vermont electric power company

2018 Vermont Long-Range Transmission Plan

January 17, 2018

Message from VELCO CEO Tom Dunn

The rapid change in the electric grid and its regulatory environment that formed the context for the 2015 Vermont Long-Range Transmission Plan—particularly declining loads and increases in distributed generation—has only accelerated in the past three years. Where there was once a debate about whether change was really coming, today there's broad consensus that a reformation—if not a revolution—is well underway in the way we produce, store, manage and use electricity. These changes present vast opportunities for the environment, economy and society. But the very nature of the change demands a collaborative and thoughtful approach to anticipating challenges and planning in new ways. That's why the 2018 Vermont Long-Range Transmission Plan is so important.

Vermont Electric Power Company (VELCO) constructs, owns and operates our state's electric transmission system and must maintain the integrity of this critical infrastructure. State law and Public Utility Commission Order require VELCO to plan for Vermont's 20-year transmission reliability needs and update this Plan every three years. The legal requirements for the Plan focus on our central mission: planning for electric system reliability as measured by mandatory standards set by the North American Electric Reliability Corporation (NERC).

The central obligation of this plan remains unchanged: identify where load growth or other changes may result in the need for system reliability investments, and share that information in sufficient time to consider alternatives to building poles and wires. But while that task seemed relatively straightforward in 2006, when our reliability planning system was written into Vermont law, today it is far more complex. ISO New England has fully assumed it's federally designated responsibility for bulk transmission system planning as our Regional Transmission Organization. Vermont loads have declined, and energy efficiency and distributed generation have increased. Thus, it is increasingly vital that this Plan go beyond a load-growth focused scope to address the grid implications of the trends that are reshaping our grid.

At its most basic level, this Plan and related public engagement process were enacted to provide early, reliable analysis to utilities, policy makers and other stakeholders to ensure the full range of options remains open to Vermont to solve challenges to grid reliability at the least cost. In the past, the process achieved a collaborative success in deferring over $150 million in transmission projects. Today's issues are more complex, which makes credible analysis even more critical to inform decisions that have limited precedent in the traditional utility world.

This year's Plan has a new component: analysis of possible future scenarios based on current trends like increasing distributed generation and state policy like carbon reduction goals. We adopted this approach, with the input of the VSPC's Forecasting Subcommittee, to anticipate possible futures that are not yet statistically evident, but are grounded in policy and practice. The high-solar scenario, in particular, reveals emerging reliability and economic challenges to grid operation.

The scenario discussion in this Plan is not meant to question the underlying policy drivers; it is meant to inform decisions about how Vermont achieves its goals and the adaptive work that possible paths will demand of utilities and other stakeholders. At its essence, this is what planning is meant to do.

Thank you for taking the time to read and consider the 2018 Vermont Long-Range Transmission Plan and what it portends for our state and region. Many have worked hard on this document to make it as informative, readable, and up-to-date as possible. Above and beyond regulatory requirements, our intent is to foster dialogue and conversations as one important contribution to Vermont's public engagement on energy issues and policy.

Tom Dunn
VELCO CEO

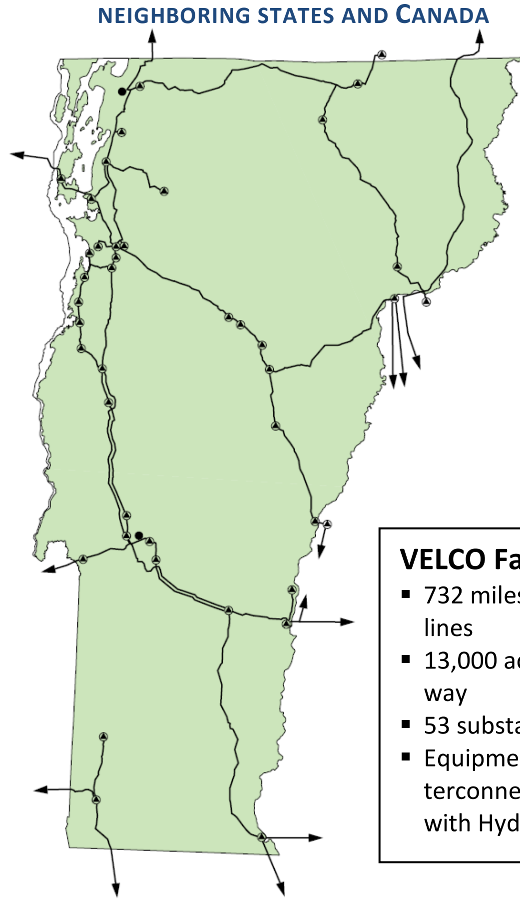
Table of Contents

Introduction

Vermont law and Public Utilities Commission (PUC) order require VELCO to plan for Vermont's long-term electric transmission reliability, share our plan with Vermonters and provide an update every three years. The Plan's purpose is to ensure Vermonters can see where Vermont's electric transmission system may need future upgrades, and how those needs may be met through transmission projects or other alternatives. Ideally, the plan enables all manner of interested people—local planners, homeowners, businesses, energy committees, potential developers of generation, energy efficiency service providers, land conservation organizations and others—to learn what transmission projects might be required, and how and where non-transmission alternatives, such as generation and load management, may contribute to meeting electric system needs at the lowest possible cost.

VELCO's planning process is extensive and collaborative. The Vermont system is part of New England's regional electric grid operated by ISO-New England (ISO-NE). ISO-NE is responsible for conducting planning for the region's high-voltage transmission system, under authority conferred on it by the Federal Energy Regulatory Commission (FERC). VELCO, along with the region's other transmission owners and according to established processes, participates with ISO-NE in its planning and system operations to meet mandatory reliability standards set by the North American Electric Reliability Corporation (NERC), the Northeast Power Coordinating Council (NPCC), and ISO-NE.

VELCO TRANSMISSION LINES AND TIES TO NEIGHBORING STATES AND CANADA



VELCO Facts

- 732 miles of transmission lines
- 13,000 acres of rights-of-way
- 53 substations
- Equipment that enables interconnected operations with Hydro-Québec

The 2018 Vermont Long-Range Transmission Plan—the Plan—is the fourth three-year update of the Vermont 20-year transmission plan, originally published in 2006 and updated in 2009, 2012 and 2015. Much has changed since 2006. ISO-NE began operating as FERC's designated Regional Transmission Organization for New England in 2005. Since then, ISO-NE has continually refined its regional planning process, and added staff, as it has assumed the planning authority it was granted by FERC. Also during this period, more rigorous, binding performance standards for the high-voltage electric transmission system, and penalties for non-compliance, were authorized by Congress in response to the blackout of 2003, and adopted by NERC, NPCC and ISO-NE in 2007. These changes required that Vermont's planning process coordinate closely with the regional planning work managed by ISO-NE.

In 2016, ISO-NE added requirements in its tariff to ensure fair competition among all qualified transmission project sponsors throughout the regional planning process to implement new procedures established by the FERC through its Order 1000 that introduced competition in the electric transmission sector. Today, VELCO receives system study information and is invited to provide comments at the same time as other members of the ISO-NE Planning Advisory Committee.

ISO-NE and VELCO completed a NERC planning assessment in 2016 as required by the recently approved NERC TPL-001-4[1] planning standard. The ISO-NE NERC planning assessment utilized the results of the 10-year Needs and Solutions studies of the Vermont and New Hampshire systems completed in 2014. ISO-NE supplemented these results with stability and short circuit studies completed in 2016 to meet the requirements of the NERC planning standard. The VELCO NERC planning assessment included a new steady state analysis as well as more extensive stability and short circuit studies required by the newly revised TPL-001-4 standard. The VELCO and ISO-NE studies indicated a need for system protection improvements that will be achieved concurrent, for the sake of efficiency, with already planned VELCO substation asset condition projects. System protection deficiencies are not related to load growth, and do not increase capacity. In most cases, they do not require a section 248 permit, and cannot be addressed by non-transmission alternatives.

This Plan is based on ISO-NE's and VELCO's 2016 NERC TPL-001-4 planning assessment, whose horizon is ten years consistent with the NERC TPL-001-4 standard. VELCO supplemented these ten-year studies in several ways to meet Vermont specific planning requirements and to ensure the regional results were effectively translated to Vermont's small—approximately four percent—share of the region's electric demand.[2] VELCO's supplementary analyses frame Vermont's reliability issues in a manner that facilitates development of alternatives to transmission solutions, consistent with Vermont legal and regulatory requirements. VELCO also conducted analysis beyond NERC planning standard's 10-year horizon, analyzed the sub-transmission system[3], included the effects of renewable energy programs and budgeted energy efficiency, and considered non-transmission alternatives as appropriate, all consistent with applicable Vermont policy.

The 2018 Plan acknowledges a profound transformation happening on the electric grid. Many changes that are underway or on the horizon will challenge reliable operation of the system as traditionally designed and operated, and provide promising opportunities for new utility models and a more diverse grid. Key factors in the current transformation include retirement of traditional, base load generation, a significant increase in distributed renewable resources, greater investment in demand-side resources such as energy efficiency and demand response, and the impact of technological trends such as heat pumps and electric vehicles. These trends have been reflected in underlying load forecast for the 2018 Plan. The Plan includes narrative discussion of those trends that cannot yet be quantified with confidence.

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[1] TPL-001-4 establishes transmission system planning performance requirements for the bulk electric system (BES). http://www.nerc.com/files/tpl-001-4.pdf

[2] Each New England utility funds a percentage of regional transmission projects based on its share of the total New England load.

[3] Sub-transmission includes those portions of the grid that are not considered "bulk system," i.e., they are above the distribution system level but at voltages below 115 kV, and their costs are not shared across the New England region. Generally, VELCO owns and operates the bulk system and some distribution utilities own and operate sub-transmission.

Beginning on page 30, this Plan shows the reliability needs on Vermont's high-voltage, bulk electric system[4]. Predominantly bulk system issues begin on page 50 and sub-system issues follow, on page 51. The Plan discusses the potential to address each issue with non-wires solutions. The Plan also reflects the considerable uncertainties in today's environment due to the effects of changing energy policy and production trends.

[4] The bulk electric system, in the context of the Plan, is the portion of the grid that is at 115 kV and above.

Issues addressed since the 2015 plan

The 2015 Plan identified one major bulk system reliability concern and seven predominantly bulk reliability concerns requiring mitigation, and a potential thermal concern that may occur in 2028, based on the 2014 load forecast, which did not require mitigation because the timing was so far in the future. The plan also identified several subsystem issues to be further investigated by the distribution utilities. Some previously noted issues have been resolved by planned upgrades. Other concerns have been postponed by lower-than-anticipated load levels.

The 2017 load forecast now projects lower peak demand than was forecast in 2014, particularly during the first ten years of the 20-year planning horizon. Reasons include the lingering effects of the recession, load reductions due to ongoing energy efficiency programs, demand response, and the net effect of small-scale renewable generation.

The table below shows how the reliability concerns identified in the 2015 Plan have been addressed or deferred. *(For 2015 bulk system concerns, please refer to pages 23 to 26 of the 2015 Plan. For predominantly bulk system concerns see pages 27 and 28, and for subsystem issues see pages 29 and 30.)*

DISPOSITION OF BULK AND PREDOMINANTLY BULK RELIABILITY ISSUES IDENTIFIED IN THE 2015 PLAN

Item identified *Page #s refer to 2015 Plan*	**Identified deficiency**	**Resolution or deferral of concern**
Connecticut River Valley *Pages 24-25*	Overloads and voltage concerns for N-1 and N-1-1 conditions	Resolved by the Connecticut River Valley project
Rutland area *Page 27*	Overloads and loss of load for N-1 conditions	Resolved by the projects identified in the Rutland Area Reliability Plan and lower load levels
Northern area *Page 28*	Low voltage for N-1 conditions	Resolved by lower load levels

Other reliability issues were predicted to occur near the 15-year timeframe based on the 2014 load forecast. No mitigation was required for those issues due to long horizon, and they are not listed in the above table. They will continue to be monitored in every planning cycle, including this current plan.

Analyzing the transmission system

The power system has been called the most complex machine in the world. In every second of every day the power supply must match power demanded by customers, or load. In areas where demand is greater than locally available supply, the electrical network must be robust enough to accommodate power imports from outside sources. Where supply is greater than local demand, the system accommodates the export of power only up to the capacity of the system, referred to as an export limit, and grid operators maintain export flows below system limits through various means including curtailment of generation. Since upgrades of electrical infrastructure generally require significant time and money, and modern society relies heavily on reliable power supply, planners must identify and address reliability concerns early without imposing unnecessary cost.

ISO-NE, VELCO, and other transmission system owners and operators are bound by federal and regional reliability standards to maintain the reliability of the high-voltage electric system. System planners use computer simulation software[5] that mathematically models the behaviors of electrical system components to determine where violations of standards may occur under various scenarios or cases.

Establishing what scenarios to study—like all planning—involves making assumptions about the future. Some of these assumptions are dictated by federal, regional and state reliability criteria. Others reflect specialized professional skill, such as forecasting electric usage. Still others rely on understanding evolving trends in the industry and society. Some of these factors involve greater uncertainty than others and involve longer or shorter time frames. The following section discusses some major assumptions or parameters reflected in this transmission Plan.

Mandatory reliability standards

The criteria used to plan the electric system are set by the federal and regional reliability organizations, NERC[6], NPCC[7], and ISO-NE. These standards are the basis for the tests conducted in planning studies. Failure to comply with NERC standards may result in significant fines, and more importantly, unresolved deficiencies can lead to blackouts affecting areas in and outside Vermont.

As required by the standards, planners measure system performance under three increasingly stressed conditions to determine whether the system will remain within mandatory performance criteria under various operating scenarios. Planners analyze the system under three kinds of conditions.

1. All facilities in service (no contingencies; expressed as N-0 or N minus zero).
2. A single element out of service (single contingency; expressed as N-1 or N minus one).
3. Multiple elements removed from service (due to a single contingency or a sequence of contingencies; expressed as N-1-1 or N minus one minus one).

[5] VELCO uses Siemens PTI Power System Simulator for Engineering (PSS/E).

[6] NERC is the North American Electric Reliability Corporation, which is designated by the Federal Energy Regulatory Commission and Canadian authorities as the electric reliability organization for North America.

[7] NPCC is the Northeast Power Coordinating Council, which is delegated authority by NERC to set regional reliability standards, and conduct monitoring and enforcement of compliance.

In the N-1-1 scenario, planners assume one element is out of service followed by another event that occurs after a certain period. After the first event, operators make adjustments to the system in preparation for the next potential event, such as switching in or out certain elements, resetting inter-regional tie flows where that ability exists, and turning on peaking generators in importing areas or backing down generators in exporting areas. In each scenario, if the software used to simulate the electric grid shows the system cannot maintain acceptable levels of power flow or voltage, a solution is required to resolve the reliability concern.

Funding for bulk system reliability solutions

Because Vermont is part of the interconnected New England grid, bulk system transmission solutions in Vermont that are deemed by ISO-NE to provide regional reliability benefit are generally funded by all of New England's grid-connected customers, with Vermont paying approximately four percent of the cost based on its share of New England load. Likewise, Vermont pays four percent of reliability upgrades elsewhere in New England. Facilities subject to regional cost sharing are called Pool Transmission Facilities or PTF. Most of the transmission reinforcement needs discussed in Vermont's Plans would likely be eligible for PTF treatment.

Regional sharing of funding for transmission projects has been present in New England for more than a decade. Since 2008, through the creation of a regional energy market called the Forward Capacity Market (FCM), providers of generation and demand resources (energy efficiency and demand response) are compensated through regional funding for their capacity to contribute to meeting the region's future electric demand. These capacity supplies may reduce the need for building transmission if properly located with respect to transmission system capacity and local load levels. Capacity and energy resources are part of a competitive market, and transmission upgrades necessary to connect new resources are funded by project developers, consistent with the requirements of the ISO-NE's transmission tariff. In contrast, transmission upgrades needed to maintain reliable service to load are funded by all distribution utility customers pursuant to ISO-NE's transmission tariff. Separation between markets and transmission is a basic principle in current FERC rules, which creates a barrier to regional cost sharing of non-transmission alternatives, even when they are more cost-effective than a transmission upgrade. Vermont continues to advocate regionally for funding parity between transmission and non-transmission options to ensure the most cost-effective alternatives can be chosen to resolve a system constraint.

