GEC Response to Enbridge Interrogatory #1

Question:

Reference: Exhibit L.GEC.1, page 7
EB-2015-0049, Exhibit B, Tab 1, Schedule 2, Page 25 of 26

Preamble:

Page 7 of GEC's report states that "The current Technical Evaluation Committee (TEC) and Audit Committee (AC) processes work fairly well and should be retained with some important modifications….However, several refinements to those processes would be welcome:

a. Adding Board staff to all of the committees.
b. Removing the last vestiges of control of the Custom Project Savings Verification (CPSV) processes from the utilities; ideally the Auditor should now hire and manage the CPSV work.
c. Establishing a streamlined process for addressing the few situations in which consensus is not reached in the TEC."

Request:

a) Please confirm that page 18 of Section 7.1.3 in the Board's Guidelines already addresses having the auditor hire the CPSV firm.

"…the Board will be responsible for selecting an auditor to assess the results of the natural gas utilities' DSM programs. The Board will strive to have an auditor hired by October 1st for the year to be audited[1]*. This would enable the auditor to hire engineering firm(s) who will conduct verification studies, including custom project savings verifications ("CPSV") and the evaluation of other programs…"*

b) Please further confirm that the Audit Committee were involved in reviewing the bids, selecting the CPSV firm and involved in subsequent discussions with the CPSV firm.

[1] This process will begin in 2015 and be applicable to the 2015 DSM program year results.

Response:

a) Confirmed. Since the Board's guidelines are just that – guidelines – I thought it important to highlight the key changes to the current process that would be important. In this case, my recommendation is consistent with the Board's guidelines.

Witness: Chris Neme

b) Partially confirmed; partially not confirmed. I do not recall having ever seen a written proposal or bid from a CPSV firm; nor have I ever been invited, as a member of Enbridge's Audit Committee to participate in a process to select a CPSV firm from among a set of competing proposals.

That said, my recollection is that the 2013 Enbridge Audit Committee did endorse a request by Enbridge to sole source its 2013 Commercial CPSV work to the firm that did the work in 2012. It also had an opportunity to provide input on the 2013 Industrial CPSV bidders list. Only one bid was received in response to the 2013 Industrial CPSV RFP. Also, in 2014, a decision was made by the TEC to allow – for practical purposes – the utilities to use the same CPSV firms for their 2014 audits as they use for their 2013 audits.

It is also fair to say that Audit Committee members were involved in meetings with the CPSV firms periodically throughout the 2014 audit process.

GEC Response to Enbridge Interrogatory #2

Question:

Reference: Exhibit L.GEC.1, page 10

Request:

Of statewide natural gas DSM budgets within each jurisdiction presented in Figure 1, please identify the portion of natural gas DSM budgets which are dedicated to programs which do not seek to achieve direct or measureable natural gas savings (i.e. non-Resource Acquisition programs).

Response:

All of these jurisdictions, to varying degrees, devote effort to non-resource acquisition activities including support for compliance with building codes, general education, research and development activities and pilot programs. However, it is often not easy to discern from reported spending levels what portion of DSM budgets are allocated to such activities.

Witness: Chris Neme

GEC Response to Enbridge Interrogatory #3

Question:

Reference: Exhibit L.GEC.1, page 10

Request:

For each jurisdiction in Figure 1, please provide any goals, objectives, principles or priorities of natural gas DSM which may be considered equivalent to the guiding principles and key priorities outlined by the Board in its DSM Framework.

Response:

In general, the jurisdictions referenced in Figure 1 are addressing goals, objectives, principles and/or priorities that are in many ways comparable to those articulated by the Board in its recent DSM framework. They may not be identical, but they are generally similar. It is difficult to document all of the goals and objectives in these jurisdictions because they are not necessarily all articulated in one place. Thus, the examples provided below should be viewed as only illustrative and not comprehensive.

Massachusetts[1]

The Massachusetts utilities' joint 2013-2015 DSM plan filing identifies the following as among their goals and objectives:

- "Capture all cost effective energy efficiency";
- "Maximize societal net economic benefits";
- Address "climate and environmental goals";
- "Consider both short term customer bill impacts and longer-term benefits expected from proposed efforts";
- "focusing on education-based initiatives in schools as a way to help create a culture of sustainability in the state";
- "training for trade allies in support of infrastructure development" and to promote "economic development and job growth";
- "addressing…accessibility and affordability, as well as any tenant-landlord or unique service territory barriers, through…programs, initiatives, community engagement efforts and hard-to-measure programs";
- "integrating gas and electric energy efficiency services";

[1] Massachusetts Utilities Joint Statewide Three-Year Electric and Gas Energy Efficiency Plan: 2013-2015, November 2, 2013, regulatory cases D.P.U. 12-100 to D.P.U. 12-111 Exhibit 1.

- “engaging third party stakeholders”; and
- embracing “innovation”.

Rhode Island[2]

National Grid summarizes its primary goal as to “create economic value and cost savings for Rhode Islanders through energy efficiency.” It noted that it adopted four high level strategies to meet that goals:

- “Energy Efficiency is for Everyone” – in which the utility “focused on broadening the portfolio of programs and removing participation barriers so that every Rhode Island customer could benefit and more would participate.”
- “Reaching Customers Where They Live and Work” – in which the utility endeavored to design program strategies that brought efficiency services to customers “in ways that increased the value of energy efficiency specifically for them”.
- “Innovation” – this objective is self-explanatory. However, it is worth noting that one way the utility addresses it is to implement pilot programs to test new technology and/or program concepts.
- “Economic Growth” – “the utility looked for new ways to contribute to the addition of jobs in Rhode Island.”

Vermont[3]

Vermont Gas is required to “design and implement demand-side services and initiatives to comprehensively address cost-effective opportunities associated with natural gas energy efficiency.” In doing so it must:

- “Increase the efficiency of buildings, equipment, products, and other end uses;
- Reduce absolute energy use through controls, sizing, operation and maintenance practices, and other consumer actions;
- Maximize the acquisition of Net Benefits for all customers;
- Prioritize lost opportunity markets;
- Pursue market transformation strategies;
- Coordinate with and leverage regional and national efficiency efforts;
- Provide all VGS Eligible Customers with the opportunity to participate in EEU (Energy Efficiency Utility) services and initiatives;

[2] The Narragansett Electric Company (d/b/a National Grid), “2014 Energy Efficiency Year-End Report”, RIPUC Docket No. 4451, May 1, 2015.
[3] Vermont Public Service Board, “Order of Appointment for Vermont Gas Systems, Inc., Pursuant to 30 V.S.A. § 209(d)(2), April 17, 2015.

- Strive to provide comprehensive services to all customers;
- Provide information, technical assistance, and/or financial incentives for cost-effective demand-side resources to help overcome market barriers to their implementation;
- Seek to maximize and facilitate customer contributions;
- Pursue innovative approaches to the cost-effective acquisition of energy efficiency resources;
- Make continuous and proportional progress toward attaining the overall state building efficiency goals established by 10 V.S.A. § 581, by promoting all forms of energy end use efficiency and comprehensive sustainable building design;
- Design and implement programs that are extendable and scalable in future years to achieve § 581 goals;
- Coordinate the services and initiatives established under this Appointment with those of similar programs, including programs offered by other EEUs appointed to provide service to customers who are also VGS customers, so as to maximize administrative efficiency and the benefits provided to Vermonters consistent with principles of least cost integrated resource planning;[4]
- Provide information and education that will empower consumers to manage their energy use."
- "Be responsible for the development of comprehensive approaches to acquiring all reasonably available, cost-effective demand-side resources to reduce customer natural gas requirements, as contemplated under 30 V.S.A. § 209(d) and (e), and § 218c, including:
  - Reducing natural gas capacity requirements through peak day and base load reduction and management in targeted areas, if applicable;" and
  - "Participating in gas system planning and cooperating with the Department of Public Service ("DPS" or "Department"), Vermont Utilities, and the EEUs authorized to provide service to customers who are also VGS customers in the provision of least cost service under 30 V.S.A. § 218c."

Minnesota[5]

Statutory requirements include:

- An annual energy savings goal of at least 1.0% of sales.[6]

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[4] Note that all such "other EEUs" in the state are primarily charged with promoting electric efficiency.
[5] CenterPoint Energy, 2016 Conservation Improvement Plan, Docket No. G008/CIP-12-564, June 1, 2015.
[6] The savings requirement applies to sales to non-exempt customers. Minnesota law allows some large customers to opt out of DSM. For example, in the case of Centerpoint, Minnesota's largest gas utility, approximately 15% of its sales are to exempt customers. For 2016, Centerpoint is proposing to achieve savings from its non-exempt customers equal to 1.80% of its sales to those customers.

- Utilities must spend at least 0.4% of gross operating revenue from residential customers on low income programs.
- Utilities' programs must support "professional engineering verification" to qualify a building as Energy Star-labeled, LEED certified or Green Globes-certified.
- May spend up to 10% of DSM funds on research and development
- Must estimate both on peak and annual energy savings
- Must facilitate the involvement of community energy organizations

GEC Response to Enbridge Interrogatory #4

Question:

Reference: Exhibit L.GEC.1, page 18

Request:

a) Please provide a version of Table 3 on page 18 which includes a column for first year benefits only (as opposed to net present value of benefits).

b) Please also provide a column with first year costs.

Response:

a) and b) See table below. Note that some of the values in the original table in my evidence have been updated and/or corrected (see M.GEC.EP.1).

		1st Year Benefits per Annual m^3 Saved		1st Year Benefits as % of Avg Annual Budget (2016-2020)		NPV of Benefits per Annual m^3 Saved		NPV of Benefits from Utilities' Proposed 2016-2020 DSM Plans (millions $)		NPV of Benefits as % of Avg Annual Budget (2016-2020)	
	Benefit	**Enbridge**	**Union**	**Enbridge**	**Union**	**Enbridge**	**Union**	**Enbridge**	**Union**	**Enbridge**	**Union**
1	Avoided carbon regulation costs	$0.05	$0.05	6%	7%	$0.98	$0.98	$73.2	$73.9	101%	129%
2	Price suppression effects	$0.01	$0.01	1%	1%	$0.08	$0.08	$6.2	$6.3	9%	11%
3	Reduce purchase of most expensive gas	$0.01	$0.02	1%	2%	$0.10	$0.18	$7.2	$13.3	10%	23%
4	Avoided distribution system costs	$0.04	$0.02	4%	3%	$0.38	$0.24	$28.1	$18.2	39%	32%
	Total	**$0.11**	**$0.10**	**11%**	**13%**	**$1.54**	**$1.49**	**$114.7**	**$111.7**	**158%**	**195%**

The inclusion of a column showing first year costs could be confusing as there are no costs associated with each of the rows in Table 3. Thus, I have instead included columns showing the percent of average annual DSM budgets that the first year benefits would offset. That is consistent with how the table compares NPV of benefits to annual DSM budgets in the last two columns.

Note that concerns about the fact that benefits occur over time while DSM costs are felt in the year in which they occur could be addressed by amortizing (rather than expensing) DSM costs. Note also that DSM programs in 2014, 2013, 2012 and all other preceding years will be providing the same kinds of rate-reducing impacts, to participants and non-participants alike, in 2015, 2016 and other future years (i.e. for the lives of the efficiency measures installed).

Witness: Chris Neme

GEC Response to Enbridge Interrogatory #5

Question:

Reference: Exhibit L.GEC.1, page 19

"…the combined effects on rates of *both* DSM budgets *and* the system-wide benefits they produce…would be on the order of $1 per month *reduction* over the life of the efficiency measures installed."

Request:

Please provide a detailed description of the inputs and formulae used to establish the above noted value in excel format.

Response:

This was not a calculation performed in Excel. Rather it was computed using a simple logic as follows:

- The utilities average annual DSM budgets over the 2016-2020 period were at levels approximately consistent with the Board's guidelines to keep spending to about $2 per month per residential customer.

- Mr. Neme's estimates of the benefits that accrue to all ratepayers, including non-participants, were estimated (per Table 3 of his evidence) to be on the order of 1½ times the utilities' average DSM spending levels.

- $2 – (1.5 X $2) = ~-$1

Witness: Chris Neme

GEC Response to Enbridge Interrogatory #6

Question:

Reference: Exhibit L.GEC.1, page 32

"…many customers have measures with very short paybacks that they do not pursue without DSM program support."

Request:

a) Please confirm that there are factors beyond payback, and perhaps in spite of short paybacks, that a customer considers when deciding whether or not to pursue a DSM project.

b) Please elaborate on what other barriers there might be to uptake of energy savings activities without DSM assistance.

Response:

a) Confirmed.
b) There are many other potential barriers, including the following:
   - Customers' lack of information on the opportunity for cost-effective savings
   - Customers' inability to devote the time to assess efficiency opportunities given other demands on their time
   - Customers' lack of information on which contractors or vendors of efficient products and services to trust;
   - Competing demands for capital and/or lack of access to capital;
   - Vendors and/or others in the supply chain do not always routinely stock the most efficient equipment;
   - Limited ability of some contractors or vendors of efficiency services to fully diagnose opportunities for cost-effective savings (i.e. lack of technical skill)
   - Split incentives between landlords and tenants, as well as between builders/developers and future building owners
   - Lenders do not typically fully value the benefits of efficiency when assessing either consumers' eligibility for loans or interest rates that should be charged (to reflect different risks of loan defaults)
   - A mismatch between utility supply-side planning horizons and customers' investment horizons.

   Not all of these barriers apply in all cases.

Witness: Chris Neme

GEC Response to Enbridge Interrogatory #7

Question:

Reference: Exhibit L.GEC.1, page 41

Preamble:

Mr. Neme references two reports that he co-authored; one with Mr. Grevatt (2015), and another with Mr. Sedano (2012).

Request:

Please provide the cited reports.

Response:

The Neme and Sedano report was filed in the GTA pipeline case EB-2012-00451 at M.GEC.EGD.6 Attachment A.

The Neme & Grevatt report is attached.

Witness: Chris Neme

Northeast Energy Efficiency Partnerships

Energy Efficiency as a T&D Resource:

Lessons from Recent U.S. Efforts to Use Geographically Targeted Efficiency Programs to Defer T&D Investments

January 9, 2015

Chris Neme & Jim Grevatt, Energy Futures Group

About NEEP & the Regional EM&V Forum

REGIONAL EVALUATION,
MEASUREMENT & VERIFICATION FORUM

NEEP was founded in 1996 as a non-profit whose mission is to serve the Northeast and Mid-Atlantic to accelerate energy efficiency in the building sector through public policy, program strategies and education. Our vision is that the region will fully embrace energy efficiency as a cornerstone of sustainable energy policy to help achieve a cleaner environment and a more reliable and affordable energy system.

The Regional Evaluation, Measurement and Verification Forum (EM&V Forum or Forum) is a project facilitated by Northeast Energy Efficiency Partnerships, Inc. (NEEP). The Forum's purpose is to provide a framework for the development and use of common and/or consistent protocols to measure, verify, track, and report energy efficiency and other demand resource savings, costs, and emission impacts to support the role and credibility of these resources in current and emerging energy and environmental policies and markets in the Northeast, New York, and the Mid-Atlantic region.

About Energy Futures Group

EFG is a consulting firm that provides clients with specialized expertise on energy efficiency markets, programs and policies, with an emphasis on cutting-edge approaches. EFG has worked with a wide range of clients – consumer advocates, government agencies, environmental groups, other consultants and utilities – in more than 25 states and provinces.

Table of Contents

Acknowledgements

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This report benefitted from the contributions of the many professionals who are designing, implementing, testing, and regulating the use of energy efficiency and other non-wires approaches as alternatives to traditional T&D construction. We especially thank the following for giving us their assistance:

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- T.J. Poor, Vermont Public Service Department;
- Gillian Eaton, Efficiency Vermont;
- Chuck Cohen & colleagues, Maine Public Utilities Commission;
- Beth Nagusky, formerly Environment Northeast;
- Dan Blais, GridSolar;
- Ian Barnes, Efficiency Maine;
- Jeff Schlegel, Schlegel & Associates;
- Marco Padula, NY Public Service Commission;
- Nita Zimmerman and colleagues, Bonneville Power Administration
- Eric Winkler, ISO New England
- Sharon Daly, MA Department of Public Utilities

The generous contributions of time and knowledge from those listed above made the report possible, but any fault for errors or mischaracterizations that it may contain lies with the authors alone.

[1] See: http://www.neep.org/sites/default/files/EMV-Forum_Geotargeting_Subcommittee-List_12-5-14.pdf.

I. Introduction

Improvements in the efficiency of energy use in homes and businesses can provide substantial benefits to the consumers who own, live in and work in the buildings. They can also reduce the need for capital investments in electric and gas utility systems – benefits that accrue to all consumers whether or not they participate in the efficiency programs. This report focuses on the role efficiency can play in deferring utility transmission and distribution (T&D) system investments. In particular, it addresses the role that intentional targeting of efficiency programs to specific constrained geographies – either by itself or in concert with demand response, distributed generation and/or other "non-wires alternatives" (NWAs)[2] – can play in deferring such investments. The report focuses primarily on electric T&D deferral, since that is where efforts in this area have focused to date. However, the concepts should be equally applicable to natural gas delivery infrastructure.

The report builds on a report published by the Regulatory Assistance Project (RAP) nearly three years ago.[3] Selected portions of the text of the RAP report – particularly for older case studies for which no update was necessary – have been re-used here. Several of the case studies highlighted in the RAP report have evolved considerably in the intervening years. There are also new case studies on which to report. This report documents these experiences and highlights some important new developments in the field that the recent experience has brought to light. In addition, to address the interests of the Regional EM&V Forum project funders, this report also includes an explicit set of policy recommendations or "guidelines".

The remainder of the report is organized as follows:

> **Section II: Efficiency as a T&D Resource** – summarizes the magnitude and drivers of T&D investment in the U.S., and provides an introduction to the concept of geo-targeting efficiency programs to defer some such investments.

> **Section III: Summaries of Examples** – provides high level summaries of about a dozen examples across the U.S. in which geographically targeted efficiency has been employed and/or is in the process of being employed, either alone or in combination with other NWAs, in order to defer more traditional T&D investments.

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[2] We use the term "non-wires alternatives" (NWAs) throughout this paper when referring to a range of alternatives to investment in the T&D system. That term is synonymous with "non-wires solutions", "non-transmission alternatives" (when referring to just the transmission portion of T&D), "grid reliability resources", "distributed energy resources", and other terms sometimes used by other parties. It should be noted that "non-wires" is an imperfect, "shorthand" term that is intended to refer to alternatives to a wide range of traditional T&D infrastructure investments, many of which – e.g. substations and/or transformers – are not really "wires".

[3] Neme, Chris and Rich Sedano, *"U.S. Experience with Efficiency as a Transmission and Distribution System Resource"*, Regulatory Assistance Project, February 2012.

Section IV: Detailed Case Studies – provides more detailed discussions of four of those examples which offer unique insights.

Section V: Cross-Cutting Observations and Lessons Learned – summarizes key conclusions the authors have drawn from the case studies examined in the report.

Section VI: Policy Recommendations – presents four policies that state governments should consider pursuing if they would like to effectively advance consideration of non-wires alternatives to traditional T&D investments.

Section VII: Bibliography **–** provides a list of all of the documents referenced in the report.

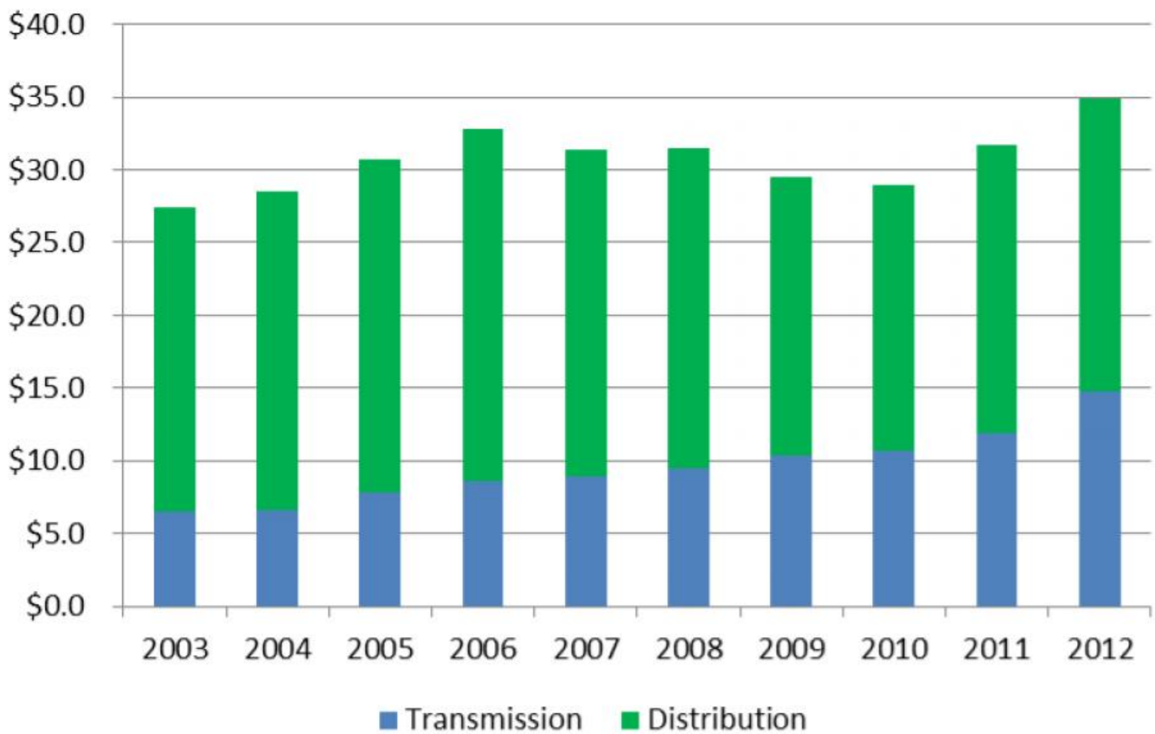
Appendices – contain excerpts from legislation in Vermont, Maine and California; regulatory standards for Rhode Island; and screening forms for Vermont that underpin those states' current requirements to consider and, where appropriate, promote non-wires alternatives.

