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# US Experience with Efficiency As a Transmission and Distribution System Resource

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February 2012

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## Acknowledgements

The authors would like to thank the following individuals who provided valuable feedback and suggestions on an initial draft of this report: Joshua Binus and Mike Weedall of the Bonneville Power Administration, Terry Black of The Project for Sustainable FERC Energy Policy, Dan Engel of The FSC Group, Toben Galvin of Navigant Consulting, Chris Gazze of the International Atomic Energy Agency (and former manager of Consolidated Edison's targeted demand-side management program), Chuck Goldman of Lawrence Berkeley National Laboratory, Jeremy Newberger of National Grid, Scudder Parker of the Vermont Energy Investment Corporation, Dan Peaco of La Capra Associates, and T.J. Poor of the Vermont Department of Public Service.

A number of other individuals also provided invaluable information, ideas, and perspective on the case studies we examined. They include most of the reviewers identified above as well as Dave Grimason of Grimason Associates (and formerly of Green Mountain Power), Larry Holmes of NV Energy, Ottie Nabors and Frank Brown of Bonneville Power Administration, Beth Nagusky of Environment Northeast, Rick Weiyo of Portland General Electric, and Mike Wickenden of the Vermont Energy Investment Corporation and Efficiency Vermont. Their input was very much appreciated.

Though we could not have completed this report without the help of those identified above, it is important to note that some of the feedback we received was conflicting. In addition, in a few cases, we disagreed with and therefore elected not to make some specific changes suggested by one or more reviewers. We make these points to underscore that we, the authors, are ultimately solely responsible for the information presented and the conclusions drawn in the report.

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## Executive Summary

Improvements to electric efficiency in homes and business provide a variety of benefits to both the customers making the improvements and to the electric system as a whole. The most widely recognized are energy savings and system peak demand savings. A much less widely recognized or valued benefit is the potential to enhance the reliability of the transmission and distribution (T&D) system. This paper focuses on that potential, summarizing lessons learned from US initiatives in which geographically targeted efficiency programs have played a major role in electric utility funded efforts to defer T&D investments.

### Importance of T&D Investments

The potential to defer T&D upgrades deserves much more serious consideration than it has received to date. The U.S. utility sector has invested on the order of \$35 to \$40 billion per year in the T&D system over the past decade and is forecast to invest nearly \$50 billion per year over the next two decades. As Figure ES-1 shows, this represents approximately 60% of total forecast investments for the sector. Only 6% of the forecast capital investments are in advanced metering infrastructure (AMI), energy efficiency (EE) and demand response (DR). Not all forecast T&D investments will be deferrable. Some will be required to address time-related deterioration of equipment or other factors that are independent of load. However, a significant portion of T&D investment is likely to be associated with load growth. The potential benefits of deferring even a

modest portion of such investments could be substantial.

### Passive Deferral vs. Active Deferral

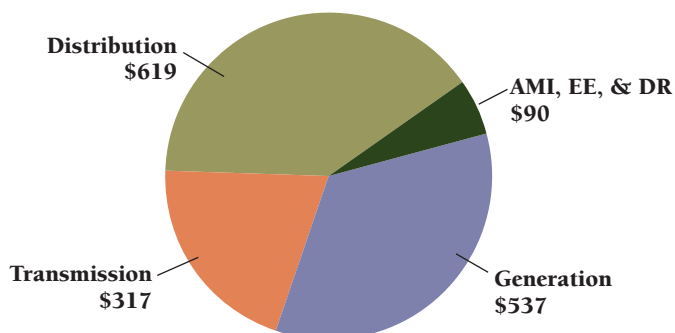
Efficiency programs can defer T&D investments either passively or actively. We define “passive deferrals” as those that occur as a result of efficiency programs that were not undertaken primarily for the purpose of deferring T&D upgrades. For example, system-wide efficiency programs will reduce loads on virtually all major elements of the T&D system. As a result, at least some load growth-related investments in the T&D system will be deferred for at least some period of time. Indeed, Consolidated Edison (Con Ed) reduced its projected T&D capital expenditures by more than \$1 billion after separately adjusting 10-year load forecasts for each of its 91 distribution networks and load areas in New York to reflect the expected impacts of system-wide efficiency programs.

In contrast, “active deferrals” are those that result from efficiency programs that are geographically-targeted for the express purpose of deferring the need for upgrades to specific elements of the T&D infrastructure. Though there are a number of notable exceptions, this concept has not yet been widely pursued due to a variety of inter-related factors:

- **Financial incentives** – utilities typically earn more from investing in “poles and wires” than from investing in efficiency and/or other alternatives;
- **Efficiency’s multiple attributes/benefits** – because efficiency investments provide energy savings, peak capacity savings, reserve margin savings, and other benefits in addition to T&D reliability improvements, comparing them to “poles and wires” investments requires a holistic, systemic perspective that has not been universally adopted by utilities, their regulators, independent system operators (ISOs), or regional transmission operators (RTOs);
- **System planning is highly technical** – the technical specialization needed to do T&D planning fosters an environment biased to technical solutions;
- **System engineers distrust demand resources** – those charged with planning to meet reliability needs typically have limited interaction with efficiency program managers and limited direct experience with the performance of demand resources;

Figure ES-1

US Power Sector Capital Investment Needs (2010 – 2030)  
(in billions of 2009 dollars)



- **Risk aversion** – utilities are typically reluctant to try new approaches, particularly if they perceive any regulatory risk in doing so;
- **Socialization of transmission investment costs** – while the cost of transmission solutions are often socialized regionally, the cost of efficiency programs or other non-wires solutions that could meet the same reliability objectives are not; and
- **Responsibility for transmission planning is diffuse** – with state regulators, utilities, independent system operators or regional transmission operators and the Federal Energy Regulatory Commission all having roles, it is difficult for a new approach (i.e. non-wires solutions) to gain traction.

## U.S. Experience with Active Deferrals of T&D Investments through Efficiency

Though far from widespread, a number of jurisdictions have tested and/or are in the process of testing the role that geographically-targeted efficiency programs could play in cost-effectively deferring T&D investments. This paper examines ten different initiatives or policies – four in the 1990s and six others that are much more recent and/or still underway. As summarized below, this experience provides valuable lessons to guide future policies for the successful deployment of energy efficiency as a T&D resource.

### Pacific Gas and Electric's Delta Project (California, early 1990s)

The project aimed to defer the need for a new substation that would otherwise be required to serve a growing community of 25,000 homes and 3000 businesses in far eastern Contra Costa County. Several efficiency programs were quickly launched in the region to reduce peak loads, with more than 10% of homes receiving some major measures. The project did defer the need for the substation for at least two years, though at a higher cost than expected because some measures provided much lower peak savings than expected. While other measures provided greater savings than expected, the compressed timeframe for the project did not allow for switching of strategies early enough to keep average costs at more reasonable levels.

### Portland General Electric's Downtown Portland Pilot (Oregon, early 1990s)

This project focused on several opportunities. In the case of individual buildings where load reductions were needed to defer transformer upgrades, the utility aggressively marketed existing system-wide efficiency programs to

the building owners. For grid network objectives, where peak demand reductions of 10-20% for entire 10-15 block areas were needed, the utility contracted with energy service companies (ESCOs) to deliver savings. Results were mixed. For one building, savings were enough to defer and possibly permanently eliminate the need for a \$250,000 upgrade. In another building an unexpected conversion from gas to electric cooling eliminated any opportunity to defer the upgrade. The ESCOs contracted to achieve savings in a grid area network succeeded in reducing peak load by more than the 20% required. However, the utility's distribution engineering staff decided to proceed with their construction project before the savings were documented.

### BPA's Puget Sound Area Electric Reliability Plan (Washington, early 1990s)

The Bonneville Power Administration (BPA) and local utilities decided to address a transmission reliability concern through a strategy of adding voltage support to the existing transmission system (the most important part of the strategy) and more intensive deployment of energy efficiency programs (a complementary element). The project ended up delaying construction of a new cross-Cascade transmission line for more than a decade.

### Green Mountain Power's Mad River Valley Project (Vermont, mid to late 1990s)

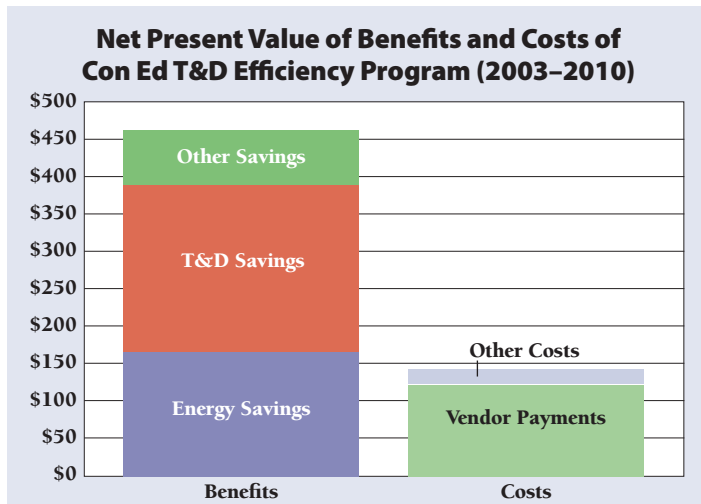
The project aimed to defer the need for a new distribution line in an area dominated by a large ski resort which had announced expansion plans that would add 15 MW of new load to the system. When it became clear that the resort may be required by Vermont regulations to bear most of the cost, negotiations between the utility, the resort and the state's rate-payer advocate led to an alternative plan in which the resort would better manage its load to ensure that total loads were within existing system tolerances and the utility would aggressively pursue efficiency improvements with its customers in the region. In the end, the project succeeded with the efficiency programs coming close to achieving overall savings goals.

### Consolidated Edison (New York City, early 2000s to present)

In 2003, Con Ed launched a program to defer distribution system upgrades using a competitive bidding process to select the resources it would pursue. To date, only efficiency resources have been selected. To address reliability concerns, contracts for those resources include both significant upfront security and downstream liquidated damage provisions. All told, between 2003 and 2010, the Company employed geo-

graphically-targeted efficiency programs to defer upgrades in more than one third of its distribution networks. The resulting savings were very close to forecast needs and, as Figure ES-2 shows, provided more than \$300 million in net benefits to ratepayers. In some cases, the efficiency investments not only deferred upgrades, but bought enough time to allow the utility to refine load forecasts to the point where it now believes that capacity extensions may never be needed.

Figure ES-2



### Efficiency Vermont Geo-Targeted DSM (2007 to present)

Efficiency Vermont's performance goals were modified to include not only system wide savings targets, but also much more aggressive targets in selected geographic areas which the state's utilities had identified as candidates for deferring T&D investments. The initiative has had some success. Although peak demand savings in the targeted areas were at least 30% below targets, they were still three to five times greater than those achieved statewide (notable since the statewide savings were already the highest in the nation). The state's largest utility has observed that it has not had to schedule deployment of additional system upgrades in the targeted areas. The extent to which that is attributable to the geo-targeted efficiency programs, changes in economic conditions, other factors has not yet been determined.

### NV Energy (Nevada, late 2000s)

NV Energy launched an efficiency initiative in and around Carson City in an effort to obviate the need to either run the locally situated but relatively expensive Fort Churchill generating station more frequently or construct a new transmission line and substation to bring less expensive power into the region. At the same time, the

utility began re-conductoring the existing 120-kVA line to the region. An economic recession also hit at the same time, dampening growth. As a result, the Company has not had to revisit the need for either running the Fort Churchill station more often or adding new T&D capacity.

### Central Maine Power (currently under development)

In 2010, the Maine regulators approved a settlement agreement that supported construction of most elements of a large transmission project, but identified two areas – the Mid-Coast region and the city of Portland – where pilot projects to test the efficacy of non-transmission alternatives would be launched. In March 2011, Central Maine Power filed a plan for the Mid-Coast region that proposed using a competitive process to identify and acquire needed distributed resources. The plan suggested that efficiency resources were expected to be “highly competitive”. A variety of issues regarding both the forecast capacity needs and the process for acquiring distributed resources were unresolved as this report was being finalized.

### National Grid (Rhode Island, currently under development)

In 2006, Rhode Island adopted a “System Reliability Procurement” policy that required utilities to file plans every three years. The plans must consider non-wires alternatives – including energy efficiency – whenever a T&D need is not based on an asset condition, would cost more than \$1 million, would require no more than a 20% reduction in load to defer and would not require investment in a “wires solution” for at least three years. Based on these guidelines, in late 2011, National Grid proposed an initial pilot project to defer the upgrading of a substation through a combination of load management and energy efficiency.

### Bonneville Power Authority (Washington, Oregon and Idaho, currently under consideration)

In 2002, the Bonneville Power Authority launched an initiative in which it committed to investigating options for deferring potential transmission reinforcement projects. A year later, it formed a Non-Wires Solutions Round Table of key stakeholder groups to provide input to its work. It then developed a formal process by which transmission alternatives – including efficiency – would be assessed. That process includes an initial screening to determine if a project is a possible candidate for a non-wires solution. The project qualifies if it is estimated to cost at least \$5 million, it is driven by load growth and the need is at least eight years in the future. Bonneville is currently conducting detailed



feasibility assessments of non-wires solutions to three projects – one each in Oregon, Washington and Idaho – that passed this initial screen. In each case, efficiency is part of a package of options being considered.

## Lessons Learned

Our review of these efforts to use efficiency programs to defer T&D investments – alone or in concert with other resources – leads us to the following initial conclusions:

- **Geographically-targeted efficiency can defer T&D investments.** That appears to have been the case in New York City; Vermont's Mad River Valley; Portland, Oregon; and Contra Costa County, California.
- **Efficiency can be a cost-effective T&D resource.** There is less evidence regarding the cost-effectiveness of efficiency as an alternative to T&D investments. However, analysis of the most intensive and longest-standing effort – Con Ed's experience in New York City – concluded that T&D savings alone out-weighed the cost of efficiency. When all efficiency benefits are considered, the initiative had a three-to-one benefit-cost ratio.
- **Unexpected events can affect the benefits of efficiency.** In several of the cases analyzed, some or all of the T&D investment being considered for deferral ended up being constructed for reasons having nothing to do with the effectiveness of deployment of efficiency resources. However, forecasting uncertainty works in both directions. Indeed, in a couple of cases, efficiency investments bought enough time to enable a utility to conclude that – contrary to initial forecasts – a T&D upgrade may never be needed.
- **Sufficient lead time is critical.** It is necessary to allow for sufficient planning, for sufficient deployment of efficiency resources to meet needs (particularly for larger projects) and for refinement of efficiency strategies during the deployment process.
- **Smaller is easier.** The smaller the area being addressed, the easier it is to consider efficiency and other non-wires alternatives. It is easier to characterize the opportunity in small areas. Also, savings will need to be acquired from fewer customers. Both of those things mean shorter lead times will be required.
- **Distribution is easier than transmission.** Distribution deferral projects will be smaller in scope. They are also less technically complex, involve fewer parties, and do not involve ISOs/RTOs and associated regional cost allocation frameworks (i.e. cost socialization issues).
- **Cross-discipline communications is critical.** Collaboration between efficiency program managers and T&D planners is critical to considering deploying

efficiency as an alternative to T&D investments. Both have much to learn from each other. Some level of trust must be developed between the two groups.