A note about the planning horizon: 10 years vs 20 years

Vermont regulations require VELCO to plan using a 20-year horizon. Federal NERC standards and long-term studies performed in New England use a 10-year horizon. The longer the horizon of a planning analysis, the more uncertain its conclusions due to uncertainties regarding load level predictions, generation, system topology, technological developments, changes to planning standards, and changes to public policy that impact how the transmission system will be utilized. This report reflects VELCO's 20-year analysis; however, the main focus is on the 10-year period through 2028. Results beyond 10 years were used to examine system performance trends, evolving system needs, the effects of increased demand, and longer-term solution options. This approach was reviewed with the Vermont System Planning Committee (VSPC).[8]

Limitations in the scope of the Plan

The projects covered in this Plan include transmission system reinforcements that address transmission system reliability deficiencies as required by Vermont law and regulation as articulated in Title 30, subsection 218c of Vermont Statutes and the PUC Docket 7081[9]. As such, the Plan may not include all transmission concerns that must be addressed in the coming period. VELCO sought input in multiple phases during its analysis to identify all load-serving concerns that may require system upgrades; however, some concerns may not have been identified due to insufficient information, unforeseen events, new requirements or the emergence of new information.

In addition, from time to time, VELCO must make improvements to its system to replace obsolete equipment, make repairs, relocate a piece of equipment, or otherwise carry out its obligations to maintain a reliable grid. While VELCO has in place a process for identifying degraded equipment before failures occur, equipment degradation sometimes happens unexpectedly, and VELCO addresses these concerns quickly. The transmission plan requirements are not meant to include those asset condition or routine projects that are proposed to maintain existing infrastructure in acceptable working condition. Sometimes these activities require significant projects, such as the refurbishment of substation equipment and the replacement of a relatively large number of transmission structures to replace aging equipment or maintain acceptable ground clearances. Although the Plan requirements do not apply to these types of projects, VELCO is listing these projects for the sake of information. These projects are needed to maintain the existing system, not to address system issues resulting from load growth, and VELCO routinely shares plans for many of these projects with the VSPC as part of its "non-transmission alternatives" (NTA) project screening process. The formal NTA screening tool employed in this process[10] "screens out" projects that are deemed "impracticable" for non-transmission alternatives because they are specifically focused on resolving asset condition concerns. Below are currently known VELCO asset condition assessments that may or may not lead to asset condition projects:

Substation condition assessments

St Albans—VELCO has conducted an assessment of this substation, and has determined that its degraded condition requires mitigation. The project screened out of a detailed NTA analysis, and a section 248 permit application has been filed with the PUC.

[8] The Vermont System Planning Committee is a collaborative process, established in Public Service Board Docket 7081, for addressing electric grid reliability planning. It includes public representatives, utilities, and energy efficiency and generation representatives. Its goal is to ensure full, fair and timely consideration of cost-effective "non-wires" solutions to resolve grid reliability issues. For more information see *https://www.vermontspc.com* .

[9] Links to these documents are provided on the VSPC website at https://www.vermontspc.com/about/key-documents

[10] The two non-wires alternatives screening tools used by Vermont utilities are available on the VSPC website at https://www.vermontspc.com/about/key-documents

Barre—VELCO has conducted an assessment of this substation, and has determined that its degraded condition requires mitigation. The project screened out of a detailed NTA analysis, and a section 248 permit application has been filed with the PUC.

VELCO is assessing the Sand Bar, Berlin, Florence and Windsor substations, and the scope of potential refurbishments is unclear at this time.

Line condition assessments

VELCO's assessment of its transmission line structures revealed a large number of structures in various stages of degradation. Due to the large number of structures affected, VELCO determined that it would be necessary to accelerate its maintenance activities by replacing 300 structures per year beginning in 2014 and returning to a normal rate of structure replacement of 100 structures per year in 2019. At the end of 2017, approximately 1500 structures have been replaced under this accelerated effort.

VELCO has assessed the 17-mile K42 line, between the Highgate and Georgia substations. VELCO has not been able to take the line out service for repair in quite some time, and the recent assessment indicated that approximately 50 percent of the poles need to be replaced in the near future, and nearly all poles need to be replaced between three years and 15 years from now. Further analysis will be conducted to determine whether to rebuild the line entirely or piecemeal. It may be necessary to rebuild the line alongside the existing line to minimize reliability impacts and outages of generators and imports.

Study assumptions

When performing a study, system planners pay attention to three main parameters: the electrical network topology, generation, and the electrical demand or load. These study assumptions serve as the foundation for the analysis underlying this Plan.

Network topology

The analysis models the electrical network in its expected configuration during the study horizon. Planners model new facilities and future system changes only if they have received ISO-NE approval, which provides a level of certainty that the facility will be in service as planned.

Assumptions regarding Plattsburgh-Sand Bar imports along existing facilities

The flow of power from New York to Vermont over the Plattsburgh-Sand Bar transmission tie was modeled at or near zero megawatts (0 MW) pre-contingency. System constraints in New York have led New York to request that studies assume 0 MW will flow over the tie, and that, under certain conditions, Vermont will export to New York. This assumption is more conservative in cases where insufficient capacity exists to serve Vermont load, but is also conservative from the New York perspective during heavy wind generation and lower load levels. The recently completed ISO-NE 10-year study found no system constraints aggravated by the tie flow at 0 MW.

No "Elective" transmission, or market-related projects in the Plan

ISO-NE's tariff includes a process for considering transmission projects needed to connect generation to markets and to increase the capacity of a transmission corridor that otherwise limits the ability to move electrical power from one part of the system to another. Such projects, needed for purposes other than ensuring reliability, are categorized as elective transmission, and are financed by the project developer, not end-use customers.

Regarding the class of transmission projects called Elective Transmission Upgrades (ETU) that were proposed as a means to import energy from New York or Canada to and through Vermont, VELCO modeled these ETUs and their associated upgrades out of service, because although some of them have been approved by ISO-NE, they are quite uncertain due to the complex economic constraints involved. The price of energy at the receiving end of the proposed transmission projects would include both the cost of energy at the sending end and the cost of the transmission facilities, which tend to handicap these projects when compared to most generation projects. Therefore, the financial viability of these projects is greatly improved if a buyer is willing to pay a premium for other benefits, such as renewable energy, capacity value, and the ability to address system concerns, such as high short circuit levels, unacceptable system voltages and transmission constraints.

In addition, the ETU projects were not modeled in service because the long range plan analysis would not provide any more information than the projects' ISO-NE system impact studies, which were comprehensive by evaluating both import and export conditions. The system impact studies identified the need for several system upgrades to address system concerns that would arise if the ETUs were constructed.

Generation

All Vermont generators are modeled in service unless a basis exists to model them out of service. Until recently, New England studies began by assuming two significant generation resources in the study area were out of service. This assumption was based on the sufficiently high and historically demonstrated expectation that any two resources can be unavailable due to planned outages or unforeseen events. While significant for some New England states, this assumption is not as significant for Vermont because of our limited generation portfolio. Vermont generators are small and the vast majority of them are not base load generators, which are expected to run at or near full capacity nearly every day for hours at a time. The largest Vermont generator is a 65 MW wind plant that would be characterized as an intermittent resource since its output varies as wind speed varies. The next largest generator is a 50 MW wood-burning plant whose operation approaches that of a base load generator. Other base load plants are rated 20 MW or less and total approximately 30 MW. Therefore, this 50 MW generator was the only resource considered significant and modeled out of service in this analysis.

ISO-NE has recently developed a new process for determining the amount of generation that should be assumed out of service prior to testing outage events. The new process is the result of a careful evaluation of overlapping probabilities of generation outages and load levels, and it has been adopted and deployed in the ten-year studies that have recently started. During the development of this process, ISO-NE predicted this probabilistically based dispatch can be skewed depending on the number and type of generation resources in the study area. ISO-NE's first attempts at utilizing probabilistic dispatch yielded more severe generation outages pre-contingency, and ISO-NE had to modify the probabilistic approach by applying a two-generator outage limit to generators at an individual substation in order to prevent these dispatches from being unreasonable.

Proposed generation projects in the ISO-NE interconnection queue

The 2018 analysis takes into account any new generators that have a capacity supply obligation, either through the ISO-NE FCM or through bilateral contracts. Conceptual or proposed projects were not considered. Historically, many proposed generation projects ultimately withdraw their interconnection requests due to financial difficulties, permitting, local opposition, inability to find customers and other factors. Since the 2015 Plan, several generation projects have withdrawn for the ISO-NE generation interconnection queue, most of which consists of solar photovoltaic (PV) generation. The Deerfield 30 MW wind plant became commercial at the end of December 2017, and the Coolidge 20 MW solar PV plant is scheduled to be commercial by the end of 2018.

Vermont as a net importer

Vermont has roughly 800 MW of installed generation, which accounts for approximately 85 percent of the summer peak load; however, due to the performance characteristics of the in-state generation, Vermont has relied heavily on its transmission network to import power from neighboring states. Following the shutdown of Vermont Yankee in 2014, Vermont has become a net importer of power at all hours from New York, New Hampshire, Massachusetts and Canada in order to meet the state's load requirements. Without significant new in-state generation, this situation will be a long-term operating condition. Historical data from the past three peak summer and winter hours indicate that the transmission system is used to serve anywhere from 80 to 95 percent of the peak load depending on the production of intermittent generation resources. The following section discusses in-state generation and other resources that have an impact on the Vermont analysis.

The Highgate Converter

The Highgate Converter is the point at which energy flows from Hydro Québec (HQ) to Vermont's electric grid. The converter can carry the full amount contracted between HQ and Vermont distribution utilities during all hours of the year except periods of high demand that can affect the HQ system. Recent upgrades on the HQ system allow the converter to operate at its full 225 MW capacity[11], but the converter currently operates slightly below this amount because the current 225 MW contract is located at the US border, not at the converter.

As described above, transmission planners begin testing the system by assuming that one or more significant resources are out of service, simulating conditions that are not unusual in system operation. Although Highgate is a significant resource supplying Vermont load, Vermont stakeholders proposed, and ISO-NE agreed, not to include Highgate as a significant resource assumed unavailable in long-term needs assessments prior to testing the impact of additional events or contingencies. While this assumption allowed the avoidance of potentially costly transmission reinforcements, it also increases exposure to customer-impacting events or the need to run costly generation in the event of a failure.

[11] Accounting for losses, a slightly higher import amount, say 226 MW or 227 MW, needs to cross the US border to achieve 225 MW at the converter without undue negative system effects on the HQ and Vermont systems.

Vermont peaking generation

ISO-NE's 10-year analysis counted 80 percent of peaking power capacity; however, historical data shows actual performance below this level. Thirteen Vermont generators with a nameplate capacity of approximately 130 MW count as peaking resources—generators that are expected to run only during peak load conditions, or when demand is near system capacity, or during some form of system emergency. The ISO-NE system analysis considered the 130 MW suitable for providing 10-minute reserves—resources able to get to full output within 10 minutes—and assumed 80 percent of those 130 MW would be turned on following an event or contingency meaning that 20 percent would fail to start or run when needed. The Vermont peaking units for the past ten years have performed well below the 80 percent assumption during emergency conditions. ISO-NE recently received FERC approval for a new market mechanism called "Pay-for-Performance," which rewards generators that perform consistent with their market obligations and penalize those that do not. Pay-for-performance, which will start in 2018, may improve peaking generation, or some of these units may leave the market if they see the penalty risks as too high. For these reasons, VELCO modeled 70 percent of peaking power capacity for purposes of this long-range plan.

Hydro and wind generation

Consistent with ISO-NE study methodology, hydro generation was modeled at 10 percent of audited capacity, and wind generation was modeled at 5 percent of nameplate capacity to represent expected summer conditions. The corresponding values for winter conditions were 25 percent for both hydro and wind generation.

Small-scale renewable generation

State policy, grant funding, federal tax incentives, and robust organizing and advocacy have greatly increased the amount of small-scale generation on Vermont's distribution system. The legislature in 2012 and 2014 adopted proposals that further expand state incentives for small-scale renewables. Two programs—net metering[12] and standard offer program[13]—are assuring a market for the output of small scale renewables. New net metering rules that became effective on July 1, 2017[14] eliminate any annual cap on net metering expansion, and provide positive and negative adjusters to the price paid for excess generation depending on siting and the ownership of renewable energy credits. As of October 2017, the PUC has permitted approximately 160 MW of net metering capacity.

In 2013, the PUC modified the standard offer program to establish an annual solicitation at a pace dictated by statute, gradually increasing from the initial 50 MW amount to 127.5 MW over the next decade. As of December 2017, approximately 63 MW of standard offer resources were in service, 81 percent of which were solar PV resources. Since January 2014, new standard offer installations include 0.6 MW of farm methane, 2.2 MW of hydro, and 33 MW of solar PV accounting for 92 percent of the total

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[12] Net-metering is an electricity policy for consumers who own small sources of power, such as wind or solar. Net metering gives the consumer credit for some or all of the electricity they generate through the use of a meter that can record flow in both directions. The program is established under 30 V.S.A. § 219a.

[13] For more information about the standard offer program see http://www.vermontstandardoffer.com/.

[14] Rules are available on the PUC's website at http://puc.vermont.gov/about-us/statutes-and-rules/proposed-changes-rule-5100-net-metering

amount added since 2014. In this analysis, it was assumed that all future standard offer projects would be solar PV.

ISO-NE assumes that solar PV generators will contribute approximately 26 percent of their installed capacity at the summer peak hour because of the timing of the New England wide summer peak. Since the Vermont summer demand peak is after sundown, this analysis assumed that incremental solar PV would contribute approximately 2.5 percent of installed capacity, which coincides with a 7 PM peak hour. This assumption is somewhat optimistic because the summer peaks for years 2015, 2016 and 2017 have occurred at 8 PM, 9 PM, and 8 PM, respectively, times when solar PV generation is 0 MW. In addition, since winter peaks occur after dark, solar PV also contributes 0 MW in winter.

Further, factors are encouraging in-state renewables development including the Vermont Small-Scale Renewable Energy Incentive Program, the Clean Energy Development Fund, and green pricing programs. In addition, multiple organizational resources, such as Renewable Energy Vermont and the Biomass Energy Resource Center, provide support and advocacy for one or more types of renewable energy resources. Many of the more than 100 local energy committees in Vermont communities are considering community-based renewable development programs.

Lastly, in 2015 Vermont established a renewable energy standard (RES) and electric transformation (ET) requirement as described in Act 56. The highlights are as follows:

- Total renewable requirement (55 percent by 2017 increasing to 75 percent in 2032), known as Tier 1— Includes any vintage and large hydro
- Distributed generation carve-out (1 percent of sales in 2017 increasing to 10 percent in 2032), known as Tier 2
- Energy Transformation Projects (2 percent of sales in 2017 increasing to 12 percent in 2032), known as Tier 3—Reduce fossil fuel use, including in thermal and transportation sectors (heat pumps, weatherization, electric vehicles and other beneficial electrification)

All of the above programs put Vermont on a path to meet the renewable energy goals set in the 2016 Vermont Comprehensive Energy Plan (CEP). These goals expand upon the statutory goal of 25 percent renewable energy by 2025, and they are noted briefly below:

- Reduce total energy consumption per capita by 15 percent by 2025, and by more than one third by 2050.
- Meet 25 percent of the remaining energy need from renewable sources by 2025, 40 percent by 2035, and 90 percent by 2050.
- Three end-use sector goals for 2025: 10 percent renewable transportation, 30 percent renewable buildings, and 67 percent renewable electric power.

These renewable energy goals serve as an important backdrop for the 2018 Plan.

FORECASTING DEMAND

The analysis models future electric demand consistent with the results of a load forecast completed in October 2017 by ITRON, an energy firm that offers highly specialized consulting expertise in load forecasting, under contract with VELCO. Planning studies for this long-range plan assume peak load conditions that occur during extreme weather conditions also called a "90/10" forecast, meaning there is a 10 percent chance that the actual load will exceed the forecast. This long-range plan analyzed summer peak and winter peak loads, as well as a lower load level, net of solar PV generation, which the transmission system would serve on a normal sunny day in spring.

The forecast of future demand for electricity is a critical input in electric system planning. The forecast determines where and when system upgrades may be needed due to inadequate capacity. Predicting future demand relies on assumptions about economic growth, technology, regulation, weather and many other factors. In addition, forecasting demand requires projecting the demand-reducing effects of investments in energy efficiency and small-scale renewable energy. The following section summarizes the forecast underlying this Plan. More detailed information about the forecast can be viewed at www.vermontspc.com/2017LoadForecast.

