DOCKET 7873 WORKING GROUP A
UTILITY GAP ANALYSIS AND PROCESS RECOMMENDATIONS
AS REVISED – 4/1/2013

BACKGROUND/INTRO

Act 170 of the 2013 Vermont General Assembly, Section 4 adds the following language to 30 V.S.A. § 8005a(d), providing an exemption from the annual cap for certain standard offer projects:

> (d) Plants outside cumulative capacity. The following categories of plants shall not count toward the cumulative capacity amount of subsection (c) of this section, and the board shall make standard offers available to them provided that they are otherwise eligible for such offers under this section:
>
> . . . .
>
> (2) New standard offer plants that the board determines will have sufficient benefits to the operation and management of the electric grid or a provider's portion thereof because of their design, characteristics, location, or any other discernible benefit. To enhance the ability of new standard offer plants to mitigate transmission and distribution constraints, the board shall require Vermont retail electricity providers and companies that own or operate electric transmission facilities within the state to make sufficient information concerning these constraints available to developers who propose new standard offer plants.
>
> (A) By March 1, 2013, the board shall develop a screening framework or guidelines that will provide developers with adequate information regarding constrained areas in which generation having particular characteristics is reasonably likely to provide sufficient benefit to allow the generation to qualify for eligibility under this subdivision (2).
>
> (B) Once the board develops the screening framework or guidelines under subdivision (2)(A) of this subsection (d), the board shall require Vermont transmission and retail electricity providers to make the necessary information publically available in a timely manner, with updates at least annually.

Docket 7873 Working Group A was formed to provide information about current constraints for the initial year of implementation of the standard offer cap exemption, and to provide input to the Board on how the cap exemption process should be implemented. The operating assumption of the group has been that analysis of the current constraints would inform the development of a practical framework for implementing the provisions of the statute, and at the same time, would provide "sufficient information concerning [current] constraints" for 2013.

The task of Group A was further defined by a set of questions proposed by the Public Service Department (PSD), which have formed the basis for utility analysis presented in this document. This document provides input from the participating utilities to the Public Service Board (PSB) regarding the following questions:

1. Identify areas of transmission and sub-transmission systems that have reliability constraints that could be affected by additional load and to provide a forecasted need date.[1]

2. Identify the wires solution and provide an estimated cost for that solution.

3. Describe the performance characteristics that any solution must meet in order to satisfy the appropriate reliability criteria.

4. Identify geographic areas where generation or load reduction could defer or avoid the wires solution, and estimate the quantity of generation or load reduction necessary to effectively address the constraint.

5. Quantify the amount of energy efficiency potential in the targeted area that is not already incorporated in the controlling forecast.

In addition, the document includes recommendations to the Board regarding the process to be used this year and annually for utilities to provide sufficient information regarding system constraints.

This document represents the input of the following utilities: Burlington Electric Department (BED), Green Mountain Power (GMP), VELCO, Vermont Electric Cooperative (VEC), Vermont Public Power Supply Authority (VPPSA), and Washington Electric Cooperative (WEC).

PROCESS ASSUMPTIONS/RECOMMENDATIONS

USE OF THE DOCKET 7081 NTA SCREENING TOOL TO IDENTIFY BULK SYSTEM AND SUBSYSTEM DEFICIENCIES

The Memorandum of Understanding (MOU) in Docket 7081, ¶21, requires the Vermont System Planning Committee (VSPC) to adopt a screening tool "to screen from further analysis only those projects that have no reasonable likelihood of being cost-effectively addressed by [non-transmission alternatives] NTAs." Utilities must apply the screening tool to bulk and predominantly bulk system deficiencies that are identified in the context of VELCO's three-year cycle for updating the 20-year Vermont Long-Range Transmission Plan (LRTP), or otherwise identified by a utility or by ISO-New England outside the cycle. A deficiency that "screens in" is then subjected to full NTA analysis to determine whether a specific configuration of NTA solutions, or a hybrid of transmission and NTAs can resolve the deficiency cost-effectively.

The current analysis assumes and recommends that the relevant constraints for which standard offer projects may provide sufficient benefit to be exempt from the program cap are the constraints that have been "screened in" using the NTA Screening Tool. In other words, relevant constraints are those that have some reasonable likelihood of being cost-effectively addressed by NTAs, as defined by the screening tool's criteria.

[1] After this question was framed, Group A agreed to expand the scope of its consideration to include distribution constraints. This document addresses one distribution constraint (St. Albans) and discusses how the group considered other potential distribution issues. The group acknowledged that contracting for standard offer projects to address distribution constraints (and potentially subtransmission constraints as well) raises issues of cost allocation equity where all Vermont utilities are put in a position of paying to provide "sufficient benefit" to the utility whose system is constrained. The cost allocation issues have not yet been discussed or resolved.

