.

Distribution System Metrics

Table 4-2 summarizes various metrics of the PNW utilities' distribution systems, including numbers of substations and segmentation of circuits by length.

Table 4-2
Summary of Utility Distribution System Metrics

Utility	**Total No. Substations**	**Substations Serving Res. & Small Com.**	**Substations Operating at Lower Voltage as Standard Practice**	**Average Substation Voltage for Res. & Small Com.**	**% Circuits < 3miles**	**% Circuits 3 – 12 miles**	**% Circuits > 12 miles**
Avista	120	60	-- [a]	126V	15%	60%	25%
Benton County PUD	22	13	--	126V	60%	35%	5%
Clark Public Utilities	50	38	38	121V	*10%*	80%	10%
Clatskanie	5	4	-- [a]	126V	0%	83%	17%
Eugene Water & Electric	34	20	20	124V	95%	5%	0%
Grant County PUD	41	20	20	123V – 121V	5%	75%	20%
Idaho Power	220	140	140	124V – 120V	13%	38%	49%
Inland Power	43	39	-- [a]	126V	2%	85%	13%
Pacific Power *	1,000	800	--	126V	40%	40%	20%
Portland General	150	75	--	126V	80%	15%	5%
Puget Sound Energy	300	90	--	126V	30%	60%	10%
Seattle City Light	12	4	--	126V	95%	5%	0%
Snohomish PUD	68	50	50	124V – 119V	90%	10%	0%
Tacoma Power	44	40	40	124V – 118V	90%	10%	0%
TOTALS	**2,070**	**1,393**	**308**				

* Figures reflect entire Pacific Power territory, including Utah and Wyoming

[a] Not including substations involved in PCS UtiliData® pilot study for Bonneville Power Administration and Northwest Energy Efficiency Alliance (Alliance)

Based on the data in Table 4-2, we observe that the market penetration of voltage reduction as a standard practice is approximately 15% of total substations and 22% of substations serving residential and commercial circuits. These results are considerably higher than the national estimate of 7.5% market penetration by number of circuits, as referenced on page 4-1.

4.3 CVR Factors

Based on the results of the subset of interviewed utilities that have implemented or tested voltage reduction to reduce load, we estimate the national average CVR Factor as 0.8. The average was computed as the simple mean of the recorded CVR factors in Table 4-3 below, and is not weighted by the number of circuits per utility.

Table 4-3
Utility CVR Factors, Based on Implementations or Tests

Utility	**CVR Factor**[22]	**Comments**
California IOUs	0.75	
New York State Electric & Gas	0.6	
Central Florida Electric Cooperative	0.5 – 0.75	0.5 in the summer; 0.75 in the winter
Clay Electric Cooperative (Florida)	1.0	
Progress Energy – Florida	1.0	
Georgia Power	0.8 – 1.7	1.25
Cobb EMC (Georgia)	0.75	
Progress Energy – Carolinas	0.4	
Avista Utilities	1.09	Ongoing pilot project
Clatskanie PUD	1.4	Ongoing pilot project
Inland Power & Light	0.93	Ongoing pilot project
Snohomish PUD	0.65	
Seattle City Light	0.13	Discontinued program
Average	**0.8**	**Mean of all values, equally weighted, with mid point values used for ranges.**

This factor of 0.8 is bit higher than the more conservative 0.7 factor that the Alliance has elected to use in its cost effectiveness model.

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[22] CVR Factor = % Load Reduction per 1% Voltage Reduction

4.4 Drivers for Distribution Efficiency Implementation

Table 4-4 captures the factors cited by utilities surveyed in the PNW region as drivers for them to either consider, study, test, or implement voltage reduction as a distribution efficiency practice.

This table reveals several interesting findings.

- Perhaps most surprisingly, regulators were not once cited by any utility as playing a factor in their decision to consider voltage reduction.
- The goal of attaining energy savings was most frequently cited as the main internal driver for pursuing voltage reduction.
- The influence of third parties in the region, principally Bonneville Power Administration (BPA), played a vital role in the decision of several utilities to pursue voltage reduction. Funding provided by BPA was instrumental for Avista Utilities, Clatskanie PUD, and Inland Power to agree to pilot demonstrations of adaptive voltage control equipment on their systems.

Table 4-4
Drivers for Studying, Testing and/or Implementing Distribution Efficiency Projects
(Rank Ordered)

	Internal				**External**		
	Reduce Peak Demand	Energy Savings	Increase Operating Efficiency	Other	Regulators	Vendors	Other
Avista	--	2	--	--	--	1 [c]	1 [d] [e]
Benton	1	--	--	--	--	--	--
Clark Public Utilities	--	--	--	1 [f]	--	--	--
Clatskanie	--	--	--	--	--	2 [c]	1 [d]
Eugene Water & Power	2	1	3	--	--	--	--
Grant County PUD	--	--	--	1 [g] 2 [b]	--	--	--
Idaho Power	--	--	1	2 [b]	--	--	--
Inland Power	4	3	--	--	--	2 [c]	1 [d]
Pacific Power	2	1	--	3 [h]	--	--	--
Portland General	--	1	--	--	--	--	--
Puget Sound Energy	3	1	2	--	--	--	--

	Internal				**External**		
	Reduce Peak Demand	Energy Savings	Increase Operating Efficiency	Other	Regulators	Vendors	Other
Seattle City Light	1	2	--	--	--	--	--
Snohomish PUD		2	1 [i]	3 [j]	--	--	--
Tacoma Power	1 [k]	2	--	--	--	--	3 [l]

[a] Regulator priorities: (1) Energy conservation, (2) Ratepayer savings

[b] Preventing customer complaints

[c] PCS UtiliData®

[d] Bonneville Power Administration (BPA) involvement and financial support

[e] Northwest Energy Efficiency Alliance (Alliance)

[f] Has been standard operating practice for 30 years

[g] Operational flexibility

[h] Reduce capital spending

[i] Reducing system losses (i.e. improving power factor)

[j] Opportunity to profitably resell excess capacity made available through voltage reduction

[k] Driven by power crises of 2001, which affected western states

[l] Influenced by Snohomish PUD's experience and results in voltage reduction

5 MARKET ACTORS

Chapter 5 discusses relevant market actors, their awareness and attitudes towards distribution efficiency / voltage reduction practices, the information channels they utilize, and their influence on one another.

5.1 Utilities

There are four key groups within a utility that have influence, or need to be influenced, with respect to DSE:

- Distribution Engineering (DE)
- Distribution Operations (DO)
- Energy Efficiency / Demand Side Management (DSM)
- Executive / Senior Management

In our observation, the initial impetus for exploring DSE usually comes from the DE group. The usual internal path towards implementation is for the DE group to obtain buy-in from the DO group before approaching more senior utility executive management together. The DSM group is often overlooked in this process. However, we believe that this group should be involved because of their common interest in energy conservation and access to funding channels that can help to subsidize DSE initiatives.

Distribution Engineering

For most utilities that implement some form of CVR, the Distribution Engineering (DE) group is the driving force behind the decision. CVR proponents and advocates are usually found within this group. In every example of a utility implementing some form of CVR without an explicit regulatory mandate to do so, there has been a highly motivated technical “evangelist” who has championed the concept with the organization, often over a long period of time.

Motivations

The primary motivation of a DE group is to maintain system reliability and ensure sufficient capacity margin. A DE group must be convinced of the technical feasibility of any voltage regulation practice before designing the procedural specifications for the Distribution Operations (DO) group to execute.

Opportunities

The improvements to the distribution infrastructure, including automation, necessary to implement CVR also enhance system reliability, which is an important objective of distribution engineers.

Barriers

A DE group may express technical skepticism at the efficacy of voltage reduction to yield load reduction – a barrier that a technical champion must overcome. Since each utility regards its service territory and load characteristics as unique, performance results from other utilities may not be very influential a given utility's DE group. The best way to overcome this barrier is to establish a small-scale demonstration of voltage regulation practices. In our observation, the personal influence of the technical champion determines whether an internal study or demonstration of voltage regulation occurs.

Distribution Operations

Typically, once the DE group buys into a DSE/voltage regulation scheme, it must convince the Distribution Operations (DO) group to follow suit. The DO group is most affected by any change in voltage practices, and is therefore usually the most resistant to CVR since it often leads to a disruption, albeit brief, in their workload and in retraining. This includes operators who monitor the system as well as substation maintenance crew who often have to go into the field to implement changes such as resetting relays and adjusting regulator controls, to facilitate CVR.