The following graph depicts the 20-year extreme weather, or 90/10, forecast adjusted for the effects of energy efficiency, demand response, the standard offer and net metering programs, and future load increases due to heat pumps and electric vehicles. The load forecast reflects the long-term weather effects that do not vary significantly from year to year, and the forecast curve is smoother than actual peaks, which vary from year to year depending on actual weather conditions. The load forecast projects net summer peak load levels in 2018, 2028 and 2037 of 991 MW, 1000 MW and 1092 MW, respectively. The corresponding net winter peak load levels are 960 MW, 977 MW and 1054 MW, respectively. The net forecasts take into account not only predicted energy efficiency effects, but also demand response that has qualified in the forward capacity auctions. This explains why the winter peak forecasts are lower than recent peaks. In fact, Vermont has been winter peaking in recent years.

The forecast not only projects that load reduction measures will decrease the summer peak load for at least ten years, it also projects that future heat pump and electric vehicle loads will start to increase the load to the point where the summer peak load will exceed the 1000 MW load level after 11 years. The most recent highest summer peak was 1040 MW, which occurred in 2013, and the summer peak has been lower than 1000 MW for the last three years. The load forecast shows that the summer peak load will return to the 1040 MW load level after 16 years, and the 20-year summer peak forecast will not reach the historical all-time peak load level of 1120 MW set in 2006. This forecast was used to determine the timing of reliability deficiencies in this 2018 Plan update.

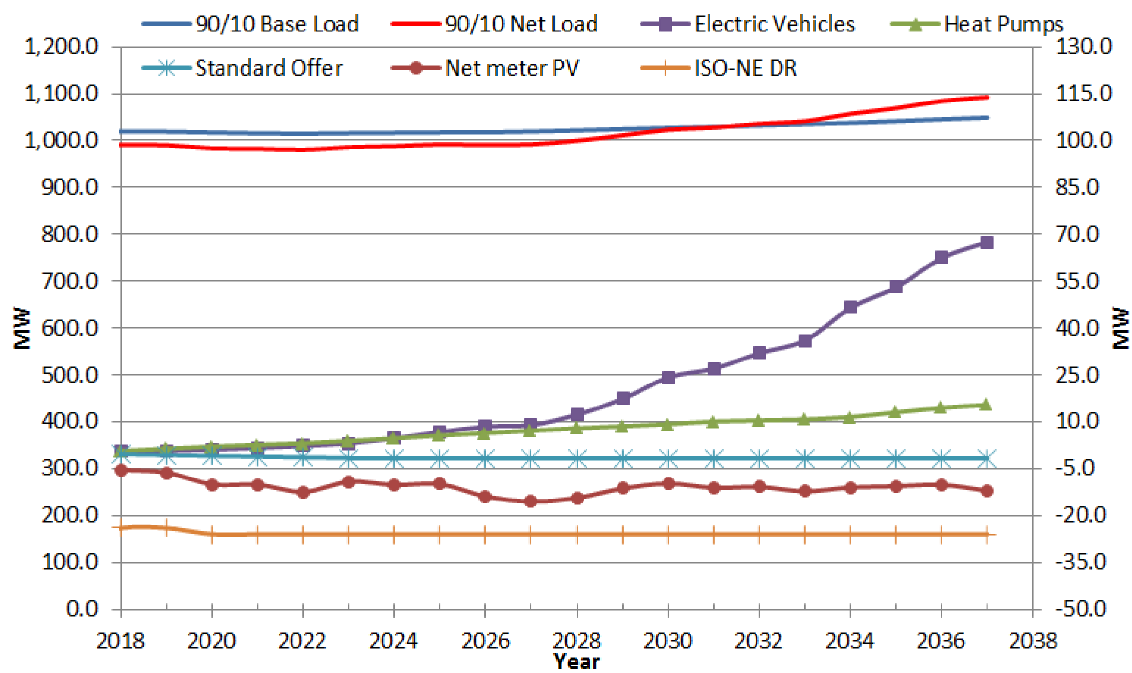
In developing the forecast, ITRON incorporated the latest energy efficiency projection in collaboration with the Vermont Public Service Department (PSD), the Vermont Energy Investment Corporation (VEIC) and the VSPC, which includes representatives of the distribution utilities and the public. ITRON employs an end-use model that essentially forecasts each consumption type, e.g. lighting, heating, cooling, and so on, that contributes to the overall load forecast. Regression analyses are then performed to capture the effects of economic growth, weather, and other factors affecting energy consumption and peak demand.

Incorporation of future energy efficiency

Development of the current forecast was particularly complex, but Vermont's collaborative approach contributes to a reasonably robust forecast that is understood and supported by a wide array of Vermont stakeholders. Similar to the previous forecast, the load forecast model captured a portion of the ongoing energy efficiency. The most recent analysis determined that the load model captured 90 percent of residential sector efficiency, compared to 80 percent in the 2015 analysis, so the 2018 Plan applies 10 percent of the forecasted energy efficiency to future loads to avoid double counting of energy efficiency effects. As more time passes, a greater proportion of ongoing energy efficiency will be captured by the model. Energy efficiency is embedded in the load, and therefore is not plotted separately in the graphs below.

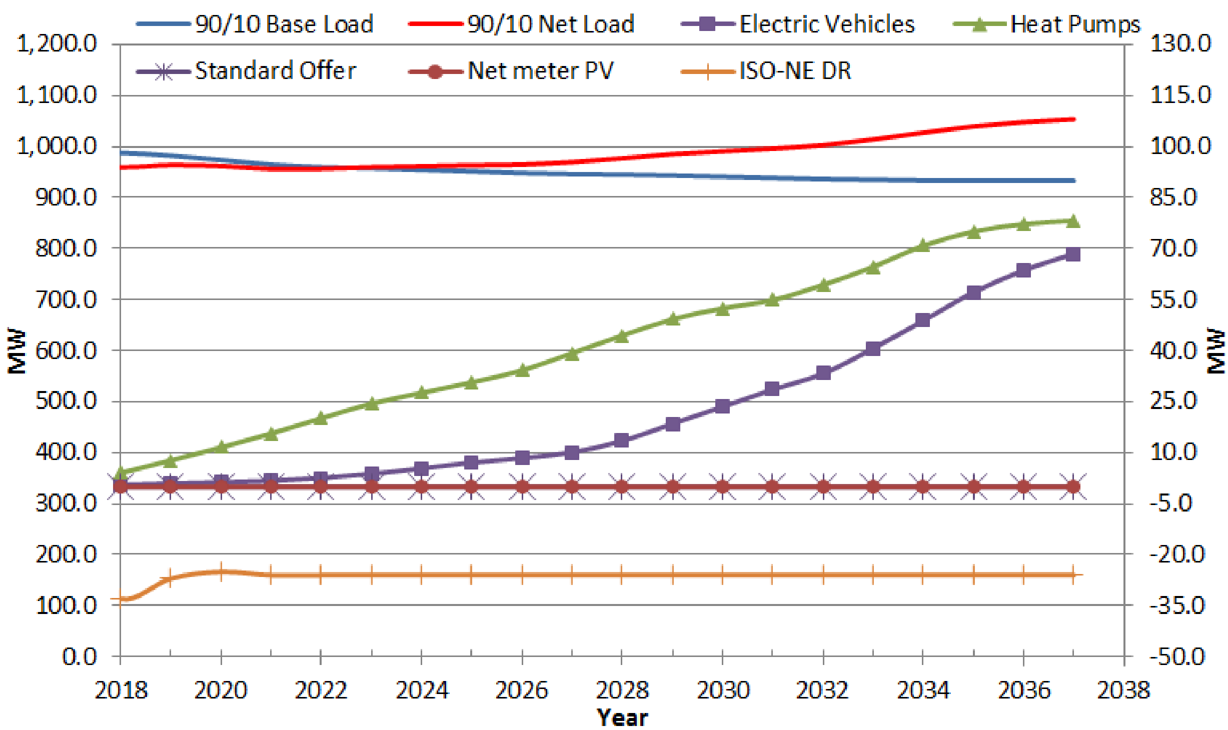
This approach is different from the ISO-NE approach where energy efficiency is forecast separately from the load and the amount is based on the energy efficiency that has cleared the ISO-NE forward capacity auctions plus future energy efficiency as estimated by the ISO-NE energy efficiency forecast working group. Further, ISO-NE's 10-year analysis included the effects of the demand response that cleared the last forward capacity auction; however, there is no mechanism to forecast demand response beyond the last forward capacity auction, as demand response varies based on market forces, and can easily leave the market at any time. Demand response was modeled at 41 MW in the 2012 plan, 28 MW in the 2015 plan, and is now modeled at 26 MW in this plan based on the latest auction results.

PROJECTED VERMONT SUMMER PEAK LOAD AND ITS COMPONENT FORECASTS



The vertical axis on the left of the graph (0 to 1200 MW) applies to the base load forecast (top blue line) and the net load forecast (red line), which is the load the transmission system will be designed to serve. The net load forecast is the sum of the base forecast and the component forecasts that would either increase or decrease the load depending on the technology. The vertical axis on the right of the graph (-50 to 130 MW) applies to the component forecasts affecting the net load forecast that the transmission system will serve. These component forecasts representing the projected impact of electric vehicles (EV, purple line), heat pumps (HP, green line), standard offer generation additions (light blue line), net metering solar PV generation additions (dark red line), and dispatchable demand response (DR) that qualified in the ISO-NE forward capacity auctions (orange line). Below is the graph for the winter peak load forecast. The major differences appear to be that the heat pump load is projected to be much higher in the winter, and the solar PV generation is 0 MW due to the winter peak occurring at night.

PROJECTED VERMONT WINTER PEAK LOAD AND ITS COMPONENT FORECASTS



Electric vehicle forecast

The demand associated with EVs is predicted to become a noticeable element of the load in the mid- to long-term. The electric vehicle forecast was developed by VEIC, which provided the number of electric vehicles and associated energy consumption. As of February 2016, there were 1,200 EVs registered in Vermont. The forecast projects that this number will increase to approximately 125,000 EVs by 2037, but most of the growth will occur during the second 10 years of the planning horizon. It is projected that the summer peak EV electric demand will grow from 0.1 MW to 9 MW in 2027 and 68 MW in 2037. The winter peak EV load is projected to be approximately 10 MW and 69 MW in 2028 and 2037. These EV forecasts assume no load management in order to help identify the system concerns that would indicate a need for these measures.

Heat pump forecast

High-efficiency heat pumps, also called cold-climate heat pumps, can provide heating at temperatures below 0° F at greater efficiency than several other heating sources. Heat pump capabilities decrease as temperatures approach -15F, and a supplemental heat source is needed during the coldest days of the winter season.

High-efficiency heat pumps are a more efficient heat source than other alternatives, but they will shift some heating load back to electricity after a long-term trend away from electric heat,although supplemental carbon-based heating will continue to be required at times of extreme cold. The ability to cool with the same high-efficiency equipment will tend to be additive to the existing cooling load, and it is this heat pump cooling load that is projected to significantly increase summer peak load after 10 years. VEIC,with input from the VSPC Load Forecast Subcommittee, projects sales of 3,000 heat pumps per year. ITRON subtracted 700 heat pumps per year to avoid double counting naturally occuring adoption as projected by the Energy Information Administration. The heat pump summer load projection is consistent with the forecast used by Green Mountain Power (GMP) in its Integrated Resource Plan, and is projected to be 7 MW in 2027 and 15 MW in 2037, while the corresponding winter figures are 39 MW and 78 MW. In order to identify the system concerns that would indicate a need for load mangement these HP forecasts assumed no load management is incorporated with the projected adoption of heat pumps.

Net metering forecast and incorporation of standard offer

Starting in 2012, net metering and standard offer installed capacity have increased rapidly, driven by Vermont policies encouraging development of renewable energy, to the point of changing the behavior of the daily system load. As a result of these policies, Vermont has seen an explosion of solar PV generation, the predominant technology since 2012, with lesser contributions from wind, hydro, biomass, and methane. ITRON utilized a payback model to forecast net metering. The model indicated a fairly aggressive growth until 2022, when growth slows down due to phase out of the investment tax credit and projected slower declines in equipment costs. The forecast projects net metering to grow from 233 MW in 2017 to 408 MW in 2037. Standard offer is projected to grow as scheduled from 64.5 MW in 2017 to 127.5 MW in 2024, and remaining constant until 2037. It was assumed that future standard offer would be almost exclusively solar PV. Therefore, in terms of the total solar PV, the forecast projects an incremental solar PV of approximately 450 MW in 2025 and 478 MW in 2037.

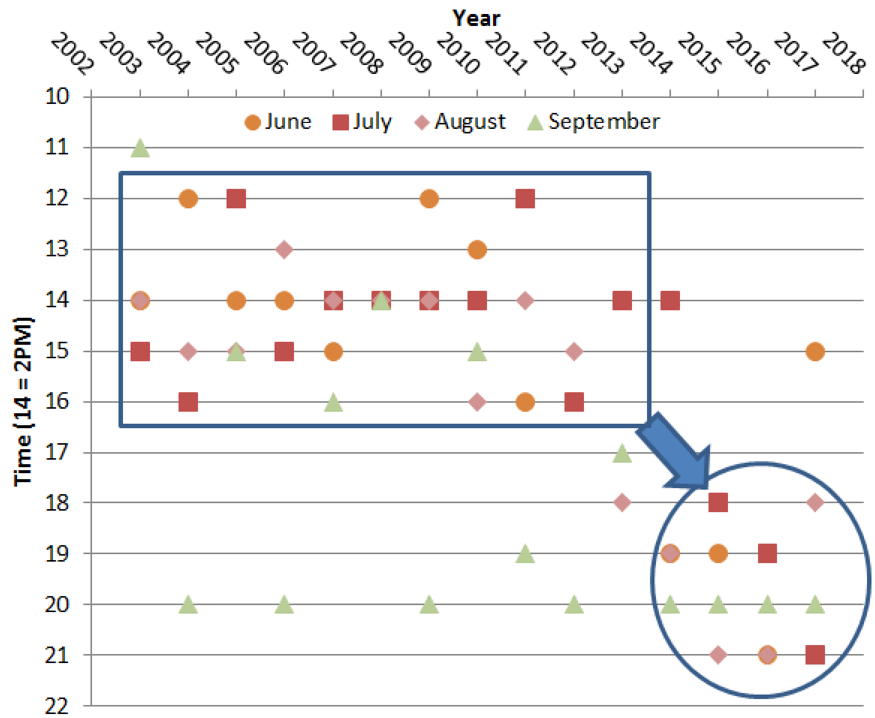
The ITRON load forecast indicated that the summer and winter peak net load will occur at 7 PM. At that time of day, the production of solar PV is expected to be 2.5 percent of the installed capacity in the summer and 0 percent in the winter. As noted earlier in the plan, the summer peak has occurred at 8 PM or later in the last three summers, and solar PV is off at those times. In any case, VELCO modeled 2.5 percent of the installed capacity for solar PV production at the summer peak.

PEAK DEMAND TRENDS

The increasing adoption of small-scale renewable energy has begun to affect the seasonal peak loads. Vermont is no longer a summer peaking state. Since the 2013/14 winter period, the winter peak load has been higher than the summer peak load. The winter peak load has been relatively constant at roughly 1000 MW while the summer peak load has decreased from 1040 MW in 2013 to approximately 950 MW in 2016 and 905 MW in 2017. We suspect that the 2017 summer peak load was significantly lower than expected primarily due to the cooler than usual summer season.

Small-scale renewable energy has also affected the timing of the peak during the summer months, June to September. The following graph shows the progression of monthly peaks for the summer period. Until recently, peak loads from June to August occurred consistently in the afternoon (2 PM plus or minus two hours). The graph shows that the timing of the monthly peaks has transitioned to later in the day from 2012 to 2014. In 2014, for the first time, May's peak occurred at 9 PM, June's peak at 7 PM, and August's peak at 7 PM. Only July, typically the month in which the annual peak occurs, did not peak later than 4 PM in 2014, but the July peak has clearly moved to the evening since then. As solar PV continues to increase, the timing of the summer peak will continue to get later to the point where incremental solar PV will no longer have any effect on the summer peak timing or load level. As noted earlier, the load forecast has determined that the peak hour will move to 7 PM. As the peak hour occurs later in the day, the contribution of solar generation during the peak hour is also reduced, from 25 percent in the previous forecast to approximately 2.5 percent in this forecast. VELCO will continue to monitor the impact of solar generation on the peak day, and future load forecasts will continue to take these effects into consideration.