- **Efficiency should be integrated with other distributed resources.** Although efficiency programs can sometimes be sufficient to defer T&D investments, they will often need to be deployed in concert with demand response, distributed generation and other resources to enable deferment of T&D investments (particularly for larger projects).

## Recommendations

The potential economic and other benefits of efficiency programs as a T&D resource are largely being ignored today. Some fundamental policy changes are required if that is to change:

- **Require least-cost T&D planning.** Experience in several jurisdictions suggest this is essential (though not sufficient) to beginning serious consideration of efficiency and other non-wires alternatives.
- **Require consideration of integrated solutions.** To ensure that potential synergies between efficiency and other non-wires alternatives are considered, any requirement for least cost-planning should make clear that all options, including different combinations of distributed resources, should be considered.
- **Institutionalize a long-term planning horizon.** The longer the lead time, the more likely it will be that efficiency and/or other distributed resources could cost-effectively defer T&D investments. At a minimum, T&D needs should be forecast at least 10 years into the future.
- **"Level the playing field" in payment for wires and non-wires alternatives.** Cost-allocation frameworks that socialize costs for transmission projects across a region but require all the cost of non-wires alternatives to be born locally create enormous disincentives to pursue least cost solutions.
- **Collect more data on efficiency's impacts.** In much of the country, relatively little data on the hourly and seasonal impacts of efficiency resources has been collected and made public over the past two decades. Better data should help address concerns of T&D system planners.
- **Start with pilot projects.** Pilots offer important, lower risk opportunities to bring together efficiency program and T&D planners.
- **Leverage "smart grid" investments.** Customer and end-use data collected through such systems may enable better assessments of the potential for efficiency to serve as a T&D resource.

## Table Of Contents

<b>Acknowledgements</b> . . . . .	<i>inside front cover</i>	Distribution is Easier than Transmission. . . . .	20
<b>I. Introduction.</b> . . . .	<b>2</b>	Cross-Discipline Communication is Critical. . . . .	20
Context – Historic and Future Investments in T&D. . .	2	Integrate Efficiency with	
“Passive Deferral” vs. “Active Deferral” . . . . .	3	Other Distributed Resources . . . . .	20
<b>II. Active Deferral of T &amp; D Investment –</b>		<b>IV. Recommendations</b> . . . . .	<b>21</b>
<b>Selected Examples</b> . . . . .	<b>6</b>	Require Least Cost T&D Planning . . . . .	21
A. Early History . . . . .	6	Rhode Island . . . . .	21
Pacific Gas and Electric (California) –		Vermont . . . . .	21
Delta Project . . . . .	6	Bonneville Power Administration . . . . .	22
Portland General Electric (Oregon) –		Require Consideration of Integrated Solutions . . . . .	23
Downtown Portland Pilot . . . . .	7	Institutionalize a Long-Term Planning Horizon . . . . .	23
Bonneville Power Administration. . . . .	8	“Level the Playing Field” in Payment for	
Green Mountain Power (Vermont) –		Wires and Non-Wires Alternatives. . . . .	24
Mad River Valley . . . . .	8	Collect More Data on Efficiency’s Impacts . . . . .	24
B. More Recent Developments . . . . .	10	Start with Pilot Projects . . . . .	24
Consolidated Edison (New York City). . . . .	10	Leverage “Smart Grid” Investments . . . . .	24
Efficiency Vermont Geo-Targeted DSM . . . . .	12	<b>Appendix A:</b> Rhode Island Standards for Least Cost	
Central Maine Power . . . . .	15	Procurement and System Reliability Planning –	
NV Energy . . . . .	16	Excerpt on Distributed Resources in Relation	
<b>III. Lessons Learned</b> . . . . .	<b>18</b>	to T&D Investment . . . . .	25
Geographically-Targeted Energy Efficiency		<b>Appendix B:</b> Excerpts from Vermont’s Act 61. . . . .	27
Can Defer T&D Investments . . . . .	18	<b>Bibliography.</b> . . . .	29
Efficiency Can Be a Cost-Effective T&D Resource . .	18	<b>Other RAP Publications on Energy Efficiency</b> . . . . .	31
Stuff Happens! Unexpected Events Can		<b>Acronym Glossary</b> . . . . .	<i>inside back cover</i>
Affect Benefits of Efficiency . . . . .	18		
Sufficient Lead Time is Critical. . . . .	19		
Smaller is Easier. . . . .	20		

# 1. Introduction

Improvements to electric efficiency in homes and businesses provide a variety of benefits to both the customers making the improvements and the electric system as a whole.<sup>1</sup> The most widely recognized are annual energy savings and system peak demand savings. Most consumers are primarily interested in energy savings because they typically drive cost savings on electricity bills. Utilities and grid operators are often most interested in reductions in load at the time of system peak, which enable them to avoid purchasing expensive peak generating capacity. A much less commonly recognized or valued benefit of efficiency investments is the potential for cost-effectively deferring upgrades to transmission and distribution (T&D) systems.

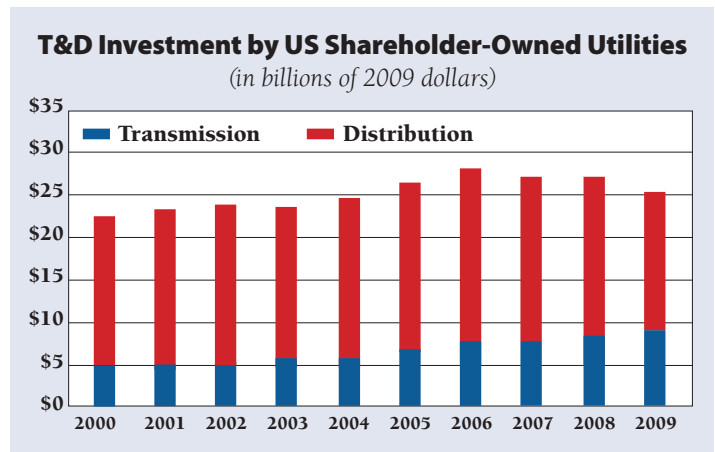
This paper focuses on that potential. In particular, it summarizes US experience to date and lessons learned from initiatives in which geographically targeted efficiency programs have played a major role in electric utility funded efforts to defer transmission and/or distribution system investments. Although other demand resources such as demand response and distributed generation can also be considered viable alternatives to T&D investments and have occasionally been deployed for that purpose, this paper does not explore those options in any detail, except when they are deployed as part of a multi-pronged strategy in conjunction with geographically targeted efficiency programs.

## Context – Historic and Future Investments in Transmission and Distribution

The potential to defer upgrades to T&D warrants much more serious consideration than it has historically been given. As Figure 1 shows, T&D investments by investor-owned utilities, which collectively account for approximately two thirds of electricity sales in the United States, have averaged about \$26 billion annually over the past decade.

If public utilities are investing in T&D at the same rate, then total T&D investment nationally would be on the order of \$40 billion per year. That level of investment is expected to continue, if not increase, in the future. Indeed, as Figure 2 illustrates, the Edison Electric Institute

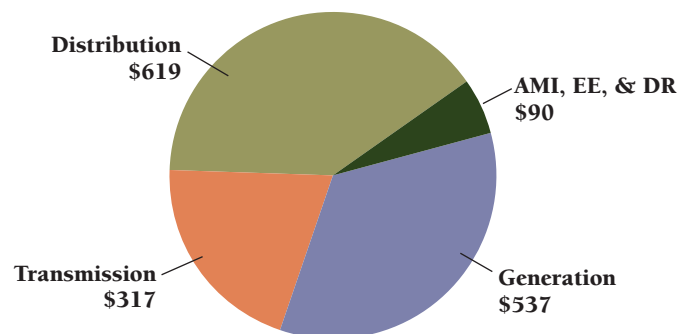
Figure 1<sup>2</sup>



recently commissioned a study that concluded the US power sector, including both investor-owned and public utilities, will require over \$1.5 trillion in capital investments

Figure 2<sup>3</sup>

**US Power Sector Capital Investment Needs (2010 – 2030)**  
(in billions of 2009 dollars)



- There are also often a number of non-energy benefits (e.g., improved comfort, water and/or other resource savings, reduced operation and maintenance costs, increased productivity) that we do not address in this paper.
- Personal communication with Steve Frauenheim, Edison Electric Institute (EEI), August 5, 2011. Data are from EEI's Statistical Yearbook of the Electric Power Industry 2009 Data, Table 9.1.



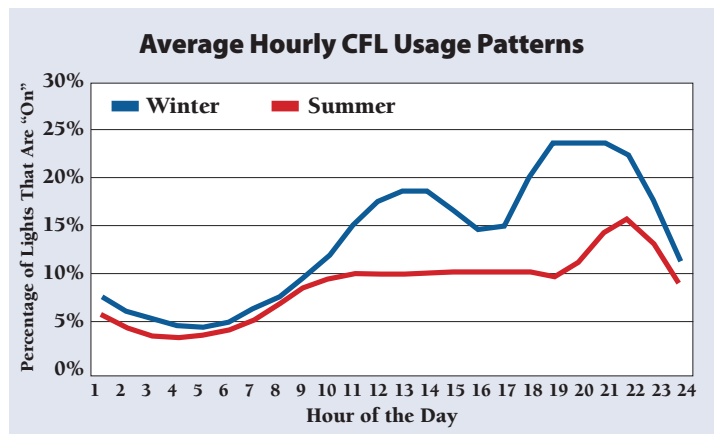
between 2010 and 2030 (2009 dollars), and that 40% of that investment – more than \$600 billion (i.e., more than \$30 billion/year) – will be in distribution system infrastructure and another 20% – more than \$300 billion (i.e., more than \$15 billion/year) – will be in transmission system infrastructure. Only about one third of the forecast investment is in new generation; another 6% is in advanced metering infrastructure, energy efficiency, and demand response.

### “Passive Deferral” vs. “Active Deferral”

Deferrals of T&D investments can take two forms: passive deferral and active deferral. Passive deferral occurs when the growth in load or stress on feeders, substations, transmission lines, or other elements of the T&D system is reduced as a result of broad-based (e.g., statewide or utility service territory-wide) efficiency programs. For example, a statewide program to promote the sale and purchase of compact fluorescent light bulbs (CFLs) will have the effect of lowering loads on every element of the T&D system every hour of the day. To be sure, the amount of load reduction from such a program will vary considerably depending on the season (more during winter than summer), hour of the day (e.g., more during the evening than the day), and the customer mix served (e.g., more for feeders, substations, etc. serving primarily residential customers). As Figure 3 shows, however, the load shape of residential lighting is such that – across a population of program participants – some reductions in energy use will occur every hour of the year. Some reductions thus will occur during every hour of peak demand for every element of the T&D system.

Passive deferral benefits are sometimes reflected in average statewide or utility service territory-wide avoided T&D costs. Such avoided costs – along with avoided costs

Figure 3<sup>4</sup>



of energy and system peak capacity – are commonly used to assess whether efficiency programs are cost-effective (usually a regulatory requirement for funding approval). At the most general level, estimates of avoided T&D costs are typically developed by dividing the portion of forecast T&D capital investments that are associated with load growth (i.e., excluding the portion that is associated with replacement due to time-related deterioration or other factors that are independent of load) by the forecast growth in system load. Such estimates can vary considerably, often as a function of the utilities’ assumptions regarding how much investment is deferrable. For example, in New England, utility estimates of avoided T&D costs typically have ranged from about \$55 per kW-year to \$120 per kW-year.<sup>5</sup> Avoided distribution costs typically account for 70% to 80% of those values (i.e., avoided distribution costs are typically two to four times greater than avoided transmission costs). Estimates for several utilities in California and the Pacific Northwest have ranged from \$30 to \$105 per kW-year, with an average of close to \$50.<sup>6</sup> Again, avoided distribution costs are the larger

- 3 Chupka, Marc et al, (The Brattle Group). *Transforming America’s Power Industry: The Investment Challenge 2010-2030*, prepared for the Edison Foundation, November 2008. The forecast presented here is for the report’s base case scenario, including “realistically achievable potential” for energy efficiency and demand response. The report’s 2006 costs were increased by 6.4% so that they could be presented in 2009 dollars (based on changes in the Consumer Price Index between 2006 and 2009).
- 4 Nexus Market Research, *Residential Lighting Markdown Impact Evaluation*, submitted to Markdown and Buydown Program Sponsors in Connecticut, Massachusetts, Rhode Island, and Vermont, January 20, 2009 (from Figures 5-1 and 5-2).
- 5 Most are in the range of \$55 to \$85 (Synapse Energy Economics, *Avoided Energy Supply Costs in New England: 2009 Report*, revised October 23, 2009, p. 6-66). Vermont’s, however, is approximately \$120 per kW-year for summer peak savings and \$80 per kW-year for winter peak savings (personal communication with Erik Brown, Efficiency Vermont, December 23, 2011).
- 6 Northwest Power and Conservation Council, *Sixth Northwest Conservation and Electric Power Plan*, February 2010 ([http://www.nwcouncil.org/energy/powerplan/6/final/SixthPowerPlan\\_Appendix\\_E.pdf](http://www.nwcouncil.org/energy/powerplan/6/final/SixthPowerPlan_Appendix_E.pdf)), p. E-14.

of the two components – on the order of twice as large as avoided transmission costs.<sup>7</sup> At the other extreme, in some jurisdictions it is conservatively assumed that no T&D investments can be avoided.<sup>8</sup>

Active deferral of T&D investments can occur when a conscious decision is made to invest in energy efficiency measures or programs – in targeted geographic locations – for the specific purpose of lowering loads on local T&D system elements. This concept has been actively pursued in relatively few jurisdictions to date. A variety of factors likely contribute to its limited testing for both transmission and distribution needs:

- **Economic incentives.** Utilities typically earn rates of return on capital investments. In many jurisdictions they do not make money on investments in efficiency.<sup>9</sup>
- **Efficiency's multiple attributes/benefits.** Efficiency resources provide a variety of benefits, including energy savings, peak capacity savings, environmental emission reductions, and T&D reliability improvements. Properly assessing whether efficiency could be a cost-effective alternative to T&D investments requires accounting for all of those benefits (e.g., although efficiency may not be cost-effective when considering just its T&D reliability benefits, it may be when considering all its benefits). That requires a holistic, systemic perspective that has not been universally adopted by utilities or their regulators, however, and is generally not a concern of ISOs/RTOs.
- **System planning is highly technical.** The technical specialization needed to do T&D planning fosters an environment biased to technical solutions. Put

another way, utilities and ISOs/RTOs tend to be engineering oriented, with a propensity toward building capacity to meet growing consumer demand.