II. Energy Efficiency as a T&D Resource

Context – Historic and Future Electric Utility T&D Investments

As Figure 1 shows, T&D investments by investor-owned electric utilities, which collectively account for approximately two-thirds of electricity sales in the U.S., have averaged a little more than $30 billion a year over the past decade. If public utilities[4] were investing at a comparable rate, total national investment would have been on the order of $45 billion per year.

Figure 1: T&D Investment by U.S. Investor-Owned Utilities (Billions of 2012 Dollars)[5]



That level of investment is expected to continue or increase in the future, with studies suggesting that the industry will spend an average of roughly $45 billion per year over the next two decades.[6,7] That would represent approximately 60% of forecasted utility capital investment.[8]

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[4] Public utilities include municipal utilities, rural electric cooperatives and the Tennessee Valley Authority.
[5] Edison Electric Institute, Statistical Yearbook of the Electric Power Industry 2012 Data, Table 9.1.
[6] Chupka, Marc et al. (The Brattle Group), *Transforming America's Power Industry: The Investment Challenge 2010-2030*, prepared for the Edison Foundation, November 2008. Harris Williams & Co., *Transmission and Distribution Infrastructure*, a Harris Williams & Co. White Paper, Summer 2014 (http://www.harriswilliams.com/sites/default/files/industry_reports/ep_td_white_paper_06_10_14_final.pdf?cm_mid=3575875&cm_crmid=e5418e44-29ef-e211-9e7f-00505695730e&cm_medium=email)
[7] Note that the ultimate cost to electric ratepayers may be significantly greater, since ratepayers will pay a rate of return on all investments made by regulated utilities.
[8] Chupka, Marc et al. (The Brattle Group), *Transforming America's Power Industry: The Investment Challenge 2010-2030*, prepared for the Edison Foundation, November 2008.

As discussed below, only a portion of T&D investment could potentially be deferred through deployment of energy efficiency and/or other non-wires alternatives. Data on the portion of U.S. T&D investment that might be deferrable are not currently available.

When Efficiency Programs Can Affect T&D Investments

T&D investments are driven by a number of different factors. Among these are:

- The need to replace aging T&D infrastructure;
- The need to address unexpected equipment failures;
- The need to connect new generation – this is particularly important for renewable electric generation that is often sited in somewhat remote locations, but can also be true for other types of electric generation;
- A desire to provide access to more economic sources of energy and peak capacity; and
- The need to address load growth.

Needless to say, some of these needs would not be significantly affected by the customer investments in energy efficiency or the programs that promote such investments. In particular, investments related to the condition of a T&D asset – whether equipment has failed due to a defect or natural disaster or whether it is just too old and/or has become insufficiently reliable – are largely unaffected by the level of end use efficiency. In that context, it is worth noting that one of the reasons some are predicting national investment in electric T&D infrastructure to be substantial in the coming years is that much of the existing infrastructure is old. For example, it is estimated that approximately 70% of transformers are over 25 years old (relative to a useful life of 25 years), 60% of circuit breakers are over 30 years old (relative to a useful life of 20 years), 70% of transmission lines are 25 years old or older ("approaching the end of their useful life"), and more than 60% of distribution poles were installed 40 to 70 years ago (i.e. are approaching or have surpassed expected useful life of 50 years).[9] All told, the electric utility industry has estimated that between 35% and 48% of T&D assets either currently or will soon need to be replaced simply because of their age and/or condition.[10]

On the other hand, energy efficiency programs can defer T&D investments whose need is driven, at least in part, by economic conditions and/or growing peak loads. In that context, it is important to note that even if total electricity sales are not growing, peak load may be. Also, even if peak loads in a region are not growing *in aggregate*, they may be growing in a portion of the region to the point where they may be putting stress on the system.

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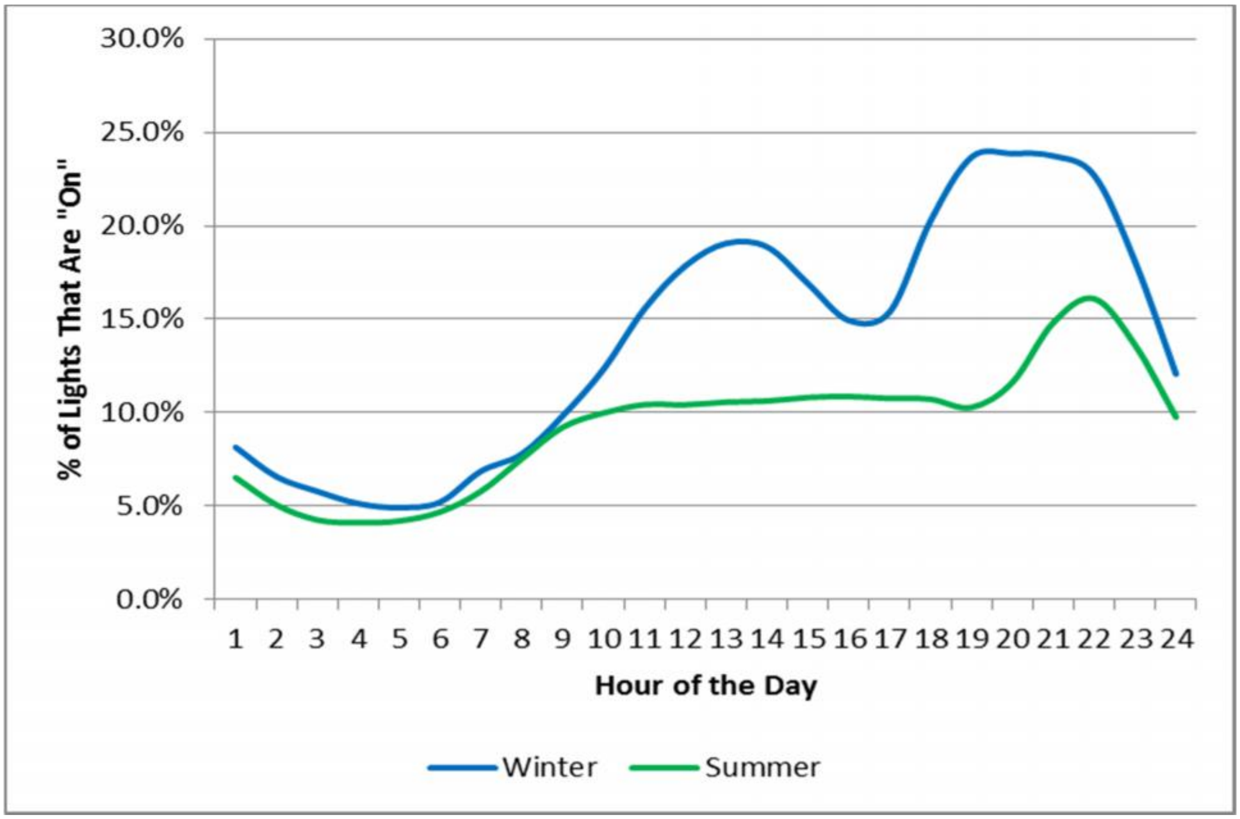
[9] Harris Williams & Co., *Transmission and Distribution Infrastructure*, a Harris Williams & Co. White Paper, Summer 2014 (http://www.harriswilliams.com/sites/default/files/industry_reports/ep_td_white_paper_06_10_14_final.pdf?cm_mid=3575875&cm_crmid=e5418e44-29ef-e211-9e7f-00505695730e&cm_medium=email).
[10] Ibid.

How Efficiency Programs Can Affect T&D Investments

Different elements of the T&D system can experience peak demand at different times of day and even in different seasons. Thus, the extent to which an efficiency program can help defer a T&D investment will depend on the hour and season of peak and the hourly and seasonal profile of the efficiency program's savings. For example, as shown in Figure 2, a program to promote the sale and purchase of compact fluorescent light bulbs (CFLs) provides some energy savings during every hour of the day (when sales are spread across many thousands of customers), but greater savings in winter than in summer and more savings in the evening than during the day.

Figure 2: Average Hourly CFL Usage Patterns[11]



Because different programs provide different levels of savings at different times and in different seasons, the *mix* of efficiency programs also matters. For example, as Table 1 illustrates, the same hypothetical mix of efficiency programs would have different impacts on three hypothetical electric substations which experience peak demands in different seasons and during different times of day because of the different mixes of customers that they serve. However, it is also worth noting that the differences across the portfolio of programs is not as great as across

[11] 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).

any individual program. This is the result of diversification, as the lower impact from one program is offset by a higher impact from another at the time of a given substation peak.

Table 1: Hypothetical Efficiency Program Portfolio Impacts on Different Substation Peaks

Substation	Customer Mix	Peak Season	Peak Hour	Annual Peak MW Savings by Program			
				Residential CFLs	Residential A/C	Commercial Lighting Retrofits	Total
A	Primarily Business	Summer	3:00 PM	0.4	0.9	0.7	2.0
B	Primarily Residential	Summer	7:00 PM	0.4	1.4	0.3	2.1
C	Primarily Residential w/Electric Heat	Winter	7:00 PM	1.0	0.0	0.4	1.4

Finally, the level of savings that the mix of programs provides also has important implications for whether any T&D investment deferral is possible and, if it is, how long a deferral the efficiency programs will provide. This is illustrated in the hypothetical example depicted in Table 2. In this example, the existing electric substation load is 90 MW and its maximum capacity is 100 MW, so capacity will need to be added by the year load is projected to exceed that level. The first scenario depicted is one in which there are no efficiency programs offered to customers served by the substation (i.e. a "business as usual" scenario). It assumes 3% annual growth in substation peak load. The other three scenarios depict different levels of efficiency program savings, presented in increments of 0.5 percentage point reductions in annual peak load growth relative to the "business as usual" or "no efficiency" scenario. In this example, the substation capacity would need to be upgraded in four years (2018) in the business as usual scenario. The degree to which the efficiency programs defer the need for the upgrade varies with the level of savings achieved, ranging from a one year deferral (to 2019) for savings sufficient to reduce the peak growth rate by 0.5% each year (i.e. from 3.0% to 2.5%) to an eight year deferral (to 2026) for savings sufficient to reduce the peak growth rate by 2.0% annually (i.e. from 3.0% to 1.0%). Clearly, if savings were greater than 2.0% per year, the need for the substation upgrade would be deferred beyond the time horizon depicted in the table.

Table 2: Illustrative Impact of Savings Level (MW) on Deferral of Substation Upgrade

Level of Savings	Net Growth Rate	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
No EE programs	3.0%	90	93	95	98	101	104	107	111	114	117	121	125	128
0.5% savings/year	2.5%	90	92	95	97	99	102	104	107	110	112	115	118	121
1.0% savings/year	2.0%	90	92	94	96	97	99	101	103	105	108	110	112	114
1.5% savings/year	1.5%	90	91	93	94	96	97	98	100	101	103	104	106	108
2.0% savings/year	1.0%	90	91	92	93	94	95	96	96	97	98	99	100	101

Passive Deferrals vs. Active Deferrals

Energy efficiency programs can lead to deferrals of T&D investments in two ways: passive deferral and active deferral. We define those two concepts as follows:

> **Passive deferral**: when system-wide efficiency programs, implemented for broad-based economic and/or other reasons rather than with an intent to defer specific T&D projects, nevertheless produce enough impact to defer specific T&D investments.
>
> **Active deferral**: when geographically-targeted efforts to promote efficiency – *intentionally designed to defer specific T&D projects* – meet their objectives.

Passive deferrals, almost by definition, will occur to some degree in any jurisdiction that has system-wide efficiency programs of any significance. However, as noted above, the degree and value of passive deferral will obviously be heavily dependent on the scale and longevity of the programs. The benefits may be modest, deferring a small number of planned investments a year or two. They can be also quite substantial. For example, Consolidated Edison (Con Ed), the electric utility serving New York City and neighboring Westchester County, recently estimated that including the effects of its system-wide efficiency programs in its 10-year forecast reduced capital expenditures by more than $1 billion.[12] Similarly, since it began integrating long-term forecasts of energy efficiency savings into its transmission planning in 2012, the New England ISO has identified over $400 million in previously planned transmission investments in New Hampshire and Vermont that it is now deferring beyond its 10 year planning horizon.[13]

The benefits of such passive deferrals are sometimes reflected in average statewide or utility service territory-wide avoided T&D costs. Such avoided costs – along with avoided costs 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,

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

[13] The initial March 2012 estimate was $265.4 million in deferred projects. In June 2013 an additional $157 million in projects was deferred (Personal communication from Eric Wilkinson, ISO New England, 11/6/14. Also see: George, Anne and Stephen J. Rourke (ISO New England), "ISO on Background: Energy Efficiency Forecast", December 12, 2012; and ISO New England, 2013 Regional System Plan, November 7, 2013).

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 currently range from about $30 per kW-year (CL&P) to about $200 per kW-year (National Grid – Massachusetts).[14]

Like passive deferrals, the benefits of active deferrals are a function of the value of each year of deferral and the length of the deferral. However, because the deferral of a specific T&D investment is the primary objective rather than by-product of the efficiency programs, benefits are always very project-specific. Examples of such benefits are provided in the following sections of this report.

It is important to recognize that deferred T&D investments – whether passive or active – are a subset of the benefits of the efficiency programs that produced the deferral. Efficiency programs always also provide energy savings to participating customers, reductions in line losses, and environmental emission reductions. They also typically provide system peak capacity savings, reduced risk of exposure to fuel price volatility and, particularly in jurisdictions with competitive energy and/or capacity markets, price suppression benefits.

Applicability to Natural Gas Infrastructure

Though this report focuses primarily on the role that efficiency programs can play in actively deferring *electric* T&D investments, the concepts are just as applicable to gas T&D infrastructure investments. That is, natural gas efficiency programs are likely to be passively deferring some gas T&D investments and, under the right circumstances – e.g. for load-related T&D needs, with enough lead time, etc. – should be viable options for deferring some gas T&D investments.

The passive deferral benefits of gas efficiency programs have either not been widely studied or not been widely publicized. However, there are at least a couple of examples worth noting. First, Vermont Gas Systems (VGS) routinely includes the impacts of its efficiency programs in its integrated resource planning (IRP). As noted in its revised 2012 IRP, efficiency programs are forecast to not only reduce gas purchases, but also contribute to "delayed transmission investment during the term of (the) plan."[15] In its 2001 plan, VGS was even more explicit, concluding that its efficiency programs would produce sufficient peak day savings to delay implementation of at least one transmission system looping project by one year.[16]

[14] Hornby, Rick et al. (Synapse Energy Economics), *Avoided Energy Supply Costs in New England: 2013 Report*, prepared for the Avoided Energy Supply Component (AESC) Study Group, July 12, 2013.
[15] Vermont Gas Systems, Inc., *REVISED Integrated Resource Plan*, 2012.
[16] Vermont Gas Systems, Inc., *Integrated Resource Plan*, 2001.

We are not aware of any publicly available documentation of examples in which a gas utility has used geographically-targeted efficiency programs to *actively defer* a T&D investment. However, there may be growing interest in this topic. For example, following a hotly contested proceeding on a very large gas pipeline project, the Ontario Energy Board recently concluded that geographically-targeted efficiency and demand response programs might have been able to mitigate the need for a portion of the project designed to meet growing loads in downtown Toronto, but "significant uncertainties", mostly related to time limitations and to Enbridge Gas' (the local gas utility's) lack of information on and experience with assessing peak demand impacts of its efficiency programs, led it to approve the project as proposed. However, the Board also stated that "further examination of integrated resource planning" is warranted and that it "expects applicants to provide more rigorous examination of demand side alternatives" in all future proposals for significant T&D investments.[17] In a very different context, some parties have suggested that geographic targeting of gas efficiency programs to areas near gas-fired electric generating stations could help alleviate pipeline congestion that is driving up the winter cost of electricity in parts of New England.[18] It is conceivable that such efforts might also help defer the need for some gas T&D investments.

NEEP will be undertaking a 2015 scoping project to document what gas system planners would need to assess the potential viability of demand-side alternatives to gas T&D investments.

[17] Ontario Energy Board, *Decision and Order*, EB-2012-0451, in the matter of an application by Enbridge Gas Distribution, Inc. Leave to Construct the GTA Project, January 30, 2014.
[18] Schlegel, Jeff, "Winter Energy Prices and Reliability: What Can EE Do to Help Mitigate the Causes and Effects on Customers", June 11, 2014.

III. Summaries of Examples

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 electric T&D investments. In this section of the report we briefly summarize examples of such efforts from ten different jurisdictions. More detailed discussion of some of these examples follows in the next section.

Bonneville Power Administration (under consideration in 2014)

The Bonneville Power Administration (BPA) has periodically considered energy efficiency and other non-wires alternatives to transmission projects over the past two decades. One notable example was in the early 1990s. At the time the Puget Sound area received more than three-quarters of its peak energy (i.e., during times of high demand for electric heat) via high voltage transmission lines that crossed the Cascade mountain range. BPA studies concluded the region could experience a voltage collapse – or blackout or brownout – if one of the lines failed during a cold snap.[19] The level of risk "violated transmission planning standards."[20] 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. However, BPA and the local utilities chose instead 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 that focused on loads that would help avoid voltage collapse. The voltage support was by far the most important of these elements.[21] 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.[22] Indeed, no new cross-Cascade transmission lines have been built to date.[23]

Several years later, BPA invested in a substantial 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.

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[19] U.S. 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.

[20] Bonneville Power Administration Non-Construction Alternatives Roundtable, "Who Funds? Who Implements?" Subcommitee, "Non-Construction Alternatives – A Cost-Effective Way to Avoid, Defer or Reduce Transmission System Investments", March 2004.

[21] Indeed, though 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).

[22] Bonneville Power Administration, "Non-Wires Solutions Questions & Answers" fact sheet.

[23] 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. Thus, today, BPA has more "North-South issues" than "East-West issues" (personal communication with Frank Brown, BPA, 11/7/11).

Although BPA has since commissioned several studies to assess non-wires alternatives to traditional transmission projects, it has not yet pursued any additional now-wires projects. BPA is currently in the process of rebooting and revamping their corporate approach to non-wires alternatives. That has included a restructuring of where this function is situated within the organization. Prior to 2012 the non-wires team at BPA was part of the Energy Efficiency team, but in early 2013 it became a corporate level function in an attempt to better integrate strategic planning for non-wires approaches across the organization by bridging the energy efficiency and resource planning functions.

BPA is also re-assessing the threshold criteria used to determine whether a project might be a good candidate for a non-wires approach. In the past, projects needed to be planned to be at least eight years in the future, and have a cost of at least $5M to be considered for a non-wires alternative. Currently the BPA team feels that an eight-year lead time is too long, because it allows too much time for projects to change in significant ways before they would be implemented. With this in mind they are now focusing on projects that are planned for five years out, feeling that this allows sufficient time to deploy non-wires resources while still providing greater surety that the project's expected need is reasonable. BPA has also reduced its minimum cost threshold from $5M to $3M.

The lead time and cost criteria are used as a "stage one" filter to identify potential NWA candidate projects. Once stage one selection is complete, a "stage two" analysis is undertaken. In stage two analysis BPA considers more specifically the types of customers in the affected load areas, and identifies the types of non-wires alternatives that could potentially be applicable and effective. Once this team has identified strong project candidates, recommendations are made to the executive team regarding projects to pursue. Once executive approval is obtained, the project would then move to a different branch of BPA for execution.

As in the Northeast there are significant unanswered questions about how future non-wires alternatives to transmission projects will be funded. Currently, transmission construction projects are socialized over a large customer base, but a similar cost-allocation mechanism has not yet been identified that would allow costs of non-wires alternatives to be similarly allocated. BPA is currently considering approaches to address this issue.

California: PG&E (early 1990s pilot, new efforts in 2014)

One of the most widely publicized of the early T&D deferral projects was the Pacific Gas and Electric (PG&E) Model Energy Communities Program, commonly known as the "Delta project". The project 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 3000 businesses could be deferred through intensive efficiency investments. The largest portion of the project's savings was projected to come from a residential retrofit program targeted to homes with central air conditioning. 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 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 2700 homes received such major measures. Later, the program changed its focus to promoting early replacement of older, inefficient central air conditioners with new efficient models. Other components of the Delta project included commercial building 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 higher cost than expected – roughly $3900 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. 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. The final evaluation of the project suggested that the savings achieved succeeded in deferring the need for the substation for at least two years.[24]

No other projects of this kind appear to have been pursued in California until very recently. Passage of Assembly Bill 327 in October 2013 required utilities to assess the locational benefits and costs of distributed resources (including efficiency), identify economically optimal locations for them, and put in place plans for their deployment. In response, PG&E started looking at specific capacity expansion projects at the distribution substation level that could be deferred if they could reduce load growth. The Company leveraged circuit-specific, 10-year, geo-spatial load forecasts[25] and identified roughly 150 distribution capacity expansion projects that would be needed over the next 5 years— and started developing criteria that would be useful in helping them select the potential deferral projects with the greatest likelihood of success. To narrow down the list, they focused on projects that:

- Were growth related rather than needed because of equipment maintenance issues;
- Had a projected in-service date at least 3 years into the future; and
- Had a projected normal operating deficiency of 2 MW or less at substation level to ensure that they would be realistically achievable in a two-year timeframe.