SUMMER PEAK LOADS ARE OCCURRING IN THE EVENING



System planning analyses take the timing of the peak into account. The shape of the Vermont load curve on a summer peak day has traditionally been quite flat. Small-scale renewable generation is making the curve even flatter during the daily peak period (+/-2 percent around the peak), which can be six to eight hours long. This transformation is relevant to the development of NTAs, such as energy efficiency and generation. An NTA that is proposed to address a summer peak problem potentially will need to be in service for eight hours or more. Renewable energy is not only affecting system planning, it is likely affecting the efficacy, i.e., the coincident factor, of energy efficiency measures at the time of the peak. For instance, if the current measures were designed to reduce a type of load from noon to 4 PM, additional measures may be needed to also reduce the load after 4 PM. Renewable energy and energy efficiency may very well work together, where renewable energy reduces daytime loads and energy efficiency nighttime loads.

INHERENT UNCERTAINTIES IN THE TIMING OF NEED FOR RELIABILITY SOLUTIONS

System analysis determines at what level of electric demand a reliability problem occurs, and load forecasting predicts when that load level will be reached by using mathematical methods to predict demand based on the expected influence of factors such as economic activity, price elasticity, population growth, new technology, efficiency, long term weather trends, and public policy effects on customer behavior. The complexity and uncertainty of these factors means the timing of load level predictions is inherently uncertain. Although load forecasters use various methods to minimize uncertainties, the longer the horizon the more uncertain are the drivers of customer demand, the resulting load forecast and, consequently, the year at which reliability concerns will arise. The following factors contribute to forecast uncertainty:

- Itron’s load forecast is based on known information, including input provided by the VSPC as part of the forecast process. Some substation loads may or may not be present in the future, and their status can affect system performance. For example, the winter peak load in the Newport load zone can be higher than the Itron forecast, depending on the amount of load at the Jay ski resort and whether currently absent load from one industrial customer is reinstated. Similarly, a load increase at a manufacturer’s facility can affect system performance in the St. Albans load zone. The status of that one customer’s load can trigger the need for a system upgrade.
- Energy efficiency may be more difficult or expensive to obtain over the long run as easier and less costly load reductions have already been achieved. The advent of small-scale renewable energy is having an impact on the timing of the peak. To the extent energy efficiency measures target specific load hours, current measures may become less effective, or their coincident factors may become less predictable due to the variability of peak load timing.
- New FERC and ISO-NE requirements for treating and paying demand response programs on par with generation introduce uncertainty regarding future participation rates and effectiveness of demand response for large customers who in the future will be called upon to curtail load based on the energy market rather than system events and conditions as in the past.
- New technology may increase or decrease electric demand in the long run. For instance the batteries in electric vehicles may become a distributed energy resource through the use of smart grid, or they may increase electric demand if they are charged during peak demand periods. The current load forecast includes an explicit forecast of electric vehicle load, which increased the state load by approximately 68 MW over 20 years. The forecast also includes a projection of high-efficiency heat pump load. This reinforces the belief that 20-year forecasts are likely too uncertain to be the primary basis for the long-range plan.
- Regional uncertainties may affect Vermont as a part of the interconnected grid. Environmental regulations will likely impact New England’s generation mix, and ISO-NE has previously projected the retirement of a large amount of New England generation due to market forces and environmental concerns. In fact, the ISO-NE 2017 Regional System Plan reported that roughly 2550 MW retired from 2010 to 2015, 1570 MW retired since 2015, and another 700 MW will retire by 2020. During that same period, a similar amount of generation was added. In addition, the ISO-NE Distributed Generation Forecast Working Group projects that over 4,700 MW of solar PV generation capacity will be installed by 2026. New sources of energy, including imports

and elective transmission, albeit regional resources, may affect the performance of the Vermont system, particularly for the period beyond 10 years. As many as six import projects have been proposed to connect to various locations in Vermont. These import projects vary in size from 400 MW to 1200 MW. The changing generation mix in the US has raised concerns about grid resilience. For example, the US Department of Energy Notice of Proposed Rulemaking on grid reliability and resilience pricing[15], proposes that FERC establish rules under which certain reliability and resilience attributes of electric generation resources would be fully valued, which would essentially create a market mechanism to pay generators that provide certain kinds of grid support not to retire.

- Recently, renewable energy and small-scale distributed generation expanded dramatically. Amendments to Vermont statutes enacted in 2012 and 2014 will greatly increase generation developed through Vermont's standard offer and net metering programs over the next decade. The forecast maintains standard offer constant at 127.5 MW beyond 2023, as it is unknown whether and how the program will be expanded.
- Reliability standards set by NERC continue to evolve in a more prescriptive direction that will further reduce discretion about how to analyze the system and what solutions are compliant with regional and federal regulation. A new planning standard that replaced several previous planning standards went into effect in January 2016. This standard is expected to continue to evolve and other standards will be developed in an effort to improve system reliability.
- The best available information was used to determine the zonal distribution of technologies that affect loads. Solar PV is allocated to zones based on currently installed solar PV distribution; EVs are allocated based on the zonal share of registered EVs; heat pumps are allocated based on zonal distribution of energy consumption; and demand response is allocated based on ISO-NE bus level load distribution. These methods while appropriate may not be an accurate depiction of future deployment. Alternative zonal distribution will affect system performance.
- Federal and state policies have a significant impact on loads. The Vermont renewable energy standard and energy transformation requirements include provisions that both increase and decrease loads. Depending on how these requirements are met and managed, loads can be higher or lower than the load forecast. Further, it is impossible to predict the timing and the specifics of new policies. The PSD prepared a comprehensive report on the deployment of storage on the Vermont grid[16] that may help guide future policymaking, however, VT may or may not establish storage requirements that affect grid performance. Storage was not modeled in the load forecast since it would be premature to do so without knowing what requirements may be imposed, however, storage is likely to be among the solutions considered to address emerging system concerns.

Some uncertainties can be quantified because they are known and well understood based on historical data. For example, we can determine the expected contribution of hydro generation to be roughly 10 percent at the time of the summer peak hour, the likelihood that a generator or type of generator will

[15] https://energy.gov/sites/prod/files/2017/09/f37/Notice%20of%20Proposed%20Rulemaking%20.pdf

[16] http://publicservice.vermont.gov/sites/dps/files/documents/Pubs_Plans_Reports/Energy_Storage_Report/Storage_Report_Final.pdf

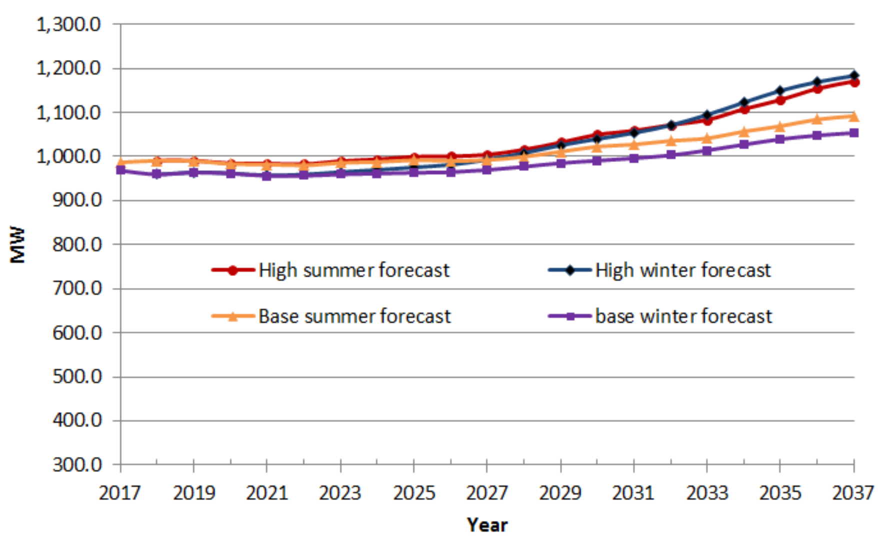
be unavailable, the probability that the summer peak load forecast will be exceeded, and so on. Other uncertainties are unknown and even unknowable, such as generation expansion, natural disasters or terrorist attacks, and public policies whose timing, specific requirements and corresponding impacts on future loads can have a significant impact on system performance. Planning under conditions of uncertainty involves making decisions that minimize or hedge against risks, and several approaches are used, such as what-if analyses and minimax regret optimization. Faced with significant unknowns, a high-load scenario and a high-solar PV scenario were developed to represent two potentially impactful energy futures—recognizing that they are not necessarily the only possible futures—in an effort to understand these impacts and wisely guide investment decision that will support Vermont's overall goals and maintain electric system reliability.

High load forecast scenario

Planners have addressed load forecast uncertainties by preparing a high forecast and a low forecast in order to bound uncertainties. In this case, we do not believe a low forecast would provide much value because the base load forecast is already quite low, and previous studies have shown that the transmission system should be able to serve the base load forecast for more than ten years. Therefore, only a high load forecast was evaluated.

The high load scenario is meant to quantify the amount of load that the transmission system would need to serve if the state's goal of 90 percent renewable energy by 2050 is on track. The 2016 Comprehensive Energy Plan sets energy reduction milestones to reduce energy consumption by 15 percent in 2025 and 33.33 percent in 2050. Goals for the remainder are to serve 25 percent from renewable sources by 2025, 40 percent by 2035 and 90 percent by 2050. The VSPC and particularly the Department helped ITRON determine how to increase electric vehicles and heat pump loads to equal the levels contemplated as part of the total energy study. To achieve the 2035 target, cold climate heat pump saturation increases to 40 percent versus 23 percent in the reference forecast, and the number of EVs increases to 171,000 registered vehicles (the VEIC medium case) from 107,000 vehicles in the reference forecast (the VEIC low case). The result of that analysis is shown in the graph below.

HIGH LOAD FORECAST SCENARIO



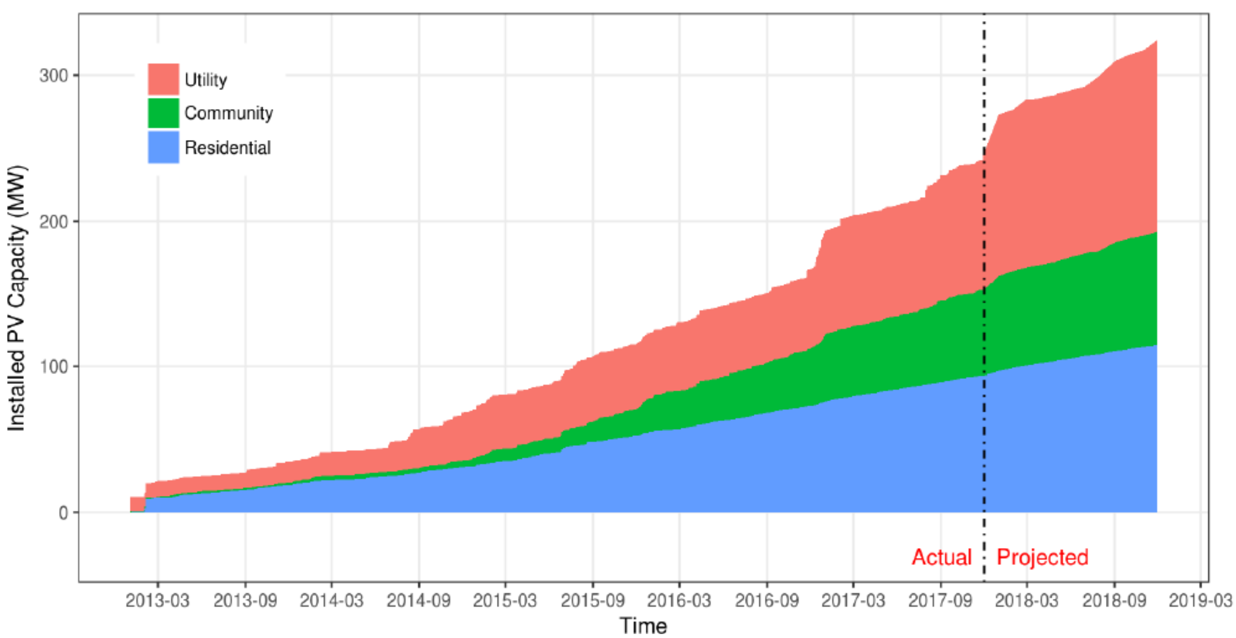
The graph shows that the summer high load forecast (red line) is almost the same as the summer base load forecast (orange line) during the first ten years of the planning horizon, and begins to exceed the base load forecast after that point. The summer high load forecast is higher than the base load forecast by 12 MW in 2027, 36 MW in 2032, and 79 MW in 2037. The high load scenario advances the timing of base peak load by roughly three years.

The load differences are more significant for the winter forecast primarily because of higher heat pump loads in the high load scenario. The winter high load forecast (blue line) is higher than the base load forecast (purple line) by 23 MW in 2027, 68 MW in 2032, and 130 MW in 2037. Interestingly, the summer and winter high load forecasts are almost equal, also because of higher heat pump loads in winter.

High solar PV forecast scenario

Solar PV has grown to nearly 260 MW as of December, 2017. The following graph shows the installed capacity as provided by Utopus Insights[17]. Roughly 15 MW should be added to the total amount shown on this graph to account for solar PV data that have not been provided yet.

HISTORICAL SOLAR PV GROWTH AND ONE-YEAR STRAIGHT LINE PROJECTION

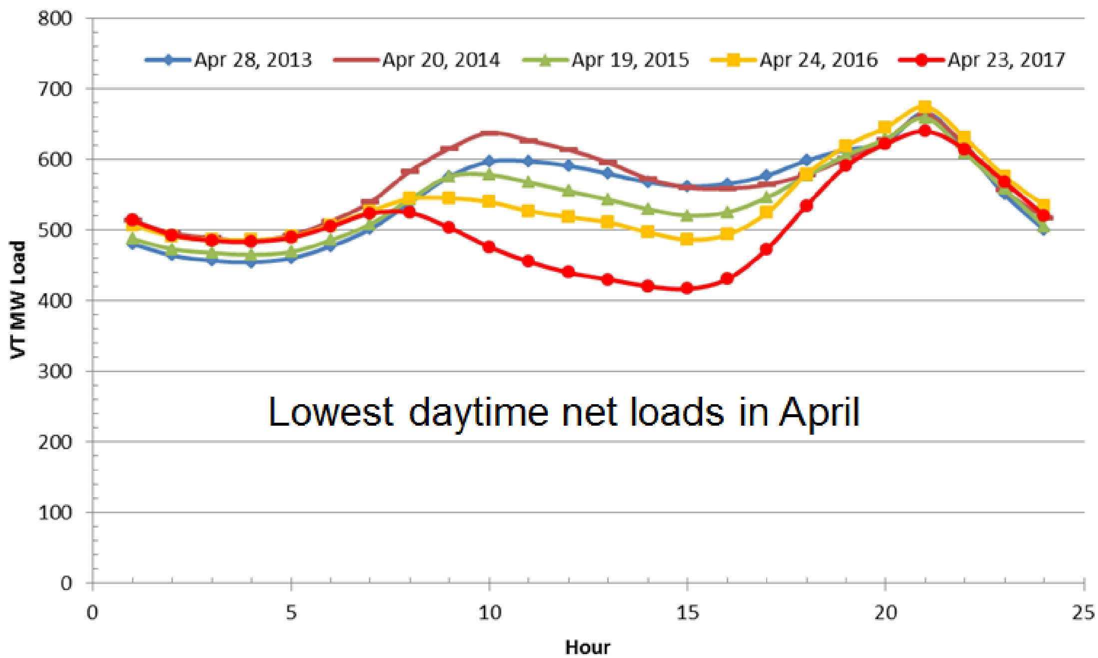


While this rapid growth has affected the peak loads, it is also having a significant impact on midday loads, particularly during spring when the load is typically lower due to cooler temperatures and solar PV production is higher. Historical data show that the midday load has become lower than the nighttime

[17] Utopus Insights (http://www.utopusinsights.com/) is a grid analytics company that was spun off in 2017 from IBM, with VELCO as a strategic partner holding a financial stake in the venture. The new company is building on collaborative work done previously to develop the Vermont Weather Analytics Center, among other former IBM projects.

load starting in 2017. The following graph shows how midday loads have progressively dropped over the last five years.