TREATMENT OF CONSTRAINTS FOR WHICH ANALYSIS IS NOT COMPLETE

The submitting parties recommend that, for constraints where analysis is not yet complete enough to determine whether standard offer projects, or other NTAs, can provide effective mitigation, or where the amount of these resources needed cannot yet be determined, consideration of standard offer sufficient benefit be deferred in the current year's cycle. The Docket 7081 process requires that the affected utility submit a "project specific action plan" indicating the critical path and timing to resolve any identified deficiency, and that the utility update the VSPC quarterly and the Board and Department annually on implementation of the action plan. These provisions of Docket 7081 ensure continuing attention to deficiencies once they have been identified. Further, the requirement of the standard offer process for annual updating means that an issue for which analysis is not yet complete in the current year's cycle can be revisited within one year.

CONSTRAINTS ADDRESSED IN THIS DOCUMENT

Three system constraints or reliability deficiencies were identified in the 2012 LRTP:

- Central Vermont
- Rutland Area
- Hartford/Ascutney

The Central Vermont deficiency is a bulk system issue for which all Vermont distribution utilities (DUs) are affected utilities[2]. A study group comprised of the DUs and VELCO, led by Green Mountain Power (GMP) has been conducting a full NTA analysis for the Central Vermont area. The work of that group and the ISO-New England Vermont/New Hampshire Needs Assessment has informed the analysis presented herein.

The Rutland Area deficiency is a predominantly bulk system deficiency for which GMP is the affected utility. GMP presented information about the Rutland Area deficiency to Group A during the current process indicating that it has not yet completed updated studies to address the five questions relevant to quantifying the reliability gap, the cost of the poles-and-wires solution and the performance characteristics needed for an NTA to be viable. Based on the current status of GMP's analysis, the participants recommend this constraint be considered for its potential to be mitigated by standard offer projects outside the cap in the 2014 cycle.

The Hartford/Ascutney constraint was identified in the 2012 LRTP as "screened in," but further analysis by GMP has identified two viable sub-transmission solutions with estimated costs below $2.5 million. The NTA Screening Tool screens out of full NTA analysis those projects for which the likely reduction in costs from the potential elimination or deferral of all or part of the upgrade is less than $2.5 million. This criterion is intended to avoid expenditure of extensive time and money where the potential for savings is negligible. Based on the re-screening of Hartford/Ascutney using the screening tool, the participating [utilities/parties] recommend the

[2] "Affected utilities" is defined in the Docket 7081 MOU as a Vermont Utility, the facilities or load of which cause, contribute to, or would experience an impact from, a Reliability Deficiency, or in whose territory a proposed solution to a Reliability Deficiency would be implemented.

Hartford/Ascutney deficiency be eliminated as a candidate to be addressed by standard offer projects in the current cycle. If further analysis results in a differing conclusion, GMP will submit information on this deficiency in the 2014 cycle.

Group A also evaluated whether any distribution constraints had the potential to be mitigated by standard offer projects that provide sufficient benefit to be exempt from the cap. Participating utilities were asked to informally review their systems and Integrated Resource Plans to identify potential candidates, and participants considered the data generated by the VSPC's process for recommending areas to be geotargeted for energy efficiency. This informal review identified one candidate distribution constraint – the St. Albans area. Analysis of the St. Albans distribution constraint is addressed beginning on page 12.

ANALYSIS OF THE CENTRAL VERMONT DEFICIENCY

Introduction: ISO-NE published the results of a 10-yr study for Vermont and New Hampshire in April 2012. VELCO published the Vermont 20-year long range plan in June 2012. The bulk transmission portion of the Vermont 20-year plan was based on the ISO-NE 10-year study, however, the calculation of reliability gaps and their timing relied on a forecast developed in concert with the VSPC. VELCO updated that forecast in October 2012 to reflect the latest economic performance and the effects of additional in-state renewable resources. The following responses are based on an updated reliability assessment that reflects that latest load forecast. Reliability constraints whose timing is more than 10 years in the future are not discussed. Those constraints involve the West Rutland to North Rutland transmission line and several transmission lines located in the Northwest Vermont reliability area. ISO-NE is about to initiate another 10-year study of the Vermont and New Hampshire transmission systems. That updated study may change the timing of the system deficiencies discussed below.

Question 1: Identify areas of transmission and sub-transmission having reliability constraints that could be affected by additional load, and provide a forecasted need date.