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[24] Pacific Gas and Electric Company Market Department, *"Evaluation Report: Model Energy Communities Program, Delta Project 1991-1994"*, July 1994.
[25] Using Integral Analytics proprietary "LoadSEER" software.

Applying these criteria reduced the number of projects being considered to about a dozen. PG&E then looked at each of the remaining projects more closely to better understand which customers were connected to those feeders and what their load profiles were like to determine if the needed reductions could be reasonably secured over the next two years. Through this process they ultimately selected four projects for which to deploy non-wires alternatives, including energy efficiency, for 2014-15. By the end of 2015 they expect to be able to show significant progress in developing their understanding of the strengths and potential limitations of these non-wires approaches, which will allow them to better integrate NWA approaches into future planning efforts. This current effort is discussed more thoroughly in the next section – detailed case studies – of this report.

Maine (2012 to present)

In 2010, the Maine Public Utilities Commission approved a settlement agreement reached by Central Maine Power and a variety of other parties regarding a large transmission system upgrade project. A key condition of the settlement was that there would be a pilot project to test the efficacy of non-wires alternatives. The first such pilot was to be in the Boothbay region. Another condition was that the non-wires pilot would be administered by an independent third party. Grid Solar, an active participant in case, was selected to be the administrator.

The Boothbay pilot began in the Fall of 2012 with the release of an RFP designed to procure 2.0 MW of non-wires resources. Rather than solicit a purely least cost mix of resources, the project aimed to ensure that a mix of resource types would be procured and tested by establishing desired minimums of 250 kW for each of four different resource categories: energy efficiency, demand response, renewable distributed generation and non-renewable distributed generation. A second RFP was issued in late May of 2013 after one of the original winning bids withdrew due to challenges in acquiring financing. As of the Summer of 2014, 1.2 MW of non-wires resources, including approximately 350 kW of efficiency resources, were deployed and operational; another 500 kW was expected to be operational by late 2014. Due to revised load forecasts that total of 1.7 MW is all that is now expected to be needed to defer the transmission investment. The cumulative revenue requirement for the non-wires solution is now forecast to be approximately one-third of what the cost would have been for the transmission solution. This project, as well as recent legislation that requires assessment and deployment of less expensive non-wires solutions in the future, is discussed in greater detail in the next section of this report.

Michigan: Indiana & Michigan/AEP (2014)

Indiana and Michigan (I&M), a subsidiary of American Electric Power (AEP), is currently forecasting that it will need to invest in an upgrade to a transformer at its substation in Niles, Michigan. The substation serves about 4400 residential customers, nearly 600 commercial customers and about 60 industrial customers. Peak load on the substation is currently 23.2 MW. It is forecast to grow by about 200 kW per year, though system planners need to address a possibility that peak loads will grow by 5% above normal weather levels – i.e. 210 kW per year.

I&M is currently considering a pilot project to use more aggressive efforts to promote energy efficiency investments to offset load growth and thereby defer the transformer upgrade. The efficiency program offerings would build on the system wide programs that are already offered across I&M's Michigan service territory, including both increased rebates for customers in Niles and more aggressive customer outreach and marketing efforts. There may also be efforts to explore integration of efficiency offerings with promotion of demand response and distributed generation.

Nevada: NV Energy (late 2000s)

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 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…"*[26]

NV Energy pursued a variety of efforts to focus its existing efficiency programs more intensely on the Fort Churchill area through increased marketing and, in one case (Commercial building retrofit program), higher financial incentives.[27] It also offered an "Energy Master Planning Service" to the Carson City and Douglas County School districts, though both declined the service. Of these efforts, NV Energy's second refrigerator collection and recycling program (including a new element of CFL distributions) and the commercial retrofit program were together responsible for the vast majority of the increased DSM savings in the region.[28]

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

[26] 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
[27] Sierra Pacific Power Company, 2010 Annual Demand Side Management Update Report, July 1, 2010, pp. 6-9.
[28] Ibid. and Jarvis et al.

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.[29]

New York: Con Ed (2003 to present)

Consolidated Edison (Con Ed), the electric utility serving New York City and neighboring Westchester County, has been perhaps the most aggressive in the US in integrating end use energy efficiency into T&D planning. Geographically targeted investment in efficiency at Con Ed began in 2003, when growth in demand was causing a number of Con Ed's distribution networks to approach their peak capacity. In its initial pilot phase, the Company established contracts with three ESCOs to provide load reductions in nine networks 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 Island and four in Westchester County. ESCOs were allowed to bid virtually any kind of permanent load reduction. However, through 2010, the only cost-effective bids submitted and accepted were solely for the installation of efficiency measures. 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. The resulting savings were very close to forecast needs and provided more than $300 million in net benefits to ratepayers.[30] In some cases, the efficiency investments not only deferred T&D upgrades, but bought enough time to allow the utility to refine load forecasts to the point where some of the capacity expansions may never be needed.

After these successful distribution deferral projects were completed in 2012, Con Ed experienced a brief hiatus from non-wires projects simply because there were no distribution upgrade projects being planned that would meet the criteria for non-wires approaches (see detailed case study in following section for discussion of these criteria). That changed in the summer of 2013, when an extended heat wave placed severe capacity pressure on areas of Brooklyn and Queens, causing Con Ed to identify a greatly accelerated need for upgrades to its system in these areas. Con Ed subsequently decided to request approval for approximately $200M in investments to defer distribution system upgrades related to these capacity constraints.

That proposal was also made in the context of strong signals coming from New York's regulators indicating a pending re-structuring of the electric utility industry in the state, with a much greater expectation that in the near future the utilities will be responsible for taking advantage of all available resources for managing the grid in the most economic manner. In

[29] Personal communication with Larry Holmes, NV Energy, 11/9/11.
[30] 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; updated estimates provided by Chris Gazze, formerly of Con Ed, February 11, 2011.

Commission Staff's view, this includes deploying all manner of Distributed Energy Resources (DERs) to their cost-effective levels. This viewpoint is clearly reflected in ConEd's Brooklyn-Queens filing and the associated RFI that ConEd has issued that includes an extraordinary level of flexibility regarding the creative use of non-wires approaches. The Brooklyn-Queens project is discussed in much greater detail in the following "detailed case studies" section of this report.

New York: Long Island Power Authority (2014)

PSEG Long Island[31] has submitted a proposed long-term plan to the Long Island Power Authority (LIPA) for its approval.[32] The plan includes initiatives designed to defer substantial transmission upgrades in the Far Rockaway region in southern Long Island and the South Fork region in eastern Long Island. Both include a proposed RFP to procure peak load relief, with any type of demand side measure – including energy efficiency – being eligible as long as it is commercially proven, is measurable and verifiable and is not duplicative of other programs already proposed for the areas.

In the case of the Far Rockaway region, the effort would be designed to help defer what would otherwise be a transmission reinforcement between the towns of East Garden City and Valley Stream in 2019. LIPA has already issued and received responses to an RFP for new generation, energy storage and demand response (GSDR) resources which may satisfy some or all of the need in the area. Thus, the proposed new RFP for demand-side resources is essentially a contingency plan. If deployed, it would seek to acquire 25 MW of "guaranteed capacity relief". PSEG Long Island has stated that the RFP process would be similar to Con Ed's process for addressing its Brooklyn-Queens constraint.

In the case of the South Fork region, the effort would be designed to help defer a $294 million capital investment in (primarily) new underground transmission cables and substation upgrades over the next eight years ($97 million by 2017 and the other $197 million through 2022). Approximately 20 MW of coincident peak capacity is needed by 2018, with more required in later years. It is expected that some of this need will be addressed by acquisition of storage resources through the GSDR RFP described above and 21.6 MW (nameplate capacity)[33] of solar PV procured through a different initiative. The RFP for demand side resources would seek at least 13 MW of guaranteed load relief, unless a parallel effort to acquire peak savings through a residential Direct Load Control program RFP acquires enough load control resources in the South Fork area to reduce the need.

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[31] PSEG Long Island is currently contracted to provide all aspects of LIPA's utility services, other than procurement of supply resources. Starting in January 2015, it will also be responsible for supply procurement as well.
[32] PSEG Long Island, *"Utility 2.0 Long Range Plan Update Document"*, prepared for the Long Island Power Authority, October 6, 2014.
[33] That equates to more like 10 MW of coincident peak capacity and even less in early evening hours when demand in the region is still very high (personal communication with Michael Voltz, PSEG Long Island, November 13, 2014).

As of the writing of this report, these efforts are just proposals. They are expected to be considered for approval by the Long Island Power Authority Board in December 2014.[34]

Oregon: Portland General Electric (early 1990s)

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.[35] 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 five-year transmission and distribution plan. Though 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.[36]

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 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%.[37]

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. However, savings for another building 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."[38]

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

[34] Personal communication with Michael Voltz, PSEG Long Island, November 11, 2014.
[35] Personal communication with Rick Weijo, Portland General Electric, August 10, 2011.
[36] 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.
[37] Ibid.
[38] Ibid.

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. However, the utility's distribution engineering staff decided to proceed with construction of the upgrade before the magnitude of the achieved savings was known because they did not have sufficient confidence that the savings would be achieved and 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.[39]

Despite some notable successes with its pilot, PGE has not subsequently pursued any additional efforts to defer distribution system upgrades through energy efficiency.[40]

Rhode Island: National Grid (2012 to present)

In 2006, Rhode Island adopted a "System Reliability Procurement" policy that required utilities to file plans every three years. Guidelines detailing what to include in those plans were developed by the state's Energy Efficiency and Resource Management Council (EERMC) and National Grid and approved by regulators in 2011 (see Appendix D). The guidelines make clear that plans must consider non-wires alternatives, including energy efficiency, whenever a T&D need meets all of the following criteria:

- It is not based on asset condition;
- It would cost more than $1 million;
- It would require no more than a 20% reduction in peak load to defer; and
- It would not require investment in the "wires solution" to begin for at least 36 months.[41]

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.

Based on these guidelines, National Grid proposed an initial pilot project in late 2011. The project was designed to test whether geographically targeted energy efficiency and demand response could defer the need for a new substation feeder to serve 5200 customers (80% residential, the remainder small businesses) in the municipalities of Tiverton and Little Compton. The pilot began in 2012 with the objective of deferring the $2.9 million feeder project for at least four years (i.e. from an initial estimated need date of 2014 until at least 2018). The load

[39] Ibid.

[40] Personal communication with Rick Weijo, Portland General Electric, August 10, 2011.

[41] These criteria are identical to internal guidelines National Grid had developed in 2010/2011 (personal communication with Lindsay Foley, National Grid, December 22, 2014).

reduction necessary to permit the deferral was estimated to be 150 kW in 2014, rising to about 1000 kW in 2018.[42]

The pilot was designed to leverage National Grid's statewide efficiency programs in a couple of ways. First, the Company is more aggressively marketing those statewide programs to customers in Tiverton and Little Compton. Second, it is using the same vendor that manages its statewide residential and small commercial efficiency retrofit programs to promote demand response measures in the two towns. Because the substation's peak load is in the summer, there is a strong emphasis on addressing cooling loads. Initially, the demand response offering was a wi-fi programmable controllable thermostat for homes with central air conditioning. However, when the saturations of central air proved to be lower than expected, the pilot was broadened to include demand response-capable plug load control devices for window air conditioners. Marketing of the program offerings was limited to "direct contact" with customers in the affected towns. National Grid recently reported to state regulators that the need for the new feeder has been pushed out from 2014 to 2015, suggesting that the peak load reduction that has been realized thus far has been large enough to defer the investment by one year.[43]

Vermont (mid-1990s pilot, statewide effort 2007 to present)

In 1995, Green Mountain Power (GMP), Vermont's second largest investor-owned electric utility at that time, 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. Sugarbush, which 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. Ensuing negotiations between GMP, Sugarbush and the state's ratepayer advocate ultimately led to an alternative solution in which 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, and GMP would invest in an aggressive effort to promote investment in energy efficiency among all residential and business customers in the region. To meet its end of the bargain, GMP filed and regulators approved four efficiency programs targeted to the Mad River Valley, including a large commercial/industrial retrofit program, a small commercial/industrial retrofit program, a residential retrofit program that focused on homes with electric heat and hot water, and a residential new construction assessment fee program which imposed a mandatory fee on all new homes being constructed in the valley. The fee program paid for a home energy rating and offered both repayment of the fee and an additional incentive for building the home efficiently. The project as a whole came close to achieving its overall savings goal.

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[42] Anthony, Abigail (Environment Northeast) and Lindsay Foley (National Grid), "Energy Efficiency in Rhode Island's System Reliability Planning", 2014 ACEEE Summer Study on Energy Efficiency in Buildings, Volume 10.
[43] Ibid.

Since that early project, Vermont has invested significant efforts in developing a thoughtful methodology for assessing the prudence of non-wired alternatives to capital investments in poles and wires. The Vermont Public Service Board (PSB) issued orders in Docket 7081 that established expectations for analysis of non-transmission alternatives, and in Docket 6290 for non-wires alternatives to distribution and sub-transmission projects. While the requirements vary slightly, similar approaches are used for both distribution and transmission needs. The state's distribution utilities and Vermont Electric Power Company (VELCO), the state's electric transmission provider, submit twenty-year forecasts of potential system constraints and construction projects as part of utility Integrated Resource Plans (IRPs) and a Long Range Transmission Plan (LRTP) every three years. The forecasts are updated annually. The forecasts include preliminary assessments of the applicability of non-wires alternatives based on criteria that have been agreed upon by Vermont System Planning Committee (VSPC), a statewide collaborative process for addressing electric grid reliability planning.[44] The VSPC helps Vermont fulfill an important public policy goal: to ensure that the most cost-effective solution gets chosen, whether it is a poles-and-wires upgrade, energy efficiency, demand response, generation, or a hybrid solution. The work of the VSPC is carried out by a broad cross section of stakeholders, including representatives from utilities, regulators, environmental advocates and Efficiency Vermont, and follows a highly prescribed process to assure that potential solutions are reviewed comprehensively.[45]

The current collaborative planning process was developed in response to Act 61, the 2005 legislation that clearly establishes the basis for the Public Service Board to require long range consideration of non-wires solutions as alternatives to T&D construction. Act 61 emerged in part as a result of public, regulatory, and legislative frustration with the Northwest Reliability Project, a transmission upgrade project that the Board ultimately felt it had to approve because, when permit applications were submitted there was no longer sufficient lead time to fairly consider NWAs. Act 61 also removed statutory spending caps for Efficiency Vermont, authorizing the Board to establish appropriate budgets. When the Board ordered budgets to increase beginning in 2007, it also required that a portion of the increase be devoted to special efforts to obtain additional savings in areas that the utilities had indicated had the potential to become constrained. Five geographic areas were initially targeted. At the time the Board required this geographic targeting effort primarily as a proof of concept, to assess Efficiency Vermont's ability to increase targeted savings while a better planning process was developed. Efficiency Vermont employed a number of program strategies in pursuit of their geographic goals, including enhanced account management approaches for commercial customers, a direct-install lighting program for small businesses, aggressive promotion of retail efficient lighting including community-based marketing approaches, and enhanced efforts to increase shell efficiency or fuel-switch electric heating customers. Vermont's process for evaluating the potential for non-

[44] http://www.vermontspc.com/
[45] http://www.vermontspc.com/library/document/download/599/GTProcessMap_final2.pdf

wires solutions is discussed in much greater detail in the following “detailed case studies” section of this report.

IV. Detailed Case Studies

1. Con Ed

Early History with Non-Wires Alternatives

Con Ed arguably has more on the ground experience with using geographically targeted energy efficiency to defer or avoid T&D investments than any other utility in North America. 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 in and around New York City, much of the company's system is underground, making upgrades expensive and disruptive. Thus, the Company 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."[46] However, a decision was later made to proceed with geographically-targeted demand resource investments whenever it was determined that such investments were likely to be both feasible and cost-effective.

For these early projects, the Company chose to contract out the acquisition of demand resources to energy service companies (ESCOs). To address reliability risks its contracts contained both "significant upfront security and downstream liquidated damage provisions", as well as rigorous measurement and verification requirements, including 100% pre- and post-installation inspections. Contract prices were 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 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 were 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 Island and four in Westchester County. Though ESCOs were allowed to bid virtually any kind of permanent load reduction, all of the accepted bids were solely for the installation of efficiency measures. 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.

[46] 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.

This approach had considerable success. 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.[47] As a result, Con Ed collected considerable liquidated damages from participating ESCOs. Load reductions in subsequent phases were close to those contracted in aggregate. Those aggregate results masked some differences across network areas. In particular, reductions in areas dominated by residential loads with evening peaks were achieved ahead of schedule while "ESCOs targeting commercial customers in daytime peaking networks struggled somewhat due to the economic recession."[48] On the other hand, the economic recession also had the effect of dampening baseline demand, offsetting most of the efficiency program shortfalls.[49] This highlights an important benefit of some efficiency programs – their savings can be tied, in part, to the same factors (e.g. the vitality of the economy) that cause demand growth to rise or fall. Put another way, participation in some efficiency programs tends to increase when load is growing more quickly and decrease when load is not growing quickly.

Another benefit of efficiency programs is that they can create a hedge against load growth uncertainty. 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."*[50]

As Figure 3 shows, from 2003 to 2010, Con Ed estimated that it saved more than $75 million when comparing the full costs of its geographically targeted efficiency programs to just the T&D costs that were avoided. When other efficiency benefits (e.g., energy savings and system capacity savings) were also considered, the efficiency investments were estimated to have saved Con Ed and its customers more than $300 million. It should be noted that these estimates include the benefits of the longer-than expected deferrals and even outright elimination of the need for some T&D projects that resulted from the downside hedge against forecasting uncertainty described above. The benefits of just the planned deferrals – i.e. what would have been realized had the projects only been deferred as initially forecast – were lower.

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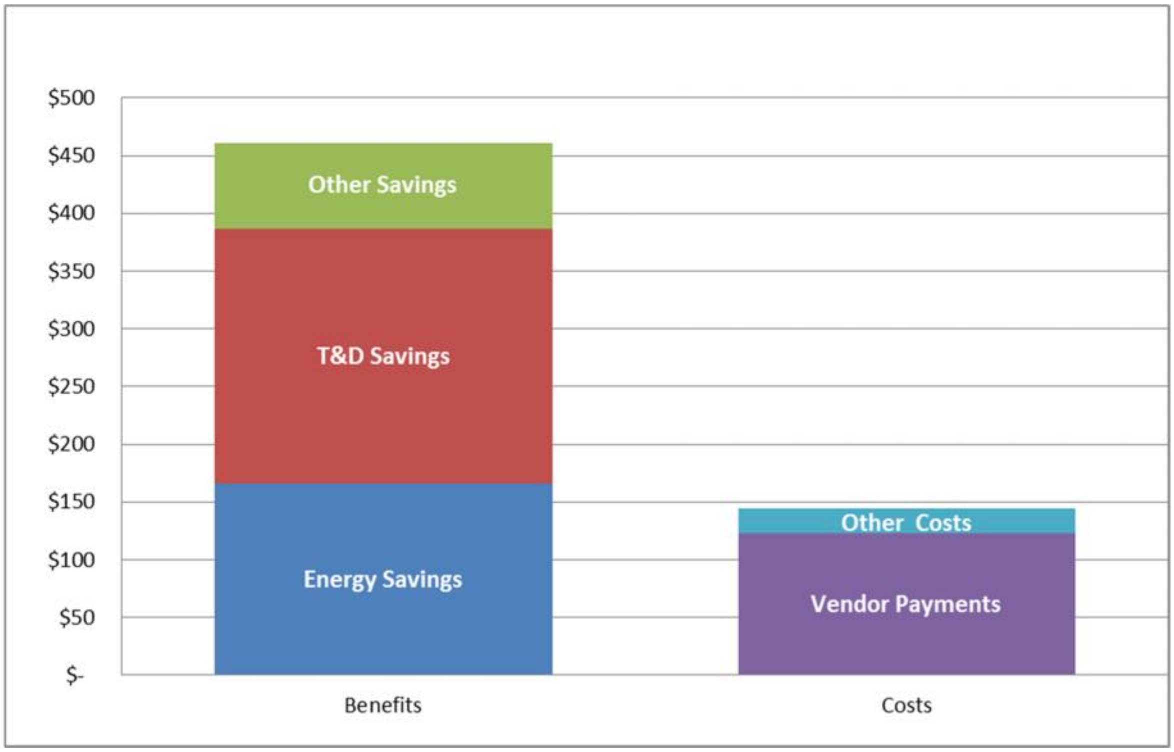
[47] Data obtained from graph in Gazze, Mysholowsky, Craft and Appelbaum (2010).
[48] Gazze, Mysholowsky, Craft and Appelbaum (2010).
[49] Gazze, Mysholowsky, Craft and Appelbaum (2010).
[50] Gazze, Chris et al., "Con Ed's Targeted Demand Side Management Program: Replacing Distribution Infrastructure with Load Reduction", in Proceedings of the ACEEE 2010 Summer Study on Energy Efficiency in Buildings, Volume 5, pp. 117-129.