SOLAR PV IMPACT ON VERMONT NET LOADS

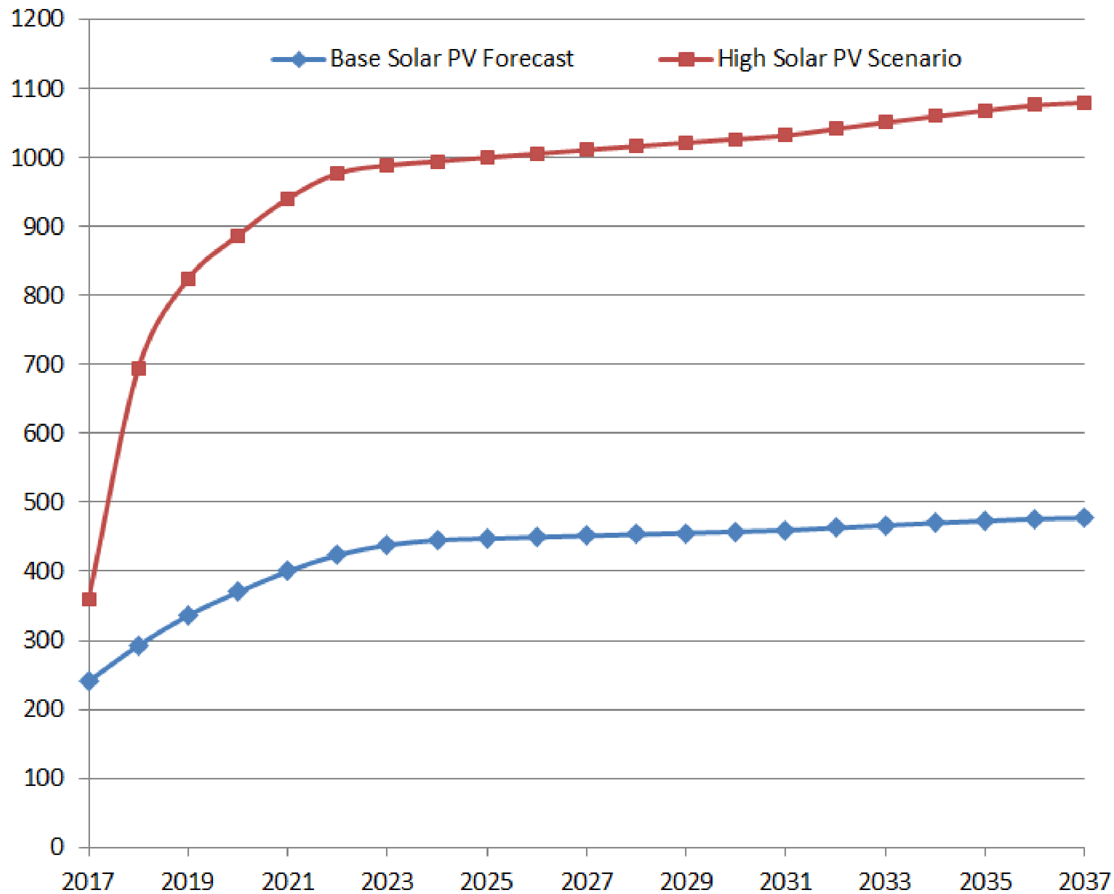


On a more local level, solar PV has started to reverse power flows through VELCO transformers serving distribution utilities. Flow reversal is not a reliability concern, but one could envision transformers and other substation equipment overloading eventually as solar PV continues to grow. In areas where hydro and wind generation is high compared to native load, these generators can be curtailed to prevent system concerns.

To understand how the system might be negatively affected by a very large amount of statewide solar PV, ITRON prepared a high solar PV scenario modeling a hypothetical 1000 MW solar PV level that corresponds to the amount analyzed as part of the Solar Pathways study performed by the Vermont Energy Investment Corporation (VEIC) under a Department of Energy contract[18]. The Solar Pathways study, assumed that solar PV would meet at least 20 percent of total electric generation needs by 2025. The study concluded that 1000 MW of solar PV is achievable and the electric grid can handle this amount of solar PV with careful planning, upgrades to operations and planning systems, including the use of smart grids, demand management and storage. The Plan will attempt to put a finer point on the upgrades that might be needed to support such a large amount of solar PV. Below is graph showing a comparison between the base solar PV forecast and the high solar PV scenario.

[18] https://www.veic.org/vermont-solar-pathways

HIGH SOLAR PV SCENARIO



Below is a table showing how the solar PV was distributed across the state under the base solar PV forecast and the 1000 MW solar PV forecast. As noted previously, these solar PV forecasts were distributed based on the current distribution of solar PV, and were applied to loads that would occur during a sunny spring day. The gross loads are without solar PV effects; the net loads take solar PV into consideration.

SOLAR PV DISTRIBUTION DURING SPRING 2025

Zone names	Gross loads	Base solar PV forecast		1000 MW Solar PV Scenario	
		Installed capacity	Net loads	Installed capacity	Net loads
Newport	19.8	-9.1	10.7	-20.3	-0.5
Highgate	23.8	-10.2	13.6	-22.7	1.1
St Albans	39.7	-31.0	8.7	-69.3	-29.6
Johnson	6.6	-4.0	2.6	-8.9	-2.3
Morrisville	24.3	0.0	24.3	0.0	24.3
Montpelier	48.6	-33.9	14.7	-75.8	-27.2
St Johnsbury	14.7	-7.7	7.0	-17.3	-2.6
BED	39.8	-1.3	38.5	-2.8	37
IBM	60.6	0.0	60.6	0.0	60.6
Burlington	94.1	-97.4	-3.3	-217.7	-123.6
Middlebury	19.7	-46.9	-27.2	-104.9	-85.2
Central	37.6	-66.2	-28.6	-147.9	-110.3
Florence	22.6	-0.3	22.3	-0.6	22
Rutland	61.7	-55.2	6.5	-123.4	-61.7
Ascutney	39.5	-21.4	18.1	-47.9	-8.4
Southern	65.6	-62.9	2.7	-140.5	-74.9
Total	618.7	-447.5	171.2	-1000	-381.3

Transmission results

The following section presents the findings of the ISO-NE and the VELCO 2016 TPL-001-4 assessments, supplemented with other analyses to satisfy Vermont statutory and regulatory planning requirements.

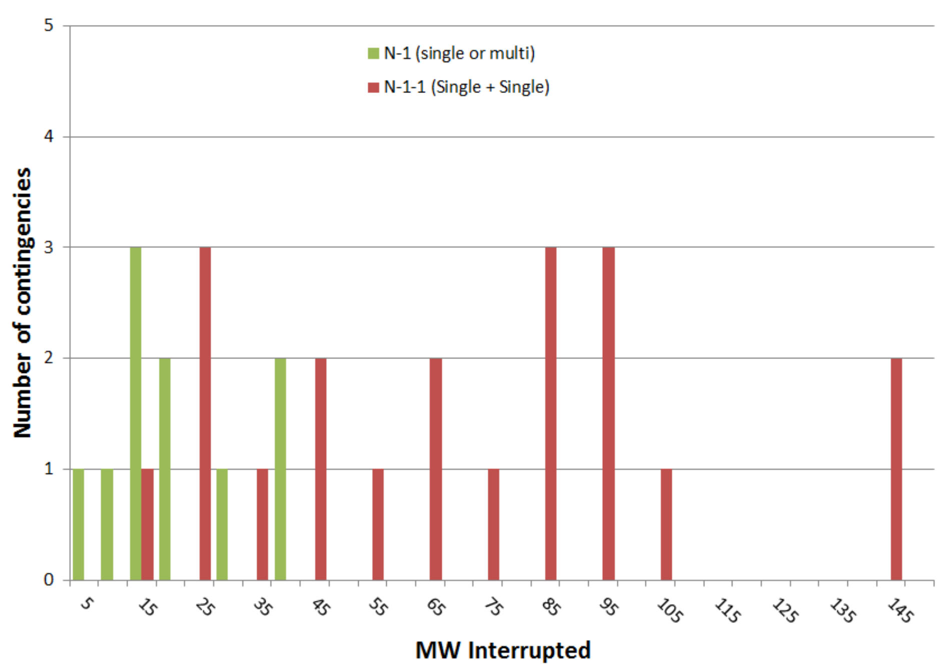
Bulk system issues

This section describes reliability issues on the bulk transmission system, which includes Pool Transmission Facilities or PTF, for which costs are shared across the New England region through ISO-NE, as well as non-PTF facilities at voltages of 115 kV and above. The 10-year study performed by ISO-NE in 2014 identified bulk system reliability issues in the Connecticut River area. These concerns have been addressed by the recently completed Connecticut River project. This 2018 Plan confirms that there are no bulk system reliability concerns within the first ten years of the planning horizon. In fact, it has been determined that reliability concerns would only occur beyond fifteen years, and therefore would not require any grid reinforcements to be further evaluated in the current planning cycle. This result came about as the result of the lower load levels as well as our ability to rely on our tie lines with New York and New Hampshire.

Loss of load exposure

While the analysis determined that no reinforcements are necessary, the Vermont system is exposed to loss of load that has been determined to be acceptable based on ISO-NE guideline for pool funding of transmission projects. In essence, ISO-NE ensures that there are no adverse impacts to the PTF under such circumstance and the ISO-NE guideline states that up to 100 MW of load loss is potentially acceptable for single outage events, and up to 300 MW of load loss is potentially acceptable for N-1-1 outage events. Following the completion of the Connecticut River projects, none of the load loss exposures exceeds these thresholds.

Loss of load exposure



In the above graph, the vertical axis shows the number outage events that would cause loss of load. The green bars represent the amount of load that would be disconnected following an N-1 event as noted in the horizontal axis, and the red bars represent the amount of load that would be disconnected following an N-1-1 event. For example, there are three N-1 outage events and one N-1-1 event that would cause approximately 15 MW to be disconnected; there are two N-1 outage events that would cause approximately 40 MW to be disconnected, and two N-1-1 outage events that would cause approximately 145 MW to be disconnected.

EFFECT OF THE HIGH LOAD SCENARIO

A high load scenario, as described earlier, was also prepared to determine the amount of electric demand that would be associated with achieving the renewable energy targets outlined in the 2016 Vermont CEP. A review of the high load forecast showed no major load increase within the first ten years of the study. Beyond the ten-year period, the higher load forecast would only advance the timing of potential transmission concerns by three years. The conclusions of the bulk system assessment are unchanged since the timing of future transmission concerns would continue to be beyond the ten-year horizon.

BASE SOLAR PV IMPACTS AT LOWER LOAD LEVELS

Solar PV has been growing at a fast pace for the last few years. Since the northern portion of the system, shown as being above the SHEI line in the figure on page 32, is already experiencing constraints during heavy wind and hydro generation, significant addition of solar PV generation will aggravate these concerns. The current amount of installed solar PV generation is estimated at roughly 250 MW. The system was tested with the 2025 solar PV forecast of approximately 450 MW, where roughly 20 MW of additional solar PV was located in the so-called SHEI area and roughly 30 MW in the St. Albans load zone, which is located just south of the SHEI area. This 450 MW solar PV forecast would account for about 73 percent of a typical spring day load. Exports out of the SHEI area are currently limited on a pre-contingency basis to prevent voltage and overload concerns post-contingency. System operators maintain exports at or below these limits by reducing SHEI area generation under their control based on market rules. VELCO conducted a study to evaluate potential options to mitigate generation curtailments in the SHEI area. Seventeen options and forty-five combinations (cases) of those options were tested. The options involved improving voltage support, reconductoring subtransmission or transmission lines, installing new transmission lines, and adding energy storage. One or more of the options can be selected depending on the amount of incremental generation export desired. Improvements ranged from 0 MW to over 100 MW depending on the option combination. The preferred option or combination of options will be selected by Vermont stakeholders based on their economic objectives.

The analysis was performed with all thermal units (gas, diesel and wood burning) modeled out of service, and all other renewable resources (hydro, wind, and methane) and the Highgate converter modeled at full capacity, assuming that existing renewable generation would not be curtailed to accommodate new solar PV generation. With the additional 20 MW of solar PV generation, the SHEI export level reached roughly 450 MW. The long range plan analysis did not show any bulk system concerns except in the SHEI area, where overloads were observed along the entire Highgate-Georgia transmission path, and voltages were significantly below acceptable levels. The SHEI study showed that a shorter section of the

Highgate-Georgia line would be overloaded. The results of the long-range plan analysis were more severe because of the additional 30 MW of solar PV modeled in the St. Albans load zone causing overloads that were not identified in the SHEI study. This means that the SHEI options that achieve a 450 MW export will need to be augmented by the upgrade of another section of the Highgate–Georgia line. This also means that, as solar PV generation increases, system constraints will expand to other parts of the system.

Effect of the high solar PV scenario

Summary

A high solar PV scenario was prepared to identify system concerns assuming total installed solar capacity reaches 1000 MW in 2025. This corresponds to the amount of solar PV generation specified in the Vermont Solar Pathways study, conducted by VEIC, that would be needed for Vermont to supply 20% of its electricity demand by solar PV generation. Analysis of this scenario shows four notable areas of concern:

- Voltage regulation pre- and post-contingency
- Power flows pre- and post-contingency
- System losses
- Limitations on tie flows from neighboring systems

Study setup

Load

This scenario was examined using a gross load level of approximately 620 MW, which represents a typical mid-day load in April without solar PV generation. However, the load seen by the system includes power system losses; with 1000 MW of solar modeled in the case, 80 MW of losses were observed. This is significantly greater than the losses seen in the shoulder case used in the Long Range Plan reliability analysis. Effectively, this high solar PV case has a load of 700 MW. During a period of low load, such as is modeled here, solar PV generation can exceed local loads at the distribution system level, which could then cause the excess power to flow on to the higher voltage subtransmission and transmission systems, potentially causing a violation of system criteria.

Imports and generation dispatch

The amount of power imported on Vermont's ties with New York and New Hampshire, which can be regulated by the use of power system equipment, was kept to a lower level than is typical so as to allow more Vermont generation to run. The PV20 tie to New York was modeled at 0 MW, and the F206 tie to New Hampshire was modeled at 100 MW importing. In keeping with the premise of testing a stressed case with maximum renewable generation, it was assumed that there could be sufficient wind, water flow, and solar irradiance for all existing wind, hydro, and solar PV installations to generate at their maximum possible output. As such, the following renewable generation units were dispatched at full output:

- Kingdom Community Wind
- Sheffield Wind
- Georgia Mountain Wind
- Searsburg Wind
- Deerfield Wind (installed 2017)
- Coolidge Solar PV (installed 2018)
- Sheldon Springs Hydro
- Highgate Falls Hydro
- All other hydro units in Vermont

In addition, the Highgate converter and the McNeil and Ryegate wood burning plants were modeled in service to represent their typical operational status.

Solar PV allocation

1000 MW of solar PV was distributed across the state at each low voltage distribution load bus. The allocation of this 1000 MW was provided by Itron as a separate projection from its baseline forecast, and mirrored present day allocation by electrical load zone; for example, if a load zone contained 10 percent of distributed solar in the state today, it was considered to have 100 MW in the 2025 case. Sixteen electrical load zones are designated in the state, and they correspond roughly to the areas represented by the regional planning commissions.

There are, however, other methods of allocating distributed solar across the state. Notwithstanding any geographical restrictions due to system or regulatory restrictions, solar resources could be dispersed in proportion to peak demand, where a representative aggregate solar unit is placed at each distribution station that serves load, and sized at the same percentage of 1000 MW as the load is to Vermont peak load (coincidentally, 1000 MW). Since the load level under study is only 700 MW, this would have the effect of netting out all loads and also, effectively, creating net generators at each distribution substation according to how much load they serve at the time of peak demand.

Alternatively, distributed solar could be dispersed proportionally to electrical energy usage. The process to do so is like that described above, except that the proportion of each unit is determined by the percentage of energy consumption at that load to total energy consumption in the state.

Yet another method would be to allocate solar as each planning commission projects the solar nameplate capacity in its area for 2025. Such a projection would necessarily be based on the area's peak electrical demand and total electrical energy consumption, as well as available and preferred land area. Care must be taken when collating the multiple sources of data produced by the commissions, both that the methods are consistent by which the respective capacity for each area is calculated, and that the statewide aggregate capacity sums to the desired amount of solar. As of the completion of this analysis, sufficient data was not available to review this solar PV allocation approach.

For this study, we decided to distribute solar PV generation according to the first method described above, i.e., to extend the present day distribution to the future case. Though it may be possible that solar PV will develop differently, this method was selected to apply a degree of conservatism regarding the intentionality of solar distribution. Certainly, one of the other solar PV distributions could be the subject of future analysis. Discussion among all Vermont stakeholders regarding the differences between the solar allocation methods outlined in this report, including their feasibility, likelihood, and economic and social consequences, would be a necessary step on the path to refining the core assumptions of a future study.