- **System engineers distrust of demand-side resources.** System engineers trust assets that they can control, like “poles and wires,” and tend to be more skeptical or distrustful of investments on the customer side of the meter to reduce demand.
- **Risk aversion.** Related to the point above, utilities (like many other businesses) are often reluctant to try something different, particularly if they perceive any regulatory risk from doing so.

In general, the barriers to deployment of non-wires solutions to transmission needs are greater than those for distribution system needs. To begin with, transmission needs are typically more technically complex. In addition, the magnitude of the demand resources needed to defer them are larger and spread across much larger populations of customers. That can enhance system planners' fear of the ability of demand resources to meet reliability needs. It also typically means that longer lead times for consideration of non-wires solutions are necessary. Two additional factors are also critically important.

- **Socialization of transmission investments, but not non-wires alternatives.** The costs of transmission investments are often socialized regionally (i.e., across the entire grid), whereas the costs of efficiency programs or other non-wires solutions must typically be borne entirely by the local utility and its customers. This creates a classic “tragedy of the commons” in which it is less expensive for the local utility to choose what is often the most expensive option for a region.

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7 Ibid. Figures E-5 (avoided transmission costs) and E-6 (avoided distribution costs) each provide eight separate examples. Only three of those examples are common, however: PG&E, PacifiCorp and PGE. For those three utilities, avoided distribution cost estimates were roughly double avoided transmission cost estimates.

8 For example, see: Consumers Energy, *2012-2015 Amended Energy Optimization Plan*, submitted to the Michigan Public Service Commission, Case No. U-16670, August 1, 2011, p. 25.

9 A recent ACEEE study identified 18 states that had a mechanism that allowed investor-owned utilities to earn shareholder incentives for good performance in administering efficiency programs (Hayes, Sara et al, *Carrots for Utilities: Providing Financial Returns for Utility Investments in Energy Efficiency*, ACEEE Report Number U111, January 2011).

- **Diffusion of responsibility for transmission planning and decision-making.** State regulators, utilities, ISOs/RTOs, and ultimately FERC all have roles in transmission planning and approval of transmission investments. It is difficult for a new approach (i.e., non-wires solutions) to get traction when there is no one entity “in charge” that can require consideration of such approaches. It is unclear how the recent FERC Order 1000, which requires ISOs/RTOs to consider state policies in their decisions, will change things.

Despite these barriers, aggressive geographically targeted

energy efficiency programs have been implemented in several jurisdictions in an attempt to defer specific T&D projects. The purpose of this paper is to document the lessons learned from those efforts. Again, although there are a variety of potential non-wires alternatives that can be and have been deployed to defer T&D investments, the focus of this paper is only on those projects in which energy efficiency played or is playing a substantial role. It is also important to note that this paper documents the consideration of efficiency as a T&D resource as of late 2011. Several of the cases described below are still evolving, potentially in ways that could add significantly to information and ideas presented herein.

## 2. Active Deferral of T&D Investment – Selected Examples

### A. Early History

The concept of using geographically targeted energy efficiency investments to cost-effectively defer T&D system upgrades is not a new one. One can find numerous papers on the concept in efficiency conference proceedings going back to at least the early 1990s. The Electric Power Research Institute (EPRI), a research organization serving the utility industry, began pursuing several projects to assess the potential for integrating demand-side management (DSM) into utility T&D planning during the same time period. Most important, several groundbreaking projects were undertaken in the 1990s to test the concept. What follows are brief descriptions of those projects.

#### **Pacific Gas and Electric (California) – Delta Project**

One of the most widely publicized of these early projects was the Pacific Gas and Electric (PG&E) Model Energy Communities Program, commonly known as the Delta Project, which ran from July 1991 through March 1993. Its purpose was to determine whether the need for a new substation that would otherwise be required to serve a growing “bedroom community” of 25,000 homes and 3,000 businesses in far eastern Contra Costa County, California could be deferred through intensive efficiency investments. Peak demand in this area occurred on summer weekdays between 7 pm and 8 pm – much later than PG&E’s system peak (typically between 3 pm and 5 pm). This later local peak was driven by the fact that 74% of the peak load was residential, with many of the residential customers being two-income families who had long commutes from the San Francisco and Oakland areas and turned on their air conditioners when arriving home to 100° F heat.<sup>10</sup>

As a result, the largest portion of the project’s savings was

projected to come from a residential retrofit program targeted to homes with central air conditioning (the vast majority of homes in the targeted area). Under the initial design, participating homes would receive free installation of low-cost efficiency measures (e.g., CFLs, low flow showerheads, water heater blankets) during an initial site visit and would be scheduled for follow-up work with major measures such as duct sealing, air sealing, insulation, sun screening, and air conditioner tune-ups. More than 2,700 homes received such major measures. Later the program changed its focus to promoting early replacement of older, often over-sized and inefficient central air conditioners with new, efficient models. Other components of the Delta Project included commercial retrofits, a residential new construction program, and a small commercial new construction program.

Evaluations suggested that the project produced 2.3 MW of peak demand savings. The savings did come at a high cost – roughly \$3,900 per kW. This can likely be attributed to a couple of key factors. First, the project had an extremely compressed timeframe. It was planned and launched within six months; the implementation phase was less than two years. A second related factor was that some of the efficiency strategies produced much lower levels of savings than initially estimated, whereas others produced more. Because of the compressed timeframe for the project, the switch in emphasis to the better performing program strategies could not occur early enough to keep total costs per kW at more reasonable levels. For example, the residential shell and duct repair efforts were initially projected to generate nearly 1.8 MW of peak demand savings, but in the end, produced only about 0.2 MW at a cost of over \$16,000 per kW. In contrast, the early replacement residential central air conditioners produced 1.0 MW of peak savings – about 2.5 times the original forecast of about 0.4 MW – at a cost of about \$900 per kW.

<sup>10</sup> The Results Center, “Pacific Gas & Electric Model Energy Communities Program,” Profile 81, 1994.

The final evaluation of the project suggested that the savings achieved succeeded in deferring the need for the substation for at least two years.<sup>11</sup> Although the project suggested that geographically targeted DSM could potentially defer T&D investments, no projects of this kind appear to have been pursued in California since.

### Portland General Electric (Oregon) – Downtown Portland Pilot

In 1992, Portland General Electric (PGE) began planning the launch of a pilot initiative to assess the potential for using DSM to cost-effectively defer distribution system upgrades; implementation began in early 1993.<sup>12</sup> The pilot focused on several opportunities for deferring both transformer upgrades planned for large commercial buildings and grid network system upgrades planned for downtown Portland, Oregon. The projects were identified from a review of PGE's 5-year transmission and distribution plan. Although the PGE system was winter-peaking, downtown Portland was summer-peaking, so the focus would be on efficiency measures that reduced cooling and other summer peak loads. To be successful, deferrals would need to be achieved in one to three years, with the lead time varying by project. In each case, the value of deferring the capital improvements was estimated. The estimates varied by area, but averaged about \$35 per kW-year.<sup>13</sup>

Two different strategies were pursued. In the case of the individual commercial buildings, where peak demand reductions of several hundred kW per building were needed to defer transformer upgrades, the utility relied on existing system-wide DSM programs, but target marketed the programs to the owners of the buildings of interest using sales staff that already had relationships with the building owner or property management firm. For the grid network system objectives, where peak reductions of 10% to 20% for entire 10- to 15-block areas were needed, the utility contracted with energy service companies (ESCOs) to deliver savings. The ESCO contracts had two-tier pricing structures designed to encourage comprehensive treatment of efficiency opportunities and deep levels of savings. The first tier addressed savings up to 20% of a building's electricity consumption. The second tier was a much higher price for savings beyond 20%.<sup>14</sup>

The results of the pilot were mixed. For example, savings in one of the targeted commercial buildings was nearly twice what was needed, deferring and possibly permanently

eliminating the need for a \$250,000 upgrade. Savings for another building, however, fell short of the amount of reduction needed to defer its transformer upgrade. While other options were being explored to bridge the gap, an unexpected conversion from gas to electric cooling of the building "eliminated any opportunity to defer the upgrade."<sup>15</sup> The results for the first grid area network targeted were also very instructive. Of the 100 accounts in the area, the largest 20 accounted for more than three quarters of the load. By ultimately treating 12 of those 20, the ESCOs contracted by PGE actually succeeded in reducing load through efficiency measures by nearly 25% in just one year. That was substantially more than the 20% estimated to be necessary to defer the need for a distribution system upgrade. The utility's distribution engineering staff decided to proceed with construction of the upgrade before the magnitude of the achieved savings was known, however, because they did not have sufficient confidence that the savings would be achieved and would be reliable and persistent. It is also worth noting that the utility's marketing staff who were managing the ESCO's work were not even made aware of the decision to proceed with the construction until after it had begun – a telling indication of the lack of communication and trust between those responsible for energy efficiency initiatives and those responsible for distribution system planning.<sup>16</sup>

Despite some notable successes with its pilot, PGE has not subsequently pursued any additional efforts to defer distribution system upgrades through energy efficiency.<sup>17</sup>

- 11 Pacific Gas and Electric Company Market Department, *Evaluation Report: Model Energy Communities Program, Delta Project 1991-1994*, July 1994.
- 12 Personal communication with Rick Weijo, Portland General Electric, August 10, 2011.
- 13 Weijo, Richard O. and Linda Ecker (Portland General Electric), "Acquiring T&D Benefits from DSM: A Utility Case Study," *Proceedings of 1994 ACEEE Summer Study on Energy Efficiency in Buildings*, Volume 2.
- 14 Ibid.
- 15 Ibid.
- 16 Ibid.
- 17 Personal communication with Rick Weijo, Portland General Electric, August 10, 2011.



## Bonneville Power Administration

In the early 1990s, the Puget Sound area received more than three quarters of peak energy (i.e., during times of high demand for electric heat) via high voltage transmission lines that crossed the Cascade mountain range. Bonneville Power Administration (BPA) studies concluded the region could experience a voltage collapse – or blackout or brownout – if one of the lines failed during a cold snap.<sup>18</sup> The level of risk “violated transmission planning standards.”<sup>19</sup>

The traditional option for addressing this reliability concern would have been to build additional high voltage transmission lines over the Cascades into the Puget Sound area. BPA and the local utilities chose instead, however, to pursue a lower cost path that included adding voltage support to the transmission system (e.g., “series capacitors to avoid building additional transmission corridors over the Cascades”) and more intensive deployment of energy efficiency programs (focused on loads that would help avoid voltage collapse). The voltage support was by far the most important of these elements.<sup>20</sup> The project, known as the Puget Sound Area Electric Reliability Plan, ended up delaying construction of expensive new high voltage transmission lines for at least a decade.<sup>21</sup> Indeed, no new cross-Cascade transmission lines have been built to date.<sup>22</sup>

As discussed further below, BPA has not yet pursued an

additional project to defer transmission system investments with efficiency programs.<sup>23</sup> It has, however, institutionalized a process for assessing whether non-transmission alternatives, including efficiency, would be preferable and, for the past decade or so, has initiated that process on several occasions (the most recent just getting started in the spring of 2011).

## Green Mountain Power (Vermont) – Mad River Valley

In 1995, Green Mountain Power (GMP), Vermont’s second largest investor-owned electric utility, launched an initiative – the first of its kind in the state – to defer the need for a new distribution line in the Mad River Valley – a region in the central part of the state made famous by the Sugarbush and Mad River ski resorts. The existing U-shaped 34.5-kV line serving the valley had a reliable capacity of 30 MW. Sugarbush, which was located at the base of the “U” (its weakest point) and was already the largest load on the line, had announced plans to add up to 15 MW of load associated with a new hotel, a new conference center, and additional snow-making equipment. The existing line could not accommodate that kind of increase. Studies suggested that a new parallel 34.5-kV line would need to be added at a cost of at least \$5 million. Sugarbush initially requested that GMP

18 US Department of Energy, Bonneville Power Administration, Public Utility District Number 1 of Snohomish County, Puget Sound Power & Light, Seattle City Light and Tacoma City Light, “Puget Sound Reinforcement Project: Planning for Peak Power Needs,” Scoping report, Part A, Summary of Public Comments, July 1990.

19 Bonneville Power Administration Non-Construction Alternatives Roundtable, “Who Funds? Who Implements?” Subcommittee, “Non-Construction Alternatives – A Cost-Effective Way to Avoid, Defer or Reduce Transmission System Investments,” March 2004.

20 Indeed, although the plan included additional investments in efficiency, the additional capacitors, coupled with the addition of some local combustion turbines, were likely enough to defer the transmission lines even without the additional efficiency investments (personal communication with Frank Brown, BPA, 11/7/11).

21 Bonneville Power Authority, “Non-Wires Solutions Questions & Answers” fact sheet.

22 The system has been significantly altered over the past two decades as a result of substantial fuel-switching from electric heat to gas heat, the addition of significant wind generating capacity (much of it for sale to California), and other factors. At least until recently, BPA thus has had more “North-South issues” than “East-West issues” (personal communication with Frank Brown, BPA, 11/7/11). That may change in the future as utilities begin to rely more on wind generators east of the cascades (personal communication with Joshua Binus, BPA, 12/12/11).

23 In the mid to late 1990s, however, it did invest substantially in a demand response initiative in the San Juan islands to address reliability concerns after the newest of three underwater cables bringing power to the islands was accidentally severed. The initiative ran for five years and succeeded in keeping loads on the remaining cables at appropriate levels until a new cable was added.



pay for the new line. GMP was hesitant to do so, however, and Vermont's line extension rules were such that the utility and others could legitimately argue that much of the cost should be directly imposed on Sugarbush (and therefore less on other ratepayers).<sup>24</sup> Ensuing negotiations between GMP, Sugarbush, and the state's rate-payer advocate ultimately led to an alternative solution:

1. Sugarbush would ensure that load on the distribution line – *not just its load, but the total load of all customers* – would not exceed the safe 30 MW level;<sup>25</sup> and
2. GMP would invest in an aggressive effort to promote investment in energy efficiency among all residential and business customers in the region.<sup>26</sup>

To meet its end of the bargain, GMP filed and regulators approved the following four efficiency programs targeted to the Mad River Valley:

- Large commercial/industrial retrofit program (targeting the 10 largest customers in the valley);
- Small commercial/industrial retrofit program;
- Residential retrofit program, focusing particularly on homes with electric heat and hot water (promoting both fuel-switching and weatherization); and
- Residential new construction assessment fee program, which imposed a mandatory fee on all new homes being constructed in the valley to pay for a home energy rating and offered both repayment of the fee and an additional incentive for building the home efficiently.<sup>27</sup>

A couple of these programs were largely the same as programs GMP was offering to customers across its entire service territory, except that they were more aggressively marketed to Mad River Valley customers. In 1996, the year during which most of the project activity took place, GMP's efficiency program spending on the Mad River Valley represented about one quarter of its total DSM spending,<sup>28</sup> despite the fact that the area served represented no more than about 5% of its sales base.<sup>29</sup>

By the time the targeted efforts were concluded in early 1997, roughly half of the target populations had participated in the small commercial and industrial (C&I) retrofit and residential retrofit programs, and 7 of the 10 customers targeted by the large retrofit program had participated. Further, three of the four programs had achieved their savings goals. The large C&I retrofit program was the one exception, having achieved only about 20% of the forecasted savings (suggesting that the depth of savings achieved per participant was much lower than projected). Because that program represented less than one fifth of the total savings projected for the Mad River Valley project, however, the project as a whole came close to achieving its overall savings goal.