To the extent that capital projects such as reconductoring or installing new capacitors in involved, a utility Construction group will also be affected by a change in voltage control procedure.

Motivations

DO groups are motivated to maintain system reliability and avoid customer complaints, while at the same time not increasing their overall work burden.

Opportunities

In order to gain its buy-in, a DO group must be convinced that adopting a new set of voltage regulation practices will ultimately improve system efficiency, not result in customer complaints, and will not increase its work burden. [is the opportunity here training presentations at conferences development of reasonable tools?]

Barriers

DO groups may be resistant to changes in operational procedures, since they may disrupt their normal way of doing things and may require retraining. Depending on how automated a utility's distribution system may be, implementing new voltage regulation practices may initially require dispatching field operators to substations manually adjust transformer settings. DO groups may be resistant to such "additional work" above and beyond their usual operations and maintenance activities.

Energy Efficiency / Demand Side Management

Our discussions with distribution individuals from numerous utilities reveals that, in general, a utility's distribution group and energy efficiency group operate in their own silos and do not interface across departments. This is not surprising, considering that distribution planning, engineering and operations are distinct disciplines from demand-side program design and evaluation. However, the overall lack of collaboration between distribution and DSM that we observe may be preventing the implementation of voltage reduction practices that could save an enormous amount of energy on a national basis.

Most DSM professionals are focused on the demand-side of the house, and may not be aware of the energy savings potential of voltage reduction. At the same time, DSM professionals are generally more familiar with funding sources for energy efficiency measures, such as public benefits charges that exist in many states. By working together, a DSM group might be able to help a Distribution group access these funding sources (which are almost exclusively applied to fund demand-side programs) for a voltage reduction initiative. On the margin, such funding could tip the economic equation in favor of implementing voltage reduction in some cases.

Motivations

Utility DSM individuals are motivated by the twin goals of cost-effective energy conservation and peak load reduction. DSM groups are tasked to develop energy efficiency programs that meet a given threshold of cost-effectiveness in terms of the utility, the customer, and society.

Opportunities

Utilize voltage regulation as a means to achieve targeted energy efficiency and peak demand reduction goals to meet regulatory requirements.

Barriers

The primary barrier for utility DSM professionals is their exclusive retail focus – that is, on the end uses of electricity. As a result, many may not be familiar with the distribution side of the utility house, and consequently would not be aware of vast energy conservation potential of voltage regulation. Once the DE and DO groups within a utility have embraced the idea of implementing voltage regulation, it would be advisable for them to approach the DSM group to apprise them of the energy savings potential of voltage regulation.

Executive / Senior Management

The decision of whether or not to implement DSE may escalate to the level of senior utility executives.

Motivations

Acceptable return on investment; using capital wisely; if an IOU, providing an acceptable return for shareholders; keeping rates competitive.

Opportunities

Utilizing voltage regulation as a hedge to delay or in some cases even avoid large capital expenditures on constrained distribution lines, which can have a substantial Net Present Value.

Barriers

The senior ranks of utilities have traditionally been heavily weighted with individuals with technical and engineering backgrounds. However, from our discussions with numerous utilities there has been a greater representation of senior utility executives with financial backgrounds in recent years. From the perspective of a distribution engineering group attempting to advance voltage regulation within a utility, this trend is itself a barrier, since it is harder to convince less technically-inclined people about the energy savings impact of voltage regulation.[not if the business case is clearly presented. Might be perspective of DE group but they need to create a business case]

Senior management is also sensitive to the forgone revenue from reduced power consumption associated with voltage regulation. As explained in Section 3.6, utility engineering personnel are challenged to quantify the net economic impact of voltage regulation to their senior management. For utilities that have to either procure peak power at high rates or engage their own costly peaker plants, the marginal economic impact of reducing voltage to reduce load can be positive. However, utilities that do not face peak capacity constraints or who are unable to resell capacity on the wholesale market are particularly hard-pressed to justify the economics of voltage regulation.

Finally, utility senior management tends to be conservative and risk-averse, particularly with regard to changes in operational procedures that might trigger customer complaints.

5.2 Vendors

Distribution Infrastructure Equipment Vendors

For the most part, vendors of standard distribution infrastructure equipment such as voltage regulators, transformers, load tap changers, capacitors, SCADA systems, and related controls, are indifferent to the specific manner in which utility customers choose to operate their equipment. They are generally neither proponents nor advocates of CVR. Two exceptions are PCS UtiliData®, which is focused on adaptive voltage control equipment tailored for CVR applications (and whose equipment is being piloted in the PNW region by Avista Utilities as one facet of the Alliance DEI as well as by Clatskanie PUD and Inland Power & Light through support from BPA) and Cooper Power (capacitor manufacturer), which offers training on how their equipment can be used to facilitate CVR.

On-Site Voltage Regulation Equipment Vendors

There is another category of vendor – those who provide on-site voltage regulation equipment for homes and businesses. One of these vendors, MicroPlanet, is demonstrating its Home Voltage Regulator (HVR™) unit as part of the Alliance DEI. The HVR™ is a small box that houses a programmable personal computer board that controls a small transformer to either lower or raise incoming voltage to set values. Plugged into a power customer's meter, the HVR™ can stabilize voltage at lower levels, thereby reducing energy consumption, which results in a savings for the average household that otherwise would receive higher voltages. MicroPlanet also markets the Enterprise Voltage Regulator (EVR™) for commercial customers. Unlike vendors of general distribution equipment, vendors such as MicroPlanet serve as advocates of voltage regulation given their vested interest.

Legend Power Systems is another similar vendor. Its UL-listed Electrical Harmonizer™ product, which is installed on-site on a commercial customer’s electrical room, is designed to optimize voltage and improve the quality of the incoming power supply, thereby reducing electricity bills and maintenance costs.

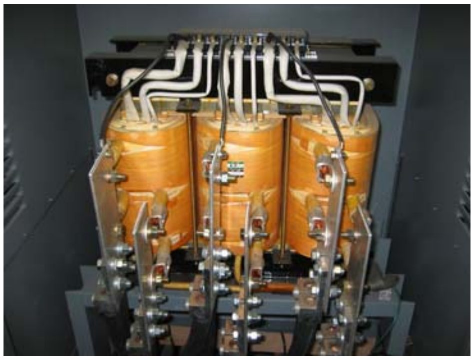

Figure 5-1
Legend Power Systems Electrical Harmonizer™

Note: Photograph from Legend Power Systems Website

Engineering, Consulting, and Software Firms

Of the many engineering and consulting firms that provide distribution-related consulting services and software to utilities, a few assist in the development of voltage regulation.

R.W. Beck, a technical consulting firm that helps utilities plan, design and implement a host of solutions, is currently providing project management services for the Alliance DEI. In this capacity, R.W. Beck has worked in conjunction with the Alliance and with vendors such as PCS UtiliData® and MicroPlanet in ongoing pilot demonstrations.

Netherlands-based KEMA offers T&D consulting and testing services, and have been known to recommend voltage regulation to utility clients.

Utility Consulting International (UCI), a California-based consulting firm, provides consulting services and software tools for utility SCADA and distribution system automation. In this context, UCI has advised many utility clients in areas of voltage regulation and Volt-VAR optimization, including: BC Hydro, Georgia Power, Oglethorpe Power (Georgia), Northern States Power, Oklahoma Gas & Electric; and international utilities such as Hong Kong Electric and Manila Electric Company (Philippines).[23]

5.3 Regulators

With the exception of California, Massachusetts, Connecticut, and New York, we have not observed regulators play a significant role with respect to mandating or recommending voltage reduction practices. Table 4-4 indicates that in the Pacific Northwest, which is one of the most active regions with regard to voltage reduction, regulators are not influential to utilities in their voltage reduction decision-making.

5.4 Third Party Entities

The relatively high level of utility voltage reduction activity in the PNW region is attributable, to some degree, to the involvement of prominent regional entities such as BPA, the Alliance, and the Northwest Power Planning Council. Table 4-4 indicates that Avista Utilities, Clatskanie, and Inland Power – the three utilities currently conducting pilot studies of the PCS UtiliData® AdaptiVolt™ system for voltage regulation – cite BPA and the Alliance as highly influential in their decision to proceed. The Northwest Power Planning Council included conservation voltage regulation into its Fourth Regional Power Plan and its Regional Technical Forum is currently developing a verification protocol for automated conservation voltage regulation.