Below is a table displaying solar PV distribution by electrical load zone using those methods above for which data was available; all entries are in MW.

Planning Zone Solar PV Distribution by Allocation Method

Planning Zone Data			Base solar PV forecast		1000 MW Solar PV scenario Spring 2025					
			Historical solar PV distribution		Same distribution as base solar PV forecast		MW load ratio share		MWh load ratio share	
Zone numbers	Zone names	Gross loads	Installed capacity	Net loads	Installed capacity	Net loads	In-stalled	Net loads	Installed capacity	Net loads
725	Newport	19.8	9.1	10.7	20.3	-0.5	36.9	-17.1	40.0	-20.2
735	Highgate	23.8	10.2	13.6	22.7	1.1	39.1	-15.3	38.0	-14.2
835, 838	St Albans	39.7	31.0	8.7	69.3	-29.6	68.2	-28.5	63.6	-23.9
745	Johnson	6.6	4.0	2.6	8.9	-2.3	11.5	-4.9	12.0	-5.4
785	Morrisville	24.3	0.0	24.3	0.0	24.3	35.1	-10.8	36.7	-12.4
775	Montpelier	48.6	33.9	14.7	75.8	-27.2	86.0	-37.4	91.3	-42.7
715	St Johnsbury	14.7	7.7	7.0	17.3	-2.6	26.2	-11.5	28.9	-14.2
765	BED	39.8	1.3	38.5	2.8	37.0	61.9	-22.1	61.8	-22.0
878	IBM	60.6	0.0	60.6	0.0	60.6	62.4	-1.8	70.5	-9.9
755	Burlington	94.1	97.4	-3.3	217.7	-123.6	164.5	-70.4	142.4	-48.3
795, 798	Middlebury	19.7	46.9	-27.2	104.9	-85.2	36.1	-16.4	30.5	-10.8
845	Central	37.6	66.2	-28.6	147.9	-110.3	67.5	-29.9	67.2	-29.6
855, 858	Florence	22.6	0.3	22.3	0.6	22.0	25.6	-3.0	34.1	-11.5
805	Rutland	61.7	55.2	6.5	123.4	-61.7	93.0	-31.3	92.8	-31.1
815	Ascutney	39.5	21.4	18.1	47.9	-8.4	71.7	-32.2	69.7	-30.2
825	Southern	65.6	62.9	2.7	140.5	-74.9	114.4	-48.8	120.4	-54.8
	Total	618.7	447.5	171.2	1000	-381.3	1000	-381.3	1000	-381.3

The method chosen, “Same distribution as base solar PV forecast,” resulted in PV nameplate capacities for each utility and regional planning commission as shown in the tables below.

Solar PV Capacity by Distribution Utility

Distribution Utility	Solar PV Capacity (MW)
BED	3
GMP	930
VPPSA	11
VEC	47
WEC	9
State	1000

Solar PV Capacity by Regional Planning Commission

Distribution Utility	Solar PV Capacity (MW)
Northwest (NRPC)	69
Northeastern (NVDA)	40
Lamoille (LCPC)	9
Chittenden (CCRPC)	233
Central (CVRPC)	66
Addison (ACRPC)	119
Two (TRORC)	147
Rutland (RRPC)	114
Southern (SWCRPC)	50
Bennington (BCRC)	65
Windham (WRC)	88
State	1000

Inverter properties

Voltage control

One of the most important assumptions made in the setup of this study concerned the voltage regulation capabilities of distributed solar PV. Currently, inverters for distributed PV installations are not required to maintain a set voltage at their point of connection to the distribution line. As such, the PV modeled in the study case was assumed to have no voltage control capability. This results in the PV being effectively equivalent to negative load, since it reduces or even reverses the loading seen at the distribution substation. This drastic shift in power system behavior, and the need to account for it via requirements on solar PV inverters, is reflected in the findings of this study.

Low voltage ride through

Low voltage ride through—the ability of a generating unit to maintain stable operation through contingency events—is not currently required of solar PV inverters. As a result, they may detect grid faults and trip offline before the rest of the system has a chance to stabilize. In such cases, the loss of solar PV generation can exacerbate any adverse effects caused by the contingency, or could even cause a cascading loss of additional generation. Ride through capability forces solar PV units to stay online in order to support the system post-contingency.

To thoroughly evaluate consequences of the lack of ride through capability exceeds the scope of this Plan; however, preliminary testing was performed to determine any adverse system impact from a representative contingency that caused PV to trip. The Burlington, Central, and Southern Planning zones were considered; these zones have the largest amounts of PV in the tested case, and so they were expected to be impacted most heavily by the loss of PV. For each zone, a handful of single (N-1) and two-part (N-1-1) contingencies were simulated, followed by a manual trip of all PV in the zone to model a worst case scenario. Voltage was monitored at relevant buses in and around the zone pre-contingency, post-contingency, and after the PV had been tripped offline.

The results were fairly consistent across the three tested zones, and showed that when a pocket of the subtransmission network has several connections to the rest of the grid, the loss of PV does not have a drastic effect on system performance, and in many cases has only a mild effect at most. However, contingencies that trip large amounts of PV on a radial subtransmission path, with only one connection to the rest of the grid, can have considerable impact. Though the contingencies that cause these drastic effects are few and highly situational compared to single contingencies, low voltage ride through capability of solar PV units, as required by the soon to be adopted IEEE 1547 standard, may help to prevent violation of system criteria as levels of PV in Vermont continue to increase.

Vermont transmission interfaces

The Vermont transmission system is subject to several power transfer interface limits established by ISO-NE. It is the responsibility of the VELCO and ISO-NE system operators to ensure that these interface limits are not violated, which is done by adjusting tie flows and generation as necessary. One such interface is the Sheffield Highgate Export Interface (SHEI), an export-constrained pocket of the grid in the northern part of Vermont. It is possible for enough generation to run in this pocket to cause unacceptable system conditions, so that a forced transmission outage could result in catastrophic system voltage collapse. As such, ISO-NE will curtail generation to prevent the system from operating in an unreliable state.

In typical system planning studies conducted by VELCO, the transmission system is adjusted to simulate operator action taken to prevent violation of the SHEI and other interfaces. However, for this scenario analysis, these interface limits were not respected. This was done in order to better represent the effects of a high level of solar PV penetration on the grid running in conjunction with other existing renewable generation. For the relatively large amount of solar PV (43 MW) that fell within the SHEI area using the allocation method specified above, it would have been necessary to turn off dispatchable generation in the SHEI area. Since the primary focus of this study was the integration of solar PV across the state, it was assumed that a solution would be implemented to allow the studied amount of generation in the SHEI to run reliably. The transmission and subtransmission solutions under consideration, as well as a much more comprehensive explanation of the SHEI constraint, can be found in the SHEI analysis completed by VELCO and posted to the VSPC website.

Summary of results

The large amount of solar PV used in this study was observed to reduce flows in some areas, and to actually reverse flows on the subtransmission system, which resulted in voltages above acceptable levels. Many subtransmission capacitor banks needed to be switched off to reduce voltages at the subtransmission level; however, high voltages were still observed. Interestingly, the high solar PV penetration increases flow on the transmission system, which lowers voltages. As a result, many transmission capacitor banks needed to be switched on to raise voltages within acceptable levels, though there were no observed voltage violations on the transmission system. Normally, few capacitor banks are placed in service on the transmission and subtransmission systems during lower load levels. These voltage results are different from current system behavior, and they indicate a need to install dynamic voltage support at the subtransmission or distribution level. Dynamic reactive power devices can provide such support by responding to system needs almost immediately, and in some cases in a continuous fashion. Generators, synchronous condensers and power electronics devices, such as static VAR compensators or inverters, can provide dynamic support, which is different from the stepwise and slow support that a shunt capacitor bank or shunt reactor would provide.

Traditional "wires" solutions

Transmission and subtransmission thermal solutions

High solar PV changes the flow pattern at all system levels, distribution, subtransmission, and transmission. Beyond the violations related to SHEI that are described above, the high solar PV analysis identified several overloads on the transmission and subtransmission networks, including some of the transformers serving the subtransmission system and transformers serving distribution loads. On the transmission level, several lines overload with all lines in; that is to say, without any system outage. For instance, some lines along the Essex to Williston transmission path were found to experience thermal overload. Under contingency conditions, the overloads can be particularly severe along the Essex to Williston path, and may also occur along the Highgate to Essex path and the New Haven to West Rutland path. In addition, several VELCO transformers were observed to overload, mostly along the western side of the state in the vicinity of the noted transmission line overloads.

These high flows have two effects, which are not reliability concerns, but should be characterized as negative. The first is that system losses are higher when lines are more highly loaded. This is why load reduction measures, such as energy efficiency and demand response, take credit for loss savings, which improves the economics of those programs. With the 1000 MW of solar PV contributing to higher flow on the transmission system, it was observed that losses increased to more than twice the amount that would be expected during low loads on a spring day. Generally, losses would be on the order of 30 MW on the Vermont system, but under the high solar PV scenario, losses increased to approximately 80 MW.

The second negative effect relates to the capability of the Vermont transmission system to import power. Vermont imports power from New York along the Plattsburgh-Sand Bar path, and from New Hampshire along the Comerford-Granite path. With the amount of solar PV modeled in this study, Vermont will not be able to import as much from these areas, which could cause negative impacts in New York, New Hampshire and other parts of the system that have been designed with the assumption that Vermont can absorb or inject power depending on system needs. Wind generation in New York that is typically exported to Vermont may be curtailed in order to prevent overloads on the Vermont transmission system. However, under certain system conditions, it may not be possible to completely prevent flow from New York to Vermont. In this case, it would become necessary to curtail dispatchable generation in Vermont in order to bring the system back into a reliable operating state.

On page 38 below is a listing of system concerns and their proposed mitigation measures that can be postponed or eliminated by a non-transmission alternative to the extent that these concerns are caused exclusively by the amount of solar PV generation that is incented to connect to the grid.

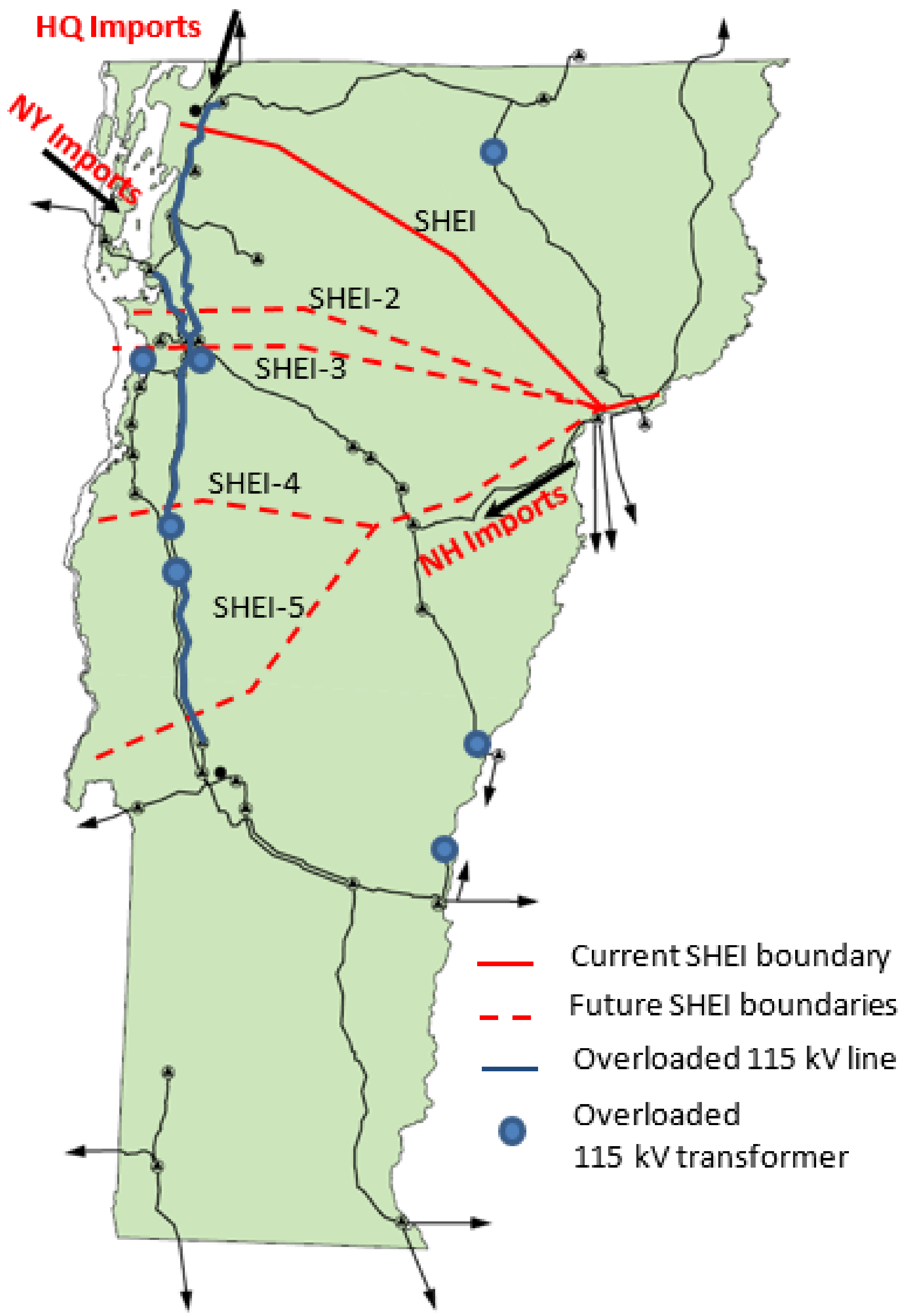
The transmission cost estimates noted in the table are high-level conceptual cost estimates, which tend to be much higher than actual costs because they include a large amount of contingency to account for uncertainties at this early stage. As uncertainties are removed in latter stages of project development, cost estimates can generally be reduced. Further, alternative system upgrades, such as energy storage, may be able to achieve acceptable performance at a lower cost. A more detailed analysis would be necessary to refine the system upgrade design. The above information is provided to indicate how the system would be affected by a large amount of solar PV generation, which should allow us to develop a mitigation plan. The Plan does not address distribution level concerns nor the cost of potential distribution upgrades.

Page 39 features a diagram illustrating the thermal impacts of the high solar PV scenario on the transmission system. The blue circles show the location of overloaded 115/34.5 kV and 115/46 kV transformers. The blue solid lines indicate overloaded 115 kV lines. The solid red line is the current SHEI area, within which generation has been curtailed from time to time to prevent system concerns associated with transmission outages. The dotted red lines illustrate the progression of the transmission constraints for this high solar PV scenario. As solar PV generation is increased, the SHEI area will extend further south and encompass dispatchable renewable generation that is not currently exposed to curtailments. For example, as the export constrained area expands to SHEI-2 and SHEI-3, the 10 MW Georgia Mountain Wind plant will be exposed to curtailments. Within SHEI-4 and SHEI-5, the 50 MW McNeil biomass plant will be exposed to curtailments.