This project was initially touted as "the first of many" designed to address T&D constraints.<sup>30</sup> As discussed further below, it took more than a decade for that vision to begin to be realized. Nevertheless, it was an important stepping stone in the process of distributed utility planning in Vermont.

24 Cowart, Richard et al., "Distributed Resources and Electric System Reliability, Regulatory Assistance Project, September 2001. Available: <http://www.raponline.org/document/download/id/682>.

25 This was possible because Sugarbush was such a large portion of the load on the line. It subsequently installed a real-time meter to monitor the consumptions of its own operations and telemetry to monitor total load from all customers at the local substation. It used this information to manage its own operations, including the timing of its snow-making, to keep total loads on the substation below 30 MW. In addition to avoiding any costs associated with its responsibility for the need to upgrade the power line, Sugarbush also received a rate discount from GMP. (Ibid.)

26 Ibid.

27 Green Mountain Power Corporation, "Demand Side Management Program Filing," April 28, 1995 (Revised 5/5/95).

28 Green Mountain Power Corporation, "Demand Side Management Programs 1996 Annual Report," April 1, 1997.

29 Personal communication with Dave Grimason, former GMP efficiency program manager, November 7, 2011.

30 Green Mountain Power Corporation, "Demand Side Management Program Filing," April 28, 1995 (Revised 5/5/95), Executive Summary p. 2.

## B. More Recent Developments

In the past several years, several additional efforts to defer T&D system investments have been undertaken. In a couple of additional jurisdictions, processes have been put in place to require that efficiency and other demand resources be considered as alternatives.

### Consolidated Edison (New York City)

Consolidated Edison (Con Ed), the electric utility serving New York City and neighboring Westchester County, has been perhaps the most aggressive in the United States in integrating end-use energy efficiency into T&D planning. That integration has occurred on two levels.

First, as part of the annual development of its 10-year “load relief plan” (in which it forecasts any shortfalls in transmission, sub-transmission, and area substation capacity and establishes plans for addressing those shortfalls), the Company now routinely estimates the effects of system-wide efficiency programs on the individual peak demands of each of its 91 distribution networks and load areas, adjusting for the geographic variability in the market penetration of different efficiency programs, the load profiles of different efficiency programs, and the load profiles (and peak periods) of each distribution network. The company recently estimated that “including demand-side management in the 10-year forecast reduced projected capital expenditures by more than \$1 billion.”<sup>31</sup>

Second, Con Ed routinely assesses whether additional, geographically targeted investments in demand resources could cost-effectively defer investments in its distribution system. More important, where analysis suggests such cost-effective deferrals are possible, the utility invests in, closely tracks, and carefully evaluates the impacts of those resources. When Con Ed assesses cost-effectiveness, it considers all the benefits of efficiency investments, not just the T&D benefits (i.e., it compares the net present value of energy savings, system peak capacity savings, and T&D deferral benefits to the costs of the efficiency programs).

This geographically targeted investment in efficiency

began in 2003, when growth in demand was causing a number of Con Ed’s distribution networks to approach their peak capacity. Given the density of its customer base, much of the company’s system is underground, making upgrades expensive and disruptive. The Company thus began to assess whether it would be feasible and cost-effective to defer such upgrades through locally targeted end-use efficiency, distributed generation, fuel-switching, and other demand-side investments. At least initially, the focus was on projects “with need dates that were up to five years out and... required load relief that totaled less than 3% to 4% of the predicted network load.”<sup>32</sup> A decision was made to proceed with geographically targeted demand resource investments, however, whenever it was determined that such investments were likely to be both feasible and cost-effective.

To maximize the financial benefits of relying on demand resources, Con Ed has chosen “not to hedge its bets by continuing the T&D planning and implementation process” in parallel with its pursuit of alternative demand resources. Instead, the Company has chosen to contract out the acquisition of demand resources to ESCOs and – to address reliability risks – to include in those contracts both “significant upfront security and downstream liquidated damage provisions,” as well as rigorous measurement and verification requirements. Contract prices are established through a competitive bidding process, with the Company’s analysis of the economics of deferment being used to establish the highest price it would be willing to pay for demand resources. Those threshold prices have varied from network to network. When the amount of demand resources bid at prices below the cost-effectiveness threshold were insufficient to defer T&D upgrades, supply-side improvements have been pursued instead.

In its initial pilot phase, the Company established contracts with three ESCOs to provide load reductions in nine network areas: five in midtown Manhattan, three in Brooklyn, and one in The Bronx. In subsequent phases, four different ESCOs were contracted to deliver load reductions in 21 additional network areas: 13 in Manhattan, four on Staten

31 Gazze, Chris and Madlen Massarlian, “Planning for Efficiency: Forecasting the Geographic Distribution of Demand Reductions,” in *Public Utilities Fortnightly*, August 2011, pp. 36-41.

32 Gazze, Chris, Steven Mysholowsky, Rebecca Craft, and Bruce Appelbaum. “Con Edison’s Targeted Demand Side Management Program: Replacing Distribution Infrastructure with Load Reduction,” in *Proceedings of the ACEEE 2010 Summer Study on Energy Efficiency in Buildings*, Volume 5, pp. 117-129.

Island, and four in Westchester County. Although ESCOs were allowed to bid virtually any kind of permanent load reduction, all of the accepted bids to date have been solely for the installation of efficiency measures. There have been a couple of explorations of distributed generation, but they have not yet been shown to be cost-effective.<sup>33</sup> All told, between 2003 and 2010, the Company employed geographically targeted efficiency programs to defer T&D system upgrades in more than one third of its distribution networks.

This approach has had considerable, but not universal, success. As Figure 4 shows, in aggregate the level of peak load reduction for Phase 1, which ran through 2007, was approximately 40 MW – or 7 MW less than the contracted level. As a result, Con Ed collected considerable liquated damages from participating ESCOs. Load reductions in subsequent phases have been close to those contracted in aggregate. Those aggregate results mask some differences across network areas, however. In particular, reductions in areas dominated by residential loads with evening peaks were achieved ahead of schedule, whereas reductions in areas whose loads were dominated by commercial customers with mid-day peaks have lagged behind goals. On the other hand, much of that commercial sector savings shortfall appears attributable to the recent

Figure 4<sup>36</sup>

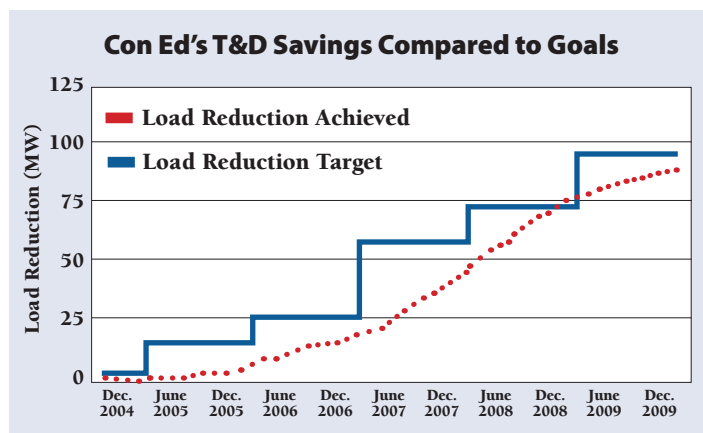
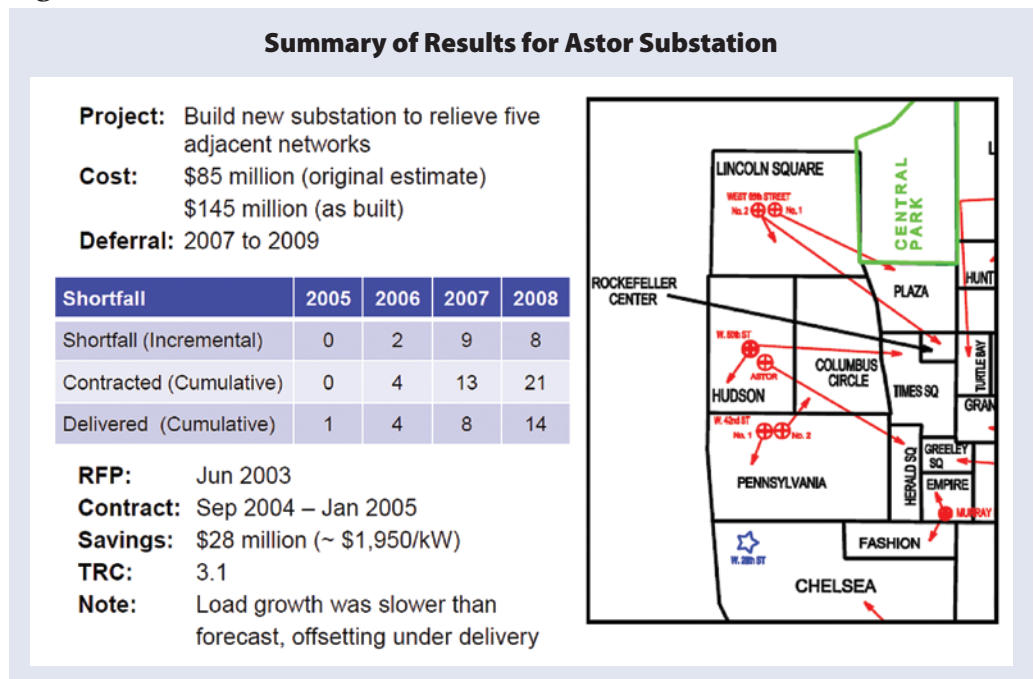


Figure 5<sup>37</sup>



economic recession, which also had the effect of dampening baseline demand, offsetting most of the efficiency program shortfalls.<sup>34</sup> As shown in Figure 5, even when there was a shortfall relative to the savings target for the largest of the T&D deferral projects Con Ed undertook in Phase 1 – the Astor Substation deferral project – the efficiency investments still produced substantial economic benefits (\$28 million, or about \$1,950 per kW of savings) that were very cost-effective (benefit-cost ratio of 3:1).<sup>35</sup>

This highlights an important benefit of efficiency programs – they are often load-following. Put another way,

33 Although all types of demand resources have been considered, only energy efficiency has been pursued to date, because it is the only demand resource proven to be cost-effective (personal communication with Chris Gazze, February 2011).

34 Gazze, Mysholowsky, and Craft (2010).

35 Gazze, Chris (Con Ed) and Bruce Appelbaum (ICF), “Con Edison’s Targeted DSM Program,” presentation at ACEEE Summer Study on Energy Efficiency in Buildings, August 18, 2010, Pacific Grove, CA.

36 Graph reproduced from Gazze, Mysholowsky, Craft, and Appelbaum (2010) with permission from Con Ed.

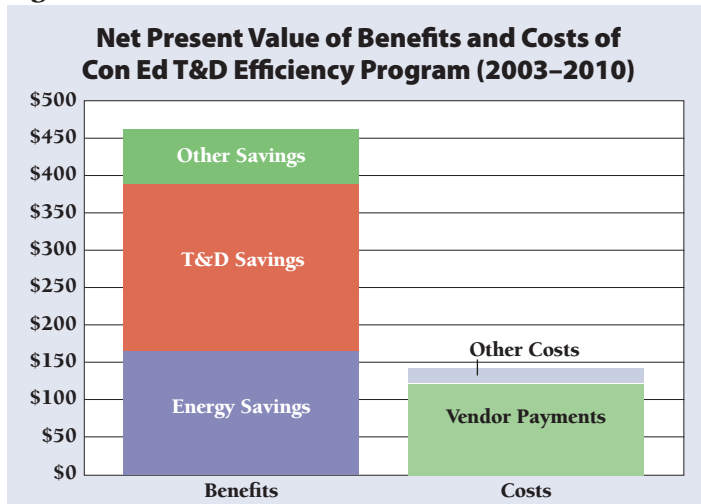
37 Graphic from Gazze and Appelbaum presentation, used with permission from Chris Gazze.

participation in efficiency programs tends to increase when load is growing more quickly and decrease when load is not growing quickly. In that sense, efficiency programs can help mitigate risk associated with forecast uncertainties. As Con Ed put it:

*“...using DSM to defer projects bought time for demand uncertainty to resolve, leading to better capital decision making. Moreover, widespread policy and cultural shifts favoring energy efficiency may further defer some projects to the point where they are never needed...In fact, Con Edison has projected that in the absence of this program it would have installed up to \$85 million in capacity extensions that may never be needed.”<sup>38</sup>*

As Figure 6 shows, in aggregate, Con Ed has saved more than \$75 million when comparing the full costs of the efficiency programs to just the T&D costs that were

**Figure 6**<sup>39</sup>



avoided. When other efficiency benefits (e.g., energy savings and system peak capacity savings) are also considered, the efficiency investments have saved Con Ed and its customers more than \$300 million.

### Efficiency Vermont Geo-Targeted DSM

Shortly after the Mad River Valley project (see discussion earlier) was completed, negotiations began within the state to shift responsibility for efficiency program administration from the utilities to a dedicated “efficiency utility” – eventually to be named “Efficiency Vermont” – that would be selected through a competitive bidding process. The settlement agreement and subsequent September 1999

Public Service Board (the Board) order that created Efficiency Vermont made clear that, although Efficiency Vermont would be responsible for statewide efficiency programs, the utilities would still be responsible for funding and implementing any additional efficiency that could be justified as cost-effective alternatives to T&D system upgrades (although they could contract implementation to Efficiency Vermont). The Board also agreed to “initiate a collaborative process to establish guidelines for distributed utility planning.”<sup>40</sup> That collaborative culminated in a set of guidelines approved by the Board in 2003,<sup>41</sup> as well as the creation of a number of “area specific collaboratives” in which opportunities for deferring specific T&D upgrades through non-wires alternatives would be explored. None of those discussions led to implementation of any such alternatives, however.