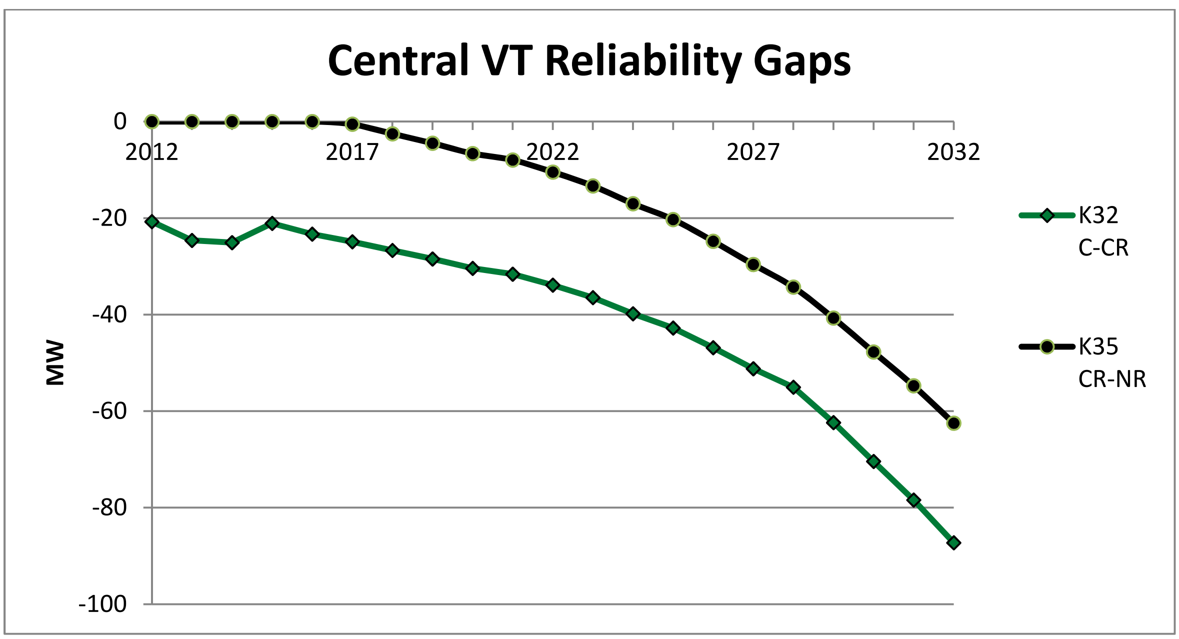
Response: Two transmission elements in central Vermont have been identified within the 10-year study horizon: the 18.2-mile K-32 line from Coolidge to Cold River and the 5.6-mile K-35 line from Cold River to North Rutland. Regarding year of need, the most recent VELCO forecast indicates the critical load level for the K-32 line has already been reached and the critical load level for the K35 line will be reached in 2017. Resources already being implemented under existing state programs and policies may meet all of the reliability need on the K-35 line thus the reliability need may be postponed beyond ten years from now. Whether or not a reliability gap exists for the K-32 line is uncertain at this time. Significantly more resources, such as those acquired through the ISO-NE forward capacity market or those developed independently, may be added in the next few years.

VELCO will continue to monitor the system to confirm whether there is a continuing need to reinforce the system. ISO-NE is undertaking an update of the VT/NH Needs Assessment in 2013 that will utilize ISO-NE's most recent load forecast, which projects declining load as a result of incorporating long-term energy efficiency and other resources. As a consequence of these developments, and its own work to date described below, the NTA Study Group has concluded that it is premature to quantify a need until the ISO-NE study is completed and the existence and size of a gap for the K-32 line can be more firmly established.

Based on current data regarding future demand and supply resources, and projected summer peak loads, the current Central Vermont reliability deficiency/gap is small and will likely reduce over time, potentially disappearing within the next five to ten years. The most appropriate response is to manage the reliability deficiency through operational means until the temporary deficiency disappears. Implementing a long-term solution, whether transmission or non-transmission, is not necessary nor in the best interest of customers. If a system emergency occurs during the interim period, the Vermont system operators will use all means at their disposal. Some of the tools available include optimizing our ties, triggering demand response, maximizing existing generation, implementing equipment ratings based on real-time ambient conditions, and shedding load as the last resort in case the previous steps are not sufficient. Presently, both regional and local area load shedding plans rely on the Vermont distribution utilities to shed load via remote control of sub-transmission and distribution circuit breakers and switches, and the VELCO system operators will direct the amount of load to shed.