Figure 3: NPV of Net Benefits of Con Ed's 2003-2010 Non-Wires Projects[51]

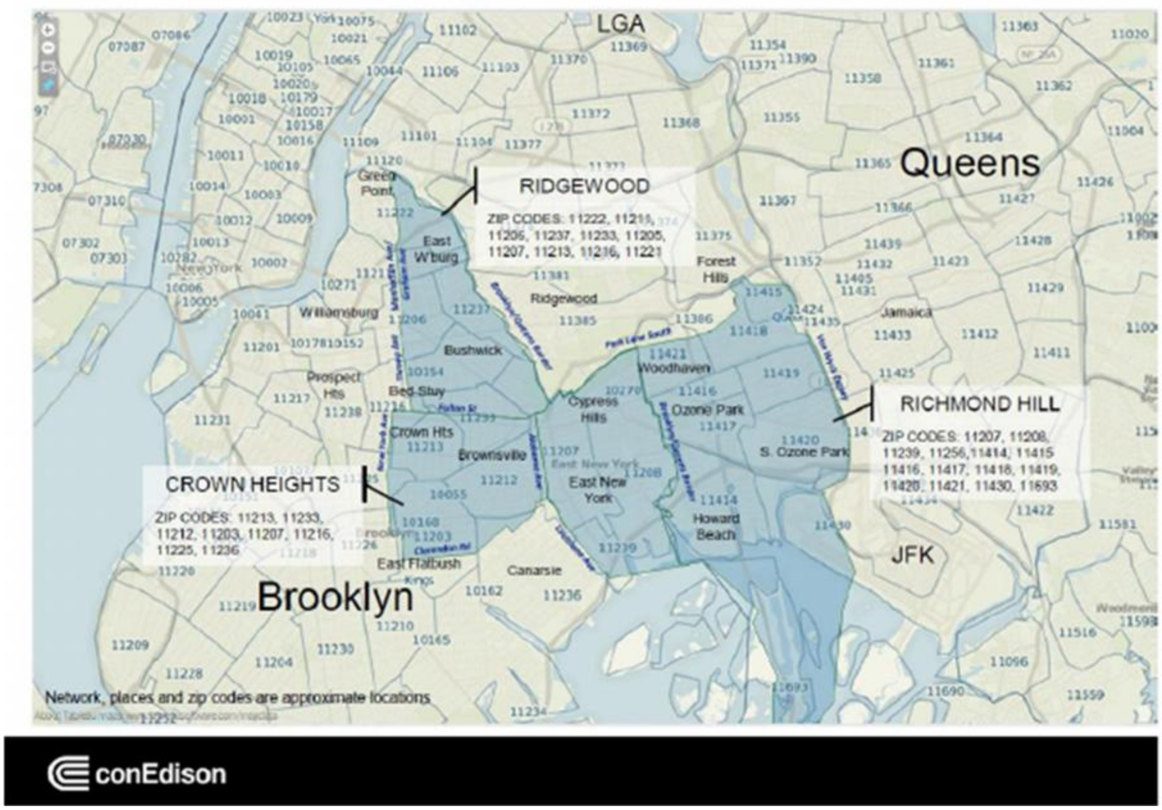


The Next Big Step - $200 Million Brooklyn-Queens Project

Building on this experience, in the summer of 2014 Con Ed requested regulatory approval to invest approximately $200M in a number of different approaches aimed at mitigating the immediate need for system reinforcement in areas of Brooklyn and Queens that surfaced during an extended heat wave in the summer of 2013 (see Figure 4).

[51] 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).

Figure 4: Targeted Brooklyn-Queens Networks[52]



Con Ed knew that there would be capacity constraints in these areas in the future, but the extreme weather placed severe capacity pressure on the sub-transmission feeders that feed the Brownsville No.1 and No.2 substations (serving areas of Brooklyn and Queens), causing Con Ed to identify a greatly accelerated need for upgrades to its system in these areas.[53] Rather than proceeding with a traditional construction solution, Con Ed's proposal calls for it to achieve 41 MW in customer side solutions and another 11 MW of capacity savings through "non-traditional utility side solutions" between 2016 and 2018. This will be combined with another 11 MW of load transfers and 6 MW from the installation of new capacitors that will be operational by 2016 to meet the increased demand during this period. To be clear, Con Ed views these measures as a deferral, rather than a replacement strategy, that will allow delaying the construction of a new substation and associated other improvements from 2017 until 2019. Future upgrades at two other substations are expected to extend this deferral until 2026.[54]

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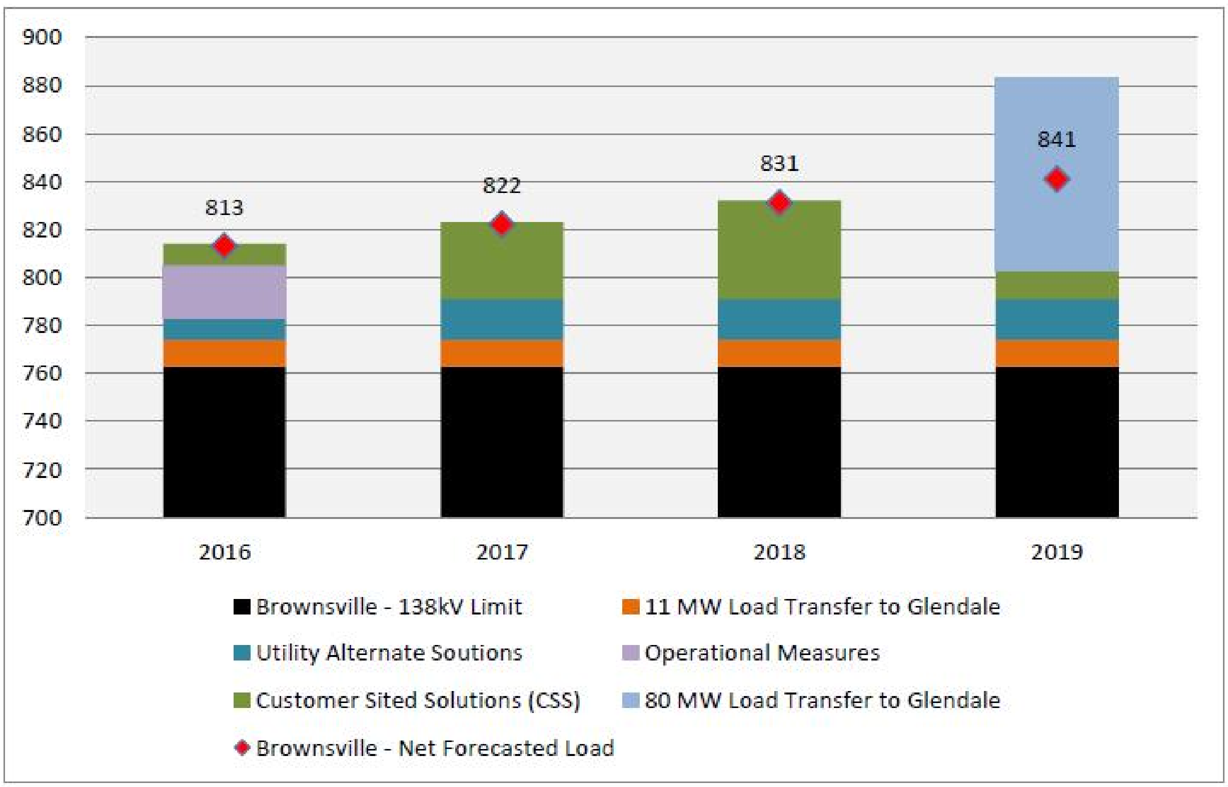
[52] Consolidated Edison Company of New York Request for Information, July 15, 2014, p.11.
[53] Personal communication with Michael Harrington of Con Ed, July 24, 2014.
[54] Data regarding Con Ed's proposal are from Consolidated Edison Company of New York, Inc. Brownsville Load Area Plan, Case 13-E-0030, August 21, 2014.
http://documents.dps.ny.gov/public/MatterManagement/CaseMaster.aspx?MatterCaseNo=13-e-0030, filing # 518

The overall expected project cost of the combination of the $200M in customer-side and utility-side investments, along with costs associated with the load transfers, new capacitors, and upgrades at the two other substations is not available in the documents reviewed in preparing this paper. However, Con Ed does say that the cost of the alternative purely "poles and wires" solution would be about $1 billion."[55] This traditional solution would include "…expansion of Gowanus 345kV switching station into a new 345/138kV step-down station…and…construction of an area substation and new sub-transmission feeders that would have been constructed and in service by the summer of 2017…."[56]

Figure 5 below illustrates the annual contribution of each component that combined will provide the needed load relief for the Brownsville Load Area in Brooklyn and Queens. Both traditional "poles and wires" solutions and non-traditional alternatives are needed to meet the anticipated load. The blue "utility alternate solutions" and the green "customer-sited solutions" together make up the NWAs for which Con Ed has sought approval.

Figure 5: Brownsville Load Area Plan by Component: 2016-2019 [57]



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[55] Brownsville Load Area Plan, p.10
[56] Brownsville Load Area Plan, p.10
[57] Brownsville Load Area Plan, p.22

Con Ed's past success with implementing non-wires solutions gives it what is perhaps a unique, experience-based level of confidence in the effectiveness of alternatives to distribution construction. Likely of equal importance in Con Ed's decision to request approval for the Brooklyn-Queens project are the strong signals coming from New York's regulators, initially through feedback in a rate case[58] and later reinforced through proposals to re-structure the electric utility industry in New York. In particular, New York's Public Service Commission Staff have indicated that they foresee that in the near future the utilities will be held increasingly responsible for managing the grid in the most economic manner. In Commission Staff's view, outlined in *Reforming the Energy Vision* (REV),[59] this includes deploying all manner of cost-effective Distributed Energy Resources (DERs), in an environment where their benefits are accurately measured and given full attribution. The REV proceeding is currently underway in New York and the outcomes are undecided at the time of this writing, but clearly Con Ed has reflected anticipated changes in the regulatory framework in its Brooklyn-Queens filing, which will provide the most comprehensive test to date of the principles outlined in the REV.

Consistent with its regulatory filing, Con Ed issued an RFI in July of 2014 under the title "*Innovative Solutions to Provide Demand Side Management to Provide Transmission and Distribution System Load Relief and Reduce Generation Capacity Requirements*". The RFI allows for an extraordinary level of flexibility regarding the creative use of non-wires approaches:

> *"Respondents are encouraged to submit alternative, creative proposals for DSM marketing, sales, financing, implementation, and maintenance, or transaction structures and pricing formulas that will achieve the demand reductions sought and maximize value to Con Edison's customers."*[60]

While the Brooklyn-Queens project is receiving much attention for its unprecedented scale and ambition as a non-wires project, a concurrent evolution in several aspects of Con Ed's overall approach to non-wires alternatives may be even more important in the long run. Four recent developments are particularly noteworthy:

- **Management structure**: Con Ed's management of analysis and deployment of non-wires alternatives has been elevated to higher level in the Company and become more integrated/inter-disciplinary;
- **Data-driven tools**: Con Ed is developing data driven tools to enable much more sophisticated analysis of non-wires options; and

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[58] Personal communication with Michael Harrington, Con Ed, December 9, 2014.
[59] NYS Department of Public Service Staff, *"Reforming the Energy Vision"*, Case 14-M-0101, 4/24/2014. http://www3.dps.ny.gov/W/PSCWeb.nsf/96f0fec0b45a3c6485257688006a701a/26be8a93967e604785257cc40066b91a/$FILE/ATTK0J3L.pdf/Reforming%20The%20Energy%20Vision%20(REV)%20REPORT%204.25.%2014.pdf
[60] Consolidated Edison Company of New York Request for Information, July 15, 2014, p.6

- **Research to support tools**: Con Ed is investing in research to generate data necessary to support the use of those tools.
- **Proposed shareholder incentive mechanism**: Con Ed has proposed a new mechanism for enabling shareholders to profit from investment in non-wires alternatives.

Evolution of Management Approach

Con Ed has taken significant steps in advancing internal communications and collaboration for the Brooklyn-Queens project that are expected to apply to other projects in the future. A working group has been formed within the company specific to this project that includes members of all relevant functional areas such as energy efficiency and demand management, distribution engineering, substation planning, electric operations, and the regional engineering groups that are responsible for Brooklyn/Queens. This has been done with the sponsorship, and under the guidance of one of Con Ed's Senior Vice-Presidents, who has championed the project and who regularly chaired early project meetings. Con Ed's senior management team regards the success of the Brooklyn-Queens project as highly important, and has brought organizational focus to it in a way that we did not observe in any of the other organizations we explored.[61]

Development of New Data-Driven Analytical Tools

With a focus on system and cost management, along with the growth in efficiency and demand management technology and associated customer strategies, Con Ed identified the need for increased visibility into customer and technology potential and economics on the demand side. To address this need, Con Ed, along with Energy & Environmental Economics (E3) and Navigant, has created the Integrated Demand Side Management (IDSM) Potential Model – a dynamic, geographically specific, and technology integrated analysis tool to assess the market potential and economics of efficiency and demand management for cost effective deferral or avoidance of capital expenditures required to meet growing customer demand. The IDSM project is groundbreaking in its ability to breakdown the in-depth analysis into geographically specific electric networks to best match the needs of electric system planners.

The IDSM project goes beyond traditional efficiency measure stalwarts (lighting) to give Con Ed a view into potential deployments of all commercially available and near-term available technologies potentially applicable to the Con Ed service territory. The IDSM project will enhance Con Ed's ability to identify and market to high potential market segments to achieve efficient and effective capital project deferral projects. The model will also enable analysis of various DSM scenarios to customize and optimize project results and maximize cost effectiveness. Lastly, the IDSM project can be extended for use beyond TDSM project analysis

[61] Maine and Vermont have addressed the cross-functional nature of successful NWA planning and implementation through collaboratives that include members of different organizations, but we are not aware of an example other than Con Ed where this level of collaboration has occurred within a single utility.

to support Con Ed's strategic planning and resource planning (forecasting) efforts by identifying the market potentials and impacts for any number of customer technology adoption scenarios.

Research to Support New Tools

Of course, analytical tools are only as good as the data put into them. Thus, Con Ed also embarked on a couple of research projects to support deployment of the IDSM.

In the first, Con Ed built up network profiles for eight test networks by collecting detailed granular customer data that accounts for building-level characteristics, and that are aggregated for up to 13 commercial and two residential segments for each electric network analyzed. Drawing from both internal billing data and external sources, the network profiles will include applicable service classes, meter information, annual and peak energy usage, air conditioning use, existing thermal storage, physical characteristics of the building, prior program participation, in-place DG/RE, end-use profiles, and more.

The second research task was a technology assessment to identify current and near-market technologies that have the potential to improve energy efficiency, support demand response, improve building operations, and maximize comfort. The assessment looked at the measures identified in a 2010 potential study, as well as additional technologies related at a minimum to lighting, controls, motors, HVAC, and thermal and battery storage. The project also looked at customer sited generation across a range of technology options.

In addition, the technology assessment included the develop of a measure specific load curve library by customer segment (e.g. 8760 and peak load curves for interior lighting measures for the retail customer segment) This tool connects the dots between the technology assessment and the network profiles to ensure the energy and demand reductions for measures being deployed for the specific customer segments are specific to the network(s) being analyzed. The tool does this by comparing the measure-segment load curves to the 8760 and peak load curves of the specific network. For example, the tool is able to assess the different impacts that residential lighting will have compared to commercial lighting in a night peaking network.

Proposal for Shareholder Incentives

Con Ed has proposed to the Commission that it defer the bulk of the costs associated with customer-side activities and recover them over a five-year amortization period, and for utility-side expenditures it has proposed ten-year recovery. Con Ed suggest that "The shorter amortization periods than those traditionally afforded in rates reflect the nature of the expenditures…where no physical asset exists".[62] Con Ed suggests that it should earn a rate of

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[62] Consolidated Edison Company of New York, Inc., "*Petition for approval of Brooklyn/Queens Demand Management Program*", p.20. http://documents.dps.ny.gov/public/Common/ViewDoc.aspx?DocRefId=%7bB2051869-3A4A-4A7D-BB24-D83835E2026F%7d

return equal to its overall approved rate of return, stating that "…ratemaking should make the Company indifferent to whether it invests in traditional or non-traditional solutions…."[63]

Further, Con Ed has proposed that the Commission establish up to a 100 basis point incentive on Brooklyn-Queens program investments that would be incremental to its approved rate of return so that it has a clear, direct interest in the success of the project. And lastly, the company has proposed that the Commission establish a shared savings incentive as well, with Con Ed earning 50% of the difference between the carrying costs of the traditional solution and the total annual collections for the Brooklyn-Queens program. As of this writing the Commission has not indicated how it will rule on these requests.

2. Maine (Boothbay) Pilot

Project History and Plan

In 2008, Central Maine Power proposed a $1.5 billion investment in the Maine Power Reliability Program (MPRP) to modernize and upgrade the state's transmission network. The project was challenged, with one party – GridSolar – proposing instead that the state invest in 800 MW of photovoltaics (100 MW in the first five years) to offset the need for the entire MPRP. 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 GridSolar and several public interest advocates.[64] The settlement supported construction of most elements of the MPRP, 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. The Mid-Coast pilot was later reduced to a smaller pilot in the Boothbay region, roughly 35 miles ("as the crow flies") northeast of Portland (see Figure 6 below).

[63] Ibid., p.21.
[64] Maine Public Utilities Commission, Order Approving Stipulation, Docket No. 2008-255, June 10, 2010.

Figure 6: Location of Maine (Boothbay) NTA Pilot[65]

The Boothbay pilot was to be a hybrid solution. It included some transmission system investments, including rebuilding of the Newcastle 115 kV substation ($2.8 million), installing a second 2.7 MVAR capacitor bank at Boothbay Harbor 34.5 kV bus ($0.5 million, and 2.4 MVAR power factor correction at Boothbay Harbor 12 kV level.[66] In addition, the plan initially called for approximately 2 MW of non-transmission resources to be procured (in lieu of an $18 million investment in rebuilding of a 34.5 kV line).

The settlement agreement called for an independent third party to administer the acquisition and management of the non-transmission resources. GridSolar was contracted to serve as a third party administrator. Though the selection was not based on a competitive solicitation, the Maine Public Utilities Commission did formally ask if other parties would be interested and did not receive any other expressions of interest. In a docket that is currently open, the Commission is exploring, among other things, whether there should be an independent third party administrator for such projects in the future and, if so, how such parties would be selected (see discussion on next steps below).

[65] Map copied from U.S. Department of Interior, U.S. Geological Survey, *The National Atlas of the United States of America*, www.nationalatlas.gov.
[66] Jason Rauch, Maine Public Utilities Commission, *"Maine NTA Processes and Policies"*, presentation to the Vermont System Planning Committee's NTA Workshop, October 11, 2013.

GridSolar used a competitive solicitation process to procure the non-transmission alternatives. The initial RFP was released in late September 2012. Because it was a pilot, it was decided that the Boothbay project would not solely be designed to acquire the least-cost non-wires solution for the area. Rather, it would also test the efficacy of a wide variety of alternative resource options. To that end, the RFP made clear that, to the extent feasible, GridSolar would endeavor to cost-effectively acquire (i.e. at a cost less than the transmission alternative) at least 250 kW of each of the following categories of resources:

- Energy efficiency;
- Demand response;
- Renewable distributed generation (at least half of which should be from solar PV); and
- Non-renewable distributed generation (with preference for those with no net greenhouse gas emissions).[67]

The RFP called for all bidding resources to be "on-line and commercially operable" by July 1, 2013 – just nine months after issuance of the RFP and less than six months after the expected date of contract signing – and committed to remain in service for a least three years. Contracts would guarantee payments for that three year period, with an option to extend payments for up to an additional seven years if approved by the Commission. Failure to meet the contractual deadline would result in a penalty of $2/kW-month.[68]

The RFP produced 12 bids from six different NTA providers totaling almost 4.5 MW. This included bids for efficiency, demand response, solar PV, back-up generators, and battery storage.[69] Nine of the bids were submitted for approval to the Commission. The nine bids would collectively have provided 1.98 MW spread across five different resource types – 156 kW of efficiency, 250 kWh of demand response, 338 kW of solar PV, 736 kW of back-up generators, and 500 kW of battery storage. During a January 2013 technical conference, GridSolar was given "preliminary approval" to negotiate contracts on those nine bids.[70]

In April 2013 GridSolar reported it had executed or was close to executing almost all of the contracts. The one key exception was a contract with one provider – Maine Micro Grid – who had bid all of the demand response and battery resources and a portion of the solar and back-up generator resources being recommended. While there was agreement on the contract terms, Maine Micro Grid was having difficulty securing financing for the project[71] and ultimately

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[67] GridSolar, LLC, "*Request for Proposals to Provide Non-Transmission Alternatives for Pilot Project in Boothbay, Maine Electric Region*", September 27, 2012.
[68] Ibid.
[69] GridSolar, *"Interim Report: Boothbay Harbor Sub-Region Smart Grid Reliability Pilot Project"*, for Docket No. 2011-138, March 4, 2014.
[70] GridSolar, *"Implementation Plan & Final NTA Service Contracts"* (redacted version), for Docket no. 2011-138, April 5, 2013 (filed electronically on April 9, 2013.
[71] Ibid.

withdrew its bid, explaining that the limited contract commitment of three years was insufficient to satisfy investors "that the required 6-year holding period for the federal investment tax credit incentive would be satisfied."[72]

As a result, the Commission directed GridSolar to install a temporary back-up 500 kW diesel generator and issue a second RFP to fill the gap. The second RFP was issued on May 30, 2013. It produced 22 bids from ten different NTA providers totaling just over 4 MW. It too included bids for efficiency, demand response, solar PV, back-up generation and battery storage. The bid prices for all resources except energy efficiency went down in the second RFP. Even though the energy efficiency bid prices went up, efficiency resources remained by far the lowest cost resources (just by a smaller margin). After eliminating the most expensive bids, GridSolar recommended and received approval to proceed with putting in place contracts for the mix of resources summarized in Table 3. As discussed below, the final mix of NTAs contracted was slightly different from the mix shown in the table. The final contract prices were the same for the back-up generator (BUG) and demand response, but roughly $4 to $5 per kW-month higher for efficiency, solar PV and battery storage than the weighted three year prices shown in the table.[73]

Table 3: Recommended NTA Resources[74]

	RFP I*	RFP II	Totals	Pct.	Units	Weighted 3 Year Price	Weighted 10 Yr. (Levelized) Price
Efficiency	237.00	111.25	348.25	19%	7	$23.51	$10.47
Solar	168.83	106.77	275.60	15%	14	$46.05	$13.19
BUG (same)	500.00	500.00	500.00	27%	1	$17.42	$20.63
Demand Response	0.00	250.00	250.00	13%	1	$110.00	$57.65
Battery	0.00	500.00	500.00	27%	1	$163.70	$75.99
Total	905.83	1468.02	1873.85		24		

* RFP I excludes Maine Micro Grid project; Efficiency increased to reflect EMT contract option.