Interviews with representatives of these utilities indicate that they would not have been able to conduct these pilot studies without the involvement and financial support of BPA in particular. Aside from financial support, the involvement of BPA and the Alliance has brought a high level of influence and credibility to the subject of voltage reduction.

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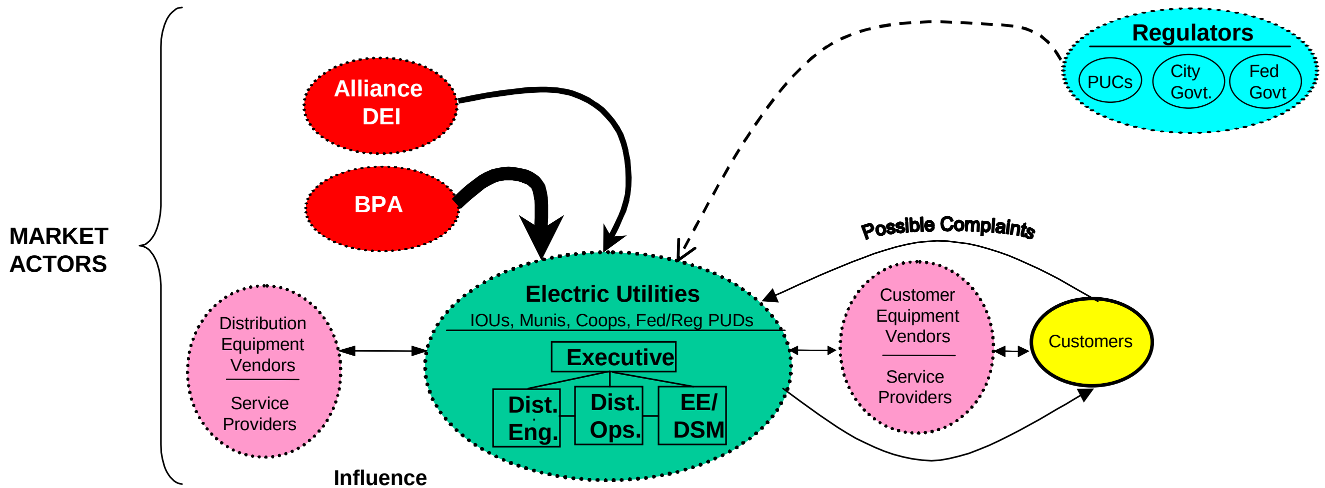
[23] UCI Website (www.uci-usa.com/projects.htm)

By contrast, most other regions of the country do not have similar regional institutions that provide support and direction for broad energy efficiency practices. This may be one contributing factor to the lesser degree of voltage reduction practices observed through most of the rest of the country.

5.5 Market Influence Diagram

The interaction and information flow between these market actors, as described in the preceding section, creates market dynamics and influence patterns. Figure 5-1 diagrams our understanding of the how market actors influence each other.



CURRENT PERSPECTIVES ON VOLTAGE REGULATION	**Neutral**	**Influence and Support to Benefit the Public Good**	**Energy Savings, & System Reliability**	**Increased Business**	**Possible Equipment Malfunction & Complaints**	**Reliable Service & Low Rates**
MARKET BARRIERS	**Distribution equipment vendors typically neither advocate nor dismiss voltage reduction for utility customers**		**• Information & search costs • Performance uncertainties and technical skepticism (Distribution Engineering) • Obtaining buy-in from Distribution Operations staff, who may resist disruption of status-quo operation procedures • Obtaining buy-in from DSM group to access to Energy Efficiency funds • Executive mandates for paybacks and concerns over hidden costs • Lack of tools/information cooperation to create business case**	**Lack of availability of product or service**	**Hidden Costs**	**Concern over impact on reliable service to customers**

Figure 5-2
Market Influence Diagram

In the PNW region, the influence and funding of BPA and the Alliance has been instrumental in furthering the cause of voltage regulation. Without BPA and Alliance funding and support, ongoing pilot demonstrations of the PCS UtiliData® AdapiVolt™ system at Avista Utilities, Clatskanie, and Inland would likely not have occurred. The ongoing Alliance DEI, with its pilot demonstrations of the benefits of voltage regulation from both the distribution and customer sides of the meter, continues to keep voltage regulation on the agenda of utilities in the region.

Within a utility, the dynamics between four groups determine the extent of voltage regulation activity. Typically, any movement by a utility towards voltage regulation begins in the Distribution Engineering group. In our observation, most utilities that practice voltage regulation for DSE (including energy conservation, peak demand reduction, and operational efficiency improvement) have been influenced by a technical champion from the Distribution Engineering group.

5.6 Future Market Influences

Emerging trends that may influence voltage regulation in the future are Broadband over Powerline (BPL), IntelliGrid, Gridwise, and CERTS.

Broadband over Powerline (BPL)

Broadband over Powerline (BPL) is beginning to emerge as an alternative means of providing high-speed Internet access and other broadband services using medium- and low-voltage lines to reach customers. Advances in signal processing technology allow data to be transported along electric powerlines at significantly higher frequencies – in the 2 to 80 MHz range – than electricity, which is conveyed at a 50 to 60 Hz frequency range.

Utilities interested in offering BPL would have to invest in some upgrades to their distribution systems – upgrades that could also allow the utilities to more easily implement voltage regulation.

IntelliGrid

A public-private partnership of electricity companies, government agencies, and other interested parties dubbed the IntelliGrid Consortium[24] is currently spearheading the development of a transformed electricity system architecture for the 21st century. Coordinated by EPRI, IntelliGrid includes participants such as: U.S. Department of Energy, Alliant Energy, BPA, Cisco Systems, Consolidated Edison, Electricite de France, Exelon, the Long Island Power Authority, the New York Power Authority, the Salt River Project, TXU, and We Energies.

IntelliGrid is focusing industry attention on the requirements and functionality of the utility infrastructure of the future, including enhanced transmission and distribution automation and

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[24] IntelliGrid was formerly known as the Consortium for Electric Infrastructure to Support a Digital Society (CEIDS)

communication systems, replacing electro-mechanical switching with digital controls. Insofar as IntelliGrid is able to stimulate industry interest in distribution automation and infrastructure improvements, this may lay a foundation for more widespread implementation of voltage regulation enabled by improved infrastructure.

Gridwise

Gridwise is an initiative to stimulate the development and adoption of a more intelligent and effective U.S. electric power system, through improvements and new standards in network communications architecture. The motivation for Gridwise is to enhance the intelligence of the U.S. electric grid to make better use of existing generation, such that the deployment of new power plants can be delayed or avoided. This initiative is being sponsored by the U.S. Department of Energy Office of Electricity Transmission and Distribution (DOE O-ETD) in conjunction with the Pacific Northwest National Labs (PNNL). It is anticipated that Gridwise will spur innovative opportunities for energy efficiency as well as operational efficiency measures, including CVR and smart energy technology. (For more information, consult the official program website at www.gridwise.org.)

CERTS

The Consortium for Electric Reliability Technology Solutions (CERTS) was formed in 1999 to research, develop, and disseminate new methods, tools, and technologies to protect and enhance the reliability of the U.S. electric power system and the functioning of a competitive electricity market. This consortium, which includes the U.S. Department of Energy, several U.S. national laboratories (Pacific Northwest, Oak Ridge, Lawrence Berkeley, and Sandia) and the California Energy Commission, is helping to develop technology solutions that support competitive electric markets and electricity reliability – thereby protecting the public interest.

Among CERTS' areas of research focus is Real-Time Grid Reliability Management, which entails the development and prototyping of software tools to enable the electricity grid to function as an intelligent, automatic, switchable network. Another focus area is Reliability Technology Issues and Needs Assessment, which entails the monitoring and identification of technology trends and emerging gaps in electricity system reliability R&D. Insofar as CVR fits both of these research objectives, it can potentially be supported through CERTS

6 MARKET BARRIERS AND OPPORTUNITIES

Chapter 6 discusses the market barriers mentioned in Chapter 5 in more detail.

6.1 Summary of Market Barriers Identified by PNW Utilities

The interviews conducted with utilities across the country and in the PNW region revealed a number of recurring explanations of barriers to the consideration or implementation of voltage reduction as a standard operating practice. Table 6-1 summarizes the barriers expressed by each utility interviewed.