Using the VELCO's load forecast (which is higher than ISO-NE's forecast, but not the controlling load forecast for regional transmission planning), the NTA Study Group has been refining the analysis of projected need, based on the effects of state policies and programs in terms of known resources, currently in place or in the planning stages. The NTA Study Group further refined the analysis to incorporate the input from Docket 7873 Working Group A. The analysis, presented below, includes the following technical concepts:

> ***Critical load level***—The load level, measured in megawatts (MW), at which the transmission system can be operated without violating reliability criteria. In very simple terms, violations typically involve a transmission line exceeding its rating, or voltages being outside of acceptable limits.
>
> ***Reliability gap***—The amount of resources that would be required in any given year to reduce the actual or forecasted load down to the critical load level. The concept of reliability gap is illustrated in the graph below.



The above plots depict the reliability gaps on the K32 (Coolidge to Cold River) and K35 (Cold River to North Rutland) lines using the latest VELCO forecast. For example, in the year 2016 a 23 MW reliability gap is projected for the K32 line. This means that 23 MW of resources, ideally located, would be required to close the reliability gap. Since there is always a degree of uncertainty in the forecast, in the analysis and in the performance of any solution, it is desirable to provide some amount "reliability margin," described below. A final note: the reliability gap of the Coolidge to Cold River line (K 32) is approximately 20 MW greater than the Cold River to North Rutland gap throughout the study period. This represents the controlling gap and for simplicity only the results of the K 32 analysis are presented.

Reliability margin—The difference between the actual or forecasted load and the critical load level of the transmission element. A positive margin indicates the degree of robustness of the solution while a negative margin indicates a reliability gap.

Effectiveness factor*—**A measure of how ideally a resource is geographically located to solve a reliability gap. An effectiveness factor of 100% indicates a resource is ideally located; every one MW of resource would count one MW towards reducing the gap. While an effectiveness factor of 50% would indicate two MWs of resource would be required at that location to reduce the gap one MW. As illustrated in the response to question 4 below, effectiveness factors can range from 100% to 0% and in some cases, can even be slightly negative, such as Southern, Zone O. A negative effectiveness factor indicates that adding resources in that geographic area would actually ***increase the gap or reliability deficiency of the transmission element.

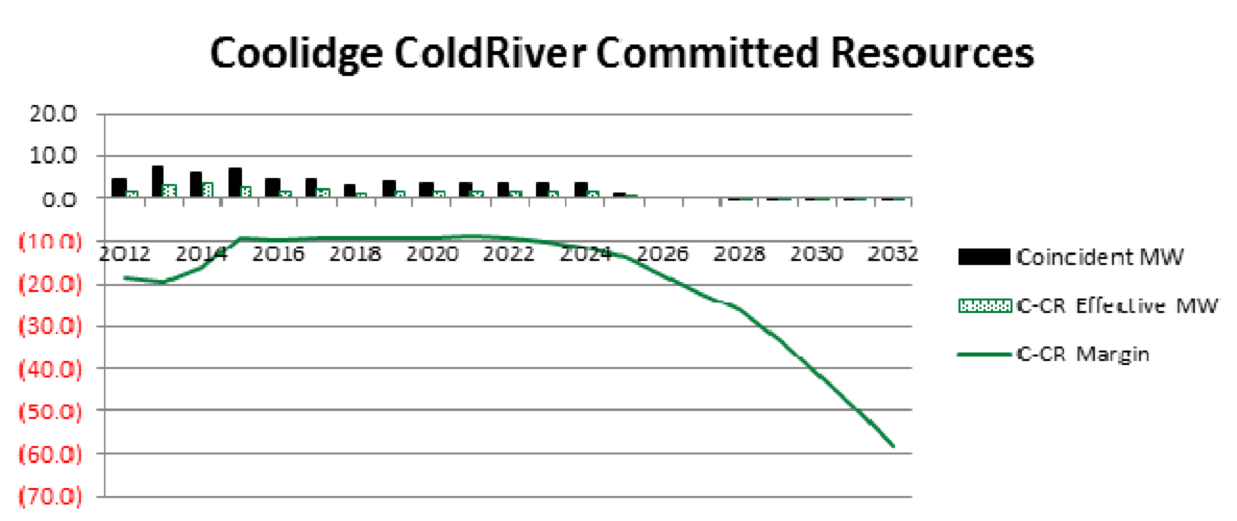
***Coincidence factor*—**A measure of how ideally the output or contribution of a resource coincides with the occurrence of the reliability need. The reliability deficiency for Central Vermont is associated with the Vermont summer peak, which typically is a six-hour period centered around 2 p.m. Fully dispatchable resource, such as demand response or some forms of generation, would *ideally coincide* with the summer peak and hence be 100% coincident. Other measures, such as LED street lights, would entirely miss the summer peak and therefore be 0% coincidence. In between falls a variety of resources with a wide range of coincidence factors, as discussed below in response to Question 2.