At roughly the same time (i.e., 2003), VELCO, the state’s transmission utility, formally proposed a very controversial large project to upgrade transmission lines from West Rutland to South Burlington (known as the Northwest Reliability Project). As required by Vermont law, VELCO filed an analysis of non-transmission alternatives. In all, five different combinations of alternatives were analyzed – four combinations of different kinds of local generation and a fifth combination of local generation and aggressive DSM. The analysis suggested that the four generation-only options were more expensive than the transmission line, but that the fifth option including DSM had a lower societal cost than the transmission line.<sup>42</sup> That option, however, would involve much larger capital expenditures than the transmission line. Further, whereas much of the cost of the transmission option would be socialized across the New England Power Pool (Vermont pays a very small share of the portion of costs that are socialized across the region), the cost of the alternative path would be borne entirely by Vermont ratepayers due

38 Gazze, Mysholowsky, and Craft (2010).

39 Cost and benefit data provided by Chris Gazze, February 11, 2011. Note that “other costs” includes program administration (\$2.9 million), M&V (\$9.2 million), and customer costs (\$9.9 million).

40 State of Vermont, Public Service Board Order, Docket No. 5980, pp. 54-58.

41 State of Vermont, Public Service Board Order, Docket No. 6290.

42 La Capra Associates, “Alternatives to VELCO’s Northwest Reliability Project,” January 29, 2003.



to New England ISO rules. Those concerns, coupled with VELCO's concerns that the level of DSM envisioned would be unprecedented, led the utility to argue in favor of the transmission option.<sup>43</sup> The Board ultimately approved VELCO's proposal in early 2005, but expressed concern and frustration with VELCO's planning process, namely that it did not consider alternatives, particularly efficiency, early enough in the process to make them truly viable options.<sup>44</sup>

The approval of the transmission line contributed to the passage later that year of legislation (Act 61) that eliminated the statutory spending cap for Efficiency Vermont, instructed the Board to determine the optimal level of efficiency spending, and made clear that cost-effectively deferring T&D upgrades should be one of the objectives the Board considers in establishing the budget. The Board subsequently increased Efficiency Vermont's budget by about \$6.5 million (37%) in 2007 and \$12.2 million (66%) in 2008 and ordered that all of the additional spending be focused on four geographically targeted areas: northern Chittenden County, Newport, St.

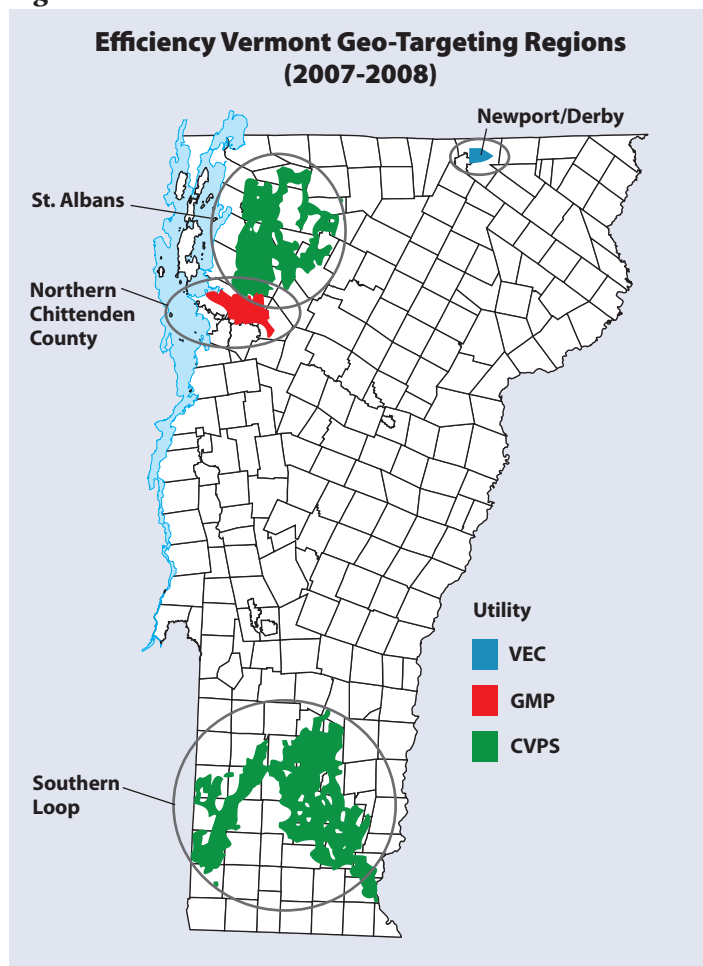
Albans, and the "southern loop" (see Figure 7).<sup>45</sup> Those areas had been identified by the state's utilities as areas in which there may be potential for deferring significant T&D investment. Collectively, these efforts became known as Efficiency Vermont's "geo-targeting" initiative.<sup>46</sup>

As Table 1 shows, these areas were fairly diverse in terms of the density of population, the geographic area they cover, the relative importance of residential vs. commercial and industrial loads, and the number of large customers. Two of the areas were summer peaking, one was winter peaking, and one had similar summer and winter peaks. The peak loads in the area varied from 18 to 70 MW in 2007. Forecasted load growth without efficiency programs ranged from 1.7% to 4.3% per year. Collectively, the four areas contained 63,000 customers – or 18% of the state's customer base. A total of 167 were large users (greater than 500 MWh of annual consumption), 8,600 were other business customers (many of them quite small), and about 54,000 were residential customers.<sup>48</sup>

It is important to note that the investment in geo-targeting was viewed by the Board, utilities, and Efficiency Vermont as a "proof of concept" experiment. The selection of the targeted areas was rushed and probably not as well vetted as necessary to ensure deferral potential. Indeed, savings targets were not established from an analysis of how much was needed to defer the capital investments. Rather, they were set based on what was estimated to be achievable given available budget resources.

The original 18-month savings targets (from mid-2007 through the end of 2008) were 7.2 MW of summer peak savings (across the three areas with summer peaks) and 7.7

Figure 7<sup>47</sup>



43 Ibid.

44 Vermont Public Service Board, "Board Approves Substantially Conditioned and Modified Transmission System Upgrade", press release, January 28, 2005.

45 State of Vermont Public Service Board, Order Re: Energy Efficiency Utility Budget for Calendar Years 2006, 2007 and 2008, 8/2/2006.

46 Efficiency Vermont Annual Plan, 2008-2009.

47 Efficiency Vermont Annual Plan, 2007-2008.

48 Massie, Jim, Nancy Wasserman, and Blair Hamilton, "Fast Capacity Reduction through Geographically Targeted, Aggressive Efficiency Investment: Early Results from a Vermont Experiment," in Proceedings of 2008 ACEEE Summer Study on Energy Efficiency in Buildings, Volume 5, pp. 194-205.

Table 1 <sup>49</sup>

Characteristics of Vermont Geographically Targeted Areas (2007-2008)								
	Urban vs. Rural	Size of Area	C&I Sales %	Large C&I Customers	Peak Period	2007 Peak (MW)	Annual Load Growth w/o DSM	Projected Load Growth w/ Targeted DSM
<b>N. Chittenden</b>	Urban	Small	65%	72	Summer	64	4.3%	1.2%
<b>Newport</b>	Urban	Small	64%	15	Both	18	1.7%	-0.5% <sup>50</sup>
<b>St. Albans</b>	Urban	Moderate	64%	42	Summer	29	3.4%	-3.3%
<b>Southern Loop</b>	Rural	Large	48%	38	Winter	70	3.4%	-3.4%

MW of winter peak savings (across the two areas with winter peaks). These targets represented a 7- to 10-fold increase in the peak savings Efficiency Vermont had achieved in the same areas during the previous 18 months. It was estimated that peak demands would not only stop growing but would actually decline in three of the four areas. In the fourth area (Chittenden North), which had the fastest natural growth rate, load growth was projected to decline by about 75% (from 4.3% to 1.2% per year).

To meet these savings goals, Efficiency Vermont implemented a three-pronged strategy:

1. Intensive account management of large commercial and industrial customers (targeted to approximately 148 customers using more than 500 MWh/year) to identify opportunities for deep savings and to negotiate financial incentives (often greater than those offered in other parts of the state) designed to achieve those savings;
2. Launch of an aggressive small commercial/industrial program (targeting those using 40 to 500 MWh/year) in which high savings measures (primarily lighting measures, but also other cost-effective HVAC, refrigeration, and custom measures) designed to achieve an average of 15% savings per business are directly installed at no cost or very low cost to the customer; and
3. Aggressive local promotion of CFLs to residential and small business customers through both targeted marketing campaigns, community awareness campaigns, and the use of direct mail coupons.

All customers in the areas were also still eligible to participate in other statewide programs.

After the selection of the initial four targeted areas, a working group consisting of the state's largest utilities, Efficiency Vermont, and the Vermont Department of Public Service developed a set of criteria for future selections for geo-targeting:

- Areas experiencing high load growth;
- Areas with known concerns regarding the capacity of existing T&D

infrastructure;

- Areas for which the minimum planning horizon for deferral was three years, with a preference for horizons of at least five years; and
- Areas for which there were “no other circumstances requiring immediate investment.”<sup>51</sup>

Ultimately, decision-making on geo-targeting priorities was supposed to move to the Vermont System Planning Committee (VSPC), which VELCO was charged by the Board with initiating. Initially, “although the VSPC was formed and has been functioning, for all intents and purposes the selection process remained with the founding geotargeting utilities.” This may have been because many parties still regarded geo-targeting as an experiment.<sup>52</sup> More recently, however, the VSPC has assumed the role it was intended to play and initiated a robust process to select targeted areas for future efforts.

Approximately one year into its delivery, one of the four initially targeted areas (Newport) was dropped from the geo-targeting program when the distribution utility determined

49 Massie et al and Navigant Consulting et al., “Process and Impact Evaluation of Efficiency Vermont’s 2007-2009 Geotargeting Program,” Final Report, Submitted to Vermont Department of Public Service, January 7, 2011, p. 103.

50 This is the forecasted growth in winter peak demand. The baseline peak demands for summer and winter were the same. Efficiency Vermont forecast that it could reduce summer peak by more than winter peak, however. That would make winter peak the more constraining variable.

51 Navigant et al. (2011), p. 3.

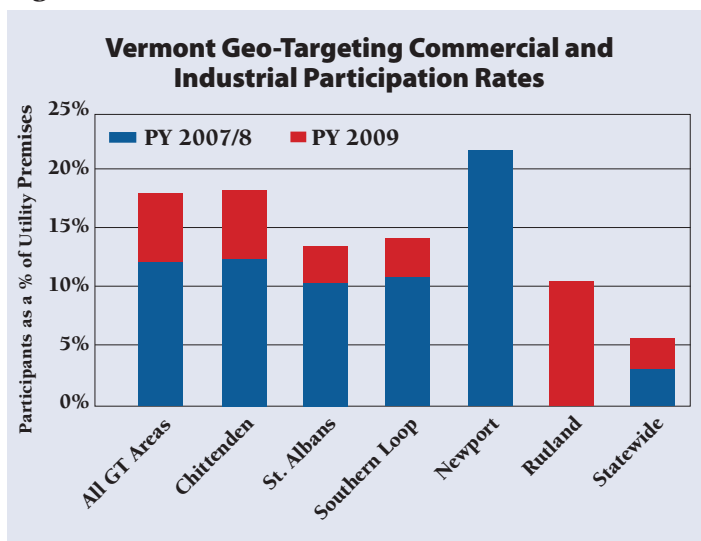
52 Ibid.



that the substation whose rebuilding the program was intended to defer needed to be rebuilt for reasons other than load growth (i.e., “destabilization of the substation property due to river flooding”).<sup>53</sup> Independent of that decision, a new target area – Rutland – was added to the program beginning in 2009.

A recent evaluation of the geo-targeting program suggests that it has had some success, although not all results were as good as hoped or projected. To begin with, efficiency program participation was considerably higher in geo-targeted areas than in the rest of the state. For example, as Figure 8 shows, commercial and industrial customers in geo-targeted areas participated at a rate nearly four times as great as their counterparts in the rest of the state. For those areas that were in their third year of geo-targeted DSM in 2009, the participation rate multiplier (compared to the rest of the state) declined to 2 to 1. The multiplier for the newly added geo-targeted region (Rutland), however, was roughly the same 4 to 1 ratio experienced by the other regions in their first two years.<sup>54</sup> Savings per participant were also higher than in the statewide programs – 20% to 25% higher for commercial and industrial customers and 30% higher for residential customers. That increase appears to reflect success in achieving greater depth of lighting savings per participant rather than increased penetration of non-lighting efficiency measures.<sup>55</sup> The net result of those two factors was summer peak demand savings that were three to five times greater (depending on the region) in the first couple of years of the program than would have been achieved under the statewide programs.<sup>56</sup>

Figure 8<sup>57</sup>



All told, over the 2007 to 2009 time period, the program achieved summer peak demand reductions in the targeted areas of 10 MW – about 70% of its goal. Winter peak demand savings were more problematic, with the program achieving only 4.1 MW of reductions, or only about 40% of its goal. Nevertheless, analysis of loads on individual feeders in geo-targeted areas suggests that geo-targeting program impacts “are detectable at the system level” and that the magnitude of savings observed at the utility system level was consistent with those estimated through evaluation of customer savings.<sup>58</sup>

Evaluation of the impacts of the observed peak demand reductions on the potential deferral of T&D investments has not yet been conducted. Central Vermont Public Service (the state’s largest utility), however, has observed that it “has not been required to schedule the deployment of additional system upgrades in Rutland, St. Albans and Southern Loop areas.” While it is difficult to know the extent to which that situation should be attributed to the geo-targeting of DSM, to changes in economic conditions (i.e., the recent economic recession), or to other factors, the Company has recommended to the Board that geo-targeting of DSM continue.<sup>59</sup>

## Central Maine Power

In June of 2010, the Maine Public Utilities Commission approved a settlement agreement reached by Central Maine Power (CMP) and a variety of other parties (including several public interest advocates) regarding a large transmission

53 Navigant et al. (2011), p. 26.

54 Navigant et al. (2011), pp. 85-87.

55 Navigant et al. (2011), pp. 89-91.

56 It is important to note that the statewide programs are already considered quite aggressive, achieving greater savings as a percent of sales than any state in the country in both 2007 (Eldridge, Maggie et al., *The 2009 State Energy Efficiency Scorecard*, ACEEE Report Number E097, October 2009) and 2008 (Molina, Maggie et al., *The 2010 State Energy Efficiency Scorecard*, ACEEE Report Number E107, October 2010).

57 Graphic courtesy of Navigant Consulting.

58 Navigant et al. (2011), p. 10.

59 Silver, Morris, Counsel for Central Vermont Public Service, letter to the Vermont Public Service Board regarding “EEU Demand Resources Plan – Track C, Geotargeting,” January 18, 2011.

system upgrade project (the Maine Power Reliability Project) that the utility had proposed.<sup>60</sup> The settlement supported construction of most elements of the upgrade, but identified two areas – the Mid-Coast region and the city of Portland – where pilot projects to test the efficacy of non-transmission alternatives would be launched.