Table 6-1
Barriers to Considering, Implementing, or Expanding Voltage Reduction Practices
(Rank Ordered)

Perceived Barriers		Experiential Barriers	
	No. Utilities		No. Utilities
Technical Skepticism	4	**Project Financing / Budget**	3
Concern over Customer Complaints	4	**Unfavorable Internal Test or Prior Implementation**	3
Distribution Operators Concerned About Re-Training and Disruption to Daily Job Functions	2	**Difficult to Quantify Benefit-Cost Justification in a Business Case**	3
		Difficulty in Rolling Out Training to Operators and/or Enforcing Change	2
		Drain on human resources to Test/Pilot/Implement	1

6.2 Discussion of Market Barriers

Technical Skepticism

There remains some fundamental skepticism over the causal relationship between voltage reduction and load reduction. Some utility engineers believe that inductive loads such as motors and air conditioners draw more current at lower voltage levels, and that therefore lower voltage does not necessarily result in reduced loads. Utilities with prominent inductive loads, and whose peak demand is heavily comprised of inductive loads, tend to be wary of voltage reduction as a demand reduction mechanism. However, while this inverse relationship may hold true for inductive loads such as induction motors under some load and voltage conditions, data from many utilities clearly prove that other loads – i.e. resistive loads – do consume less power at lower voltages.

Our discussions with utilities concerning this barrier indicated that the only way for a utility to overcome this barrier is to perform a test or demonstration on at least one substation. Test results and supporting data from other utilities tend not to influence a given utility's opinion on the effectiveness of voltage regulation in its service territory – each utility tends to regard its service territory and load characteristics as unique.

Minimal Data Transfer Across Utilities

Having spoken to a number of utilities we have observed a relative lack of communication and sharing of information across utilities in the area of voltage reduction and distribution efficiency. Each utility tends to regard its service territory and load characteristics as unique. This poses another barrier, since a given utility may not be influenced by another utility's positive experience with voltage regulation. Not surprisingly, utilities tend not to share information about distribution voltage practices. Moreover, the mix of resistive to reactive load from circuit to circuit determines the effectiveness of voltage reduction in achieving load reduction. A utility will have some reason to doubt whether the CVR results of one utility will transfer to another, due to load characteristics such as mix of resistive to reactive load, mix of circuits, mix of residential/commercial/industrial loads on same circuits, etc.

Takeback Effect Hypothesis

A related criticism of voltage reduction and often-cited reason for skepticism is that the effect of reducing load – namely resistive load – is temporary and suffers from a "takeback" effect. According to this hypothesis, the energy savings from voltage reduction will only be temporary and will not live up to estimates because customers will adjust their usage based on perceived changes to their end-uses. For example, this hypothesis contends that if lower voltages result in perceptibly dimmer lights, some customers will therefore change to higher wattage bulbs, thereby negating the intended energy savings. There is no known study that verifies this hypothesis. Moreover, most evidence from utilities suggests a net energy savings associated with voltage reduction.

Concern Over Customer Complaints

Utilities are concerned about the potential risk of increased customer complaints stemming from low voltage (i.e., malfunctioning equipment, flickering lights, shrunk TV screen, etc.) Reduced voltage can have the effect of increasing the exposure of sensitive customer equipment to voltage sags and nuisance tripping. This can be particularly problematic for sensitive and expensive laboratory and hospital equipment, as well as tools and computers. SDG&E reports increased customer complaints when service falls below 114 volts at the customer meter. In particular, SDG&E testifies that electronic devices (including computers, motor control equipment, and manufacturing process controllers) are sensitive to voltage, and may fail under substandard voltage conditions.[25]

The University of California and California State University systems report that research laboratories experience tremendous problems with even minor voltage drops, and medical centers are extremely concerned that voltage drops could cause life support and radiology equipment to fail.

This issue is especially problematic in rural areas with long feeders, where end of line voltage can drop below the acceptable threshold.

Another technical challenge to voltage reduction is maintaining a minimum acceptable end of line voltage along long feeder lines, which typically serve rural areas, to avoid low voltage-related complaints. For example, NYSEG was unable to continue a voltage reduction program in upstate New York because voltage levels for rural customers at the end of long feeder lines would periodically drop below the 114V threshold level, and therefore resulted in complaints from customers. To reduce the voltage drop along long feeder lines, utilities have to invest in additional equipment such as capacitors.

Distribution Operators Concerned About Re-Training and Disruption of Daily Job Functions

Feedback from utility distribution professionals indicates a general lack of understanding among operational and or engineering staff on how to implement systematic voltage reduction. As a result, it is generally accepted that distribution operations staff would have to experience some retraining on voltage regulation practices, procedures and assumptions to allow for lower service voltages on feeders.

Moving the voltage control algorithm from the substation bus to customers and their load centers represents a paradigm shift for distribution operators. JEA in Florida, for example, had to roll out multiple training modules for operators to re-interpret the meaning of “standard voltage” from bus voltages to load voltages closer to load centers of customers.

Several utilities that we spoke with indicated that distribution operations staff (operators) tends to set the voltage in a way that “makes life easiest for them,” which generally means maintaining the status quo. Implementing distribution efficiency through voltage reduction, which typically involves LDC, represents a change in the way most operators view their systems. A few utilities told us that the notion of having to retrain distribution operations staff on rules changes and different uses of software was itself a strong perceived barrier to implementing or even studying voltage reduction.

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[25] California Public Utilities Commission. Rulemaking 00-10-002, Phase 2 Voltage Reduction. Decision 02-03-024. March 6, 2002.

Lack of Existing Support Infrastructure

For a given utility, the lack of a suitable distribution automation system, such as a SCADA system, through which to implement systematic voltage reduction represents a significant barrier to voltage reduction.

Difficult to Quantify Benefit-Cost Justification in a Business Case

The forgone revenue from reduced power consumption associated with voltage regulation is another significant economic barrier for utilities. As explained in Section 3.6, utility engineering personnel are challenged to quantify the net economic impact of voltage regulation to their senior management. For utilities that have to either procure peak power at high rates or engage their own costly peaker plants, the marginal economic impact of reducing voltage to reduce load can be positive. However, utilities that do not face peak capacity constraints or who are unable to resell capacity on the wholesale market are particularly hard-pressed to justify the economics of voltage regulation.

Lack of Capacity Constraints in Most Parts of the Country

Another barrier to more widespread application of voltage reduction is that most of the country is not presently capacity constrained. Many utilities have provisions in their emergency plans to resort to temporary voltage reductions during system emergencies or for only a few peak days in a given year. In areas that are capacity constrained or has experienced capacity crises, voltage reduction has been applied successfully. For example, during the energy crisis of 2001 that affected western states, utilities in the PNW region and in California reduced voltages to avoid rolling blackouts.

“If it Ain’t Broke, Don’t Fix It” Syndrome

There is a prevailing mentality within most institutions that in the absence of an obvious problem there is no reason to change current operations. Electric utilities are no exception to this mentality. Distribution operations procedures at most utilities, such as voltage regulation practices, have been in place for many years, and in the absence of any problem or crisis operators are wary to deviate from these procedures.

7 DEI SUPPLY CURVE DEVELOPMENT AND RESULTS

One of the principal objectives of this study was to update the CVR supply curves developed by BPA in 1987. These curves are obtained by combining the estimated annual energy savings and estimated implementation costs from DSE implementation. This section summarizes the development and results of this process.

7.1 Supply Curve Development

A supply curve relates the energy savings of a measure with the cost of implementing the measure. Because different measures have implementation costs that are incurred over different timeframes, it is necessary to develop a methodology that removes this variable in order to compare potential resource alternatives. To develop a supply curve, implementation costs must be levelized for a consistent comparison with the costs of other options and programs.

In this analysis, Global compared the results from three different studies and methodologies to develop a range of possible implementation costs and estimated energy savings. The first study was the original BPA results developed in 1987. The second study used in this analysis is cost-effectiveness model for CVR developed by the Alliance. Finally, Global developed another study to include in this analysis. These three studies use different methodologies and are based on very different assumptions. Additionally, the BPA model provides the technical potential for DSE in the PNW. The BPA model assumes that the DSE measures that are technically feasible, without regard to market acceptance, will be implemented without regard to time. While the Alliance and Global models provide the achievable potential of DSE over an eight and ten year timeframe. These models assume that the DSE measures must be technically feasible, acceptable to the market, and be cost-effective before the utility will implement the measures. By definition, the achievable potential is a sub-set of the technical potential. Each of these studies is described in more detail in the following sections.