To analyze the gap, the study group combined different resources located across Vermont's sixteen load zones to determine the effect of different resource configurations on meeting the reliability need in Central Vermont. Since the calculations are repetitive, the Study Group developed a spreadsheet-based "ARC[3] tool" to evaluate different combinations of resources. The tool employs a modular approach to provide flexibility for future use. If the load forecast changes or better information becomes available on coincidence factors, the spreadsheet can be easily updated.

For the initial calculations, the ARC tool was used to evaluate the contribution towards meeting the reliability gap of resources that are already committed to coming on-line during the study period. These resources include standard offer projects under the 127.5 MW statutory cap, farm methane, net metering and Community Energy Efficiency Development (CEED). This combination reflects resources that are available to help meet the reliability

[3] ARC: Alternative Resource Configuration.

gap in central Vermont at no additional cost to ratepayers, i.e., without utilities acquiring resources specifically to fill a Central Vermont gap. The findings are presented graphically below.



By the year 2015, the committed resources are projected to reduce the reliability gap to 9 MW. The gap remains constant throughout the 10-year study horizon and one year beyond before increasing under the October 2012 VELCO load forecast. It was assumed that the standard offer program would not be extended past the current 127.5 MW cap. A brief description of the Study Group's analysis of these four resources is summarized below.

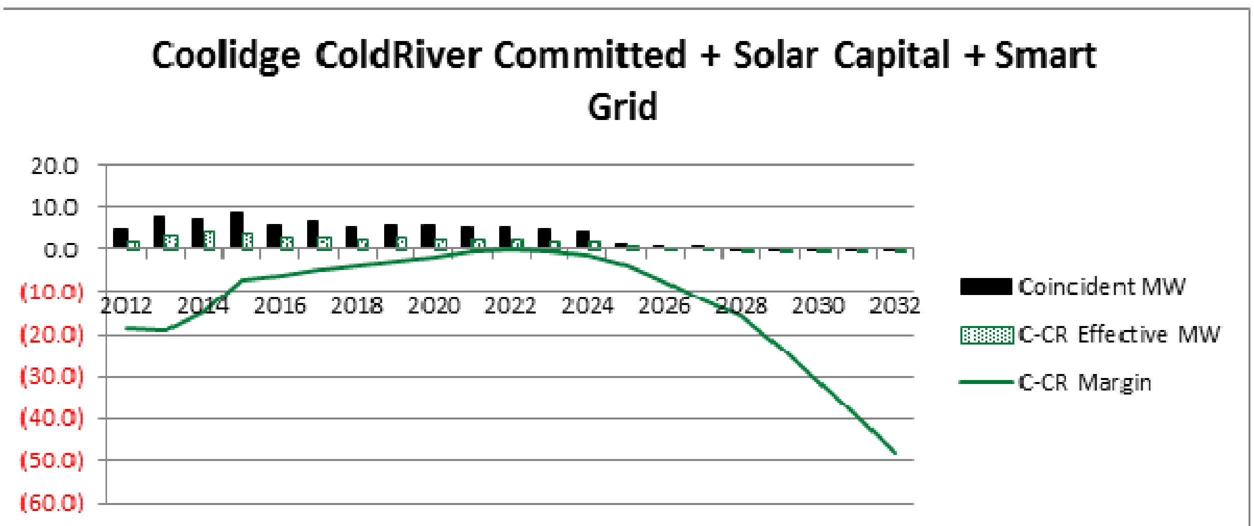
Standard offer—127.5 MW of resources are included in the analysis as set forth in 30 V.S.A. §8005a (2013-2015, 5 MW/year; 2016-2018, 7.5 MW/year and 10 MW/year thereafter until the 127.5 MW goal is achieved). The Study Group also incorporated the input of the SPEED facilitator regarding specific projects that are scheduled to come on line during the period 2012-2016. These projects were combined with existing projects to establish a distribution of resources (size and technology) across the 16 load zones. This pattern was used to develop an algorithm to distribute standard offer projects across the 16 load zones for the remainder of the study period.

Farm methane—Since farm methane is excluded from the 127.5 MW, it was evaluated as a separate resource. The methodology is similar to the standard offer. The SPEED facilitator's input was used to identify projects scheduled to come on line from 2012-2016 and an algorithm was developed to estimate farm methane projects for the remainder of the study period. A small "decay factor" was incorporated into the algorithm to reflect an anticipated decrease in new projects after the most attractive farms have been developed. The analysis anticipates that a total of 5,670 kW of farm methane resources will have been developed from 2008 through 2021.