As part of the settlement, CMP was required to conduct a needs assessment for the two regions and develop a proposal for using non-transmission alternatives in conjunction with one of the intervening parties – Grid Solar. In March 2011, CMP and Grid Solar filed a proposed plan for the Mid-Coast region. The plan looked at a couple of different scenarios, ultimately recommending an approach that would require 25 to 29 MW of distributed resources in the Camden-Rockland area and another 10 MW of distributed resources in the Boothbay region to fully obviate the need for a transmission upgrade. It also proposed to use an RFP process to identify and acquire the least cost mix of resources to meet this need. It further suggested the resources be acquired in phases, with the first RFP covering needs from 2012 through 2015 (10 MW in Camden-Rockland and 6 MW in Boothbay). Subsequent RFPs would be developed and issued “based on load growth in the Mid-coast area, on the performance of distributed resources under contract pursuant to prior RFP(s), and on changes to the physical electric transmission and distribution system circuits in the Mid-Coast area.”<sup>61</sup>

Under the proposal, any distributed resource would be eligible to respond to the RFP, including:

- Existing back-up generators (the plan identified 45 generators with a combined capacity of 25 MW in the region);
- New generators that could be acquired to provide both back-up capability to customers as well as distributed resources for the pilot;
- Demand response resources (as much as 15 MW were estimated to be in the region);
- Targeted energy efficiency (the plan estimating maximum achievable potential in the Mid-Coast region to be 15 MW, but suggested that 10 MW of that amount was already captured in CMP’s load forecast, leaving only 5 MW to potentially be acquired);
- Solar PV (the plan suggested that solar PV would not likely be competitive with other resources, but that it may be appropriate to set aside a portion of the RFP as a “solar carve out” to test the applicability of PV as

a transmission resource); and

- Storage (which was also estimated to be too expensive for initial rounds of procurement).

The plan noted that Vermont’s experience with geographically targeted efficiency programs suggested that efficiency resources would likely be “highly competitive with other distributed resources.” It also suggested that the Efficiency Maine Trust, which is responsible for and funded to implement statewide efficiency programs, could bid enhancements to its efficiency initiatives in the target region in response to the RFP. The plan left unaddressed, however, the question of how baseline levels of savings (from which additional savings from a more aggressive set of geographically targeted efforts would presumably be measured) would be established. It was also not clear whether the plan anticipated the possibility of other efficiency resource providers bidding in response to the RFP.<sup>62</sup>

These issues have not yet been fully explored. In the summer of 2011 the Maine PUC held a Technical Conference on the plan. Among the topics discussed were the impacts of both the economic recession and new (more stringent) reliability standards issued by the North American Electric Reliability Council (NERC) on the forecast resource needs. CMP and Grid Solar are expected to examine these issues and file a new needs analysis and plan in late November 2011. A second Technical Conference is expected to follow in December 2011.<sup>63</sup>

## NV Energy

In 2008 NV Energy faced a situation in a relatively rural portion of its service territory, east of Carson City, in which growth in demand was going to need to be met by either running the locally situated but relatively expensive Fort Churchill generating station more frequently or constructing a 30-mile, 345-kVA transmission line and new substation

60 Maine Public Utilities Commission, Order Approving Stipulation, Docket No. 2008-255, June 10, 2010.

61 Central Maine Power and Grid Solar, Non-Transmission Alternative Pilot Plan and Smart Grid Proposal including Attachments 1-7, filed under Docket No. 2008-255 (Phase II), March 25, 2011.

62 Ibid.

63 Personal communication with Beth Nagursky, Environment Northeast, 11/16/11.

to bring less expensive power from the more efficient Tracy generating facility (situated further north, about 20 miles east of Reno) to the region. When the local county commission began expressing concerns about permitting construction of the substation, regulators instructed the Company to increase the intensity of its DSM efforts in the targeted region as an alternative to meeting the area's needs economically:

*"...the concentration of DSM energy efficiency measures in Carson City, Dayton, Carson Valley and South Tahoe has the potential to reduce the run time required for the Ft. Churchill generation units. The increased marketing costs and increased incentives and subsequent reduction in program energy savings required to attain an increased participation in the smaller market area are estimated to be more than offset by reduced fuel costs. Sierra Pacific, d.b.a. NV Energy, will make a reasonable effort within the approved DSM budget and programs to concentrate DSM activities in this area..."*<sup>64</sup>

NV Energy pursued a variety of efforts to either focus its existing DSM programs more intensely on the Fort Churchill area and/or launch new initiatives. This included:<sup>65</sup>

- **Non-Profit Agency Grants.** NV Energy gave priority to projects in the impacted area and marketed the program accordingly. In the end, 12 of the 35 applications it received were from the targeted area.
- **Energy Education.** NV Energy concentrated its education events in the region, ultimately holding 19 in 2009 – up from just two the previous year.
- **Low Income Weatherization.** NV Energy asked its implementation contractor to make a special effort to solicit program participation in the targeted area. Participation in the targeted area increased from just eight homes in 2008 to 57 in 2009.
- **ENERGY STAR Lighting and Appliances.** NV Energy concentrated marketing and outreach events in the Fort Churchill area, leading to an increase in participation of nearly 20% (although estimated savings did not increase due to changes in assumptions regarding average run times of CFLs).
- **Second Refrigerator Collection and Recycling.** NV Energy increased marketing efforts in the targeted region, in part through a targeted door-to-door campaign that also included distribution of nearly 100,000 CFLs to more than 16,000 homes. This resulted in increased participation in the refrigerator recycling program of nearly 15% in the targeted

region, as well as substantial lighting savings.

- **Energy Smart Schools.** NV Energy offered an "Energy Master Planning Service" to the Carson City and Douglas County School Districts, but both declined the service. The utility also launched a new initiative to distribute CFLs to school district employees.
- **Commercial Retrofit Incentive.** NV Energy renegotiated its contract with its program vendor to support increased marketing in the targeted area, increase financial incentives by 25% in the targeted area, and concentrate all direct install efforts in the target area. The result was a more than 260% increase in savings in the area.
- **Sure Bet Hotel Motel.** NV Energy increased marketing support and financial incentives for this program as well, but no increase in participation was realized.

Of these efforts, the second refrigerator collection and recycling program (primarily the CFL distributions) and the commercial retrofit program were together responsible for the vast majority of the increased DSM savings in the region.<sup>66</sup>

At the same time as these efficiency efforts were launched, NV Energy's transmission staff began re-conductoring the existing 120-kVA line to the region to increase its carrying capacity. The economic recession also hit at the same time, dampening growth. As a result, the Company has not had to revisit the need for either the additional power line and substation or increasing the run time of the Fort Churchill generating station. The project has also facilitated the beginnings of "rich conversations" between demand resource planners and transmission planners within the Company.<sup>67</sup>

64 Jarvis, Daniel et al., *Targeting Constrained Regions: A Case Study of the Fort Churchill Generating Area*, 2010 ACEEE Summer Study on Energy Efficiency in Buildings, Volume 5, pp. 178-189.

65 Sierra Pacific Power Company, 2010 Annual Demand Side Management Update Report, July 1, 2010, pp. 6-9.

66 Ibid, and Jarvis et al.

67 Personal communication with Larry Holmes, NV Energy, 11/9/11.

### 3. Lessons Learned

Although the actual implementation of efficiency as an alternative to T&D investments has not yet been what one might call “widespread,” there are enough examples in sufficiently diverse circumstances to draw initial conclusions.

#### Geographically Targeted Energy Efficiency Can Defer T&D Investments

A number of studies have suggested that aggressive, geographically targeted efficiency programs can meet T&D reliability objectives. More important, analyses of the actual deployment of efficiency as alternatives to T&D in several jurisdictions have concluded that supply-side investments were deferred for at least some period of time (e.g., Con Ed in New York City, Green Mountain Power’s Mad River Valley Project in Vermont, PG&E’s Delta Project in California, portions of PGE’s project in downtown Portland, Oregon).

#### Efficiency Can Be a Cost-Effective T&D Resource

There is less evidence regarding the cost-effectiveness of efficiency as an alternative to T&D upgrades. However, analysis of the most intensive and long-standing effort to defer T&D investments with efficiency programs – Con Ed’s experience in New York City – clearly concluded that the geographically targeted programs were very cost-effective. Indeed, the T&D benefits alone were greater than the costs of the programs. When other benefits (e.g., energy savings and system peak demand savings) are included in the analysis, the geographically targeted efficiency programs had a benefit-to-cost ratio of about 3 to 1.

The realization that energy efficiency provides a variety of electric system benefits is critically important, as that broad range of benefits can often render the pursuit of more intensive efficiency programs in localized areas a

“no regrets” strategy – at least from a purely economic perspective. Indeed, even though a determination of whether the recent Efficiency Vermont geo-targeting program has deferred T&D system upgrades has not yet been definitively made, evaluation of the program suggests it has been cost-effective – with a benefit cost-ratio of about 2 to 1 (under the Total Resource Cost Test) – even if no T&D investments are deferred.<sup>68</sup>

This suggests that, in most cases, the most important concerns regarding the deployment of efficiency as a T&D resource will likely be efficiency savings forecast issues (i.e., particularly uncertainty about whether enough customers will install enough efficiency measures to actually avoid a reliability-driven investment) and possibly equity issues (i.e., concerns about customers in targeted areas getting greater access to and/or greater financial incentives from efficiency programs than those in other areas).

#### Stuff Happens! Unexpected Events Can Affect Benefits of Efficiency

It is worth noting that in several of the case studies examined for this report some or all of the T&D investment being considered for deferral ultimately ended up being constructed for reasons having nothing to do with the effectiveness of the deployment of efficiency resources. For example, part of PGE’s project in Portland, Oregon (to defer a transformer upgrade for one commercial building) ended when the conversion from gas to electric cooling for the building added too much load to be offset by demand-side measures. More recently in Vermont, one of the original areas targeted for locally intensive DSM programs (Newport) was removed from the program when the existing substation became destabilized due to flooding, necessitating an immediate supply-side investment. In each of those cases, it could be concluded that the investments in efficiency programs ultimately provided either no T&D

68 Navigant et al. (2011), p. 100. Similar analyses for other case studies examined are not available.

benefit or very little benefit.

It is important to recognize that forecasting uncertainty works in both directions, however. In several of the examples discussed in this paper it appears as if efficiency investments not only permitted deferral of a T&D investment, but permanently eliminated the need for the investment. This happened either because the efficiency savings realized were greater than forecast (e.g., in one of the commercial buildings treated by PGE's program in Portland, Oregon) or because the efficiency investments bought enough time for more fundamental changes in demand to take hold (e.g., Con Ed's conclusion that \$85 million in T&D investments that it otherwise would have made may now never be needed).

The bottom line is that there are a variety of risks associated with forecasting of T&D system needs that can affect the potential benefits of using efficiency to defer T&D system investments. These include:

- The reliability risk of under-forecasting demand growth;
- The economic risk of over-building the T&D system due to over-forecasting of demand growth; and
- Both the reliability risk (if it takes longer than expected) and the economic risk (if it ends up costing more)<sup>69</sup> of siting new poles and wires.

It could be argued that efficiency programs are more likely to mitigate than to exacerbate these risks. To begin with, many efficiency programs are "load-following." For example, efficiency programs designed to promote efficiency in the construction of new buildings will generally have lower participation and savings when construction slows (i.e., when savings are least needed) and higher participation and savings when construction accelerates (i.e., when savings are most needed). Similarly, efficiency programs often have a harder time convincing home-owners and businesses to participate – and therefore have a harder time meeting savings goals – during difficult economic times (i.e., when loads are not growing fast and therefore concerns about exceeding T&D system capacity are lower); they often have an easier time recruiting

participants and exceeding savings goals during good economic times (i.e., when loads are naturally growing faster, imposing greater strains on T&D systems). Indeed, the reality that Efficiency Vermont launched its geo-targeting program just before the recent deep economic recession was probably a contributing factor to their failure to meet initial savings goals. On the other hand, as Central Vermont Public Service has implied, the recession is likely part of the reason the Company has not had to deploy additional system upgrades in its portion of the targeted areas.

### **Sufficient Lead Time is Critical**

It usually takes time to generate enough savings from energy efficiency programs to defer T&D system upgrades. The programs must be planned, developed, and then marketed to consumers before any savings are realized. Reaching a large segment of the eligible market requires on-going marketing and business development efforts. Initial strategies may not be as successful as anticipated, so programs are more likely to be successful if there is time to refine them in response to market feedback. As discussed above, PG&E's Delta Project did not have that luxury and, as a result, ended up falling short of overall savings goals and spending more per unit of savings than originally planned. Even though a very cost-effective strategy was identified part of the way through the project, there was not enough time for it to gain enough traction to offset the less effective results of some of the initially pursued elements. Sufficient lead time may also better enable efficiency program managers to demonstrate to T&D system planners and engineers that efficiency strategies are affecting localized peak loads. Parts of PGE's downtown Portland project ultimately failed to defer T&D upgrades not because the efficiency savings were inadequate, but rather because T&D planners and engineers did not have sufficient confidence that the savings would be achieved and be reliable and persistent.

To be sure, the amount of lead time necessary to enable efficiency programs to defer T&D investments will vary

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<sup>69</sup> For example, in July 2005, about six months after its proposal to construct a major new transmission line and make other related improvements was approved by the Vermont Board of Public Utilities, VELCO filed with the Board a revised cost estimate that was nearly double the estimate it had made two to three years earlier and presented during the course of the hearing on the project. In order of importance, the increase was attributed to a high rate of inflation for the materials and services needed, regulatory conditions of the approval, and better (higher) estimates of the materials it would need (State of Vermont Public Service Board, Order on Remand RE: Reopening Proceedings, Docket 6860, 9/23/2005).

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from project to project. In general, shorter lead times will be needed when the number of customers that must be served by efficiency programs in order to generate sufficient savings is small. One key to ensuring there is sufficient lead time is to conduct more systematic planning for meeting T&D needs, including long-term forecasting of potential needs, integrating the forecasting of such needs with forecasting of savings from system-wide efficiency initiatives, and including analysis of potential additional, localized efficiency programs in early stages of assessment of options for meeting T&D needs.

### **Smaller is Easier**

In general, the smaller the area being addressed, the easier it is to consider efficiency and other non-wires alternatives to T&D investments. Smaller areas mean that efficiency savings need to be acquired from fewer customers. That in turn means that it is often easier to characterize the opportunity for efficiency investments accurately. It also means that shorter lead times will be needed. For example, deferring a transformer upgrade on a single large commercial building may not require much time if one need just convince a single owner of the building to make an efficiency investment. Alternatively, deferring distribution substations or transmission lines serving many thousands of customers will usually take longer unless there are just a few large customers who, if served by an efficiency program, could impact localized peak demands significantly.