As of July 2014, approximately 1203 kW of NTA resources were deployed and operational.[75] An additional 500 kW battery storage unit is currently expected to be operational by the end of 2014,[76] bringing the total operational capacity to 1703 kW.[77] That is nearly 300 kW less than the

[72] GridSolar, "*Interim Report: Boothbay Harbor Sub-Region Smart Grid Reliability Pilot Project*", for Docket No. 2011-138, March 4, 2014.
[73] GridSolar, "*Project Update: Boothbay Sub-Region Smart Grid Reliability Pilot Project*", for Docket No. 2011-138, July 21, 2014.
[74] Table copied from GridSolar, "*Interim Report: Boothbay Harbor Sub-Region Smart Grid Reliability Pilot Project*", for Docket No. 2011-138, March 4, 2014.
[75] GridSolar, "*Project Update: Boothbay Sub-Region Smart Grid Reliability Pilot Project*", for Docket No. 2011-138, July 21, 2014.
[76] Personal communication with Dan Blais, GridSolar, October 14, 2014.
[77] Note that this value is about 170 kW less than shown in Table 3 above. That is because not all of the proposals initially approved for procurement were ultimately translated into contracts.

initially forecast need of 2.0 MW. However, in May 2014 Central Maine Power adjusted its forecast need for the 10-year planning horizon to be only 1.8 MW.[78] GridSolar had an option to acquire an additional 130 kW of efficiency resources from Efficiency Maine Trust. However, GridSolar, Commission Staff and other parties agreed not to pursue that option at that time, noting that it could be acquired later if necessary:

> *"A benefit of the NTA approach is that lump-investments and resource deployment can be more closely timed with need. To the extent that additional NTA resources are needed later to meet any increased load, they could be deployed at that time. The delay in investment saves ratepayers money."*[79]

Energy Efficiency Strategy

As noted above, energy efficiency resources were a key component in the mix of NTA resources procured for the Boothbay pilot, accounting for approximately one-fifth of the total NTA capacity that has been procured.

All of the efficiency resources procured to date have been provided by the Efficiency Maine Trust (EMT), the independent third party administrator of efficiency programs in the state. Before responding to the first RFP, EMT contracted for a quick high level assessment of efficiency opportunities in the region. One of the findings was that there was significant lighting efficiency potential in local small businesses, including significant opportunities to displace very inefficient incandescent lighting. Given that opportunity – and the very tight timeline originally anticipated for producing savings (contracts to be signed in January 2013 with requirements for NTAs to be operational by July 1, 2013) – EMT focused its efforts almost entirely on lighting.

EMT employed two strategies for acquiring the savings. Most importantly, it ran what it called a "direct drop" program. That involved a bulk purchase of LEDs that could replace incandescent and halogen spotlights and direct delivery of the LEDs to businesses that indicated they would install them. At the time of the delivery, EMT also assessed opportunities for more expensive upgrades. However, because many of the businesses are seasonal (relying on the summer tourism trade), both profit margins and the potential cost savings from efficiency are often modest, making it difficult to persuade them to make any substantial investments. EMT also provided an "NTA bonus" on its standard business efficiency incentives for customers in the affected region. Several businesses, including a local grocery store, took advantage of that offer.

EMT had to be careful to explain why these offers were being made, so that it was clear why only customers in the region of interest were eligible. Nevertheless, there were still some customers from just outside the region that initially expressed annoyance that they could not take

[78] Ibid.
[79] Ibid.

advantage of the NTA offers. EMT had to follow up with those customers to clarify the purpose of the program and rationale for the geographic limitations of the special offers.

It should be noted that Efficiency Maine has indicated that "it could easily have secured much more efficiency had the design of the RFP permitted more flexible bid response and longer duration commitment."[80]

Evaluation Strategy

The savings from efficiency measures in the project are estimated using the deemed values in EMT's Technical Reference Manual. As required by the RFP, those values are consistent with the values accepted for peak savings by the New England ISO in its forward capacity market.

GridSolar conducted its first test of 472 kW of active NTA resources on July 1, 2014. The BUG and demand response units were dispatched for an hour. Based on data from the units themselves, as well as data from the affected substation circuits, it appears that the capacity of these resources was as predicted.

Project Results

As noted above, to this point, the project appears to be performing as expected in terms of the magnitude of the resource being provided, though a key component for the future – battery storage – has not yet been tested.

With regards to cost, GridSolar has estimated that the project will be substantially less expensive than the transmission alternative.[81] Indeed, as shown in Figure 7, it estimates that the revenue requirements for the pilot project will be $17.6 million lower – a more than 60% savings – over the project's potential 10-year life than under the full transmission solution.[82] That is despite the intentional deployment of a range of NTAs that were not cost-optimized (so as to test a range of technology types in a pilot) and the fact that the pilot commitment to only three years of payments likely constrained potential bids. Moreover, that cost comparison is not adjusted for the substantial additional benefits that some of the NTAs provide, such as energy savings during non-peak periods.

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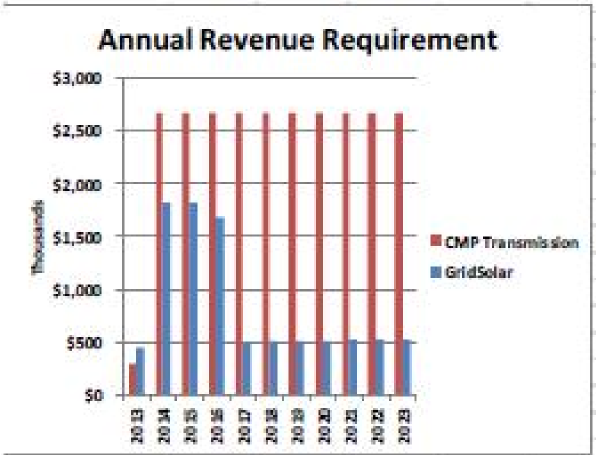
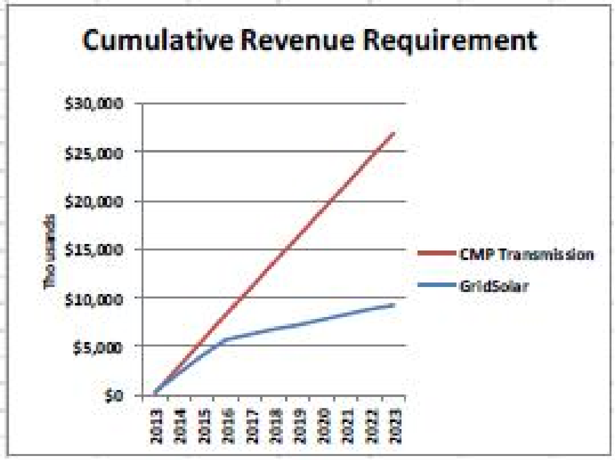
[80] GridSolar, *"Interim Report: Boothbay Harbor Sub-Region Smart Grid Reliability Pilot Project"*, for Docket No. 2011-138, March 4, 2014.

[81] As discussed above, there is a small transmission component to the pilot project. When we refer to the transmission alternative here, we are referring just to the more substantial additional transmission investment that would have had to be made in the absence of the NTA deployments.

[82] Though this analysis only looks at a 10-year horizon, GridSolar expects that the pilot project will permanently eliminate the need for the transmission alternative (GridSolar, *"Interim Report: Boothbay Harbor Sub-Region Smart Grid Reliability Pilot Project"*, for Docket No. 2011-138, March 4, 2014 and personal communication with Dan Blais, GridSolar, October 14, 2014.

Figure 7: Cost Comparison of Transmission and NTA Solutions for Boothbay





One other important result worth re-stating about the project is that many of the passive resources, particularly energy efficiency, were among the first to be deployed. As GridSolar noted in its March 2014 project updates, this "bought time" for other NTAs to be brought on line:

> *"…To date, the Pilot has deployed over 400 kW of passive NTA resources…These passive resources alone exceed the projected grid reliability requirements in the Boothbay subregion…for the initial years of the Pilot…the subregion will not reach the projected critical loads in which the full suite of NTA resources are needed to meet reliability requirements in the out years of the Pilot project. This demonstrates the dynamic and modular nature of NTA solutions, which be ratcheted up or down year to year, as conditions require – thus lowering net costs and preventing premature or stranded costs due to overbuilding.*

Moreover, as noted above, the ability to quickly deploy some of the NTA resources bought time to allow for an updated peak forecast which lowered the magnitude of the total NTA required to meet reliability needs from 2.0 to 1.8 MW.

The Future

In addition to continued implementation and evaluation of the Boothbay pilot, several other developments in Maine related to consideration of non-wires alternatives merit brief discussion.

First, and perhaps most importantly, the omnibus energy bill that became law in July 2013 contains important new language regarding consideration of NTAs. In particular, the bill requires the following:[83]

[83] HP1128, LD1559, Item 1, 126th Maine State Legislature, "An Act to Reduce Energy Costs, Increase Energy Efficiency, Promote Electric System Reliability and Protect the Environment", Part C.

- No new transmission project of either (1) 69 kV or greater or (2) less than 69 kV with a project cost of at least $20 million can be built without consideration of NTAs;
- Assessment of NTAs must be performed by "an independent third party, which may be the commission or a contractor selected by the commission";
- The commission must "give preference" to NTAs when they are lower cost to ratepayers;
- When costs to ratepayers for a transmission project and NTAs are comparable, the commission must give preference to the option that produces the lowest air emissions (including greenhouse gases);
- If NTAs can address a need at lower total cost, but higher cost to ratepayers (because of socialization of the costs of transmission through ISO New England), the commission must "make reasonable efforts" to negotiate a cost-sharing agreement among the New England states that is similar to the cost-sharing treatment the transmission alternative would receive (the commission is given 180 days to negotiate such an agreement); and
- The commission is required to advocate "in all relevant venues" for similar treatment for analysis, planning and cost-sharing for NTAs and transmission alternatives.

The first NTA study required by the law is currently being undertaken in northern Maine (Docket 2014-00048). The Commission anticipates that two other potential Central Maine Power projects will trigger the study requirement.

Second, the Commission currently has an open docket in which it is considering whether to establish a permanent third party administrator of NTAs (initially Docket 2010-00267; now under Docket 2013-00519) and, if so, to establish how the administrator would be selected and overseen.[84] GridSolar has proposed that it become the state's coordinator. Other parties have some concerns. For example, Efficiency Maine Trust has expressed reservations about creating a new statewide third party administrator to manage consumer education, research and deployment of demand resources when it already plays that role for a subset of the resources (particularly energy efficiency and renewables). It has also expressed concern about inefficiencies in requiring it, as a regulated entity, to work through another regulated third party entity to get efficiency resources to be considered part of potential NTA solutions.[85] Instead, it suggests that cost-effective efficiency NTA resource be deployed in the future through the process EMT currently uses to make changes to its Triennial Plan.[86] GridSolar has itself recommended that in future projects efficiency resources should be procured "in partnership with EMT" and "outside the RFP process used to procure other NTA resources."[87]

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[84] Maine calls this position a "Smart Grid Coordinator", perhaps in part because the role may be larger than just managing NTAs.
[85] Personal communication with Ian Burnes, Efficiency Maine Trust, September 17, 2014.
[86] Mr. Ian Burnes and Dr. Anne Stephenson, Direct Testimony, Docket No. 2013-00519, August 28, 2014.
[87] GridSolar, *"Interim Report: Boothbay Harbor Sub-Region Smart Grid Reliability Pilot Project"*, for Docket No. 2011-138, March 4, 2014.

3. PG&E

Legislative Requirements

PG&E, and presumably the other California electric utilities that are subject to the requirements of Assembly Bill 327 (AB 327), are in the early stages of identifying target areas that have rich potential for the deployment of non-wires alternatives. For PG&E, as these areas are identified, small pilot projects will be undertaken to test the potential for meeting growth-related needs through distributed resources rather than through construction of traditional poles and wires solutions. Signed by the Governor on October 7, 2013, AB 327 addresses several issues related to electric regulation and rates, and includes language laying out new expectations for resource planning, including the level of detail and rigor that utilities must apply. The law states that "Not later than July 1, 2015, each electrical corporation shall submit to the commission a distribution resources plan proposal to identify optimal locations for the deployment of distributed resources."[88] The Act further states that "…"distributed resources" means distributed renewable generation resources, energy efficiency, energy storage, electric vehicles, and demand response…." Sophisticated planning tools will be needed to meet the AB 327 requirement that these utilities must "Evaluate locational benefits and costs of distributed resources…." Until now, tools that can model distributed energy resources (DERs) have not been required.

Selection of Pilot Projects

In response to these requirements, PG&E has begun working with several vendors to explore different tools and approaches for meeting the requirement for developing locational benefits and costs and for applying these values along with load and growth forecasts to develop an optimized distributed resources deployment plan. As an approach to testing the viability of this type of planning and deployment, PG&E began looking specifically at distribution substation level projects that potentially required attention due to load growth.[89] The Company ultimately identified approximately 150 capacity expansion projects that would need to be addressed in the next five years absent any action to defer them. They then applied criteria to identify projects that would be most suitable to explore for non-wires approaches. To make this cut, projects needed to:

- Be growth-related rather than related to any type of equipment maintenance issues;
- Have projected in-service dates at least three years out from the analysis date; and
- Have projected normal operating deficiencies of 2MW or less at the substation level.

These criteria were selected for this concept-testing period to identify projects that would have a strong chance for success. Applying these criteria whittled the list down significantly— to about

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[88] Section 769, California Assembly Bill 327 https://leginfo.legislature.ca.gov/faces/billNavClient.xhtml?bill_id=201320140AB327

[89] At PG&E, distribution substations range typically serve between 5000 and 30,000 customers, with a total peak load of about between 20 MW and 100 MW (personal communication with Richard Aslin, PG&E, December 14, 2014).

a dozen remaining projects that had the potential to be candidates for NWAs. PG&E looked more closely at the connected loads and customer profiles for these remaining projects to get a more detailed sense of the types of NWAs that might be relevant in each project, and whether NWAs could realistically achieve the necessary load reductions. Through this process of careful selection, PG & E has identified four projects that it will use to test NWAs in 2014-15. By the end of 2015 they are confident that they will have a much better understanding of the opportunity to use NWAs to defer or avoid poles and wires construction projects.

Efficiency Strategies

Given that these projects are still being developed for PG & E, there is not much actual experience to report on in terms of their approach to deploying energy efficiency in the four pilot areas. PG & E has a wide array of programs in its portfolio, so at present it is not planning to develop new program offerings for targeted areas. However, it is providing significantly larger incentives for custom C&I projects in targeted areas, and is working on making the non-trivial programming changes that will allow it to make corresponding changes for prescriptive measures. Making the programming changes that will allow tracking and reporting of different incentive levels in different areas is a critical step in developing the infrastructure that will allow successful use of DERs.

For residential customers, targeted measures include pool pumps and HVAC measures, with increased incentives available through the Upgrade California initiatives. PG&E is also doing an intense marketing campaign for its residential A/C cycling demand response program, and is offering increased incentives as well. To try to make sure that messaging is going to the right customers – to avoid the possibility that ineligible customers will want to take advantage of increased incentives – PG&E is primarily marketing the programs through installation contractors rather than using any kind of broad outreach campaign.

Outreach poses challenges related to making sure that the message gets to the right customers, but one of the additional challenges that PG&E has identified is the importance of getting the right message to customers in a way that won't cause them to worry about the lights going out. Many Californians remember rolling brownouts, and any hint that reliability is in question can evoke strong reactions. This may or may not be as much of an issue in jurisdictions that have no history of reliability issues.

Addressing Management Challenges

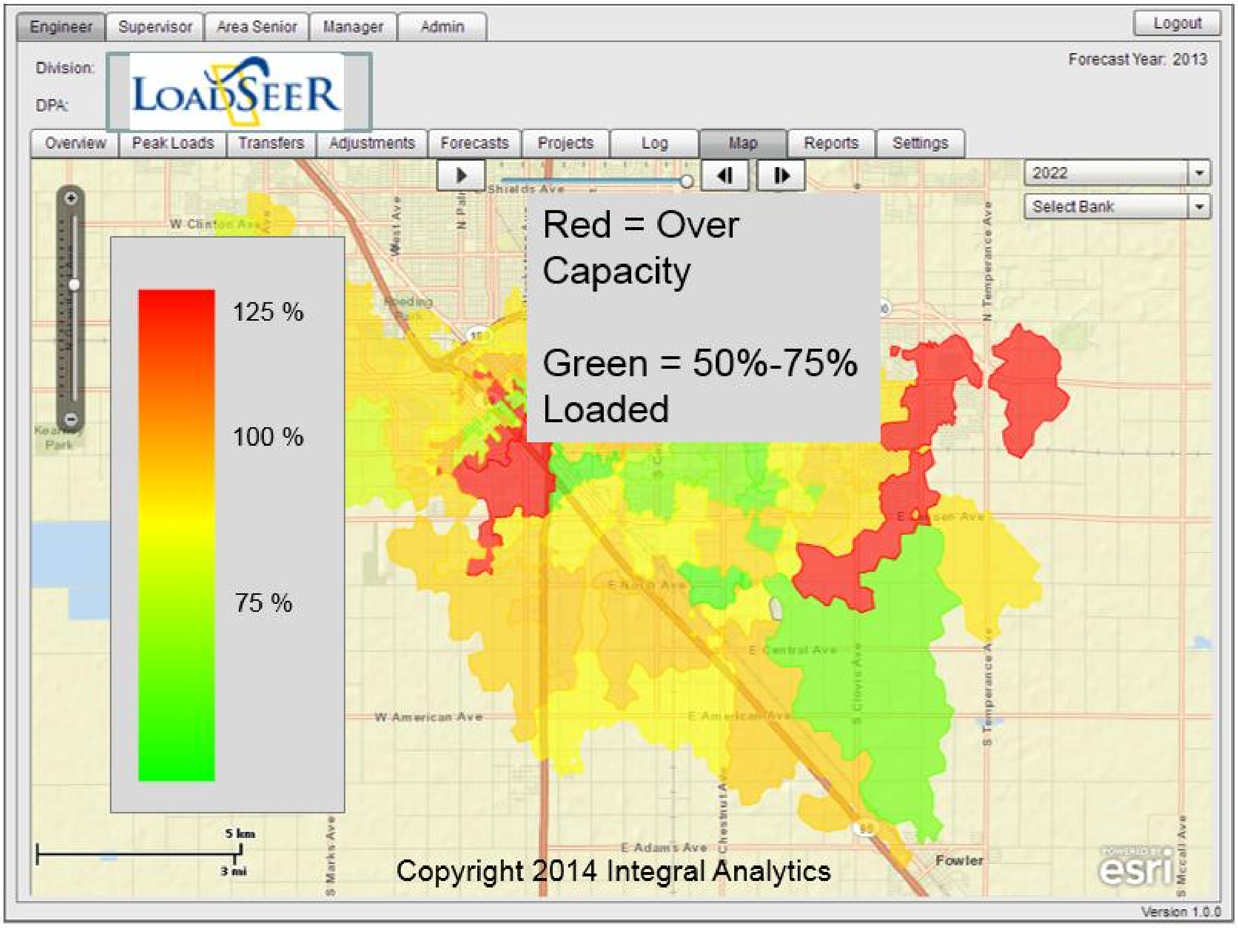
PG&E, like other utilities in this study, has identified challenges working across traditional utility organizational structures that typically have system planners operating in isolation from demand management and energy efficiency staff. PG&E, as well as other utilities with whom we talked, has found that system planners are often uncomfortable with the perceived level of uncertainty in non-wires solutions as compared with poles and wires solutions. Historically, the system planners' primary role is to provide certainty that the lights will stay on, and so the multifaceted complexity of non-wires solutions may seem less attractive than the alternatives with which they are more familiar.

PG&E staff are exploring organizational changes that might improve the cross-functional coordination of planning for alternatives to poles and wires. One of the steps that PG&E is undertaking to address planning integration between the two groups is – for the targeted substation projects – having dedicated customer energy solutions (CES) engineers and customer relationship managers work side-by-side with the distribution planning engineering teams. They are optimistic that through building these one-on-one relationships, and by having the engineers and customer relationship managers work "across the aisle", they will be able to provide the system planners with the level of assurance they require to more fully support potential NWAs.

Use of New Data-Driven Analytical Tools

Moving forward, PG&E is likely to take greater advantage of sophisticated analytics and smart grid data to refine its analyses of the optimal locations for DER approaches. Currently it is working with a number of third party vendors and consultants to test the applicability of different data-driven approaches that will provide greater assurance to planners by better addressing the unknowns in the current planning process. One of these vendors, Integral Analytics, has already developed tools that will map and forecast loads and develop "distributed" marginal pricing (DMP) at the circuit or even customer level, with far greater precision than the locational marginal pricing (i.e. avoided costs) that are currently used to evaluate demand side management programs. These models not only map current loads, but also model loads out into the future, with the capacity to provide data-driven predictions of when loads will exceed a circuit's capacity to deliver it, as illustrated in Figure 8. DMPs will allow the development of avoided costs for specific, local areas, which will in turn allow precise analysis of the costs and benefits associated with DER projects. Moreover, the incorporation of power flow analytics below the substation can identify avoided costs that are not captured in traditional approaches (e.g. service transformer "reverse flow" risk from photovoltaics, voltage benefits, power factor value, primary vs. secondary losses, etc.) but which enhance the cost-effectiveness of most DERs, if located in the areas of higher avoided costs.