Net metering—A total of nearly 10 MW net metered resources have come on line through 2012. Going forward the Study Group conservatively assumed that 1.7 MW of new net metered resources would be implemented yearly until the current cap of 4% of utility load is reached. We assumed the resources would essentially be all residential solar projects distributed across the 16 load zones based on each load zone's pro-rata share of the 2016 summer peak.

CEED—Green Energy Economics Group performed an analysis to estimate the electrical portion of the CEED program. They estimate measures being installed over the first five years that produce a total summer peak savings of approximately 6.4 MW. Taking no credit for reinvestment, the savings decay to approximately 5.5 MW at the end of the 10-year study period; which represents approximately 2.3 MW-years of effective reliability resources. For the Study Group's initial analysis these measures were allocated across all sixteen load zones; which produced approximately 3 MW-years of cumulative effective reliability resources through 2021. Based on input from Working Group A, we revised the analysis to allocate the measures across the nine load zones representing the former CVPS service territory. This change reduced the cumulative effective reliability resources from 3 MW-years to approximately 2.3 MW-years over the 10-year study period. The reduction is a result of reallocating resources from areas with high effectiveness factors in northwest and central Vermont to areas with lower effectiveness factors in southern Vermont.

The study group also analyzed the Central Vermont reliability issue adding two resources that have been committed, but have less certain timelines and magnitudes, Solar Capital and smart grid-enabled demand response. The following graph depicts the Central Vermont reliability forecast with these two additional resources included.



Including these two resources reduces the reliability gap to 6 MW in 2016. The gap is eliminated by the end of the 10-year study horizon and does not increase until 2024 under the October 2012 VELCO forecast. A brief description of how these two resources were analyzed is provided below.

Solar Capital—As suggested by Working Group A, the analysis was revised to account for the contribution of net metering and standard offer PV solar resources in the Rutland zone. Of the 7 MW of solar earmarked for Rutland, by 2016 an estimated 0.8 MW would come from the net metering program, 2.3 MW from standard offer projects and the remaining 3.9 MW from additional solar projects. For the revised analysis we assumed the 3.9 MW would be implemented in equal increments over the years 2013-2016.

Smart grid-enabled demand response—The analysis includes 15 MW of resources allocated across the 16 load zones during the years 2014-2024. Prior qualitative analyses suggested that 8MW of resources, conservatively estimated, could be obtained from the former CVPS service territory. This value was scaled-up to 15 MW to conservatively estimate the statewide potential.

The following section describes the assumptions regarding coincidence factors for each technology that underlie the assessment of the gap reflected in the graphs above.

Farm methane coincidence factor: The Central Vermont NTA study group has adopted a coincidence factor of 50% for farm methane generation. This factor appears to be generous since farm methane units have generated 40% or less of their claimed capability during the last two yearly summer peak days. Total farm methane output in the middle of the 2011 summer peak day was 1.34 MW compared to a total capacity of 4.08 MW. In 2012, the total output was 1.65 MW compared to a total capacity of 4.34 MW. The measured output was assumed to be based on the net output of the units after serving the generator's auxiliary/parasitic load, which is the correct value to report. If, however, a unit's meter is located in such a way that it also captures the effect of serving the farm's load that is not related to generation, the farm's load needs to be added to the net generation. Participants in Docket 7873 questioned the assumed capacity factor, but a specific alternative analysis has not yet been proposed. The Study Group remains open to incorporating an evidence-based alternative analysis, however, the total contribution of the resource is small enough that future adjustments will have a limited effect on the conclusion.

Run-of-river hydro coincidence factor: The Central VT NTA study group has adopted a run-of-river hydro generation coincidence factor of 10%, which is consistent with the factor that ISO-NE and New England stakeholders have adopted for planning studies. VELCO has used the same factor for ten years or more. Any proposed changes to these factors will require a New England stakeholder review.

Hydro generation is modeled based on its historical performance during the summer peak periods. For units that have ponding capability and are able to reach full output and remain at full output during the summer peak hours, these units are modeled at full output in the planning studies. That is the case for the Comerford and Moore hydro units. Alternatively, run-of-river hydro units, which are the prevalent technology in Vermont, produce minimal power during the summer peak periods. A review of historical data shows that the later the peak occurs, i.e. August versus June, the lower the output of run-of-river hydro units. For the purpose of long term planning, a 10% factor was applied to run-of-river hydro generation.