Thermal Impacts of High Solar PV Scenario

No.	Location	Upgrade	Need	Category	Length (Miles)	Estimated Cost	Affected DUs	Lead DU
1	SHEI	Install a 2nd 115 kV line between Highgate and Georgia substations	Voltage collapse	Bulk	17	$70M	All Vermont DUs	GMP
2	SHEI	Replace Irasburg transformer	Transformer overload at Irasburg substation	Predom-inantly Bulk	N/A	$5M	All Vermont DUs	GMP
3	Essex-Tafts Cor-ner-Williston 115 kV lines	Install a 2nd 115 kV line between Limekiln and Williston substations	115 kV and 34.5 kV line overloads between Essex and Queen City substations. Transformer overload at Queen City and Tafts Corner substations.	Bulk	11	$60M	All Vermont DUs	GMP
4	Williston-New Ha-ven 115 kV line	Rebuild 115 kV line be-tween Williston and New Haven substa-tions	115 kV line overload be-tween Williston and New Haven substations.	Bulk	21	$90M	All Vermont DUs	GMP
5	Middlebury-Flor-ence 115 kV line	Remove terminal limi-tation at Middlebury substation	115 kV line overload be-tween Middlebury substa-tion & Florence Tap.	Bulk	N/A	$1M	All Vermont DUs	GMP
6	New Haven	Replace New Haven transformer	Transformer overload at New Haven substation	Predom-inantly Bulk	N/A	$5M	All Vermont DUs	GMP
7	Middlebury	Replace Middlebury transformer	Transformer overload at Middlebury substation	Predom-inantly Bulk	N/A	$5M	All Vermont DUs	GMP
8	Hartford	Replace Hartford transformer	Transformer overload at Hartford substation	Predom-inantly Bulk	N/A	$5M	All Vermont DUs	GMP
9	Windsor	Replace Windsor transformer	Transformer overload at Windsor substation	Predom-inantly Bulk	N/A	$5M	All Vermont DUs	GMP
10	Gorge-McNeil 34.5 kV	Rebuild Gorge-McNeil 34.5 kV line	34.5 kV Line overloaded	Subsystem	2.3	$1M	GMP and BED	GMP
11	Ryegate-McIndoes 34.5 kV	Rebuild Ryegate-McIn-does 34.5 kV line	34.5 kV Line overloaded	Subsystem	2.0	$1M	GMP and NGRID	GMP
12	Ryegate	Replace Ryegate trans-former	Transformer overload at Ryegate substation	Subsystem	N/A	$5M	GMP	GMP
13	Fairfax Falls-E Fair-fax 34.5 kV	Rebuild Fairfax Falls-E Fairfax 34.5 kV line	34.5 kV Line overloaded	Subsystem	3.3	$2M	GMP and VEC	GMP
14	N Troy-Mosher's 46 kV	Rebuild North Troy-Mosher's tap 46 kV line	46 kV Line overloaded	Subsystem	1.8	$7M	VEC	VEC
15	Bethel-Woodstock 46 kV	Rebuild Bethel-Wood-stock 46 kV line	46 kV Line overloaded	Subsystem	16.3	$9M	GMP	GMP
16	Smead Rd-E Pitts-ford 46 kV	Rebuild Smead Rd-E Pittsford 46 kV line	46 kV Line overloaded	Subsystem	20	$9M	GMP	GMP
17	Quechee-Wind-sor#4 46 kV	Rebuild Quechee-Windsor #4 46 kV line	46 kV Line overloaded	Subsystem	14	$11M	GMP	GMP
18	Windsor-High-bridge 46 kV	Rebuild Windsor-High-bridge 46 kV line	46 kV Line overloaded	Subsystem	6	$3M	GMP	GMP
19	Seminary St-Mid-dlebry Hy 46 kV	Rebuild Seminary St-Middlebury Hy 46 kV line	46 kV Line overloaded	Subsystem	2.6	$2M	GMP	GMP
20	Weybridge-New Haven 46 kV	Rebuild Weybridge-New Haven 46 kV line	46 kV Line overloaded	Subsystem	5.1	$3M	GMP	GMP
21	Bradford-Wells River 46 kV	Rebuild Bradford-Wells River 46 kV line	46 kV Line overloaded	Subsystem	13	$7M	GMP	GMP
22	Hartford-Norwich 46 kV	Rebuild Hartford-Nor-wich 46 kV line	46 kV Line overloaded	Subsystem	0.2	$0.1M	GMP	GMP

LOCATION OF TRANSMISSION CONSTRAINTS AS A RESULT OF HIGH SOLAR PV



Distribution thermal solutions

Beyond these transmission and subtransmission thermal violations, several overloads on distribution transformers connected to the subtransmission system were identified. The location of these transformers is noted below, and these transformer locations were each utilized as a proxy for locating a battery energy storage system (BESS) as noted in the table.

POTENTIAL LOCATIONS OF DISTRIBUTED STORAGE IN SUPPORT OF HIGH SOLAR PV SCENARIO

Bus Name	Capacity (MW)
NORWICH UNIV	0.5
MOORE_D	0.5
HEWITT RD_D	5.5
LEICESTER_D	2.0
MIDDLEBRY_D1	10.0
MIDDLBURY_D2	7.5
QUECHEE	1.5
NORWICH_D	2.5

Transformer overload mitigation

By locating a battery on the low side of a distribution transformer to absorb power that, at times of high solar production, would otherwise cause power backflow in excess of the rating of the transformer, the overload of the transformer could be resolved, and provide sufficient relief to eliminate the need to replace the transformer.

Consideration of the length of time over which this battery would be needed to absorb power is necessary. A reasonable estimate, based on the amount of time that solar PV outputs near its full capacity, is four hours. As such, its size in MWh would need to allow for continuous absorption of power for about four hours. For example, a need to absorb 0.5 MW for four hours would necessitate a battery sized at 2 MWh, where a need to absorb 1 MW for four hours would necessitate a battery sized at 4 MWh. Further consideration could be given, however, to the economic case for the installation of a BESS. If the unit can be used to participate in one or more markets for the time of day or year in which the battery is not needed for reliability, market revenues could improve the economics of the BESS project. At this time, however, the market case for battery storage is not sufficient to justify most projects.

Subtransmission voltage solutions

In addition to the thermal overloads discussed above on page 36, high voltage was observed at many distribution buses, and in several pockets of the subtransmission network. This indicates a need to install or modify equipment capable of voltage control, which could include: adjusting transformer tap changers, installing transformers with automatic tap changer voltage control, requiring that all generators (including small-scale generators) regulate voltage, and installing dynamic voltage control equipment.

For the sake of consistency, the high voltage limit of 1.05 pu that was used for the transmission system was also used for the subtransmission system in this analysis. If a Vermont distribution utility wished to allow higher voltages after an unplanned outage of transmission or subtransmission equipment, the high subtransmission voltages observed may be considered acceptable, and thus would not necessitate system upgrades. However, the voltage levels found in this study are representative of the electrical effect of solar PV in large quantity that does not itself regulate voltage.

The recommended subtransmission solutions, assuming no distribution upgrades, are listed in the table below. For the purposes of this analysis, it was assumed that battery storage would be implemented for its voltage control capabilities, though other technologies could replicate this performance. For some areas, only the reactive power capability of the battery was needed to rectify voltage violations, and so the real power capacity of the battery could be used to participate in the markets. These areas are notated with a blank entry in the Real Power Capacity field. In other areas, the real power capacity of the battery was utilized to absorb solar power that would otherwise have been concentrated on a single subtransmission line, thereby affecting voltage in the area. Additionally, it was observed that thermal overloads in areas of high voltage could sometimes be resolved by use of a battery already being considered due to voltage concerns. These areas are noted on a case-by-case basis.

Subtransmission Dynamic Reactive Devices in Support of High Solar PV Scenario

Location	MW Capacity	MVAr Capacity	Notes	Cost
Milton	-	1.5		$0.5M
Danville	-	0.5		$0.2M
Ryegate	10	2.0	10 MW battery can resolve thermal overloads 12 and 21	$24M
Richmond/ Hinesburg	-	1.5	Most effective at VEC Hinesburg	$0.5M
Thetford	-	1.5		$0.5M
Alburgh	-	2.5	3.5 MVAr at Highgate 3 MVAr at South Alburgh 2.5 MVAr at Alburgh-Swanton Tap	$0.9M
Sheldon	-	3.0	Most effective at Sheldon Springs	$1.1M
Bolton	-	0.5	Most effective at Bolton Falls	$0.2M
Woodstock	-	1.0		$0.4M
Bethel/ Chelsea/ Leicester/ Pittsford	Bethel: 7.5 MW Smead Rd: 5.0 MW Leicester: 1.5 MW Sherburne: -	Bethel: 3.5 MVAr Smead Rd: 4.0 MVAr Leicester: 1 MVAr Sherburne: 2.5 MVAr	Bethel MW keeps voltages down; Smead Rd MW can resolve overload 16 (except from Pittsford Vil. to E. Pittsford)	$18M $12M $4M $0.9M

Non-transmission alternative solutions

In addition to the solutions discussed above, a solution set was created using non-transmission alternatives (NTAs). Battery storage systems and dynamic reactive devices were simulated to resolve system concerns without complete reliance on new or upgraded transmission or subtransmission lines. Batteries were assumed to operate for four hours continuously.

Transmission and subtransmission thermal solutions

With distribution-side voltage control implemented where necessary as explained below, high voltage on the subtransmission network was no longer a concern. In order to address thermal violations on the subtransmission, batteries were sited at the stations noted in the following table. To reduce the flow of power on the overloaded lines, both the real and reactive power output of the battery were utilized.

In exception to the NTA concept, the 46 kV line from Taftsville to the VELCO Windsor station was assumed to be reconductored at a cost of approximately $8 million. This was to prevent the need for approximately 50 MW more battery storage in the area, which would create an inoperable condition.

A battery sized at 150 MW was placed at the Essex 115 kV substation to resolve an overload of the 34.5 kV path from Essex to Tafts Corner for loss of the parallel 115 kV transmission path. In the traditional “wires” solution set, this overload is addressed by the installation of a new 115 kV line between the Lime Kiln and Williston substations.

Subtransmission and Transmission Batteries in Support of NTA Solutions

Location	MW	MVAr	Cost
Essex 115	150	-	$360M
Lowell 46	15	12	$36M
Crossroads 46	35	25	$84M
Pleasant St 46	5	4	$12M
Bethel 46	40	30	$96M
Hartford VT 46	8	6	$19M
Ryegate 46	1.5	1	$4M
White River Jct 46	30	25	$72M
Windsor V4 46	16	12	$38M

Location	MW	MVAr	Cost
Smead Road 46	40	30	$96M
Agrimark Tap 46	1.5	0	$4M
Fairfax Falls 34	8.5	6	$20M
Johnson 34	6	4	$14M
Websterville 34	3	2	$7M
Ryegate 34	12	10	$29M
McNeil Tap 34	20	15	$48M
Tafts Corner 34	15	12	$36M
Queen City 34	10	8	$24M

Distribution thermal and voltage solutions

Simulating voltage regulating equipment on the distribution buses rectified not only distribution overvoltages, but nearly all of the high voltages observed on the subtransmission system, as well.

On page 44 below is a table indicating where new voltage control equipment, such as batteries, were sited. As the need was specifically for voltage control, only the reactive power (MVAr) capability needed is listed, except at those stations listed in the table on page 40 that addresses distribution transformer overloads; these batteries were assumed to be in service in this NTA solution set, as well. For the rest of these batteries, only the reactive power capability of the battery was needed to rectify voltage violations, and so the real power capacity of the battery could be used to participate in the markets or to meet other needs.

Comparison of battery storage solutions

If installation of battery storage were focused at the distribution level, the system would rely on many small batteries distributed across the state. It is expected that technologies with the capability to simultaneously control many hundreds of distributed energy resources will emerge, and provide Vermont system operators with the ability to dispatch these units at once. In essence, state or local area loads could be adjusted (for a short time) to reduce stress on the grid, and so avoid some system upgrades. Such a distributed solution would introduce significant control problems; however, aggregation of distributed energy resources is the focus of much research in the power industry. Though it may be some years before this technology is commercially available, its use would prove invaluable to the grid, effectively preventing some of the problems discovered in this study, rather than simply mitigating them.

If, instead, more emphasis were placed on transmission-connected battery storage, large battery storage systems would be needed in multiple locations across the Vermont transmission system. In contrast to a distribution focused solution set, the control systems for such units exist today and are self-contained. Though such devices connected to the transmission system could be treated as traditional voltage control assets under normal operating conditions, operation of more than a few of these units for real power absorption when needed to prevent transmission violations could prove complex to the point of impractical. A coordinated control system would be required to manage these devices effectively.

Finally, if installation of battery storage were concentrated on the subtransmission system, complexities in both control design and in operation philosophy would arise. It was seen in the determination of the NTA solution set of this analysis that some system violations necessitated multiple batteries of considerable size be placed in one pocket of the subtransmission network. With relatively large units so close to each other, design of the controls systems to prevent negative interaction between them, as well as coordination of their output in real-time to prevent overloads, would prove very difficult to manage.

These solution types will have varying effectiveness in treating two different problems – that of local capacity constraints, and that of bulk system constraints. Distribution solutions will tend to be more effective where there is not sufficient capacity in a local networked area of the subtransmission or distribution system to host the solar PV connected to them. A transmission solution may not able to rectify such an issue, but is instead better suited to control flows of considerable magnitude on the transmission system where there is sufficient capacity in a radial subtransmission pocket to host solar PV in the local area. Subtransmission solutions may be best considered in the fashion of a transmission solution – that is, to alleviate high flows on a subtransmission line in a looped network where it proves more efficient than installation of many distribution-side batteries.

Care must be taken, then to select the appropriate solution for any problem, such that areas limited by transmission system capacity have sufficient transmission-connected battery storage, and areas limited by subtransmission capacity have sufficient distribution- or subtransmission-connected battery storage.

Distribution-Side Voltage Regulation in Support of NTA Solutions

Station Name	Capacity (MVAr)
VL HYDE PK_D	1.0
READSBORO	0.5
OMYA	0.5
N FERRISBURG	0.5
SAND ROAD	0.5
OKEMO	2.5
SHELBURNE	1.0
SMITHVILLE	2.5
TAFTS CORNER	0.5
VERGENNES	1.0
ESSEX_D	0.5
ETHAN ALLEN	2.0
POWNAL_D	0.5
JAMAICA	0.5
MANCHESTER1	0.5
STRATTON_D2	1.0
N BRATLBRO_D	0.5
VERNON RD_D	0.5
MACKVILLE	0.5
W DUMMRSTN_D	0.5
WOLCOTT	1.0
GA PACIFIC_D	1.0
CASTLETON_D	1.0
DORSET_D	1.0
HYDEVILLE	0.5
PAWLET_D	1.5
POULTNEY_D2	0.5
HYDEVILLE	0.5
GMPBRIDGE_D	3.5
POULTNEY_D	1.0
SO POULTNEY	1.0
LALOR_D	1.0
ALLIED_D	0.5
BRANDON_D1	0.5
BRANDON_D2	0.5
E MIDDLBRY_D	2.5
HEWITT RD_D	1.0
LEICESTER_D	3.0
MIDDLEBRY_D1	2.0
MIDDLBURY_D2	1.5
PLEASNT ST_D	4.0
WEYBRIDGE_D	2.0
SALISBURY_D	0.5

Station Name	Capacity (MVAr)
BETHEL_D	0.5
ROCHESTER_D	1.0
SHARON_D	1.5
MADBUSH	1.5
SHERBURNE_D1	2.0
SHERBURNE_D2	2.5
MAPLE C_WEC	1.0
STOCKBRDGE_D	2.0
CHELSEA	0.5
RANDOLPH	0.5
BRADFORD	2.0
ELY	0.5
NEWBURY	0.5
THETFORD	2.5
WELLS RIVER	1.5
QUECHEE	1.5
TAFTSVILLE	1.0
WINDSOR	0.5
BROWNSVILLE	1.5
CAVENDISH	0.5
MT HOLLY	1.0
NO SPRINGFLD	2.0
RIVERSIDE	2.5
SOUTH ST_D	1.5
MAPLE AVE_D	2.0
LAFAYETTE	2.0
GEORGIA	1.5
MILTON	0.5
WEST MILTON	0.5
UNDERHILL_D1	1.0
UNDERHILL_D2	1.0
ST JOHNSBURY	1.5
E BERKSHIRE2	1.0
NORTH TROY	0.5
RICHFORD 2	2.0
BARTON1	2.0
BURTON HILL2	0.5
ENOSBURG2	1.0
ISLAND POND	0.5
JAY_D2	0.5
SHELDON5	3.0
ROCK TENN 3	0.5
NORWICH_D	3.0

Conclusion

The findings of this study show that the system impacts of installing 1000 MW of solar PV in Vermont are significant. These concerns, though, can be resolved by some of the methods explored in this analysis, and the nature of the mitigating measure can vary significantly depending on the distribution of new solar PV generation. Traditional transmission and subtransmission upgrades provide a reliable solution to the system behavior associated with a high level of solar penetration. Non-transmission alternatives, primarily considered in this analysis to take the form of batteries, can also rectify violations of system criteria. The two solution sets presented in this report are only two ways of resolving system concerns; work can be done to develop any number of ways to account for 1000 MW of solar PV connected to the grid. A hybrid solution set could make use of transmission and distribution upgrades to solve those issues not easily addressed by energy storage, and make use of batteries to avoid costly projects. Such a philosophy may prove to be most effective as the amount of installed solar in the state continues to increase.

Critically, the findings of this study highlight the need for voltage control at the distribution level. In the NTA solution set, distribution bus voltage was held within a reasonable range, so as to not affect the subtransmission voltage performance; as a result, far less new equipment was needed to maintain adequate voltage on the subtransmission system. This voltage control capability can be provided by the inverters of the distributed PV units themselves. Such a requirement is in line with a standard that is to be put forth by IEEE in the months following the completion of this study.