Figure 8: Illustration of Integral Analytics LoadSEER Tool



Consistent with anecdotal reports from several of the jurisdictions surveyed for this study, one of the primary benefits of considering NWAs is that refinements to the load forecasting and planning process, coupled with improved collaboration between demand-side and distribution engineering, results in planned capacity expansion projects being deferred for reasons beyond just the projected impacts of deployed DERs.

Future Evaluation

As these pilots are just being developed at the time of this writing, there have not yet been any evaluations. However, PG&E will look very closely at the results of these pilots in the hope that DER approaches will become a much more prominent tool in its approach to reliably meeting its customers' energy needs.

4. Vermont

Early History

As discussed above, Vermont successfully tested the application of non-wires alternatives in the Mad River Valley in the mid-1990s. A few years later, the state embarked on a path to establishing an independent "Efficiency Utility" – soon thereafter named Efficiency Vermont – that would be charged with delivering statewide efficiency programs. However, the order creating Efficiency Vermont made clear that the state's T&D utilities would still be responsible for funding and implementing any additional efficiency programs that could be justified as cost-effective alternatives to investment in T&D infrastructure (though they could contract implementation to Efficiency Vermont). The Vermont Public Service Board also agreed to "initiate a collaborative process to establish guidelines for distributed utility planning".[90] That collaborative culminated in a set of guidelines approved by the Board in 2003 in Docket 6290. Among other things, the distribution utilities were required to file integrated resource plans every three years. Those plans must identify system constraints that could potentially be addressed through non-wires alternatives.[91] The order also led to 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 by the utilities, the State's Department of Public Service and other parties. However, none of those discussions led to implementation of any such alternatives.

Northwest Reliability Project

In 2003, VELCO,[92] the state's transmission utility, formally proposed a very controversial large project – the Northwest Reliability Project – to upgrade transmission lines from West Rutland to South Burlington. As required by Vermont law, VELCO filed an analysis of non-transmission alternatives. The analysis of a scenario including a combination of aggressive geographically targeted efficiency and distributed generation had a lower societal cost than the transmission line.[93] However, that option 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 born entirely by Vermont ratepayers due to New England ISO rules. Those concerns, coupled with VELCO's concerns that the level of efficiency envisioned would be unprecedented, led the utility to argue in favor of the transmission option.[94] 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.[95]

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[90] Vermont Public Service Board Order, Docket No. 5980, pp. 54-58.
[91] Vermont Public Service Board Order, Docket No. 6290.
[92] VELCO is Vermont's electric transmission-only company, formed in 1956 to create a shared electric grid in Vermont that could increase access to hydro-power for the state's utilities. http://www.velco.com/about
[93] La Capra Associates, "Alternatives to VELCO's Northwest Reliability Project", January 29, 2003.
[94] Ibid.
[95] Vermont Public Service Board, "Board Approves Substantially Conditioned and Modified Transmission System Upgrade", press release, January 28, 2005.

Act 61 – Institutionalizing Consideration of Non-Wires Alternatives

The approval of the transmission line contributed to the passage later that year of Act 61. Among other things, Act 61:

- required state officials to advocate for promotion of least cost solutions to T&D investments and equal treatment of the allocation of costs of both traditional T&D investments and non-wires alternatives "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…"
- required VELCO to regularly file a statewide transmission plan that looks forward at least 10 years; and
- 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.

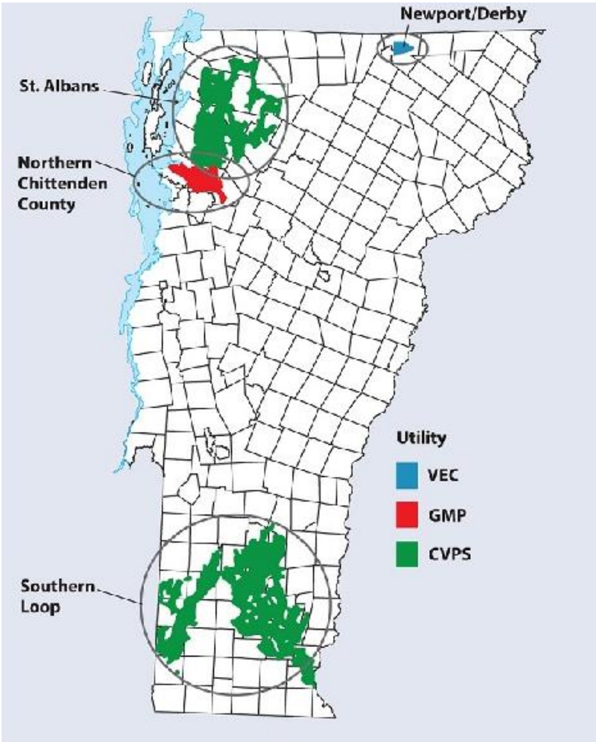
Key excerpts from Act 61 are provided in Appendix C.

Efficiency Vermont's Initial Geo-Targeting Initiative

In response to passage of Act 61, the Public Service Board 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 9).[96] 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 initial "geo-targeting" initiative. [97]

[96] Vermont Public Service Board, *Order Re: Energy Efficiency Utility Budget for Calendar Years 2006, 2007 and 2008*, 8/2/2006.
[97] Efficiency Vermont Annual Plan, 2008-2009.

Figure 9: Efficiency Vermont Geo-Targeting Regions (2007-2008)



Efficiency Vermont was given peak savings goals for these areas that represented a 7- to 10-fold increase in the peak savings it had historically been achieving in the areas through its statewide efficiency programs. To meet the goals Efficiency Vermont initiated intensive account management of large commercial and industrial customers, launched a small commercial direct install program, and locally increased marketing and promotion of CFLs.

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 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").[98] Independent of that decision, a new target area – Rutland – was added to the program beginning in 2009.

An evaluation of the 2007-2009 geo-targeting efforts suggested the results were mixed. On the one hand, program participation was two to four times higher in the geo-targeted areas than statewide. Savings per participant were also higher – 20-25% higher for business customers and 30% higher for residential customers. The net result was summer peak savings that were three to five times higher in the first couple of years than would have been achieved under the statewide

[98] 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.

programs.[99] On the other hand, those summer peak savings were still 30% lower than Efficiency Vermont's goals for the targeted areas; winter peak savings were 60% lower than goals. 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 were consistent with those estimated through evaluation of customer savings.[100]

Evaluation of the impacts of the observed peak demand reductions on the potential deferral of T&D investments was not conducted. However, Central Vermont Public Service (the state's largest utility at the time)[101] 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) and/or to other factors, the Company did recommend to the Board that geo-targeting of DSM continue.[102] One Vermont official similarly noted that

Vermont System Planning Committee

Subsequent to the passage of Act 61, the PSB initiated proceedings in Docket 7081 to develop a planning process that would ensure "full, fair and timely consideration of cost-effective non-transmission alternatives." The Public Service Board ultimately issued orders in 2007 approving an MOU between the major parties that established the Vermont System Planning Committee (VSPC) and charged it with carrying out this work.

The VSPC is a collaborative body. It brings together a wide range of viewpoints, including those of representative public stakeholders. There are six equally weighted voting contingents who are responsible for VSPC decisions on specific activities and projects:

- VELCO,
- large utilities with transmission,
- large utilities without transmission,
- other utilities without transmission,
- Efficiency Utilities (i.e. Efficiency Vermont and Burlington Electric Department) and renewable energy organizations, and
- public stakeholders.[103]

[99] 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
[100] Navigant et al. (2011), p. 10.
[101] It was subsequently purchased and has become a part of Green Mountain Power.
[102] 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.
[103] http://www.vermontspc.com/about/membership

The Public Service Board appoints the public stakeholders and the renewable energy representatives.

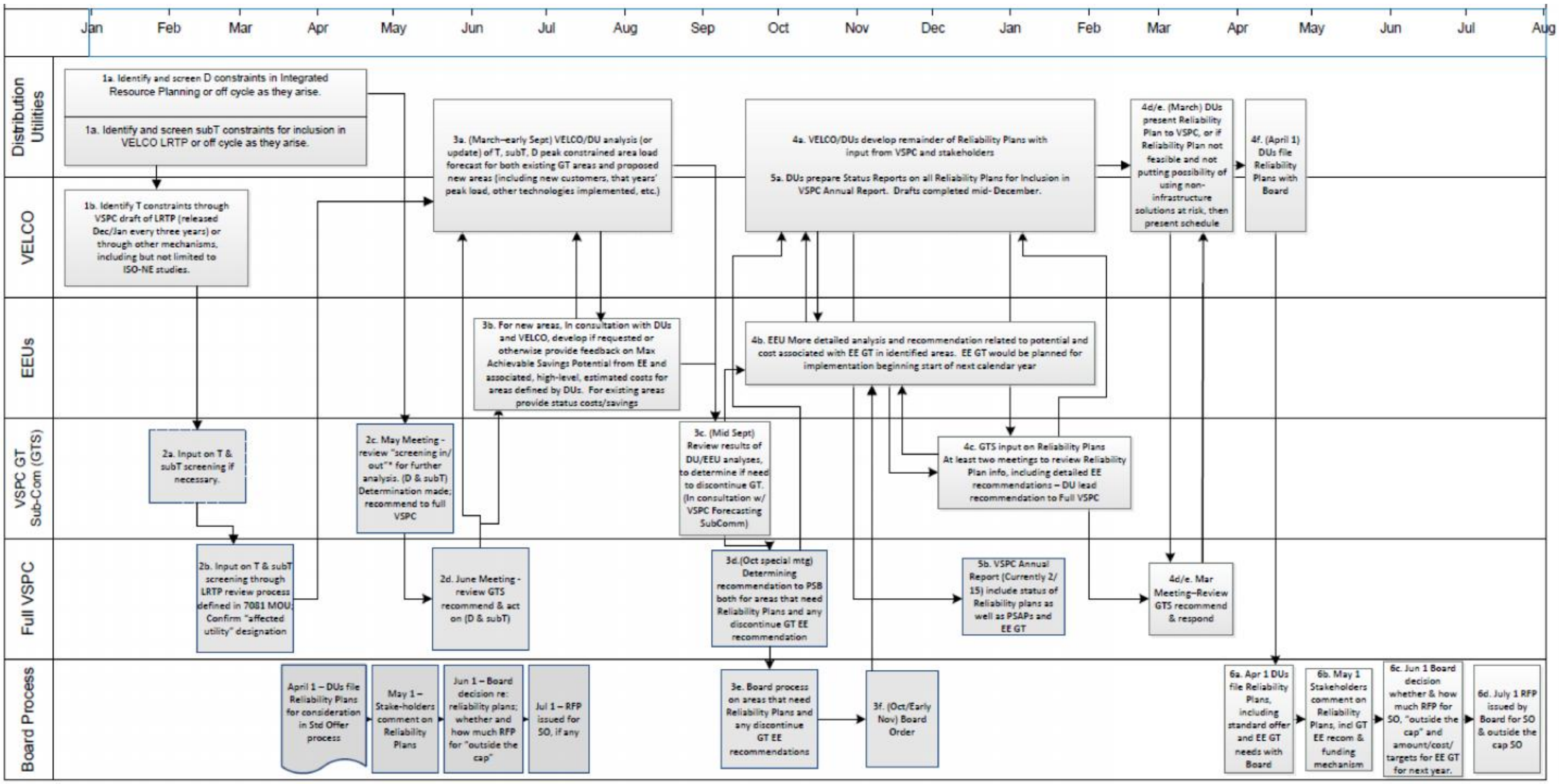
The VSPC process overcomes two significant barriers by first making sure that potential system constraints are identified as far in advance of their needed construction dates as possible, and secondly by ensuring that efficiency program planners are brought into the conversation early enough to determine whether efficiency is a viable alternative to construction given the particular customer segments that predominate in the targeted areas. Over time, the level of coordination in designing and implementing solutions has increased. In the first geographic targeting initiative undertaken by Efficiency Vermont in 2007, the state's utilities identified potentially constrained areas and then, with PSB approval, more-or-less handed the list to Efficiency Vermont. Now, with Efficiency Vermont serving as a fully participating member of the VSPC, a much more integrated approach is used, where the efficiency potential of constrained areas is investigated prior to their selection for geographically targeted efforts.

With the formation of the VSPC, significant efforts have also been invested in making sure that diverse viewpoints are represented in discussions regarding non-wires alternatives to both distribution and transmission construction. Further, a clear, well-documented and transparent process has been developed to make sure that results and decisions are firmly based on comprehensive consideration of evidence. This process has evolved over time. The current process is documented in Figure 10 below.[104]

In this process, VELCO, along with the large utilities that have transmission, is responsible for identifying bulk and predominantly bulk transmission system reliability improvement needs; the individual distribution utilities are responsible for identifying distribution and sub-transmission needs. Though they come from different dockets and legislation, in each case there is a requirement that these are identified on a three year basis, but project lists are also updated for the VSPC annually.

[104] http://www.vermontspc.com/library/document/download/599/GTProcessMap_final2.pdf

Figure 10: Vermont Geo-Targeting Process Map (as of 9/11/2013)



*"Screening" refers to the use of the Docket 7081 screening tool for bulk and predominantly bulk transmission and the Docket 6290 screening tool for subtransmission and distribution issues to determine their potential to be resolved through energy efficiency and/or alternatives such as generation or demand response (or a hybrid of transmission with efficiency and/or generation). An issue is "screened in" if it has potential for a non-wires solution and therefore requires a Reliability Plan, and "screened out" if no potential is found and, therefore, no Reliability Plan is required.

Key to abbreviations

D	distribution	LRTP	VELCO Long-Range Transmission Plan
DU	distribution utility	PSAP	project-specific action plan
EE	energy efficiency	RFP	request for proposal
EEU	energy efficiency utility	SO	standard offer
GT	geographic targeting	subT	subtransmission (subsystem)
GTS	VSPC Geotargeting Subcommittee	T	transmission (bulk/predominantly bulk)
		VSPC	Vermont System Planning Committee

As part of the development of T&D project lists, the utilities are required to use a set of "pre-screening" criteria to identify projects that might be candidates for non-wires alternatives. The key pre-screening criteria for distribution and sub-transmission projects are that the forecast "poles and wires" costs is greater than $250,000, that it is not required on an emergency basis, and that the need could be reduced by reductions in load.[105] For transmission projects to be considered for NWA approaches, the alternative needs to be projected to save at least $2.5M, needs to be able to be deferred or eliminated by a 25% or less reduction in load, does not need to be in place for at least one year into the future, and must not be needed for the purpose of meeting certain "stability" criteria related to grid performance. The VSPC reviews the utilities' initial project lists, including their pre-screening conclusions, and modifies them as appropriate. A recent example of a project list is provided in Table 4 below.

Table 4: Green Mountain Power 2014 Forecast of Distribution System Needs

Constraint	Load Growth related (Y/N)	MW Need	Year of need	Zonal identified MW available (potential study)	Further screening (Y/N)
Susie Wilson Substation Area	Yes		2037		No Continue to Monitor
Wilder - White River Junction Area	Reliability and Load Growth		2015		No
Waterbury	Reliability		2015		No
Winooski 16Y3 Feeder	No		2015		No
Hinesburg	Yes		2016		No
Dover Haystack	Yes		2015		No
Stratton	Reliability		2015		No
St Albans	Reliability and Load Growth		>10 years		Reliability Plan filed 4/2/14, Continue to Monitor
Miton	Yes		>10 years		No Continue to Monitor
Brattleboro	Yes		>10 years		No Continue to Monitor
Southern Loop	Yes		>10 years		No Continue to Monitor
Danby	Reliability and Load Growth		2016		No
Granite-Whetmore	Asset Management		2016		No
South Brattleboro	Reliability		2016		No
3309 Transmission	Reliability		2014		No Continue to Monitor / Refine the analysis
Rutland Area	Reliability		Existing Constraint		Reliability Plan filed 4/2/14, additional analysis required
Windsor Area	Reliability		2017		No

For projects that pass the initial screen, the VSPC then follows the collaboratively-developed process to consider non-wires solutions, with the efficiency and renewables alternatives given a detailed look by Efficiency Vermont and other stakeholders. To date this analysis has been

[105] http://www.velco.com/uploads/vspc/documents/ntascreening_6290.pdf

conducted with only limited use of smart grid data. Efficiency Vermont has a deep knowledge of its customer base through nearly fifteen years of program implementation, and can also easily track prior efficiency improvements that targeted customers made through participation in Efficiency Vermont initiatives. While there is diversity among Vermont's commercial and industrial customers, they are still mostly relatively small compared to the C&I base in other jurisdictions, and so far Efficiency Vermont has been able to assess these opportunities without the use of more detailed analytic tools.

Efficiency Vermont's Strategy and Planning group has been responsible for identifying opportunities to increase efficiency in targeted areas and for designing program approaches to capture that efficiency. Generally, the implementation of any geographically targeted energy efficiency alternatives has been managed by Efficiency Vermont in a manner that is highly coordinated with its other state-wide efforts. Since beginning to implement geographically targeted initiatives in 2007 Efficiency Vermont has been cognizant of the need for sensitivity when it determines to only offer certain programs to some, rather than all customers. For this reason, they have decreased the use of special incentives in targeted areas in favor of increased outreach and communications. For example, the use of account management strategies for C&I customers is increased in geographically targeted areas, meaning that smaller customers who would not have received the attention of individualized account managers in non-targeted areas do receive that attention in targeted areas. This account management approach also allows Efficiency Vermont to focus on projects that have the potential to produce higher peak savings than average, thus increasing the ability of efficiency to defer construction compared to an "average" project that did not receive this level of guidance from account managers.

Efficiency Vermont has not done competitive solicitations to identify vendors who will commit to delivering certain savings through strategies of their own devising. Rather they have designed and managed program initiatives internally, with limited use of third-party vendors to implement programs for which Efficiency Vermont has developed the parameters. However they are investigating the potential to use the targeted deployment of third-party approaches in the future, specifically those that make use of smart grid data to identify savings opportunities to engage customers who might otherwise not have been aware of them.

With the VSPC process in place, the relationship between level of effort and the amount of resource needed in a specific area is much, much stronger. Where the first of Efficiency Vermont's geographically targeted efforts involved a single goal that could be met through savings in any of several targeted areas, goals are now set that are specific to each targeted area, and that reflect the actual need in that area as determined by system planners.

The VSPC and the planning process for non-wires alternatives have matured significantly in Vermont. Conversations with the Public Service Department and Efficiency Vermont both suggest confidence in the process. Going forward, it is expected that the VSPC process will continue to be used to identify potential candidates for geographic targeting of NWAs.

V. Cross-Cutting Observations and Lessons Learned

Although the use of efficiency to meet T&D needs– either alone or in combination with other non-wires resources – is not yet widespread, it is fairly substantial and growing. That experience offers a number of insights, presented below, for jurisdictions considering the use of such resources in the future.

The Big Picture

1. Geographically Targeted Efficiency Can Defer Some T&D Investments

Projects run by Con Ed (from 2003 through 2012), Vermont (both the initial Green Mountain Power Project in the mid-1990s and more recent examples), PG&E's Delta Project in California (in the early 1990s), and portions of PGE's project in downtown Portland, Oregon (also in the early 1990s), all demonstrably achieved enough savings to defer some T&D investments for at least some period of time. Preliminary results from the first year of experience with new projects in Maine and Rhode Island suggest that they too are likely on track to defer T&D investments.

2. T&D Deferrals Can be Very Cost-Effective

The cost-effectiveness of geographically-targeted efficiency programs and other non-wires resources will unquestionably be project-specific. That said, though data on the cost-effectiveness of T&D deferrals is not available for all of the projects we have examined, the information that is available suggests that efficiency and other non-wires resources can be very cost-effective – i.e. potentially much less expensive than "poles and wires" alternatives. For example, Con Ed's evaluation suggests that its geographically targeted efficiency investments from 2003 to 2010 produced roughly $3 in total benefits for every $1 in costs; the T&D benefits alone were worth 1½ times the costs of the programs. Similarly, the revenue requirements for Maine's pilot project are forecast to be more than 60% lower than for the alternative transmission solution.

3. There Is Significant Value to the "Modular" Nature of Efficiency and Other NWAs

One of the advantages of energy efficiency and other non-wires alternatives is that they are typically very modular in nature. That is, they are usually acquired in a number of small increments – e.g. thousands of different efficiency measures across hundreds, if not thousands of different customers, across several years. In contrast, the pursuit of a "poles and wires" strategy typically requires a commitment to much larger individual investments – if not a singular investment.

The modularity of efficiency and other non-wires alternatives allows for a ramp up or a ramp down of effort, either in response to market feedback (e.g. if customer uptake is greater or lower than expected) or in response to changing forecasts of T&D need. For example, as discussed in the case study of the Maine pilot project, the magnitude of the non-wires resource needed to defer the transmission investment has declined from an initial estimate of 2.0 MW to 1.8 MW.

Moreover, perhaps in anticipation of possible future changes, a decision has been made to not yet contract for the last 0.1 MW of need because that can be addressed at a future time if it is still determined to be needed. Similarly, again as noted above, Con Ed has found that one of the biggest advantages of its non-wires projects is that they have "bought time" for the utility to better tune its forecasts, to the point in a number of cases where the T&D investments once thought to be needed are now not anticipated to ever be needed.

4. Policy Mandates Are Driving Most Deployments of NWAs

Virtually all of the examples of the use of non-wires alternatives that we have profiled in this report were at least initially driven by either legislative mandates, regulatory guidelines or types of regulatory feedback. Examples of such requirements are provided in Appendices A through D.