VELCO reviewed the performance of the standard offer hydro units for the past two yearly summer peak days, and the data are consistent with this 10% factor. Hydro generation is currently very small, as a subset of standard offer projects. Total hydro output in the middle of the 2011 summer peak day was 0.06 MW compared to a total capacity of 0.8 MW. In 2012, the total output was 0.13 MW compared to a total capacity of 1.1 MW. Because of the negligible amount of standard offer hydro generation, adopting a discount factor of 10% or 100% for future standard offer run-of-river generation is inconsequential at this time with respect to transmission planning. This factor can be adjusted in the future if a different technology, e.g. ponding hydro generation, is developed.

Onshore wind coincidence factor: The Central Vermont NTA study group has adopted a wind generation coincidence factor of 5%, which is consistent with the factor that ISO-NE and New England stakeholders have adopted for planning studies. VELCO has used the same factor for six years or more. Any proposed changes to these factors will require a New England stakeholder review.

Onshore wind generation is modeled at 5% of installed capacity based on analysis performed by ISO-NE. This analysis showed that onshore wind generation has no positive coincidence with load level, and there is a 90% probability that onshore wind will be near 0 MW during higher load levels. ISO-NE initially proposed a factor of 0% for onshore wind generation in planning studies. The 5% factor was adopted as a compromise between ISO-NE and New England stakeholders, which participate in the New England planning process through the planning advisory committee.

The results of ISO-NE's analysis are consistent with VELCO's own review of the Searsburg wind plant years ago. Until recently, Searsburg has been the only wind plant in Vermont. VELCO has used a 5% factor for wind generation in its planning studies for summer periods. Currently, wind projects have yet to be installed as part of the standard offer program. Therefore, adopting a discount factor of 5% or 100% for future standard offer wind generation is inconsequential at this time with respect to transmission planning. However, it is unlikely that wind generation will perform any better in the future as an alternative to transmission.

Question 2: Identify the wires solution and provide an estimated cost for that solution.

Response: The preferred wires solution—more accurately, the preferred transmission solution, since not all components would be lines— would be to add a second parallel 345kV line from Coolidge to West Rutland. The second 345kV line is estimated to cost between $79 and $157 million and defers the need for a second Coolidge Autotransformer ($23 million). Deferral of the second 345kV line through resources being implemented under state programs and policies will not address the need for the second Coolidge Autotransformer. Therefore, based on current data, it is expected that a transformer upgrade will be needed.

Question 3: Describe the performance characteristics that any solution must meet to satisfy the appropriate reliability criteria (the "equivalence").

Response: The reliability concern occurs in the summer near the peak level, and is associated with an N-1-1 outage scenario, which entails the outage of two facilities, allowing for system adjustments between these two outages. Our current understanding is that any non-transmission solution which is installed to address a reliability need would need to meet the following criteria:

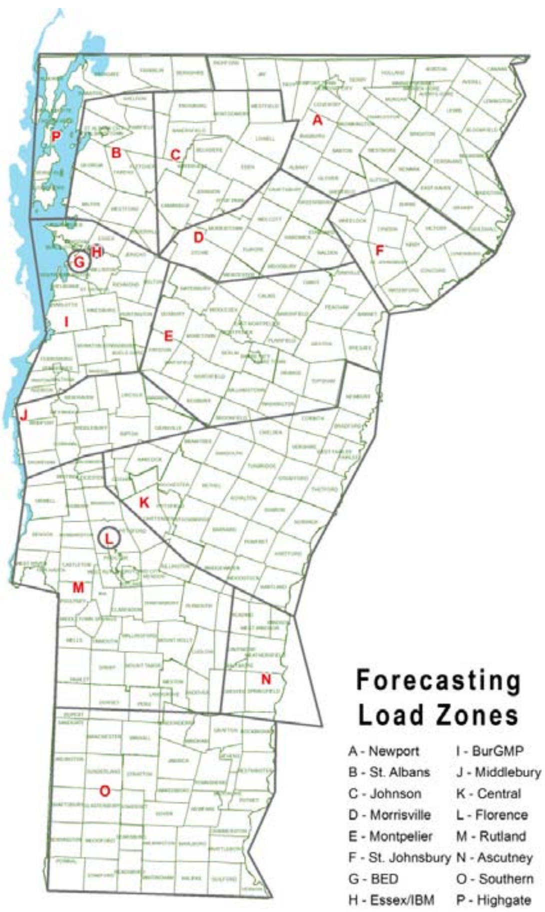
- Have a high coincidence with Vermont summer peak-day hours which typically occur over a 6-hour period centered around 2 p.m.
- Already be generating or be able to reach full generating capability within 10[4] minutes after being called.
- Remain connected and in service during and following the limiting contingencies.
- Be able to perform for multiple days where the reliability exposure exists (five 6-hour days).