7.2 DSE Measures

The characteristics of an individual utility distribution circuit determine the measures that are required to implement a DSE strategy. The types of DSE measures are described in detail in 3.4 - Distribution Efficiency / Voltage Reduction Characteristics and also in the BPA report[26]. Because of the unique characteristics of each distribution circuit, it is often necessary to combine DSE measures to maximize the voltage regulation and minimize customer impacts. Accordingly, there are a large number of permutations of DSE measures to consider in the development of a supply curve. BPA considered 27 different DSE measures in its supply curve

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[26] *Assessment of Conservation Voltage Reduction Applicable in the BPA Service Region*, Section 3.0 – CVR Equipment and Related T&D System Considerations, Page 3.1.

each with a different implementation cost and estimated energy savings for each measure as shown in Table 7-1. In the Alliance cost-effectiveness model, 8 different DSE measures are combined in 6 bundled measures as shown in Table 7.2. Global considered 6 unbundled measures as shown in Table 7-3.

Table 7-1
BPA DSE Measure Data (from BPA Report)

Option
Circuits less than 3 miles
Reregulation 5% lower and LDC
Reregulation 5% lower
LDC
Reregulation 1.2% lower
Balance feeders, LDC, and 5% regulation
Balance feeders and 5% regulation
Balance feeders and LDC
Balance feeders and 1.2% regulation
Capacitor addition
Regulation addition
Capacitors and regulators
Circuits from 3 to 12 miles
Reregulation
Capacitor addition
Regulation addition
Capacitors and regulators
Reinsulate
Reconductor
Combination
Reregulation and LDC
Capacitor addition
Regulation addition
Capacitors and regulators
Reinsulate
Reconductor
Combination
Circuits greater than 12 miles
Reinsulate
Reconductor

Table 7-2
Alliance DSE Measure Data

Option
Manual LDC
SCADA & PLC, PLC, Adv Eng
SCADA & PLC
Man. LDC & 10% OVR
Man. LDC, OVR, Adv Eng
100% OVR

Table 7-3
Global DSE Measure Data

Option
Use LDC w/ Regulators
Use LDC w/o Regulators
Balance Feeder & Add Caps
Install SCADA
Install OVR
Reconductoring

7.3 Estimated Conservation Resource

For each DSE measure included in the supply curve it is necessary to estimate the associated energy savings or conservation resource. This effort is complicated by the large number of distribution circuits in the Pacific Northwest (PNW) combined with little known information on the length, customer density, or customer type of each circuit. For consistency with other regional information, the estimated conservation resource is expressed in average megawatts (AMW) which are defined as the estimated DSE measure annual energy savings in megawatt hours (MWh) divided by 8760.

In the BPA report, energy savings were first estimated on a system-wide basis for a variety of different voltage reductions. Each DSE measure was then evaluated to determine a voltage reduction level. For each DSE measure, BPA then allocated the distribution circuits in the PNW into the DSE categories. To determine the energy savings associated with each DSE measure, BPA multiplied the system-wide impacts associated with the DES voltage reduction by the associated distribution circuit allocation. The product is the estimated energy savings for each DSE measure and is shown in Table 7-4.

Table 7-4
BPA Conservation Resource by Measure

Option	Annual Savings (AMW)
Circuits less than 3 miles	
Reregulation 5% lower and LDC	26.3
Reregulation 5% lower	32.9
LDC	31.8
Reregulation 1.2% lower	9.1
Balance feeders, LDC, and 5% regulation	1.9
Balance feeders and 5% regulation	1.5
Balance feeders and LDC	1.9
Balance feeders and 1.2% regulation	0.6
Capacitor addition	9.5
Regulation addition	10.6
Capacitors and regulators	3.9
Circuits from 3 to 12 miles	
Reregulation	4.7
Capacitor addition	7.7
Regulation addition	8.3
Capacitors and regulators	6.5
Reinsulate	1.9
Reconductor	2.9
Combination	8.9
Reregulation and LDC	5.1
Capacitor addition	8.1
Regulation addition	8.8
Capacitors and regulators	6.9
Reinsulate	2.0
Reconductor	3.0
Combination	8.3
Circuits greater than 12 miles	
Reinsulate	4.1
Reconductor	5.3

The Alliance energy savings methodology is based on the assumption that for each 1% reduction in distribution voltage will yield a 0.7% (DEI Ratio equal to 0.70) reduction in energy. The Alliance model also estimates the voltage reduction associated with each DSE measure combined with an estimate of the average energy consumption of a distribution substation. The result is an energy savings estimate for each DSE bundled measure. For example, the Alliance model assumes that implementing a manual LDC will allow the utility to reduce the distribution voltage by 2%. Accordingly, the energy savings is then 1.4% (0.7 x 0.02) of the distribution circuit or substation. The Alliance model also assumed the average substation energy consumption of 60.107 GWh per year. Accordingly, the energy savings associated with manual LDC at each substation is 841,498 kWh per year (0.014 x 60,107,000). Finally, the Alliance developed a saturation curve to estimate the number of substations that would be impacted by each DSE measure over an eight year period. The results of the Alliance methodology are shown in Table 7-5.

Table 7-5
Alliance Conservation Resource by Measure

Option	Annual Savings (AMW)
Manual LDC	4.32
SCADA & PLC, PLC, Adv Eng	7.51
SCADA & PLC	1.61
Man. LDC & 10% OVR	2.78
Man. LDC, OVR, Adv Eng	4.38
100% OVR	14.41

The Global methodology combines some elements of each of the other two strategies. Like the Alliance, Global estimated the voltage reduction associated with each DSE measure. However, Global's methodology used a different DEI ratio for each DSE measure while the Alliance model assumed a fixed DEI ratio. For example, with the installation of an OVR the Alliance model assumes that the distribution voltage can be reduced by 10% with an overall energy reduction of 7% (0.70 x 0.10). The Global model assumes that the distribution voltage can be reduced by 2.25% but with a DEI ratio of 1.00. Therefore, the energy reduction under the Global model using a OVR is 2.25% (1.00 x 0.0225). Table 7-6 provides a summary of Global's assumptions for each DSE measure.

Table 7-6
Global DSE Measure Assumptions

Option	DEI Ratio	Voltage Reduction
Balance Feeder & Add Caps	0.20%	0.50%
Use LDC w/ Regulators	0.30%	1.25%
Use LDC w/o Regulators	0.50%	1.50%
Install SCADA	0.50%	2.00%
Reconductoring	0.40%	0.75%
Install OVR	1.00%	2.25%

Like the BPA study, Global developed an allocation methodology to estimate the number of distribution circuits in the region that would utilize each of the DSE measures over a ten year period. Applying the DSE voltage reduction estimates to the allocated distribution circuits provided an energy savings estimate for each DSE measure. The Global model used the same assumption as the Alliance for substation energy consumption to develop a distribution circuit energy consumption estimate. Combining the average distribution circuit energy consumption with the DSE measure energy reduction provides the DSE energy savings. The results of Global's methodology are shown in Table 7-7.

Table 7-7
Global Conservation Resource by Measure

Option	Annual Savings (AMW)
Use LDC w/ Regulators	17.19
Use LDC w/o Regulators	20.38
Balance Feeder & Add Caps	2.57
Install SCADA	10.84
Install OVR	32.88
Reconductoring	13.59

7.4 Implementation Costs

The cost to implement each DSE measure varies widely depending on the measure and the assumptions associated with the measure. For example, the BPA report estimated the cost of reconductoring a distribution circuit to be $75,000 per mile. Both the Alliance and Global estimated the cost to be $150,000 per mile. BPA estimated that the average circuit would need 2.4 miles of reconductoring, while the Alliance assumed 0.5 miles and Global assumed 2 miles of reconductoring. Accordingly, the cost of reconductoring ranges from $180,000 for the BPA model, to $75,000 for the Alliance model, and $300,000 for the Global model. Obviously, the impacts of the cost assumptions can lead to large differences in the measure implementation costs. Table 7-8, Table 7-9, and Table 7-10 provide the levelized measure implementation costs for each model.