The importance of policy mandates may be partly indicative of the nature of the internal barriers to utility pursuit of non-wires solutions. Utilities tend to be fairly conservative institutions. That is consistent with their primary mission of "keeping the lights on". It is understandable that they would be reluctant to change practices that they know are successful in serving that mission. As noted above, there are also challenges associated with persuading system planners that demand side alternatives can also be reliable.

In addition, utilities' financial incentives are generally not well aligned with the objective of pursuing cost-effective alternatives to "poles and wires". Right now, utilities can face a choice of earning money for shareholders if they pursue a traditional T&D path (because they earn a rate of return on such capital investments) or making no money if they choose to deploy non-wires alternatives.[106] To our knowledge, Con Ed's proposal for shareholder incentives for the large new Brooklyn-Queens project is the only proposal of its kind that attempts to directly address this issue.

Implementation

5. Cross-Disciplinary Communication and Trust 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 and/or other demand resources 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

[106] Some utilities operate under capital spending caps. In such cases, the financial disincentives may be mitigated, at least in the short term, with money freed up from deployment of NWAs to defer or eliminate the need for some T&D investments effectively enabling the utility to invest in other T&D projects further down its priority list. However, if deployment of cost-effective NWAs is institutionalized, regulators could eventually respond by reducing capital spending caps.

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 T&D system engineers to work together effectively. However, those relationships and that trust must be developed if efficiency programs are to successfully defer T&D investments.

Different jurisdictions and utilities have approached the challenge of facilitating cross-disciplinary collaboration differently. Con Ed has created a multi-disciplinary team that meets regularly under the direction of a Senior Vice President. PG&E has assigned field services engineers with customer-side experience to work side-by-side with distribution planning engineers on their pilot non-wires projects, with the expectation that the experience of working together will build trust and mutual understanding over time. Vermont's System Planning Committee serves a similar function, institutionalizing communication between system planners and those responsible for efficiency program delivery (as well as other stakeholders).

6. Senior Management Buy-in Is Invaluable

Senior management support for consideration of non-wires alternatives can be critical, if not essential, to facilitating the kind of cross-disciplinary collaboration that is necessary to be successful.

Senior management support will also be necessary to get to the point where consideration of cost-effective non-wires alternatives is routine and fully integrated into the way utilities run their businesses. As discussed further below, that, in turn, may require changes to utilities' financial incentives.

7. Smaller Is Easier

In general, all other things being equal, the smaller the size of the load reduction needed and the smaller the number of customers, the easier it is to plan and execute a non-wires solution. Smaller areas allow for greater understanding of both the customer mix and the savings or distributed generation opportunities associated with those customers. It is also generally easier to mobilize the existing demand resources delivery infrastructure (e.g. HVAC, lighting and/or other contractors) to meet a smaller need.

That is not to say that only small projects should be pursued, as the economic net benefits from larger projects also tend to be larger. Larger areas do offer one advantage: a more diverse range of customers and savings opportunities from which to choose in designing and implementing an NWA solution. A corollary to this point is that networked systems may be easier to address than radial systems because they allow for treatment of a larger number of customers to address a need. However, it is also important to recognize that larger projects with more customers over a larger geographic area will also be more complex and often require more lead time to plan and execute.

8. Distribution is Easier than Transmission

This may seem like just a corollary to the "smaller is easier", as distribution projects are generally smaller than transmission projects. However, there is more to it than that. For one thing, distribution system planning is generally less technically complex and more "linear" – 1 MW of load reduction commonly translates to 1 MW (adjusted for losses) of reduced distribution infrastructure need. In transmission planning 1 MW of load reduction in an area does not necessarily translate to 1 MW of reduced infrastructure need. In addition, distribution system planning typically involves fewer parties so decision-making is often more streamlined. Moreover, distribution reliability planning criteria can be less stringent than transmission planning criteria, so there may be opportunities to use NWAs with shorter time horizons and/or with less certainty that forecast savings will be achieved (i.e. there can be more flexibility for utilities in the timing of distribution infrastructure upgrades).

Finally, and perhaps most importantly, the cost allocations for both distribution system investments and their non-wires alternatives will typically both be fully and equally born by local ratepayers. This is in stark contrast to the allocation of transmission costs, which are governed by regional frameworks that inherently bias investments in favor of traditional "poles and wires" solutions. Typically transmission investment costs are socialized across multi-state regions, so that the state in which the transmission investment is needed pays only a portion of the project costs. In the case of non-wires alternatives, the state in which the project is deployed is made to bear all of the costs. Clearly, until this is addressed, it will continue to be challenging to implement NWAs to defer transmission projects.

9. Integrating Efficiency with Other Alternatives Will be Increasingly Common and Important

In several of the examples that we examined in this report geographically-targeted efficiency programs were enough, by themselves, to defer the traditional T&D investment. However, in some cases efficiency was effectively paired with demand response and/or other non-wires alternatives. As the projects being considered become larger and more complex and the development of non-wires solutions becomes more sophisticated, we expect such multi-pronged solutions to become more common. That is certainly the case, for example, with Con Ed's new Brooklyn-Queens project. Moreover, even a comprehensive suite of NWAs may be inadequate, by themselves, to address reliability concerns. In such cases, NWAs could potentially be paired with some T&D modifications, deferring only a portion of a larger T&D investment project.

10. "Big Data" and New Analytical Tools Enable More Sophisticated Strategies

Several of the geographic targeting projects that have occurred to date have found that the availability of savings was different from their initial expectations because their assumptions about the customers in the targeted areas were found to have been inaccurate. This was true for the Tiverton project in Rhode Island, where initial plans called for a substantial amount of demand response for residential central air conditioning systems, but where it turned out that the penetration of central air conditioning was much lower than originally expected. Similarly, Con Ed found that contractors weren't able to meet their savings targets in the later years of their initial geo-targeting efforts and attributed this to the lack of a detailed understanding of the types of customers and predominant end uses in the targeted areas.

Utilities have also faced uncertainty in assessing the cost-effectiveness of NWAs, in no small part because accurately assessing loads and growth is challenging, and utility system planners—who are responsible for assuring that the lights will stay on— may have some understandable bias towards high safety margins when assessing system capacity. Put another way, accurately valuing the economic benefits of alternatives to poles and wires approaches is not easy.

Reliable and malleable planning tools are needed that will allow more accurate modeling of loads at a much more detailed level, and that will provide a better accounting of available savings and the economic value associated with them. Understanding the opportunities available to customers within defined and specific geographies, coupled with detailed load and economic information, will allow utilities to plan NWA approaches with greater confidence and to yield greater economic benefits (i.e. from the use of more granular, locational avoided costs) in the process. In recognition of this, several utilities and third party vendors are rapidly developing tools to address these emerging needs. We are aware of efforts by Integral Analytics for PG&E and others, and by Energy + Environmental Economics (E3) for Con Ed. Navigant is also participating in projects for both of these utilities, and it is likely that others are exploring this space as well.

Integral Analytics has developed a suite of proprietary software tools specifically for the purpose of providing utilities with previously unavailable capability for assessing loads down to the acre level, and for developing avoided costs that are specific to each circuit. These tools would not only provide California utilities with the means to comply with AB327, but would also allow them to assess the need for load relief with much greater precision and to plan NWAs more reliably. Integral Analytics has made special efforts to engage distribution planners in the development of their tools, in recognition of the importance of their participation in identifying and proposing NWAs.

E3 is working closely with Con Ed, as discussed above, to develop a "Decision Tool Integrator" that will overcome the earlier challenges the utility faced in accurately assessing the availability of savings, and further will allow them to identify the combinations of non-wires and traditional approaches that will be best suited to achieving the required load relief in specific areas.

Impact Assessment

11. Impact Assessment Should Focus First on the T&D Reliability Need

Conceptually, assessment of geographically-targeted efficiency programs (and other non-wires resources for that matter) can address one or more of several key questions. Chief among them are:

1. Has the forecast T&D need changed? Has it moved further out into the future, or even been eliminated as a result of targeted programs?
2. To the extent that the forecast T&D need has changed, how much of that change is attributable to the deployment of geographically-targeted efficiency and/or other non-wires resources?
3. What is the magnitude of the T&D peak reduction (for efficiency or demand response) or production (for distributed generation or storage) that has been realized as a result of the deployment of efficiency and/or other non-wires resources? Note that the answer to this question might help inform the answer to the second question above.

To date, the principal focus of most jurisdictions' efforts to assess the impacts of NWAs has been on the first question: was the need for the T&D investment pushed out into the future? This is the most directly answerable question in the sense that it is really about how the current forecast of need has changed from the original forecast of need. It is also clearly the most important because it addresses the "bottom-line" metric that dictates whether money has been saved. In contrast, the second question – how much of the deferral is attributable to the non-wires alternatives – is challenging to address, in part because it begs the question of what "baseline" the evaluation is measuring against.

It is worth emphasizing that one of the key findings from non-wires projects has been that they often "buy time" to improve forecasts of need. Thus, one could argue that a non-wires solution should get "full credit" for a deferral even if the savings that the non-wires alternatives provided were not, by themselves, responsible for 100% of the difference between the old forecast and the new forecast of T&D need. As one Vermont official put it, in discussing a recent geo-targeting effort in the city of St. Albans:

> *"It is impossible to say that one thing deferred the project. But I would also argue that energy efficiency gave us the time to realize that we didn't need the project. As long as we follow a robust process for selecting geo-targeting areas, energy efficiency can be a 'no regrets' strategy, where even if it does not defer the project the efficiency investment is cost-effective (thanks to its avoided energy, capacity and other costs) and allows for more certainty as to the need for the infrastructure. In an energy system world where decisions must be made amidst so much uncertainty, geo-targeted efficiency's risk*

> *mitigation value increases above and beyond the risk value that we give to statewide programs."*[107]

That all said, traditional evaluation, measurement and verification (EM&V) of geographically targeted efficiency programs – both impact evaluation to determine how much T&D peak demand savings were realized and process evaluation to understand what worked well and what did not – can still provide a lot of value. However, that value may be more related to informing planning for future projects than for retrospectively "scoring" the effectiveness of the geo-targeting and/or assigning attribution for T&D deferrals.

[107] Personal communication with T.J. Poor, Vermont Public Service Department, December 23, 2014.

VI. Policy Recommendations

In virtually every jurisdiction profiled in this report, the impetus for consideration of lower cost non-wires solutions to address selected reliability needs has been driven (at least initially) by some form of government policy – either legislative requirements, regulatory requirements or feedback, or both. In this section of the report, we present what lessons learned from leading jurisdictions suggests about key policies. Specifically, we offer four policies that policy-makers should consider if they are to effectively advance consideration of alternatives – including, but not limited to geographically targeted efficiency programs – to transmission and/or distribution system investments. Note that though we use the terminology "non-wires solutions" because most of the focus of this report has been on the electricity sector, the same concepts should apply to "non-pipes solutions" for the natural gas sector.

Recommendation 1: Require Least Cost Approach to Meeting T&D Needs

This is the most basic, but also the most important policy for promoting consideration of alternatives to T&D investments. It is in place in every jurisdiction that is routinely assessing such alternatives on a routine basis. Because the barriers to non-wires alternatives – both institutional and financial – are so strong, this kind of requirement is necessary. It should be emphasized that though necessary, least cost requirements are not sufficient to ensure that economically optimal solutions to reliability needs are considered (see other policy recommendations below).

One other possible alternative would be an overhaul of the way utilities are regulated, including strong financial incentives for minimizing T&D costs imposed on ratepayers. That is the path that the state of New York appears to be pursuing. While intriguing, such a twist on the concept of performance regulation is untested and will be challenging to get right. That is not to say it should not be pursued – only that it needs to be done with great care, with regular evaluation to ensure it is producing the desired results, and perhaps with "backstop" minimum requirements to ensure that the expected and desired results are achieved.

Recommendation 2: Require Long-Term Forecast of T&D Needs

One of the keys to realizing the full benefits that efficiency, demand response, distributed generation, storage and/or other non-wires solutions can provide is ensuring that they can deployed with sufficient lead time to defer T&D investments. We have highlighted several cases in this report in which non-wires solutions could have been less expensive than the wires solutions, but were not pursued (at least in part) because of concern that there was not enough lead time to be certain that the reliability need would be met. Requiring a long-term forecast of T&D investments can significantly reduce the probability of such less than optimal outcomes. By long-term we mean at least 10 years. However, 20 years – as is currently required in Vermont – may be even better. While the accuracy of these forecasts will diminish the farther out into the future they go, a 20 year forecast will still do a better job at ensuring that insufficient lead time does not preclude deployment of cost-effective non-wires solutions.

Recommendation 3: Establish Screening Criteria for NWA Analyses

One way to help effectively institutionalize consideration of non-wires solutions is to establish a set of minimum criteria that would trigger a detailed assessment of non-wires solutions. Most of the jurisdictions discussed in this report have such criteria.

All such criteria start with a requirement that the project be load-related. As the Rhode Island guidelines put it, the need cannot be a function of the condition of the asset (e.g. to replace aging or malfunctioning equipment). Some jurisdictions, such as Vermont, have a short “form” that utilities must complete for each proposed project that provides more detail on this question.

Most jurisdictions have additional criteria related to one or more of the following:

- **Sufficient Lead Time Before Need.** The purpose of this criterion is to ensure that there is enough lead time to enable deferring a T&D investment.
- **Limits to the Size of Load Reduction Required.** The purpose of this criterion is to ensure that there is a substantial enough probability that the non-wires solution can be effective before investing in more detailed assessments. The maximum reduction can be linked to the previous criterion around lead time, as the longer the lead time the larger the reduction in load (and/or equivalent distributed generation level) that could be achieved through non-wires solutions.
- **Minimum Threshold for T&D Project Cost.** The purpose of this criterion is to ensure that the potential benefits of a T&D deferral are great enough to justify more detailed analysis.

Table 5 below provides a summary of the criteria currently in place for a number of the jurisdictions assessed in this report.

Table 5: Criteria for Requiring Detailed Assessment of Non-Wires Solutions

	Must Be Load Related	Minimum Years Before Need	Maximum Load Reduction Required	Minimum T&D Project Cost	Source
Transmission					
Vermont	Yes	1 to 3 4 to 5 6 to 10	15% 20% 25%	$2.5 Million	Regulatory policy
Maine	Yes			>69 kV or >$20 Million	Legislative standard
Rhode Island	Yes	3	20%	$ 1 Million	Regulatory policy
Pacific Northwest (BPA)	Yes	5		$3 Million	Internal planning criteria
Distribution					
PG&E (California)	Yes	3	2 MW		Internal planning criteria
Rhode Island	Yes	3	20%	$ 1 Million	Regulatory policy
Vermont	Yes		25%	$0.3 Million	Regulatory policy

Documents that lay out these requirements more formally and in more detail are provided for Vermont and Rhode Island in Appendices D, E and F.

Consistent with the integrated resource planning guideline discussed above, when projects pass such initial screening criteria, the utility should be required to conduct a more detailed assessment of the potential for reduced peak demand in the geographic area of interest through any combination of distributed resources, including additional energy efficiency, demand response, distributed generation and storage. The cost of such additional distributed resources should then be compared to their benefits. The level of depth of analysis would be a function of the magnitude of the deferral project. For projects for which the more detailed assessment suggests that greater EE and DR would have positive net benefits,[108] the utility should be required to pursue the non-wires solution.

Recommendation 4: Promote Equitable Cost Allocation for NTAs

Investments in transmission solutions to reliability needs are commonly socialized across power pools. For example, a large majority of the cost of a transmission investment in Maine can ultimately be borne by ratepayers in the other five states that are part of the New England grid. In contrast, there is no comparable mechanism to socialize the cost of non-transmission investments across the region[109] – even if they would just as effectively address the reliability

[108] As discussed earlier in the report, some NWAs, including energy efficiency, provide a number of benefits beyond deferral of T&D investments. All costs and benefits of both NWAs and traditional T&D investments should be included in any economic comparisons.

[109] Note that though there is currently no mechanism for socializing the costs of implementing NTAs, there is at least an open question as to whether the costs of *analyzing* NTAs could be socialized. Indeed, some costs of analysis of

concern at a substantially lower cost. In other words, if Maine invests in a non-transmission solution, it will have to bear the full cost of that approach. This is a huge economic barrier to consideration of cost-effective non-transmission investments. Legislation in some states now requires their state officials to advocate for equal treatment of transmission and non-transmission planning and cost allocation in negotiations with and proceedings before their independent system operators, the Federal Energy Regulatory Commission (FERC) and other bodies and fora. Excerpts from the Vermont and Maine legislative language are provided below:

Vermont Act 61, Section 8

> "(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.

Maine 2013 Omnibus Energy Bill, Part C, Sec. C-7 (35-A MRSA §3132)

> **15. Advancement of non-transmission alternatives policies**. The commission shall advocate in all relevant venues for the pursuit of least-cost solutions to bulk power system needs on a total cost basis and for all available resources, including non-transmission alternatives, to be treated comparably in transmission analysis, planning and access to funding.

The greater the number of states that have such policies in place, the greater the likelihood that this barrier will be addressed. The question of what "comparable treatment" to socialization of traditional transmission and non-transmission investments means is not necessarily a simple one. It is likely to require careful thought and discussion among a number of stakeholders. States can play an important role in pressing for and shaping such discussions.

NTAs are already indirectly socialized. For example, VELCO, Vermont's transmission utility, currently recovers costs associated with its system planners through a regional tariff. Thus, when those planners work on NTAs, the costs of that work are effectively socialized across the regional. However, to our knowledge, no entity has yet tested whether other costs of analyzing NTAs (e.g. those born by other entities in a state) are recoverable through regional tariffs.

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Appendix A: California AB 327 (excerpt)

SEC. 8. Section 769 is added to the Public Utilities Code, to read:

769. (a) For purposes of this section, “distributed resources” means distributed renewable generation resources, energy efficiency, energy storage, electric vehicles, and demand response technologies.

(b) Not later than July 1, 2015, each electrical corporation shall submit to the commission a distribution resources plan proposal to identify optimal locations for the deployment of distributed resources. Each proposal shall do all of the following:

1) Evaluate locational benefits and costs of distributed resources located on the distribution system. This evaluation shall be based on reductions or increases in local generation capacity needs, avoided or increased investments in distribution infrastructure, safety benefits, reliability benefits, and any other savings the distributed resources provides to the electric grid or costs to ratepayers of the electrical corporation.
2) Propose or identify standard tariffs, contracts, or other mechanisms for the deployment of cost-effective distributed resources that satisfy distribution planning objectives.
3) Propose cost-effective methods of effectively coordinating existing commission-approved programs, incentives, and tariffs to maximize the locational benefits and minimize the incremental costs of distributed resources.
4) Identify any additional utility spending necessary to integrate cost-effective distributed resources into distribution planning consistent with the goal of yielding net benefits to ratepayers.
5) Identify barriers to the deployment of distributed resources, including, but not limited to, safety standards related to technology or operation of the distribution circuit in a manner that ensures reliable service.

(c) The commission shall review each distribution resources plan proposal submitted by an electrical corporation and approve, or modify and approve, a distribution resources plan for the corporation. The commission may modify any plan as appropriate to minimize overall system costs and maximize ratepayer benefit from investments in distributed resources.

(d) Any electrical corporation spending on distribution infrastructure necessary to accomplish the distribution resources plan shall be proposed and considered as part of the next general rate case for the corporation. The commission may approve proposed spending if it concludes that ratepayers would realize net benefits and the associated costs are just and reasonable. The commission may also adopt criteria, benchmarks, and accountability mechanisms to evaluate the success of any investment authorized pursuant to a distribution resources plan.

Appendix B: Maine 2013 Omnibus Energy Bill Excerpts

An Act To Reduce Energy Costs, Increase Energy Efficiency, Promote Electric System Reliability and Protect the Environment

PART C

Sec. C-1. 35-A MRSA §3131, sub-§4-B is enacted to read:

4-B. Nontransmission alternative. "Nontransmission alternative" means any of the following methods used either individually or combined to reduce the need for the construction of a transmission line under section 3132 or transmission project under section 3132-A: energy efficiency and conservation, load management, demand response or distributed generation.

Sec. C-2. 35-A MRSA §3132, sub-§2-C, ¶¶B and C, as enacted by PL 2009, c. 309, §2, are amended to read:

B. Justification for adoption of the route selected, including comparison with alternative routes that are environmentally, technically and economically practical; ~~and~~

C. Results of an investigation by an independent 3rd party, which may be the commission or a contractor selected by the commission, of nontransmission alternatives to construction of the proposed transmission line ~~including energy conservation, distributed generation or load management~~. The investigation must set forth the total projected costs of the transmission line as well as the total projected costs of the alternatives over the effective life of the proposed transmission line; and

Sec. C-3. 35-A MRSA §3132, sub-§2-C, ¶D is enacted to read:

D. A description of the need for the proposed transmission line.

Sec. C-4. 35-A MRSA §3132, sub-§5, as enacted by PL 1987, c. 141, Pt. A, §6, is amended to read:

5. Commission approval of a proposed line. The commission may approve or disapprove all or portions of a proposed transmission line and shall make such orders regarding its character, size, installation and maintenance as are necessary, having regard for any increased costs caused by the orders. The commission shall give preference to the nontransmission alternatives that have been identified as able to address the identified need for the proposed transmission line at lower total cost to ratepayers in this State. When the costs to ratepayers in this State of the identified nontransmission alternatives are reasonably equal, the commission shall give preference to the alternatives that produce the lowest amount of local air emissions, including greenhouse gas emissions.