### **Distribution is Easier than Transmission**

Deferring distribution system investments is generally easier than deferring transmission investments because the non-wires solutions will generally be smaller in scope (see discussion above). In addition, distribution system planning is generally less technically complex, involves fewer parties, does not involve regional ISOs/RTOs, and

does not involve regional cost-allocation frameworks that often bias investments in favor of “poles and wires” solutions.

### **Cross-Discipline Communication is Critical**

This may seem self-evident, but it is critical nonetheless. T&D planners and engineers are often skeptical of the potential for end-use efficiency to reliably substitute for poles, wires, and other T&D “hardware.” They worry that customers themselves are unreliable. Similarly, staff responsible for administration of programs that promote efficiency, load control, distributed generation, or other demand resources typically do not fully understand the complexities of the reliability issues faced by T&D system planners. Both need to better understand the needs and capabilities of the other.

It can take time to develop the relationships and confidence necessary for efficiency program implementers and their evaluated results and T&D system engineers to work together effectively. Those relationships and that trust must be developed, however, if efficiency programs are to be as successful as possible in deferring T&D investments.

Upper management can be very important in setting expectations that such communication and cross-discipline learning take place within a utility. It is much more difficult to institutionalize such communication when transmission planning has regional elements and implications that necessarily involve the ISO/RTO.

### **Integrate Efficiency with Other Distributed Resources**

Although efficiency programs can sometimes be sufficient to defer T&D investments, other times they will not be. They can, however, be married with promotion of demand-response and distributed generation initiatives to meet the same objective.



## 4. Recommendations

Though several pilot projects in the past and some more substantial projects today appear to have demonstrated that efficiency programs can be a cost-effective T&D resource, such efforts remain uncommon. Put another way, the potential economic and other benefits of using geographically targeted efficiency programs as a T&D resource are largely being ignored today. Some fundamental policy changes are required if that is to change. In this concluding section of the paper we discuss the policies that should be explored if efficiency's potential is to be realized.

### Require Least-Cost T&D Planning

As noted above, both economic incentives in many states and system planning culture have made “poles and wires” (or T&D hardware) the default solution to T&D-related reliability issues almost everywhere. Experience to date suggests that the only way that will change is if T&D planners are required by legislators or regulators to analyze alternatives and choose the least-cost option.<sup>70</sup>

Over the past decade, several jurisdictions have institutionalized such processes. Several notable examples are summarized below. There are certainly costs to such processes – both for the utilities doing the planning and for regulatory oversight. Feedback from several jurisdictions, however, suggests that the process evolves – as it is tested and refined – to one in which the burden on the utility is not only manageable but also much more than offset by cost savings. Once that point is reached and utilities are meeting a high standard in their work, the burden on regulators should be quite modest.

### Rhode Island

In 2006, Rhode Island adopted a “System Reliability Procurement” policy that requires utilities to submit system reliability procurement plans every three years. Guidelines detailing what to include in those plans were adopted more recently (see Appendix A). Those guidelines make clear that plans must consider non-wires alternatives – including energy efficiency, distributed generation, and demand response – whenever the T&D need:

- Is not based on an asset condition;
- Will likely cost more than \$1 million to address;
- Would require no more than a 20% reduction in peak load to defer; and
- Would not require investment in a “wires solution” to begin for at least 36 months.

For such cases, the plans must include analysis of financial impacts, risks, the potential for synergistic benefits, and other aspects of both wires and non-wires alternatives.<sup>71</sup>

### Vermont

Vermont has long imposed an integrated resource planning requirement on its utilities. However, the passage of Act 61 in 2005 – which reinforced those requirements by specifying minimum 10-year planning horizons, required the plans to be filed at least every three years, and required public meetings (in areas close to potential T&D upgrades) at which plans are presented (see Appendix B for legislative language) – has begun to make the process more rigorous. Indeed, VELCO and Efficiency Vermont are now working together to regularly reconcile and integrate

<sup>70</sup> Note that this works only to the extent that states actually control the planning process. Although they do for distribution system investments, responsibility for transmission planning decisions is shared with regional ISOs/RTOs. That has lessened states ability to effectively impose least-cost planning requirements. Recent FERC Order 1000, which requires ISOs/RTOs to consider state policies in planning decisions, may give states more influence in the future.

<sup>71</sup> Rhode Island Standards for Least Cost Procurement and System Reliability Planning.

their respective forecasts of baseline demand and efficiency program savings.<sup>72</sup>

### **Bonneville Power Administration**

Although not required by legislation or regulation, in 2002 BPA launched a Non-Wires Solutions (NWS) initiative in which it committed to investigating “least-cost solutions that may result in deferring potential transmission reinforcement projects.”<sup>73</sup> A year later, BPA formed a Non-Wires Solutions Round Table composed of key stakeholder groups in the region to assist it in these endeavors.<sup>74</sup> It then developed a formal process by which non-wires solutions – including energy efficiency, demand response, load control, and distributed generation – would be routinely assessed. To begin with, transmission planners annually assess potential transmission needs over the next 10 to 15 years. That assessment is tied to the Western Electricity Coordinating Council’s power flow and planning framework.<sup>75</sup> Once a transmission need is identified by BPA’s Transmission Business Line, an initial “screening” is conducted to determine whether the project is a candidate for possible non-wires solutions. A project qualifies for an analysis of non-wires solutions if it meets three criteria:

1. The transmission project cost is estimated to be at least \$5 million;
2. The project need is driven by load growth; and
3. The project need is at least eight years out.<sup>76</sup>

If these criteria are met, a high level economic assessment is conducted using a simplified spreadsheet template that has been developed specifically for this purpose. The analysis includes all of the potential benefits of non-wires solutions. Estimates of energy savings and capacity savings benefits are based on results of the Northwest Power Planning Council’s integrated resource plans (conducted every five years). Avoided transmission costs are estimated for the specific project under consideration. If the analysis suggests both that there are sufficient non-wires resources to defer a project and that the deferral could be cost-effective, a detailed feasibility study is conducted. If that study confirms that the non-wires solution is indeed feasible, then the benefits, costs, and risks of both traditional transmission and non-wires solutions are compared to decide which strategies to pursue. This process is summarized in Figure 9. BPA went through this process on four different occasions between 2002 and 2006. In all of those cases a determination was made that the traditional transmission strategy was needed.

BPA recently reconvened its Non-Wires Round Table to consider new regional transmission needs in this same framework. Three potential non-wires projects are currently undergoing intensive analysis and discussion. Energy efficiency is an element of the non-wires solution being considered for both the I-5 corridor in Oregon and the Hooper Springs area in Idaho. Efficiency plays a more central role in a third potential project that has not yet been made public.<sup>77</sup>

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72 This has not been without its challenges, because assumptions about such things as treatment of baseline efficiency conditions, the level of “naturally occurring” efficiency (related to free rider assumptions in efficiency savings forecasts), and other key issues are sometimes different or inconsistent (see Enterline, Shawn and Eric Fox, *Integrating Energy Efficiency into Utility Load Forecasts*, in Proceedings of the 2010 ACEEE Summer Study on Energy Efficiency in Buildings, Volume 5, pp. 86-96).

73 GDS Associates, “Process Evaluation of the Non-Wires Solution Initiative,” prepared for BPA, June 8, 2007.

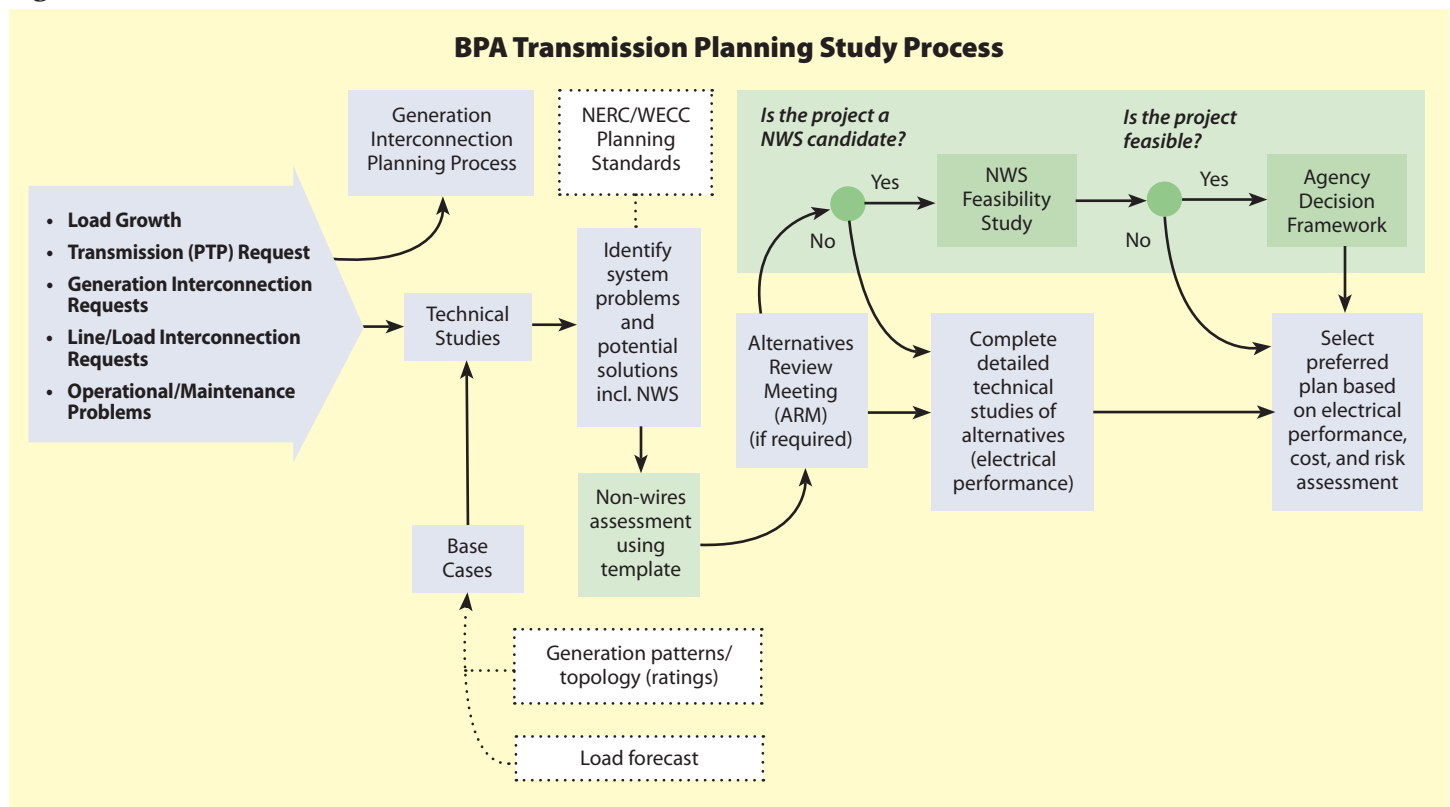
74 Although the Round Table has been organized to function collaboratively, its input is purely advisory. BPA makes all final decisions on how to address transmission needs.

75 Personal communication with Mike Weedall, Ottie Nabors, and Josh Binus, Bonneville Power Administration, 4/27/11.

76 Nabors, Ottie, “Non-Wires Alternatives Screening Process & Evaluation,” presentation at the Non-Wires Round Table, April 15, 2011.

77 Personal communication with Mike Weedall, BPA, 12/23/11.

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Figure 9 <sup>78</sup>


## Require Consideration of Integrated Solutions

Efficiency is one of several types of distributed resources – demand response, load control, and distributed generation are other notable examples – that can help to cost-effectively defer T&D investments. Indeed, there may be important synergies in combining deployment of efficiency and other distributed resources (e.g., efficiency and demand response and potentially even distributed generation can often be “sold” to customers more effectively if sold together). Any requirement for least-cost planning thus should make clear that all options, including different combinations of distributed resources, should be considered.

The ability for states to require either least-cost planning or consideration of integrated solutions is clear with respect to distribution system planning, but more complicated for transmission planning because of transmission’s regional implications and the involvement of regional ISOs/RTOs. Nevertheless, states have influenced transmission planning, and the recent FERC Order 1000, which requires ISOs/RTOs to consider state policies in their planning decisions, may give them more clout in the future.

## Institutionalize a Long-Term Planning Horizon

The longer the lead time, the more likely it will be that efficiency (or other distributed resources) could cost-effectively defer traditional T&D investments. This suggests it is critical that assessments of T&D needs are both long-term and conducted on a regular basis. As noted above, although they are all still refining their processes, all of the jurisdictions that are currently seriously considering non-wires alternatives to T&D investments are routinely forecasting T&D needs at least 10 years into the future. Con Ed develops a 10-year plan for T&D needs. Vermont requires an annual plan that looks out a minimum of 10 years. VELCO, Vermont’s transmission utility, has chosen to forecast 20 years out. Similarly BPA looks at transmission needs 10 to 15 years into the future.

78 Graphic from Nabors, Ottie, “Non-Wires Alternatives Screening Process & Evaluation,” presentation at the Non-Wires Round Table, April 15, 2011.

## **“Level the Playing Field” in Payment for Wires and Non-Wires Alternatives**

One of the biggest barriers to serious consideration of efficiency (and other demand resources) as alternatives to T&D investments is the unequal treatment of the costs of wires and non-wires solutions. For example, nearly 90% of the nearly \$290 million cost of VELCO’s Northwest Reliability Project in Vermont has been deemed by the New England ISO to be eligible for Pooled Transmission Facility (PTF) treatment – or spread across the New England region.<sup>79</sup> Because Vermont represents a relatively small portion of the total regional power pool load, its ratepayers pay only about 5% of PTF costs. Its rate-payers thus will ultimately bear less than 20% of total project costs. The ISO does not give PTF treatment to non-wires solutions. As a result, if the state had pursued a non-wires solution to its transmission reliability needs, it would have borne 100% of the costs of the project.

Such policies represent enormous disincentives to pursue non-wires solutions – even if they are less expensive than traditional transmission investments. Unbalanced treatment of wires and non-wires solutions needs to be addressed if least-cost solutions are to be routinely and seriously considered.

## **Collect More Data on Efficiency’s Impacts**

In much of the country, relatively little end-use metered data on the hourly and seasonal impacts of efficiency resources has been collected and made public over the past two decades. As a result, many jurisdictions now rely on very old end-use metering studies when developing hourly load shapes for efficiency measures. Such load shapes are essential to estimating the impacts of efficiency resources on localized transmission or distribution system peaks (peak hours can vary considerably from one distribution

element to another, even within the same utility service territory). Having more data of this kind should make it easier to address concerns of T&D system planners.