Table 7-8
BPA Levelized Measure Cost

Option	Measure Cost (¢/kWh)
Circuits less than 3 miles	
Reregulation 5% lower and LDC	0.00211
Reregulation 5% lower	0.00186
LDC	0.00431
Reregulation 1.2% lower	0.00853
Balance feeders, LDC, and 5% regulation	0.00485
Balance feeders and 5% regulation	0.00551
Balance feeders and LDC	0.01122
Balance feeders and 1.2% regulation	0.02219
Capacitor addition	0.68605
Regulation addition	0.17644
Capacitors and regulators	0.72223
Circuits from 3 to 12 miles	
Reregulation	0.00516
Capacitor addition	1.63814
Regulation addition	0.27580
Capacitors and regulators	0.95835
Reinsulate	5.35288
Reconductor	6.19467
Combination	3.62672
Reregulation and LDC	0.00239
Capacitor addition	0.76311
Regulation addition	0.12807
Capacitors and regulators	0.44503
Reinsulate	2.48576
Reconductor	2.87667
Combination	1.93158
Circuits greater than 12 miles	
Reinsulate	13.44990
Reconductor	19.44730

Table 7-9
Alliance Levelized Measure Cost

Option	Measure Cost (¢/kWh)
Manual LDC	0.45683
SCADA & PLC, PLC, Adv Eng	0.66245
SCADA & PLC	0.77195
Man. LDC & 10% OVR	0.94053
Man. LDC, OVR, Adv Eng	1.17546
100% OVR	1.28759

Table 7-10
Global Levelized Measure Cost

Option	Measure Cost (¢/kWh)
Use LDC w/ Regulators	0.06462
Use LDC w/o Regulators	0.26923
Balance Feeder & Add Caps	0.40384
Install SCADA	0.80768
Install OVR	1.68268
Reconductoring	4.03843

7.5 Supply Curve Construction

Supply curves are constructed by combining the levelized implementation cost with the estimated energy savings associated with DSE implementation. The levelized implementation costs are divided by the annual estimated energy savings to obtain the DSE measure cost in

¢/kWh. The DSE measure implementation cost (¢/kWh) and estimated conservation resource (AMW) are then sorted by implementation cost from the lowest to the highest. A cumulative sum of the conservation resource is then calculated for the sorted implementations costs. The implementation costs are then plotted against the cumulative conservation resource to obtain the supply curves.

7.6 DSE Supply Curves For The Pacific Northwest Region

The supply curves for the Pacific Northwest region represent the DSE resources potentially available from all utilities operating in the BPA service area. BPA reported the supply curve results on a logarithmic cost axis in order to reveal detail at the lower cost levels. For consistency with the BPA Report, Figure 7-1depicts the supply curve on a logarithmic basis, whereas Figure 7-2 uses traditional (absolute) axes.

The three supply curves shown in Figure 7-1 and Figure 7-2 compare the three different models described in this section.

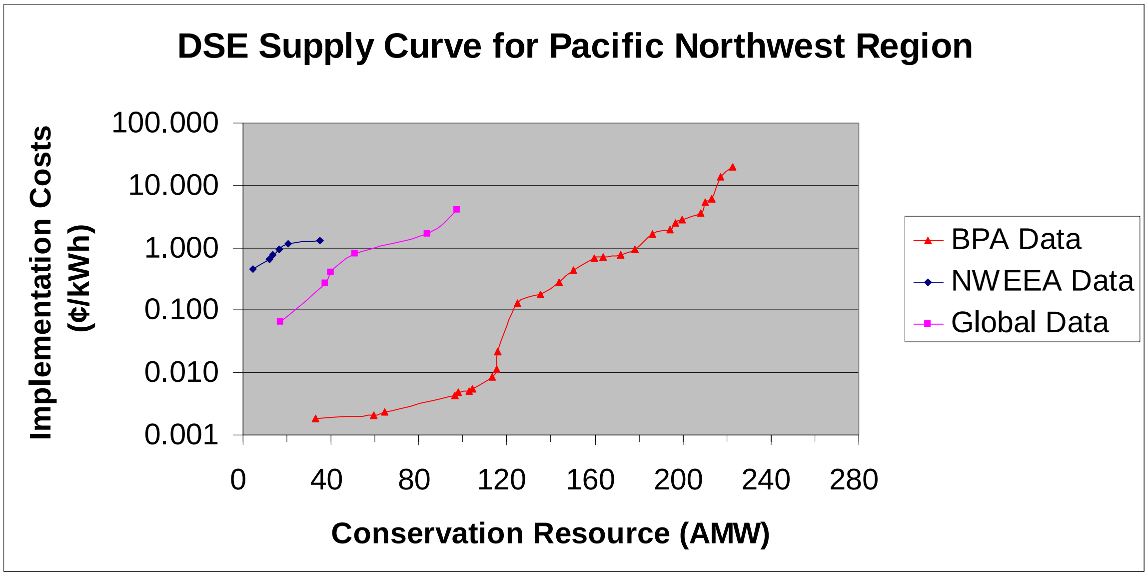

Figure 7-1
DSE Supply Curve – Logarithmic

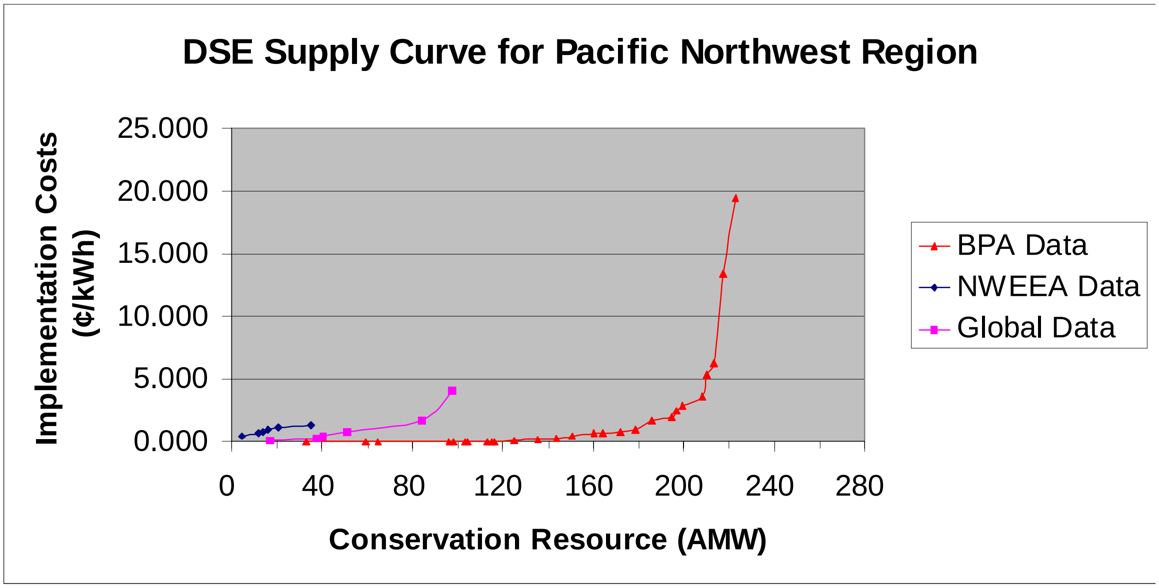

Figure 7-2
DSE Supply Curve - Traditional

7.7 Supply Curve Results and Discussion

The supply curves constructed in this analysis are based upon a set of very different assumptions and data. The technology bundles considered for implementation are different as are the assumed cost of implementation. Additionally, the assumed penetration of the DSE technologies and the timeframe of the implementation efforts are also very different. These results suggest that at a cost of 0.10 ¢/kWh the estimated DSE potential can range from zero to about 123 AMW. Additionally, at a cost of 1.0 ¢/kWh the estimated DSE potential can range from 17 AMW to about 180 AMW. The large range of impacts highlights the uncertainty surrounding the DSE efforts and suggests that additional studies should be considered to better determine the potential of DSE in the region.

The results from the Alliance and Global models imply that under the current regulatory climate and using currently available technology, only 100 AMW of DSE is achievable in the near term. The results of the three models for different implementation costs are shown in Table 7-11.

Table 7-11
Energy Conservation Resource Potential

Implementation Cost (¢/kWh)	Alliance Model (AMW)	Global Model (AMW)	BPA Model (AMW)
0.10	0	23	123
0.50	10	45	152
1.00	17	60	180
5.00	Not Achievable	Not Achievable	210

Additionally, as this report has detailed, a limited number of Utilities have applied DSE measures and strategies since the BPA study. As a result, the BPA 1987 conclusion that DSE can provide an energy conservation resource of over 200 AMW will be difficult to achieve in the near future.