[4] Confirmed by ISO-NE, November 27, 2012.

Question 4: Identify geographic areas where generation or load reduction could defer or avoid the wires solution and estimate the quantity of generation or load reduction necessary to effectively address the constraint.

Response: The relative effectiveness of resources located in the sixteen Vermont load zones is tabulated below. Percentages reflect the ability of a MW of generation or load reduction to affect the reliability need based on the geographic location of the resource or load reduction. The percentages are approximate, e.g., the first three zones highlighted in yellow can be considered as being equally effective at 80% for central Vermont concerns and 90% for northwest Vermont concerns. For the sake of simplicity, the effectiveness factors are based on the relative impacts on the most limiting transmission element affecting these regions. A more complete matrix of effectiveness factors may need to be developed in the future to reflect impacts on all relevant individual constrained transmission elements and the corresponding timing of those constraints.

Central Vermont Constraint		
Load zone*	**Load zone name**	**Relative effectiveness factor**
A	**Newport**	**41%**
B	**St Albans**	**62%**
C	**Johnson**	**57%**
D	**Morrisville**	**37%**
E	**Montpelier**	**59%**
F	**St Johnsbury**	**18%**
G	**BED**	**82%**
H	**Essex/IBM**	**78%**
I	**BurGMP**	**79%**
J	**Middlebury**	**91%**
K	**Central**	**22%**
L	**Florence**	**100%**
M	**Rutland**	**98%**
N	**Ascutney**	**7%**
O	**Southern**	**-2%**
P	**Highgate**	**60%**



Question 5: Quantify the amount of cost-effective energy efficiency potential in the targeted area that is not already incorporated in the controlling forecast.

Response: GMP, in connection with the Central Vermont NTA Study, commissioned an analysis by Green Energy Economics Group to estimate the amount and cost of additional, geographically targeted energy efficiency that could address any Central Vermont gap that is determined to exist once the Central Vermont re-study is completed by ISO. At the end of 2012 GMP received some very preliminary results of the energy efficiency analysis. After the full report is received and the study group reviews the findings, energy efficiency will be incorporated as appropriate into evaluation of the Central Vermont constraint.

ANALYSIS OF THE ST. ALBANS DISTRIBUTION CONSTRAINT BY GMP

The St. Albans area of GMP's service areas faces a future summer reliability constraint from the loss of one of the area's 34.5/12.47 kV substations in the event of a planned or unplanned transformer outage. Although load growth in this area has been flat, new demand expected to come on line over the next several years, and, in conjunction with any ancillary growth, will likely require construction of a new 34.5/12.47 kV substation at a cost of $1.5 million to maintain existing backup capability.

By letter of December 27, 2012, the Vermont System Planning Committee (VSPC) filed with the Public Service Board recommendations for geographical targeting (GT) of energy efficiency (EE) in 2013. These recommendations included the following:

> St. Albans (GMP; former CVPS service area): Continue GT in the St. Albans area. During 2013, GMP will continue to plan for the delivery of demand response programs (DR), consider the role for cost-effective technologies that are not currently supported by Efficiency Vermont (such as ice storage) and encourage the development of generation that has a high on-peak coincidence.

The St. Albans GT area was initially approved for the delivery of incremental EE treatment by Efficiency Vermont (EVt) by Order of February 16, 2012. That Order adopted the recommendations of the VSPC for the 2012 through 2014 time period calling for a budget of approximately $4.0 million to acquire 1.1 MW of energy efficiency incremental to the statewide services expected to be delivered in this area for a total area savings acquisition of 1.8 MW representing all available cost-effective EE potential. The VSPC estimated that the annual deferral value would be $250,000 (exclusive of energy and non-energy benefits associated with the cost-effective measures installed as a part of this effort).

As a part of the plan to address the constraint affecting this area, GMP is investigating other resources to address forecasted load growth, and to reduce uncertainty regarding forecasted load.

In addition to the targeted efficiency, other potential resources being explored include new demand response (DR) initiatives (either with or independent of AMI-enabled rate designs), ice-storage air conditioning and other load shifting measure that reduce area summer peak coincident loads. Generation additions that run on-peak or as needed, or have operating characteristic that result in a high on-peak coincidence, could also help to mitigate the area's constraint.

At this time GMP has yet to complete its effort to study and assess alternatives or to develop a final plan that identifies the least-cost strategy to address this area. As a result, GMP does not know if or how much new distributed generation would be required to address the constraint in a cost-effective manner.