It is worth noting that the New England region may be ahead of much of the rest of the country in this regard, in part because the region’s forward capacity market requires efficiency resource providers to use studies that are less than five years old to document achievement of the system peak demand savings that are bidding into the market. That requirement has resulted in a number of different end-use metering studies that have not only documented savings at the time of the regional system peak, but also at all other hours of the day. In many cases, the studies have been undertaken at the regional level – with all states sharing the cost – as a way to make them affordable.

## **Start with Pilot Projects**

Virtually every jurisdiction that genuinely considered efficiency as a potential cost-effective alternative to T&D investments started with pilot projects. Much has been learned from those pilots. The pilots also offered important venues for facilitating the mutual education of system engineers and efficiency program managers. Experience to date suggests that a pilot project or two will not bridge the cultural chasms between these two groups. They can be important steps in that process, however.

## **Leverage “Smart Grid” Investments**

A number of utilities have recently made or are about to make significant investments in advanced metering, customer feedback mechanisms, and other “smart grid” features. Customer and end-use data collected through such systems may enable better assessments of the potential for efficiency to serve as a T&D resource in general, and perhaps more important, in specific geographic areas.

79 ISO New England, “Summary of ISO-NE Reviewed TCA Applications under Schedule 12C of the Tariff” – Status as of 2/18/2011 ([http://www.iso-ne.com/trans/pp\\_tca/status/tca\\_application\\_status.pdf](http://www.iso-ne.com/trans/pp_tca/status/tca_application_status.pdf))

## Appendix A

# Rhode Island Standards for Least Cost Procurement and System Reliability Planning – Excerpt on Distributed Resources in Relation to T&D Investment

## Chapter 2 - System Reliability Procurement

### Section 2.1 Distributed/Targeted Resources in Relation to T&D Investment

- A. The Utility System Reliability Procurement Plan (“The SRP Plan”) to be submitted for the Commission’s review and approval on September 1, 2011 and triennially thereafter on September 1, shall propose general planning principles and potential areas of focus that incorporate non-wires alternatives (NWA) into the Company’s distribution planning process for the three years of implementation beginning January 1 of the following year.
- B. Non-Wires Alternatives (NWA) may include but are not limited to:
- Least Cost Procurement energy efficiency baseline services
  - Peak demand and geographically-focused supplemental energy efficiency strategies
  - Distributed generation generally, including combined heat and power and renewable energy resources (predominately wind and solar, but not constrained)<sup>80</sup>
  - Demand response
  - Direct load control
  - Energy storage
  - Alternative tariff options
- C. Identified transmission or distribution (T&D) projects with a proposed solution that meet the following criteria will be evaluated for potential NWA that could reduce, avoid or defer the T&D wires solution over an identified time period.
- The need is not based on asset condition;
  - The wires solution, based on engineering judgment, will likely cost more than \$1 million;
  - If load reductions are necessary, then they are expected to be less than 20 percent of the relevant peak load in the area of the defined need;
- d. Start of wires alternative is at least 36 months in the future; and  
A more detailed version of these criteria may be developed by the distribution utility with input from the Council and other stakeholders.
- D. Feasible NWAs will be compared to traditional solutions based on the following:
- Ability to meet the identified system needs
  - Anticipated reliability of the alternatives
  - Risks associated with each alternative (licensing and permitting, significant risks of stranded investment, sensitivity of alternatives to differences in load forecasts, emergence of new technologies)
  - Potential for synergy savings based on alternatives that address multiple needs
  - Operational complexity and flexibility
  - Implementation issues
  - Customer impacts
  - Other relevant factors
- E. Financial analyses of the preferred solution(s) and alternatives will be conducted to the extent feasible. The selection of analytical model(s) will be subject to Public Utilities Commission review and approval. Alternatives may include the determination of deferred investment savings from NWA through use of net present value of the deferred revenue requirement analysis or the net present value of the alternatives according to the Total Resource Cost Test (TRC). The selection of an NWA shall be informed by the considerations approved by the Public Utilities Commission which may include, but not be limited to, those issues enumerated in (D), the deferred revenue requirement savings and an evaluation of costs and benefits according to the TRC. Consideration of the net present value of resulting revenue

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<sup>80</sup> In order to meet the statute’s environmental goals, generation technologies must comply with all applicable general permitting regulations for smaller-scale electric generation facilities.



requirements may be used to inform the structure of utility cost recovery of NWA investments and to assess anticipated ratepayer rate and bill impacts.

F. For each need where an NWA is the preferred solution, the distribution utility will develop an implementation plan that includes the following:

- a. Characterization of the need
  - i. Identification of the load-based need, including the magnitude of the need, the shape of the load curve, the projected year and season by which a solution is needed, and other relevant timing issues
  - ii. Identification and description of the T&D investment and how it would change as a result of the NWA
  - iii. Identification of the level and duration of peak demand savings and/or other operational functionality required to avoid the need for the upgrade
  - iv. Description of the sensitivity of the need and T&D investment to load forecast assumptions
- b. Description of the business as usual upgrade in terms of technology, net present value, costs (capital and O&M), revenue requirements, and schedule for the upgrade
- c. Description of the NWA solution, including description of the NWA solution(s) in terms of technology, reliability, cost (capital and O&M), net present value, and timing
- d. Development of NWA investment scenario(s)
  - i. Specific NWA characteristics
  - ii. Development of an implementation plan, including ownership and contracting considerations or options
  - iii. Development of a detailed cost estimate (capital and O&M) and implementation schedule

G. Funding Plan

The Utility shall develop a funding plan based on the following sources to meet the budget requirement of the system reliability procurement plan. The Utility may propose to utilize funding from the following sources for system reliability investments:

- i. Capital funds that would otherwise be applied towards traditional wires based alternatives

- ii. Existing Utility EE investments as required in Section I of these Standards and the resulting Annual Plans
- iii. Additional energy efficiency funds to the extent that the NWA can be shown to pass the TRC test with a benefit to cost ratio of greater than 1.0 and such additional funding is approved
- iv. Utility operating expenses to the extent that recovery of such funding is explicitly allowed
- v. Identification of significant customer contribution or third party investment that may be part of an NWA based on benefits that are expected to accrue to the specific customers or third parties
- vi. Any other funding that might be required and available to complete the NWA

H. Annual SRP Plan reports should be submitted on November 1. Such reports will include but are not limited to:

- a. A summary of projects where NWA were considered;
- b. Identification of projects where NWA were selected as a preferred solution; and a summary of the comparative analysis following the criteria outlined in sections (D) and (E) above;
- c. Implementation plan for the selected NWA projects;
- d. Funding plan for the selected NWA projects;
- e. Recommendations on pilot distribution and transmission project alternatives for which it will utilize selected NWA reliability and capacity strategies. These proposed pilot projects will be used to inform or revise the system reliability procurement process in subsequent plans;
- f. Status of any previously selected and approved projects and pilots;
- g. Identification of any methodological or analytical tools to be developed in the year;
- h. Total SRP Plan budget, including administrative and evaluation costs.

I. The Annual SRP Plan will be reviewed and funding approved by the Commission prior to implementation.

## Appendix B

# Excerpts from Vermont's Act 61

### Sec. 8. Advocacy For Regional Electricity Reliability Policy

It shall be the policy of the state of Vermont, in negotiations and policy-making at the New England Independent System Operator, in proceedings before the Federal Energy Regulatory Commission, and in all other relevant venues, to support an efficient reliability policy, as follows:

- (1) When cost recovery is sought through region-wide regulated rates or uplift tariffs for power system reliability improvements, all available resources – transmission, strategic generation, targeted energy efficiency, and demand response resources – should be treated comparably in analysis, planning, and access to funding.
- (2) A principal criterion for approving and selecting a solution should be whether it is the least-cost solution to a system need on a total cost basis.
- (3) Ratepayers should not be required to pay for system upgrades in other states that do not meet these least-cost and resource-neutral standards.
- (4) For reliability-related projects in Vermont, subject to the review of the public service board, regional financial support should be sought and made available for transmission and for distributed resource alternatives to transmission on a resource-neutral basis.
- (5) The public service department, public service board, and attorney general shall advocate for these policies in negotiations and appropriate proceedings before the New England Independent System Operator, the New England Regional Transmission Operator, the Federal Energy Regulatory Commission, and all other appropriate regional and national forums. This subdivision shall not be construed to compel litigation or to preclude settlements that represent a reasonable advance to these policies.
- (6) In addressing reliability problems for the state's electric system, Vermont retail electricity providers and transmission companies shall advocate for regional cost support for the least cost solution with equal consideration and treatment of all available resources, including transmission, strategic distributed generation, targeted energy efficiency, and demand response resources on a total cost basis. This subdivision shall not be construed to compel litigation or to preclude settlements that represent a reasonable advance to these policies.

### TRANSMISSION AND DISTRIBUTION PLANNING

*Sec. 9. 30 V.S.A. § 218c is amended to read:*

#### **§ 218C. Least Cost Integrated Planning**

- (d)(1) Least cost transmission services shall be provided in accordance with this subsection. Not later than July 1, 2006, any electric company that does not have a designated retail service territory and that owns or operates electric transmission facilities within the state of Vermont, in conjunction with any other electric companies that own or operate these facilities, jointly shall prepare and file with the department of public service and the public service board a transmission system plan that looks forward for a period of at least ten years. A copy of the plan shall be filed with each of the following: the house committees on commerce and on natural resources and energy and the senate committees on finance and on natural resources and energy. The objective of the plan shall be to identify the potential need for transmission system improvements as early as possible, in order to allow sufficient time to plan and implement more cost-effective non-transmission alternatives to meet reliability needs, wherever feasible. The plan shall:
  - (A) identify existing and potential transmission system reliability deficiencies by location within Vermont;
  - (B) estimate the date, and identify the local or regional load levels and other likely system conditions at which these reliability deficiencies, in the absence of further action, would likely occur;
  - (C) describe the likely manner of resolving the identified deficiencies through transmission system improvements;
  - (D) estimate the likely costs of these improvements;
  - (E) identify potential obstacles to the realization of these improvements; and
  - (F) identify the demand or supply parameters that generation, demand response, energy efficiency or other non-transmission strategies would need to address to resolve the reliability deficiencies identified.
- (2) Prior to the adoption of any transmission system plan, a utility preparing a plan shall host at least two public meetings at which it shall present a draft of the plan and facilitate a public discussion to identify and evaluate non-transmission alternatives. The meetings shall be at separate locations within

the state, in proximity to the transmission facilities involved or as otherwise required by the board, and each shall be noticed by at least two advertisements, each occurring between one and three weeks prior to the meetings, in newspapers having general circulation within the state and within the municipalities in which the meetings are to be held. Copies of the notices shall be provided to the public service board, the department of public service, any entity appointed by the public service board pursuant to subdivision 209(d)(2) of this title, the agency of natural resources, the division for historic preservation, the department of health, the scenery preservation council, the agency of transportation, the attorney general, the chair of each regional planning commission, each retail electricity provider within the state, and any public interest group that requests, or has made a standing request for, a copy of the notice. A verbatim transcript of the meetings shall be prepared by the utility preparing the plan, shall be filed with the public service board and the department of public service, and shall be provided at cost to any person requesting it. The plan shall contain a discussion of the principal contentions made at the meetings by members of the public, by any state agency, and by any utility.

(3) Prior to the issuance of the transmission plan or any revision of the plan, the utility preparing the plan shall offer to meet with each retail electricity provider within the state, with any entity appointed by the public service board pursuant to subdivision 209(d)(2) of this title, and with the department of public service, for the purpose of exchanging information that may be relevant to the development of the plan.

(4)(A) A transmission system plan shall be revised:

- (i) within nine months of a request to do so made by either the public service board or the department of public service; and
- (ii) in any case, at intervals of not more than three years.

(B) If more than 18 months shall have elapsed between the adoption of any version of the plan and the next revision of the plan, or since the last public hearing to address

a proposed revision of the plan and facilitate a public discussion that identifies and evaluates nontransmission alternatives, the utility preparing the plan, prior to issuing the next revision, shall host public meetings as provided in subdivision (2) of this subsection, and the revision shall contain a discussion of the principal contentions made at the meetings by members of the public, by any state agency, and by any retail electricity provider.

(5) On the basis of information contained in a transmission system plan, obtained through meetings held pursuant to subdivision (2) of this subsection, or obtained otherwise, the public service board and the department of public service shall use their powers under this title to encourage and facilitate the resolution of reliability deficiencies through nontransmission alternatives, where those alternatives would better serve the public good. The public service board, upon such notice and hearings as are otherwise required under this title, may enter such orders as it deems necessary to encourage, facilitate or require the resolution of reliability deficiencies in a manner that it determines will best promote the public good.

(6) The retail electricity providers in affected areas shall incorporate the most recently filed transmission plan in their individual least cost integrated planning processes, and shall cooperate as necessary to develop and implement joint least cost solutions to address the reliability deficiencies identified in the transmission plan.

(7) Before the department of public service takes a position before the board concerning the construction of new transmission or a transmission upgrade with significant land use ramifications, the department shall hold one or more public meetings with the legislative bodies or their designees of each town, village, or city that the transmission lines cross, and shall engage in a discussion with the members of those bodies or their designees and the interested public as to the department's role as public advocate.

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# Acronym Glossary

<b>ACEEE</b>	American Council for an Energy Efficient Economy	<b>ISO</b>	Independent System Operator
<b>AMI</b>	Advanced Metering Infrastructure	<b>NERC</b>	North American Electric Reliability Council
<b>BPA</b>	Bonneville Power Administration	<b>NWS</b>	Non-Wires Solutions
<b>C &amp; I</b>	Commercial and Industrial	<b>PGE</b>	Portland General Electric
<b>CFLs</b>	Compact Fluorescent Light Bulbs	<b>PG&amp;E</b>	Pacific Gas and Electric
<b>CMP</b>	Central Maine Power	<b>PTF</b>	Pooled Transmission Facility
<b>Con Ed</b>	Consolidated Edison	<b>PTP</b>	Point-to-point
<b>DR</b>	Demand Response	<b>RTO</b>	Regional Transmission Organization
<b>DSM</b>	Demand-Side Management	<b>SPWG</b>	State Program Working Group
<b>EEI</b>	Edison Electric Institute	<b>SRP</b>	System Reliability Procurement
<b>EPRI</b>	Electric Power Research Institute	<b>T&amp;D</b>	Transmission and Distribution
<b>ESCO</b>	Energy Service Company	<b>TRC</b>	Total Resource Cost
<b>FCM</b>	Forward Capacity Market	<b>VELCO</b>	Vermont Electric Power Company
<b>FERC</b>	Federal Energy Regulatory Commission	<b>VSPC</b>	Vermont System Planning Committee
<b>GMP</b>	Green Mountain Power	<b>WECC</b>	Western Electricity Coordinating Council



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