Additionally, distribution-connected energy storage was not evaluated in large quantity, though it was implemented to resolve overloads of distribution transformers. The beneficial effect of energy storage connected at the distribution level, or even at the residential level, is to absorb power generated in excess of local load such that it does not flow on to the subtransmission system. If the amount of power flowing on the subtransmission system can be reduced, then thermal overloads may be averted and upgrades deferred.

This analysis shows that the integration of 1000 MW of solar PV into the Vermont electric grid is not trivial. It will introduce considerable system operating concerns of managing load, generation, and energy storage, as well as the need for reinforcements to Vermont's transmission, subtransmission, and distribution systems. However, the observed impacts may not be as severe in reality if such study assumptions as the voltage regulation capability of solar PV units prove to be overly conservative.

One further way by which these impacts could be lessened is efficient siting. This could be achieved by revising solar PV incentive programs currently in place, or by creating new incentive programs; additionally, developers of commercial solar PV projects may be encouraged to select a certain location if it is expected to be more favorably viewed in the approval process.

Key to this siting effort must be ongoing examination of the power system with respect to increasing solar penetration. As more solar PV comes online, grid capacity that exists currently may be depleted, and different parts of the state may prove to be most efficient for locating new solar generation. In order to gain insight into this transformation, specialized tools must be developed to identify excess grid capacity, and this data used to help inform statewide siting philosophy. A renewed focus on the growth of solar PV will be critical in ensuring that all stakeholders stay informed and engaged, so that Vermont is best able to pursue and meet the goals of the Comprehensive Energy Plan.

As for any study, the results of this analysis depend on the assumptions. The key implication of these results is that it will be challenging to accommodate 1000 MW of solar PV without curtailing existing Vermont resources. The Vermont Solar Pathways study offered some reasonable strategies to accommodate 1000 MW of solar PV. Load management, storage and other control strategies will be helpful, but they will not likely resolve all system concerns without some system upgrades. This study supplements these strategies by providing system performance information that the state would need to advance its renewable energy goals. While the results show widespread system concerns, these results are really a call to renewed focus on careful consideration in planning, technology deployment and siting of distributed generation. The results may also help inform the discussion of alternative ways to meet Vermont's carbon reduction goals, such as increased imports of renewable power through Canadian HVDC import projects, development of solar PV outside of VT, ensuring that in-state solar PV follows the IEEE 1547 standard, and the addition of storage in conjunction with solar PV projects.

System issues classified as “predominantly bulk”

The following section describes reliability issues classified as “predominantly bulk system,” meaning they do not meet the definition of bulk system, but at least 50 percent of their cost elements are part of the bulk system. Projects that are proposed to address these issues involve a combination of grid elements owned by distribution utilities and elements owned by VELCO.

VELCO’s identification of issues on the subsystem requires the assistance of local distribution utilities. VELCO coordinates closely with local distribution utilities during the preparation of the plan to identify relevant issues and share information about study findings. In cases where information about a subsystem issue is not available to VELCO in time for a three-year update of the Plan, some reliability concerns may not be included in the plan. Additionally, distribution utilities make changes to their systems from time to time to better serve customers. These changes may be made quickly, and it is difficult to predict and model all of those changes during the performance of these studies. In such cases, reliability concerns on the subsystem may not be identified as part of the Plan. Below is a description of predominantly bulk issues identified in the 2015 plan, but have since been eliminated or postponed beyond the ten-year time frame.

- The Rutland area concerns previously identified in the 2015 long range plan have been resolved by lower loads and by connecting the Florence system to the Rutland system as described in the GMP Rutland Area Reliability Plan, which may be viewed at http://www.vermontspc.com/gmp-rrp. The North Rutland transformer overload is postponed to 2031 at a 1028 MW VT load level.
- The Northern area concerns previously identified in the 2015 long range plan were dependent on a large customer reconnecting to the system. At this time, there is no indication that this customer plans to reconnect anytime soon. Therefore, it has been determined that the Northern area concerns have been resolved by lower load levels. The Barton area low voltage is postponed to 2028 at a 977 MW VT winter load level. System performance will be reevaluated in the event this customer indicates the desire to reconnect.

Subsystem results

The following section describes reliability issues classified as "subsystem" meaning they do not meet the definition of bulk transmission system, and they are not intended to serve radial distribution loads. If the affected distribution utilities determine that these issues require resolution, these projects would involve grid elements owned by distribution utilities.

Several of the reliability issues identified in the 2015 plan have been resolved as they are pushed beyond the 10-year horizon due to lower load levels based on the most recent load forecast. The problems are categorized as to whether each causes high or low voltage, or is a thermal issue in which equipment exceeds its rated temperature. Because the load forecast is flat for 10 years, the study results for year 10 were applied to the first 10 years of the planning horizon, and the timing of potential concerns is determined to be year 2017 if they are severe or 2025 if they are marginal. These subsystem findings are based on VELCO's statewide analysis. System analysis by the affected utilities using different reliability criteria and a more granular focus specifically on subsystem performance may produce different results.

The following table identifies sub-transmission areas with potential reliability issues. Flexibility is permitted at the subsystem level concerning the reliability criteria the system must meet because the sub-transmission system is not currently subject to mandatory federal reliability standards. For example, a utility may accept the impacts of an infrequent power outage rather than invest in infrastructure to eliminate the power outage risk based on its analysis of costs, benefits and risks. The affected utilities will determine what, if any, projects are required to address the potential reliability issues on the sub-transmission system.

SUB-TRANSMISSION POTENTIAL RELIABILITY ISSUES GROUPED BY LOCATION							
Location	**Year Needed (Projects needed in past listed as 2017 in this table)**	**90/10 Load Forecast for Year (MW)**	**Contingency**	**Reliability Concern**	**N-1 Criteria Violation**	**Affected DUs**	**Lead DU**
Ascutney	2025	992	Transformer Subtransmission	Low Voltage	Lafayette – Bridge St. – Bellows Falls	GMP / PSNH	GMP
Ascutney	2025	992	Transformer Subtransmission	Thermal	Highbridge – Ascutney	GMP / PSNH	GMP
Blissville	2025	992	Transformer	Low Voltage	Blissville area	GMP	GMP
Blissville	2030	1023	Transformer	Thermal	Blissville – Hydeville	GMP	GMP
Rutland	2017	< 970 Winter	Subtransmission End open	Low voltage	Snowshed (winter)	GMP	GMP
Montpelier	2031	1028	Transmission	Thermal	Marshfield – Danville GMP – Danville WEC	GMP	GMP
Montpelier	2017	< 987	Subtransmission End open	Low Voltage	Ryegate / Newbury	GMP	GMP
Montpelier	2017	970 Winter	Subtransmission End open	Low Voltage	Moretown – Irasville – Madbush (winter)	GMP / WEC	GMP
Montpelier	2017	< 970 Winter	Subtransmission End open	Thermal	Northfield – W Berlin (winter)	GMP / WEC	GMP
Burlington	2017	< 987	Transformer Subtransmission	Thermal	Gorge – McNeil	GMP / BED	GMP
St. Albans	2017	< 987	Subtransmission End open	Thermal	Welden St. – East St. Albans	GMP	GMP
St. Albans	2025	992	Transformer Transmission	Low voltage	Sheldon	GMP	GMP

The St Albans thermal and low voltage concerns will be eliminated by a line reconductoring planned for 2018 and capacitor bank additions planned for 2019. These improvements screened out of a full NTA analysis as agreed to by the VPSC as part of the 2017 VSPC geo-targeting process.

The subsystem near the Stowe substation is served from the south by a transmission line and a sub-transmission line located on the same set of poles as required by the Section 248 permit for the Lamoille County project. A common mode outage that disconnects both supplies results in low voltage on the Stowe system in 2025. Since the Lamoille County project was permitted with the preferred double circuit design, this low voltage is not considered a concern that needs mitigation.

Public input on the 2018 plan update

[To be added following the public input process.]

Glossary & Abbreviations

Glossary

90/10 load—An annual forecast of the state's peak electric demand (load) where there is a 10-percent chance that the actual system peak load will exceed the forecasted value in any given year or, stated another way, it is expected that on the average the forecast will be exceeded once every ten years.

affected utility—Affected utilities are those whose systems cause, contribute to or would experience an impact from a reliability issue.

base load—A base load power plant is an electric generation plant that is expected to operate in most hours of the year.

blackout—A total loss of power over an area; usually caused by the failure of electrical equipment on the power system.

bulk system—The bulk electric system, in the context of this Plan is the portion of the grid that is at 115 kV and above.

capacitor—A device that stores an electrical charge and is typically used to address low voltage issues on a power system.

conductor—Part of a transmission or distribution line that actually carries the electricity; in other words, the wire itself. The wire or conductor is just one part of a transmission line; other parts include the poles and the insulators from which the conductor is hung. A conductor must have enough capacity to carry the highest demand that it will experience, or it could overheat and fail.

contingency—An unplanned event creating an outage of a critical system component such as a transmission line, transformer, or generator.

demand—The amount of electricity being used at any given moment by a single customer, or by a group of customers. The total demand on a given system is the sum of all of the individual demands on that system occurring at the same moment. The peak demand is the highest demand occurring within a given span of time, usually a season or a year. The peak demand that a transmission or distribution system must carry sets the minimum requirement for its capacity.

demand-side management (DSM)—A set of measures utilized to reduce energy consumption. Energy conservation is one kind of DSM.

dispatch—As a verb: turning on or off, or setting the value or output of a generator, a capacitor bank, reactor or transformer setting.

distributed generation (DG)—Power generation at or near the point of consumption in contrast to centralized generation that relies on transmission and distribution over longer distances to reach the load. Generally DG is smaller in scale and centralized, base load power.

distribution—Distribution lines and distribution substations operate at lower voltage than the transmission systems that feed them. They carry electricity from the transmission system to local customers. When compared to transmission, distribution lines generally use shorter poles, have shorter wire spans between poles and are usually found alongside streets and roads, or buried beneath them. A typical distribution voltage would be 13.8-kV.

distribution utility—A utility in the state of Vermont that is responsible for owning, operating, and maintain the distribution part of the electric system within an area.

docket—A court case. As used in this plan, the term refers to a case before the Vermont Public Service Board.

Docket 7081—The Public Service Board case that established Vermont's current process for transmission planning. The formal title of the case is "Investigation into least-cost integrated resource planning for Vermont Electric Power Company, Inc.'s transmission system."

elective transmission—Projects needed to connect generation to markets and to increase the capacity of a transmission corridor that otherwise limits the ability to sell power from one part of the system to another. Such projects, needed for purposes other than reliability, are categorized as elective transmission, and are financed by the project developer, not the end-us customer.

easement—A right to use another's land for a specific purpose, such as to cross the land with transmission lines.

economic transmission—Transmission projects needed to achieve economic benefits, such as reducing system losses, improving market efficiency, or reducing the cost of serving customer demand.

forward capacity market—A marketplace operated by ISO-NE using an auction system with a goal of purchasing sufficient power capacity for reliable system operation for a future year at competitive prices where all resources, both new and existing, can participate.

generation or generator—A device that converts other forms of energy into electrical energy. For example, solar energy from a photovoltaic panel or mechanical energy from an engine, a water wheel, a windmill, or other source, can be converted into electrical energy.

kilowatt-hour (kWh)—One thousand watt-hours. A watt-hour is a measure of the amount of electric energy generated or consumed in a given period of time.

kilovolt (kV)—One thousand volts. Volts and kilovolts are measures of voltage.

lead distribution utility -A utility selected by the affected utilities to facilitate decision-making and to lead the effort to conduct the NTA analysis

load—see ***demand***.

megawatt (MW)—One million watts. Watts and megawatts are measures of power. To put this in perspective, the peak power demand for the New England region is approaching 30,000 MW or 30,000,000,000 (thirty billion) watts.

net metering—An electric policy that allows consumers who own small sources of power, such as wind and solar, to get credit for some or all of the electricity they generate through the use of a meter that can record flow in both directions. The program is established under Title 30 Vermont Statutes section 219a.

N-0 or **N-1** or **N-1-1**—The term N minus zero (or one or two) refers to the failure of important equipment. Although these terms sound complex, they are actually quite simple. "N" is the total number of components that the system relies on to operate properly. The number subtracted from N is the number of components that fail in a given scenario. Therefore, N-0 means that no components have failed and the system is in a normal condition. N-1 means that only one component has failed. N-1-1 means that two components have failed, which is generally worse than having only one fail (see also the definition of contingency above).

non-transmission alternative (NTA)—The use of a solutions other than transmission, such as generation or energy efficiency, to resolve a transmission reliability deficiency.

peaking resources—Generators that are expected to run only during peak load conditions, or when demand is near system capacity, or during some form of emergency.

power—The amount of electricity that is consumed ***(demand)*** or supplied at any given time.

pool transmission facility or facilities (PTF)—Generally speaking, any transmission facility operating at 69 kV or higher and connected to other transmission lines or transmission systems is considered PTF. PTF falls under the authority of ISO-New England and the construction of new PTF facilities is generally funded through ISO on a "load ratio share" basis among its member utilities, meaning funding is proportional to the amount of load served by each entity.

reconductoring—Replacing the conductor that carries the electricity. May also include poles and insulators from which the conductor is hung. Also referred to as rebuilding when a significant number of the poles need replacing.

reliability deficiency—An existing or projected future violation, before or after a contingency, of the applicable planning, design and/or operating criteria, with consideration given to the reliability and availability of the individual system elements.

renewable power source—Any power source that does not run on a finite fuel which will eventually run out, such as coal, oil, or natural gas. Renewable power sources include solar, wind and hydro generators, because sunlight, wind and running water will not run out. Generators that burn replaceable fuels also commonly qualify as renewable power sources. Examples include bio-diesel generators that run on crop-derived fuels and wood-burning generators.

right-of-way (ROW)—The long strip of property on which a transmission line is built. It may be owned by the utility or it may be an easement.

substation—A substation is a fenced-in area where several generators, transmission and/or distribution lines come together and are connected by various other equipment for purposes of switching, metering, or adjusting voltage by using transformers.

Sub-transmission—Sub-transmission lines are power lines that typically operate at a voltage of 34,000 to 70,000 volts and are generally below 100 kV.

transformer—A device that typically adjusts high-voltage to a lower voltage. Different voltages are used because higher voltages are better for moving power over a long distance, but lower voltages are better for using electricity in machinery and appliances. Transformers are commonly described by the two (or more) voltages that they connect, such as "115/13.8-kV," signifying a connection between 115-kV and 13.8-kV equipment or lines.

transmission—Transmission lines and transmission substations operate at high voltage and carry large amounts of electricity from centralized generation plants to lower voltage distribution lines and substations that supply local areas. Transmission lines use poles or structures, have long wire spans between poles and usually traverse fairly straight paths across large distances. Typical transmission voltages include 345-kV and 115 kV and generally all are above 100 kV.

transmission system reinforcements—Also referred to as Transmission system upgrades that are needed to address a reliability deficiency as defined in this Plan and in the Docket 7081 MOU. Transmission line or substation equipment added to existing transmission infrastructure.

voltage—Voltage is much like water pressure in a system of pipes. If the pressure is too low, the pipes cannot carry enough water to satisfy the needs of those connected to them. If the voltage is too low, the electric system cannot carry enough electricity to satisfy the needs of those connected to it.

voltage collapse—A phenomenon whereby a series of events ultimately results in a blackout after a certain amount of time ranging from seconds to minutes.

voltage instability—A phenomenon whereby system operators cannot maintain acceptable system voltage given the tools at their disposal for a specific combination of load, generation and transmission. Voltage collapse may ensue.

Abbreviations

AC	Alternating current
DC	Direct current
DG	Distributed generation
FERC	Federal Energy Regulatory Commission
FCM	Forward Capacity Market
GMP	Green Mountain Power
HQ	Hydro Québec
HVDC	High voltage direct current
ISO-NE	ISO New England
MW	Megawatts
MWh	Megawatt hours
NERC	North American Electric Reliability Corporation
NPCC	Northeast Power Coordinating Council
NYISO	New York Independent System Operator
OATT	Open-Access Transmission Tariff
PSD	Vermont Public Service Department
PSNH	Public Service of New Hampshire
PSB	Vermont Public Utility Commission (formerly the Public Service Board
PV	Photovoltaic generation (solar)
SPEED	Sustainably Priced Energy Enterprise Development
VEC	Vermont Electric Cooperative
VEIC	Vermont Energy Investment Corporation
VELCO	Vermont Electric Power Company
VJO	Highgate Vermont Joint Owners
VY	Vermont Yankee
VSPC	Vermont System Planning Committee