Sec. C-5. 35-A MRSA §3132, sub-§6, as repealed and replaced by PL 2011, c. 281, §1, is amended to read:

6. Commission order; certificate of public convenience and necessity. In its order, the commission shall make specific findings with regard to the public need for the proposed transmission line. The commission shall make specific findings with regard to the likelihood that nontransmission alternatives can sufficiently address the identified public need over the effective life of the transmission line at lower total cost. Except as provided in subsection 6-A for a high-impact electric transmission line and in accordance with subsection 6-B regarding nontransmission alternatives, if the commission finds that a public need exists, after considering whether the need can be economically and reliably met using nontransmission alternatives, it shall issue a certificate of public convenience and necessity for the transmission line. In determining public need, the commission shall, at a minimum, take into account economics, reliability, public health and safety, scenic, historic and recreational values, state renewable energy generation goals, the proximity of the proposed transmission line to inhabited dwellings and alternatives to construction of the transmission line, including energy conservation, distributed generation or load management. If the commission orders or allows the erection of the transmission line, the order is subject to all other provisions of law and the right of any other agency to approve the transmission line. The commission shall, as necessary and in accordance with subsections 7 and 8, consider the findings of the Department of Environmental Protection under Title 38, chapter 3, subchapter 1, article 6, with respect to the proposed transmission line and any modifications ordered by the Department of Environmental Protection to lessen the impact of the proposed transmission line on the environment. A person may submit a petition for and obtain approval of a proposed transmission line under this section before applying for approval under municipal ordinances adopted pursuant to Title 30-A, Part 2, Subpart 6-A; and Title 38, section 438-A and, except as provided in subsection 4, before identifying a specific route or route options for the proposed transmission line. Except as provided in subsection 4, the commission may not consider the petition insufficient for failure to provide identification of a route or route options for the proposed transmission line. The issuance of a certificate of public convenience and necessity establishes that, as of the date of issuance of the certificate, the decision by the person to erect or construct was prudent. At the time of its issuance of a certificate of public convenience and necessity, the commission shall send to each municipality through which a proposed corridor or corridors for a transmission line extends a separate notice that the issuance of the certificate does not override, supersede or otherwise affect municipal authority to regulate the siting of the proposed transmission line. The commission may deny a certificate of public convenience and necessity for a transmission line upon a finding that the transmission line is reasonably likely to adversely affect any transmission and distribution utility or its customers.

Sec. C-6. 35-A MRSA §3132, sub-§6-B is enacted to read:

6-B. Reasonable consideration of nontransmission alternatives. If the commission determines that nontransmission alternatives can sufficiently address the transmission need under subsection 6 at lower total cost, but at a higher cost to ratepayers in this State than the proposed transmission line, the commission shall make reasonable efforts to achieve within 180 days an agreement among the states within the ISO-NE region to allocate the cost of the nontransmission alternatives among the ratepayers of the region using the allocation method used for transmission lines or a different allocation method that results in lower costs than the proposed transmission line to the ratepayers of this State.

For the purposes of this section, "ISO-NE region" has the same meaning as in section 1902, subsection 3.

The subsection is repealed December 31, 2015.

Sec. C-7. 35-A MRSA §3132, sub-§15 is enacted to read:

15. Advancement of nontransmission alternatives policies. The commission shall advocate in all relevant venues for the pursuit of least-cost solutions to bulk power system needs on a total cost basis and for all available resources, including nontransmission alternatives, to be treated comparably in transmission analysis, planning and access to funding.

Sec. C-8. 35-A MRSA §3132-A is enacted to read:

§ 3132-A. Construction of transmission projects prohibited without approval of the commission

A person may not construct any transmission project without approval from the commission. For the purposes of this section, "transmission project" means any proposed transmission line and its associated infrastructure capable of operating at less than 69 kilovolts and projected to cost in excess of $20,000,000.

1. Submission requirement. A person that proposes to undertake in the State a transmission project must provide the commission with the following information:

A. Results of an investigation by an independent 3rd party, which may be the commission or a contractor selected by the commission, of nontransmission alternatives to construction of the proposed transmission project. The investigation must set forth the total projected costs of the transmission project as well as the total projected costs of the nontransmission alternatives over the effective life of the proposed transmission project; and

B. A description of the need for the proposed transmission project.

2. Approval; consideration of nontransmission alternatives. In order for a transmission project to be approved, the commission must consider whether the identified need over the effective life of the proposed transmission project can be economically and reliably met using nontransmission alternatives at a lower total cost. During its review the commission shall give preference to nontransmission alternatives that are identified as able to address the identified need for the proposed transmission project at lower total cost to ratepayers. Of the identified nontransmission alternatives, the commission shall give preference to the lowest-cost nontransmission alternatives. When the costs to ratepayers of the identified nontransmission alternatives are reasonably equal, the commission shall give preference to the alternatives that produce the lowest amount of local air emissions, including greenhouse gas emissions.

3. Exception. A transmission project that is constructed, owned and operated by a generator of electricity solely for the purpose of electrically and physically interconnecting the generator to the transmission system of a transmission and distribution utility is not subject to this section.

Appendix C: Vermont Act 61 Excerpts

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.

Appendix D: Rhode Island Standards for Least Cost Procurement and System Reliability Planning (excerpt)

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:
   a. Least Cost Procurement energy efficiency baseline services.
   b. Peak demand and geographically-focused supplemental energy efficiency strategies
   c. Distributed generation generally, including combined heat and power and renewable energy resources (predominately wind and solar, but not constrained)[110]
   d. Demand response
   e. Direct load control
   f. Energy storage
   g. 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.
   a. The need is not based on asset condition.
   b. The wires solution, based on engineering judgment, will likely cost more than $1 million;
   c. 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:
   a. Ability to meet the identified system needs;
   b. Anticipated reliability of the alternatives;

---

[110] 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.

c. 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)
d. Potential for synergy savings based on alternatives that address multiple needs
e. Operational complexity and flexibility
f. Implementation issues
g. Customer impacts
h. 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 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 a 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 a 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 E: Vermont Non-Transmission Alternatives Screening Form (9/27/12)

*For use in screening to determine whether or not a transmission system **reliability issue** requires non-transmission alternatives (NTA) analysis in accordance with the Memorandum of Understanding in Docket 7081. Projects intended for energy market-related purposes – "economic" transmission – and other non-reliability-related projects do not fall within the scope of the Docket 7081 process.*

Identify the proposed upgrade: ____

Date of analysis: ____

1. Does the project meet one of the following criteria that define the term "impracticable" *(check all that apply)*?
   a. Needed for a redundant supply to a radial load; or ❑
   b. Maintenance-related, addressing asset condition, operations, or safety; or ❑
   c. Addressing transmission performance, e.g., addition of high-speed protection or a switch to sectionalize a line; or ❑
   d. Needed to address stability or short circuit problems;[111] or ❑
   e. Other technical reason why NTAs are impracticable. *Attach detailed justification that must be reviewed by the VSPC.* ❑

   If any box above is checked, project screens out of full NTA analysis.

2. What is the proposed transmission project's need date? ______________________
   If the need for the project is based on existing or imminent reliability criteria violations (i.e., arising within one year based on the controlling load forecast), project screens out of full NTA analysis.

[111] "Stability" refers to the ability of a power system to recover from any disturbance or interruption. Instability can occur when there is a loss of synchronism at one or more generators (rotor angle stability), a significant loss of load or generation within the system (frequency stability), or a reactive power deficiency (voltage stability). Stability problems are influenced by system parameters such as transmission line lengths and configuration, protection component type and speed, reactive power sources and loads, and generator type and configuration. Due to the nature of instability, non-transmission alternatives involving addition of generation or reduction of load will not solve these problems.

3.	Could elimination or deferral of all or part of the upgrade be accomplished by a 25% or smaller load reduction or off-setting generation of the same magnitude? *(See note.)* *If "no," project screens out of full NTA analysis.*	❑ Yes ❑ No
4.	Is the likely reduction in costs from the potential elimination or deferral of all or part of the upgrade greater than $2.5 million. *(See note.)* *If "no," project screens out of full NTA analysis.*	❑ Yes ❑ No

Sign and date this form.

This analysis performed by: ______________________________

Print name & title

____

Company

____

Date

____

Signature

NTA Screening Form
Notes, examples and descriptions

Line 3 Non-transmission alternatives should be considered if the project can be altered or deferred with load reductions or off-setting generation, according to the schedule below, of existing peak load of the affected area at the time of the need for the preferred transmission alternatives. This schedule recognizes that deployment of a load reduction program in a specific area takes time to organize and implement. Therefore, the following assumptions including time and accrued load reduction should be considered when examining the load reduction:

Period	**Magnitude of load reduction and/or off-setting generation**
1-3 years	15% of peak load
5 years	20% of peak load
10 years	25% of peak load

Line 4 The $2.5 million is in year 2012 dollars and is adjusted for escalation in future years using the Handy Whitman transmission cost index. This threshold does not account for the expected costs of the NTAs, but rather only includes the expected savings to the cost of the transmission project.

Appendix F: Vermont Form for Selection of Distributed Utility Planning Areas (v. 28, 10/1/02)

The purpose of this form is to (1) guide the selection of DUP areas while (2) documenting which criteria apply to the decision.

Identity of the upgrade (description or project number): ____________________________

____

1.	Is the cost of the upgrade greater than $2,000,000? *(See note.)* *If so, check "Yes" and continue to Line 4; otherwise check "No" and. continue to Line* 2	Yes .☐ No ..☐
2.	Would the upgrade relieve a T&D delivery constraint in a Capacity Constrained Area? *(See note.)* *If so, check "Yes" and continue to Line* 3*; otherwise check "No" and* exclude *the expected upgrade from DU analysis.*	Yes .☐ No ..☐
3.	Is the cost of the upgrade less than $250,000? *(See note.)* *If so, check "Yes" and* exclude *the expected upgrade from DU analysis; otherwise check "No" and continue to Line 4.*	Yes .☐ No ..☐
4.	Is the upgrade driven by an emergency situation requiring the immediate replacement of equipment that has failed or is at imminent risk of failure? *If so, check "Yes" and* exclude *the upgrade from DU analysis; otherwise check "No" and continue to line 5.*	Yes .☐ No ..☐
5.	Does the upgrade constitute a minor change for the purpose of system tuning or efficiency improvements? *(See note.)* *If so, check "Yes," indicate which of the below upgrades are included (check all that apply), and* exclude *the upgrade from DU analysis. Otherwise check "No" and continue to line 6.*	Yes .☐ No ..☐
5.a	• installation or changes to relays, reclosers, fuses, switches, sectionalizers, breakers, breaker bypass switches, MOABs, capacitors, regulators, arresters, insulators, or meters	☐
5.b	• installation or replacement of underground getaways......................................	☐

5.c	• upgrade of substation bus work...	☐
5.d	• upgrade of substation structural work, fencing, or oil containment................	☐
5.e	• installation or upgrade to SCADA	☐
5.f	• transformer swaps	☐
5.g	• addition of fans to transformers	☐
5.h	• balancing of feeder phases	☐
5.i	• replacement of deteriorated poles, crossarms, structures, poles and conduit; and replacement of wires on such equipment with the least-cost wires. *(See note.)*..	☐
5.j	• Other (please describe): ______________________________ ______________________________ ______________________________ ______________________(Attach further explanation if needed.))	☐
6.	Is the upgrade a line-reconstruction project pursuant to joint use agreements with telephone or CATV or pole-attachment tariff requirements? *If so, check "Yes" and* exclude *the upgrade from DU analysis; otherwise check "No" and continue to line 7.*	Yes .☐ No ..☐
7.	Is the upgrade the result of a customer's request for a specific equipment or service for which distributed resources would not be acceptable? *(See note.)* *If so, check "Yes," describe the situation,* ______________________ ______________________________ ______________________________ ______________________________ *and* exclude *the expected upgrade from DU analysis; otherwise check "No" and continue to line 8.*	Yes .☐ No ..☐
8.	Is the upgrade required to remedy reliability, stability, or safety problems?	Yes .☐ No ..☐

	If so, check "Yes" and continue to line 9; otherwise check "No" and skip to line 11.	
9.	Could the scope and cost of the resulting project be reduced by a reduction in load level or by the installation of distributed generation? *(See note to clarify the extent of load reduction.)* *If so, check "Yes" and continue to line 10; otherwise check "No" and skip to line 11.*	Yes .☐ No ..☐
10.	Is the likely reduction in costs from the potential reduction in scope less than $250,000? *(See note.)* *If so, check "Yes" and* exclude *the upgrade from DU analysis; otherwise check "No" and continue to line 11.*	Yes .☐ No ..☐
11.	Would load reduction or generation allow for the elimination or deferral of all of the upgrade? *(See note to clarify the extent of load reduction.).* *If so, check "Yes" and proceed to* define *the scope and timing of the local DU analysis; otherwise check "No" and continue to line 12.*	Yes .☐ No ..☐
12.	Can the upgrade be implemented with different levels of capacity in the replacement equipment, with costs that could differ by more than $250,000? *If not, check "No" and* exclude *the expected upgrade from DU analysis; otherwise check "Yes" and proceed to* define *the scope and timing of the local DU analysis.*	Yes .☐ No ..☐

Remember to sign and date this form.

This analysis performed by ____________________ on ____________________

Name *Date*

____

Print Name

Notes, Examples, and Descriptions

Line 1	Any T&D project whose capital cost is expected to exceed $2 million (in year 2002 dollars, adjusted for inflation in future years), including any reasonably foreseeable related projects, sub-projects, and multiple phases, should be reviewed for the applicability of DUP.
Line 2	DUs may exclude from DUP analysis Non-Constrained Area Projects, as defined in the Docket No. 6290 MOU, of $2 million or less (determined as described in the note to line 1).
Line 3	Projects of less than $250,000 (in year 2002 dollars, adjusted for inflation in future years) may be excluded from DUP analysis. This step is intended to identify constrained situations in which the DU study would be disproportionately costly, compared to the budgeted project cost.
Line 5:	Minor projects that are only parts of a larger project should not be screened using this step. For example, a substation rebuild would include many of the items listed in 5.a–j, but would not be a project that is minor in size and scope. Therefore, larger projects such as substation rebuilds should be analyzed according to the criteria in lines 7 through 12.
Line 5i:	These situations do not include upgrading equipment *specifically* to *significantly* increase capacity, which should be reviewed at lines 11 and 12.
Line 7:	For example, the customer may be willing to pay for a distribution upgrade, but not for distributed resources. In other situations, the customer may be willing to pay for distributed resources, but may be unwilling to have the distributed resources on its premises, and resources elsewhere may not provide the required service.
Lines 9 and 11:	If reduction in present load by 25% and the elimination of all load growth would not affect the need for the project, or its cost, the project may be considered to be independent of load. The feasibility of the required load reductions will be reviewed in the resource-scoping stage of the DU analysis. The determination that load reductions would not avoid a particular investment can be established by reference to an approved policy (such as standards adopted to capture lost opportunities or simplify system operations). If so, indicate the document that specifies the policy.
Line 10:	This line addresses situations in which the upgrade is driven by considerations other than load growth, but the upgrade could be avoided, in whole or in part, by load reductions or distributed generation. Examples of situations in which significant costs may be avoidable, even though some part of the project is unavoidable, include the following: • Replacement of large transformers • looping projects or adding tie-lines to create first-contingency reliability

More rarely load reductions may reduce the costs of

- line relocations due to road or bridge reconstruction
- line relocations in response to local, state, or federal requests
- line rebuilds due to deterioration

Examples of situations in which loads would matter for these latter projects include (1) capacity increases planned to coincide with the relocation or rebuilding, and (2) lines that serve no customers along a considerable distance (e.g., over a mountain or through a wetland), where reduced loads at the other end of the line could be picked up by other facilities.

Lines 10 and 12: The $250,000 is in year 2002 dollars, to be adjusted for inflation in future years.

GEC Response to Enbridge Interrogatory #8

Question:

Reference: Exhibit L.GEC.1, page 44 and 47

Preamble:

"…ensure that at least one case study is launched as a pilot project in the field before the end of 2016 to enhance its transition plan."

Request:

Please confirm that it is prudent in natural gas infrastructure projects to fully consider and evaluate untested (in natural gas) theoretical concepts in advance of practical implementation to ensure the method is effective and the funds are appropriately spent.

Response:

The statement appears to be correct for a range of engineering applications. Enbridge should not install pipe materials, for example, that have not been tested with natural gas at the pressures that Enbridge will be using. The same would be true for compression, metering, and other equipment.

The statement is not as relevant to planning considerations. The fact that a particular technique or approach (e.g., regression analysis of demand, hedging, IRP, targeted DSM) has not been widely used in the context of natural gas DSM does not necessarily mean that applying them to natural gas is imprudent.

At a high level, the key pieces of information one needs to determine whether efficiency and/or other demand resources are likely to cost-effectively defer infrastructure investments are common to both electric and gas utilities:

1. A forecast of the growth in peak-demand on the system element for which an upgrade is being considered
2. A determination of the conditions – time(s) of day, climate conditions, etc. – under which peak demands currently occur and/or are forecast to occur
3. How soon an upgrade to infrastructure will be needed to ensure reliability, given the forecast growth in peak demand
4. The forecast cost of the infrastructure upgrade(s) that would be required by load growth
5. How much different individual efficiency and demand-response measures (or measure packages) can reduce demand under the conditions—time(s) of day, climate conditions, etc.—under which peak demands currently occur and/or are forecast to occur

Witness: Chris Neme

6. The eligible market for each key efficiency and/or demand response measure (or measure package)
7. A forecast of the market penetration rates that could be achieved for each key efficiency and/or demand response measure (or measure package) through an aggressive geo-targeting program (or set of programs)
8. A forecast of the cost of the efficiency and/or demand response measures (or measure packages) and related geo-targeting programs.

Items #1, #3 and #4 are information that utility planners —both gas and electric—must already have in order to support an infrastructure project and get it approved. Item #2, while perhaps not absolutely essential, may well already be available and/or desirable and, if not, is one that the utility should be able to develop. Again, this situation is common to both electric and gas utilities.

Items #6, #7 and #8 should all be readily developable by the utility. These are the very kinds of things that both electric and gas utility DSM planners (Mr. Neme included) routinely do. All such planners would have to do differently for a geo-targeting program is examine these questions at a more localized level (rather than system-wide).

That leaves item #5. It is generally true that assessments of gas efficiency measure load shapes (e.g. how much load varies by hour of the day and/or climate) have lagged behind assessments of electric efficiency measure load shapes. However, as noted in GEC's response to M.GEC.EP.8, there are ways to develop decent preliminary assessments of the relationships between peak hour savings and annual savings for key efficiency measures (including, in some cases, relying on electric load shape data!).

In short, while it is always prudent to "fully consider and evaluate" potential planning strategies, that appears eminently doable today.

As Mr. Neme suggests in his testimony, it would be appropriate for the gas utilities to embark on a pilot deferral project or two. The loads on the system of concern should obviously continue to be monitored as the deployment of the demand-side alternatives proceeds to determine whether the forecast load reductions (or reductions in the rate of growth of loads) appear to be on track. If loads on system components of concern are growing faster than expected or hoped—whether because the demand-side solutions are not working as forecast or due to acceleration in demand growth—then there could be a mid-course change in plan and the infrastructure investment could be pursued to ensure reliability of gas service delivery. As long as the need for the infrastructure investment is identified early enough that there is time to change plans if needed, this approach should not only save ratepayers money but do so in a way that does not compromise reliability. And, if it turns out for a given project that the efficiency investments did not sufficiently reduce peak load growth, such investments are likely to still have provided positive economic net benefits (because many efficiency measures are very cost-effective even without the benefit of targeted infrastructure deferral). In other words, there is an element of “no regrets” to this course of action. It is worth noting that the same cannot be said about most supply-side investments (i.e. they do not typically pay for themselves in other benefits if it turns out that they are not actually needed to address reliability concerns).

GEC Response to Enbridge Interrogatory #9

Question:

Reference: Exhibit L.GEC.1, page 42

Preamble:

"What is the cost of the infrastructure project? It does not make sense to invest in detailed assessments of alternatives to very inexpensive infrastructure projects. Thus, most jurisdictions now required consideration of DSM as a potential alternative if the infrastructure project costs at least $1 million."

Request:

(a) Please indicate whether this statement is in reference to the electric industry or natural gas industry.

(b) Please create a chart indicating the jurisdiction with IRP, whether it is gas or electric and the relevant threshold for considering DSM as a potential alternative.

Response:

a) The referenced criterion, as a concept, should apply to both electric and gas utilities. The specific threshold value of at least $1 million is a reference to existing electric utility planning criteria.

b) The chart requested is presented as Table 4 in Mr. Neme's testimony. All the examples are electric utility examples.

Witness: Chris Neme

GEC Response to Enbridge Interrogatory #10

Question:

Reference: Exhibit L.GEC.1, page 47

Preamble

"Instruct both utilities to work with interested stakeholders on their studies and the development of pilot projects."

Request:

Please confirm that Enbridge identified in EB-2014-0049, I.T12.EGDI.EP.32 b), that it would include stakeholders in the consultation of the IRP study and thus had already addressed Mr. Neme's recommendation. To be helpful, the excerpt from that particular interrogatory response reads as follows:

> *"Enbridge anticipates that an IRP study would benefit from intervenor involvement with respect to reviewing and commenting on draft reports and other documents at key stages of the study. This approach will ensure that intervenors representing Ontario ratepayers and other interest groups will have the opportunity to bring their perspectives to the study team."*

Response:

The quotation does not fully address Mr. Neme's concern or recommendation, in particular because it suggests intervenor involvement starts once the study is underway. In Mr. Neme's experience, one of the most critical aspects of this kind of work is the determination of the scope of work, which Mr. Neme saw for the first time in Enbridge's plan filing.

Witness: Chris Neme