As shown in this section, the estimated energy savings associated with a DSE strategy varies greatly depending on the model. Each model analyzed and used in this report assumes a different set of measures that are employed by utilities to implement a DSE strategy. Furthermore, each model also uses different assumptions for each measure to estimate the measure penetration and energy savings. The Alliance should consider fine-tuning the Alliance's cost-effectiveness model to include more measure sets that are consistent with the DSE options under consideration by the utilities and R. W. Beck. Additionally, the Alliance should also incorporate the results from R .W. Beck's activities with the PNW utilities to further refine its model.

8 CONCLUSIONS AND RECOMMENDATIONS

DSE measures such as voltage reduction have been demonstrated to provide energy savings, peak load reduction, and operational efficiency benefits to utilities. Despite these benefits, however, the CVR momentum generated in the 1970s and 80s has largely waned. In our review across the country, we determined that any utility currently involved in testing, demonstrating, or implementing some form of voltage regulation has at least one of the following characteristics:

- Regulatory mandate for voltage reduction
- Active involvement of regional third-party entity (federal power marketing agency or non-government organization) advocating and funding demonstration and implementation efforts
- Strong technical champion evangelizing DSE internally
- Current or recent energy crisis that motivated creative measures to reduce peak demand

The Alliance Initiative has taken great strides towards reinvigorating interest in voltage regulation and reduction. The results of the tests that will be completed as part of the Initiative in 2006 will be looked upon by many utilities across the country and in the Pacific Northwest as a signal to rethink their distribution voltage practices and assumptions. Another useful outcome of the Initiative is the development of a modeling tool to quantify the economic trade-offs associated with voltage regulation and determine a true net value considering all of the costs and benefits. Contractors R.W. Beck and Auriga are currently developing such a model, which promises to be a very useful tool to assist utilities in calculating the fundamental economics of voltage regulation, as conceptualized in Figure 3-9.

What follows are recommendations for the Alliance and other interested parties to consider to increase the market penetration of DSE/ voltage reduction practices to more utilities across the country.

8.1 Facilitate Summit Meeting of DSE Practitioners

Facilitate a summit meeting of practitioners and champions of voltage regulation from utilities across the country to encourage the sharing of information and development of best practices, and to begin the process of forming a national consortium for voltage regulation. Existing industry conferences, such as the recurring Peak Power Conference, could be a good venue for such a meeting.

8.2 Investigate Voltage Drop From Customer Meter to Plug

Investigate the voltage drop from the customer meter to plug in residential and commercial applications to determine whether the widely held assumption of a 4V drop is valid. Based on discussions with numerous utility distribution experts, the actual voltage drop, particularly in newer constructions, is likely much less, on average. Documentary evidence to this effect could potentially persuade utilities that may be “on the fence” with respect to CVR – out of concern for falling below 114V in service voltage – that the risk of CVR posing problems for customers is minimal.

8.3 Promote DSE in the Context of Distribution Effectiveness

With some planning and calculation, CVR or distribution efficiency can be used as a tool to justify much needed improvements in the distribution infrastructure. Depending upon the economics of its peak power costs, a utility can make a business case for CVR as a means to both a) reduce the need to generate or procure expensive peak power, and b) sell or re-sell peak power on the wholesale market to increase revenues. By deploying the capital equipment necessary to enable CVR – such as capacitor banks, voltage regulators, and improved distribution automation controls – a utility will improve its distribution infrastructure and thereby improve its operational effectiveness. The Alliance may be able to advise utilities on how to develop such a business case.

8.4 Encourage Greater Dialogue and Collaboration between Distribution and DSM Groups with Utilities

Encourage greater dialogue and collaboration between distribution and DSM groups within utilities to uncover energy savings opportunities and funding sources. Our discussions with distribution individuals from numerous utilities reveals that, in general, a utility’s distribution group and energy efficiency group operate in their own silos and do not interface across departments. This is not surprising, considering that distribution planning, engineering and operations are distinct disciplines from demand-side program design and evaluation. However, the overall lack of collaboration between distribution and DSM that we observe may be preventing the implementation of voltage reduction practices that could save an enormous amount of energy on a national basis.

Most DSM professionals are focused on the demand-side of the house, and may not be aware of the energy savings potential of voltage reduction. At the same time, DSM professionals are generally more familiar with funding sources for energy efficiency measures, such as public benefits charges that exist in many states. By working together, a DSM group might be able to help a Distribution group access these funding sources (which are almost exclusively applied to fund demand-side programs) for a voltage reduction initiative. On the margin, such funding could tip the economic equation in favor of implementing voltage reduction in some cases.

A

APPENDIX A: ANNOTATED SURVEY INSTRUMENT

The following survey instrument was applied to participants. In some cases, the instrument was sent in advance of a telephone interview. The typical interview lasted 45 to 75 minutes.

	QUESTION	ANSWER

The following sets of questions are structured to establish the size and scope of the DEI market while identifying and describing technologies that are used to implement the strategy. For example,

a. Demand (utilities)

- ***How many utilities use DEI/CVR strategies?***
- ***What are their strategies?***
- ***What are the utilities' drivers***

b. Supply (equipment and services)

- ***Who supplies the DEI equipment?***
- ***Is there a predominant vendor?***
- ***How is the equipment distributed?***
- ***Who does the selling? Vendors? Engineering Firms?***

This first set of questions establish up front whether a utility is practicing DEI, in what form, and through what techniques.

Customer Voltage Range

1. What is/are the standard service voltage range you deliver to residential single-phase feeder lines?

Note that the ANSI Standard C 84.1-1995 (R-2001) range is 126 – 114 Volts (i.e. 120 +/- 6 Volts).

Please indicate the number and percentage of circuits for each corresponding voltage range, where applicable.

Please fill-in specific ranges that apply to your utility in the shaded cells.

Start of Line (Distribution Transformer)	End of Line (Customer Meter)	# of your Circuits	% of your Circuits
126 V	114 V		%
120 V	114 V		%
117 V	110 V		%
> 126 V			%
	< 114 V		%
	< 110 V		%
123.6 V	116.4 V		%
123.6 V			
	116.4 V		%
TOTAL			100%

Please add any further description:

	QUESTION	ANSWER
2.	If, in response to Question 1, you indicated that there are some circuits for which you deliver voltage to customers at a range lower or tighter than the ANSI Standard C 84.1-1995 (R-2001) range of 126 – 114 Volts (i.e. 120 +/- 6 Volts), this implies that your company practices some form of voltage regulation (VR), conservation voltage reduction (CVR) or distribution efficiency (DE). How would you characterize your company's VR/CVR/DE activities:	☐ It is our standard practice (at least for some circuits) ☐ It is a program that we are rolling out for general deployment ☐ It is a program that we reserve for emergency load conditions ☐ It is a program that we are piloting ☐ We previously deployed a voltage regulation program, but no longer do so ☐ We tested it, but we no longer have any interest **(if you check this, please skip to Question 7)** ☐ We did some internal studies, that's all **(if you check this, please skip to Question 7)** ☐ We are not familiar with these practices **(if you check this, please skip to Question 8)** Other? Please describe.
3.	What methods do/did you use to implement VR/CVR//DE?	☐ Reregulation (lowering outgoing voltage to <126 V) • % reduction • ___V reduction ☐ Line drop compensation (___ to ___ V) ☐ Balance Feeders ☐ Capacitor Addition ☐ Regulator Addition ☐ Reinsulation ☐ Reconductoring ☐ *Other* Please describe.
4.	Is/was SCADA an essential part of your voltage regulation implementation? How does it relate?	

	QUESTION	ANSWER
5.	How long has/was your VR/CVR/DE activity or program been operating? If it has been discontinued, what stage of deployment did it attain?	
6.	How much time was needed to plan the program/procedure from concept to deployment? Was it done on a pilot (Beta) or trial basis initially? At what point was it deemed ready for larger scale deployment, if at all?	
7.	What conclusions about voltage regulation and distribution efficiency did you conclude from your internal studies or tests?	
This set of questions clarifies the planning guidelines for a utility's decision to upgrade or replace systems that would enable DEI and voltage reduction.		
	Planning Guidelines	
8.	Do you have planning guidelines for acceptable voltage ranges at distribution substations and on primary circuits? If so, please describe.	
9.	Do you have planning guidelines for voltage drops through distribution transformers and secondaries? If so, please describe.	
10.	What is the usual response if one of those guidelines is not met?	☐ Replace distribution transformer ☐ Reconductor secondaries/services ☐ Reconductor primary circuit ☐ Reset primary circuit line regulator ☐ Install switched line capacitors ☐ Reconfigure circuit using switches ☐ *Other* Please describe.
11.	How do you know if the guideline is not met? e.g. customer complaints? voltage measurements?	

<table>
<tr><th></th><th>QUESTION</th><th>ANSWER</th></tr>
<tr><td></td><td></td><td></td></tr>
<tr><td>12.</td><td>If your system uses switched capacitor banks for voltage and VAR control, what methods are used to control switching?</td><td>☐ Voltage
☐ Time
☐ Current
☐ VAR
☐ Real time through telemetry or SCADA
Other: please describe.</td></tr>
<tr><td colspan="3">This set of questions provides background into a utility’s distribution system and ability to support DEI.</td></tr>
<tr><td></td><td>Other Distribution Metrics and Data</td><td></td></tr>
<tr><td>13.</td><td>How many substations serve residential and small commercial customers in your distribution system?</td><td></td></tr>
<tr><td>14.</td><td>Voltage regulation is most applicable to circuits of shorter lengths. Can you please estimate the distribution of circuits by length? That is, what % of circuits are:
• < 3 miles ___%
• 3-12 miles ___ %
• > 12 miles ___ %</td><td>
<table>
<tr><th>Circuit Length</th><th>Percentage of Your Circuits</th></tr>
<tr><td>< 3 miles</td><td>%</td></tr>
<tr><td>3-12 miles</td><td>%</td></tr>
<tr><td>>12 miles</td><td>%</td></tr>
<tr><td>TOTAL</td><td>100%</td></tr>
</table>
</td></tr>
<tr><td>15.</td><td>Do you have distribution facilities records entered into a GIS system?</td><td></td></tr>
<tr><td>16.</td><td>Do you have a connectivity model for your distribution system? For example, do you have a database with records of which meters are connected to which circuits? Is this broken down by circuit segnment?</td><td></td></tr>
<tr><td colspan="3">This set of questions explores the dynamics of the distribution planning process in a broad sense, and with respect to DEI in particular.</td></tr>
<tr><td></td><td>Distribution Planning Process</td><td></td></tr>
<tr><td>17.</td><td>What groups in your company were involved in the decision to implement or not implement VR/CVR/DE?
Were there any particular champions of the idea?</td><td></td></tr>
</table>

	QUESTION	**ANSWER**
18.	What groups expressed the most concern about pursuing CVR / Distribution Efficiency? What were some of these concerns? Feeder length? (voltage drops on longer feeders may not be technically or economically feasible) How were these concerns overcome?	
19.	With respect to your company's distribution planning process, who makes the: • Planning decisions? • Procurement decisions? • Operational decisions? Please consider the interactions of the following roles in your organization: • COO • CFO • Rates department • Department head of T&D	
20.	How does/would VR/CVR/DE fit into your distribution planning process? Would the investment and capital expense decision process for VR/CVR/DE be the same as for other distribution improvements and expansions?	
21.	What events or conditions would initiate the planning process for distribution system changes or upgrades? e.g. • *Capacity constraints?* • Customer complaints? • O&M costs? • Periodic review? • Catastrophic failure?	
22.	What are some of your company's constraints to planning and implementing distribution system improvements? e.g. • *Budget constraints?* • Regulatory treatment of investments? • Physical conditions? • Political considerations?	

	QUESTION	ANSWER
The following questions determine information channels and influencing factors. • ***Where do utility personnel get DEI information?*** • ***What are the internal and external drivers for DEI?***		
	Awareness, Information, and Drivers	
23.	What was your company's awareness of VR/CVR/DE prior to considering it?	
24.	What sources did your company use for information on the design and implementation of a voltage regulation initiative? e.g. • Internal studies • External studies (i.e. research organizations, other utilities, etc.) Please describe.	
25.	Were there internal drivers for your VR/CVR/DE efforts? If so, what were some of the drivers? e.g. • internal studies • improve operational efficiency • improve energy efficiency • reduce peak demand Please elaborate.	
26.	Were there any outside drivers for your voltage regulation / distribution efficiency activities? e.g. • Regulatory pressure? • Customer complaints? • Inability to increase line capacity? • Expense of increasing line capacity? • Partnership with EPA? Please describe.	
The next set of questions ask utilities to specify the vendors they use to enable DEI. We explore the extent to which vendors influence a utility's decision making with regard to		

	QUESTION	ANSWER
DEI. We also ask the utility to evaluate their experience with these vendors.		
	Equipment Vendors	
27.	Did vendors of distribution equipment (i.e. voltage regulators, capacitors, load tap changers, etc.) influence your decision to pursue VR/CVR/DE? Who were the vendors in your case? Please describe.	
28.	What equipment did your company have to procure to enable this program?	☐Automated controls on substation transformer ☐Substation voltage regulators ☐Line voltage regulators ☐Switched capacitor banks ☐Other equipment integrated into SCADA system Please describe.
29.	Are there any particular vendors that you associate with enabling VR/CVR/DE? Please name them and indicate what they provide.	
30.	What is your level of satisfaction with your vendors of VR/CVR/DE -enabling equipment? Consider: • How is your VR/CVR/DE project working out? • Any estimates of savings? • Easier to operate system? • Customer complaints? • Equipment failures?	
The next set of questions are intended to understand the perspective and role of customers and related 3rd parties with regard to DEI. We explore what types of communication and information channels are used between utilities and customers.		

	QUESTION	ANSWER
	Customer Response	
31.	Have customers shown any reaction to the change in their voltage levels? e.g. • Increased complaints? • Decreased complaints?	
32.	If applicable, how did you resolve any customer complaints? Did you increase line voltage in some instances?	
33.	Did you communicate this VR/CVR/DE initiative to your customers? If so, how? How about for trial customers if you operated this as a pilot first?	
34.	Did any other groups, such as customers or industry trade associations, express concerns about VR/CVR/DE? • Res vs. non-res concerns? • Power quality concerns? What were their concerns and how did you counter these concerns?	
The next two questions are designed to determine the DEI market barriers that help explain the gap between the actual level of DEI investment or practice and an increased level that would appear to be cost beneficial. Anticipated Barriers include: • ***Information or search costs*** • ***Performance uncertainties*** • ***Hassle or transaction costs*** • ***Hidden Costs*** • ***Organizational practices or customs*** • ***Externalities***		
	Overcoming Barriers	
35.	What are/were some of the barriers to implementing VR/CVR/DE? What are/were some of the barriers to expanding VR/CVR/DE? e.g. • lost revenues • large capital expenses	

	QUESTION	ANSWER
	• perception that lowering voltage does not necessarily save energy	
36.	• How were these barriers overcome? • How would you suggest overcoming these barriers? • What were the key factors that led to the adoption of VR/CVR/DE?	
The next three questions are structured to capture the net impact of DEI efforts, positive – negative.		
	Results	
37.	Has your VR/CVR/DE initiative delivered the expected savings or other benefits? • Energy savings? • Demand reduction? • Deferring capital expenses? • Reduction in customer complaints? • Increased control? • Reduced risk of end-of-line brownouts? • Other positive results? Were you able to quantify these benefits? • ROI? • Payback? • Reduced emissions? Please discuss.	
38.	Were there any negative aspects of your company's CVR experience? Please describe:	☐ Hidden costs? ☐ Failure to deliver expected savings/benefits/results? ☐ Problems with vendors? ☐ *Problems with contractors / engineering firms involved?* ☐ *Other?* *Please discuss.*
39.	If your company has discontinued CVR, are these some of the reasons why? What other factors led to this decision?	
The next two questions are structured to obtain information on DEI trends and issues.		
	Future Issues and Trends	

	QUESTION	ANSWER
40.	What do you think are your company's key distribution planning issues and trends over the next… • *2 years?* • 5 years? Some topics to perhaps consider: • *Distributed generation* • Voltage control • Rural vs. urban strategy • Under- vs. above-ground new lines • Meeting current capacity • Building for future capacity • Reducing customer complaints • Capital vs. labor • Increasing SCADA	
41.	What role you think voltage control and regulation (VR/CVR/DE) may play in your company's distribution planning over the next… • *2 years?* • 5 years?	
The final set of questions seeks peer advice on DEI implementation, and also requests recommendations on further people to contact and studies to consult.		
	Advice and Further Contacts	
42.	What advice would you provide to a utility considering implementing a CVR program? Can you recommend any other people, in your company or out, for us to contact? Can you recommend any recent studies on CVR for us to reference?	

B
APPENDIX B: CITATIONS

ANSI C84.1, American National Standard for Electric Power Systems and Equipment – Voltage Ratings (60 Hz). American National Standards Institute.

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