Central Vermont Public Service Corporation
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TO:	Vermont Electric Power Company
CC:	Vermont System Planning Committee Participants
FROM:	CVPS Engineering
RE:	Comments on VELCO 2009 Vermont Transmission System 20-Year Reliability Analysis, VSPC Comment Draft, dated December 22, 2009
DATE:	February 13, 2009

Central Vermont Public Service Corporation ("Central Vermont," "CVPS" or the "Company") submits these comments on the VELCO 2009 Vermont Transmission System 20-Year Reliability Analysis, VSPC Comment Draft, dated December 22, 2009 (the "Draft Plan"), in accordance with the process for review of the Draft Plan contemplated under the Memorandum of Understanding approved by the Public Service Board (the "Board") by Order of June 20, 2007 (the "Docket No. 7081 MOU") establishing the Vermont System Planning Committee (the "VSPC"). Comments are organized by Draft Plan section with page reference.

In large part, Central Vermont's comments address concerns identified by VELCO regarding subsystem issues. As described in the comments, CVPS understands that VELCO needs to assess elements of the distribution utilities' ("DUs") subsystem facilities – especially facilities that might carry loads because they are parallel to bulk system facilities and could be impacted by contingencies affecting the bulk system and *vice versa*. Central Vermont is concerned, however, because the analysis suggests that certain CVPS facilities may be the subject of reliability deficiencies when tested using the VELCO criteria.

As CVPS explains, it understands that the reliability criteria applicable to DU's subsystem facilities are different from the criteria applicable to VELCO's bulk system facilities. As such, a system element could be in compliance with applicable subsystem criteria but found to be a violation when tested under stricter bulk system criteria. Central Vermont cautions that the Plan should not characterize these problems as reliability deficiencies and that such a characterization would be inapposite to the concepts that underlie the planning procedures developed pursuant to the Docket No. 7081 MOU. Stated otherwise, Central Vermont observes that the bulk system reliability criteria are too narrow for use on the subsystems and do not take into account the full range of factors that a DU needs to consider when prioritizing reliability deficiencies and possible solutions. In this regard, DUs must also take into consideration such factors as risk, applicable regulatory requirements, customer reliability impacts, rate impacts, IRP requirements, compliance with company asset management plans, and project benefit to cost ratios. Under this rubric, a decision to prioritize a reliability deficiency or solution is not a rote matter but rather requires the exercise of expert judgment that must take into account the totality of the matters then at issue. The Draft Plan should be modified to recognize this essential Distribution Utility reality.

This is not to say that CVPS does not take its reliability responsibilities seriously. To the contrary, the Company strives to maintain the reliable distribution of power to customers and is pleased that VELCO shares this commitment. Accordingly, CVPS offers these comments in the spirit of cooperation and looks forward to working with VELCO to incorporate these concerns while helping to identify solutions that are beneficial to Vermont and its electricity consumers.

1. <u>CVPS Subsystem and Distribution Planning Strategies</u>. In order for VELCO to prepare the Draft Plan, it was necessary for it to apply study criteria to identify areas where reliability concerns may arise. With respect to the assessment of subsystem and predominately subsystem elements, at Page I of the Executive Summary, the Draft Plan states that VELCO's assessment was conducted utilizing "the 'N-1' standard, which is the standard most commonly used by the Vermont distribution companies." <u>Id</u>. The Draft Plan explains that "[u]nder the N-1 standard, the system is required to not exceed applicable emergency limits for a single outage event at the peak load level." <u>Id</u>. at footnote 1. While the Draft Report does acknowledge that "[s]ome utilities design their system to different standards", Central Vermont must report that it has not adopted the N-1 standard for its subsystem and distribution systems, that it does not accept that this is the most commonly used standard for Vermont subsystems (many of which involve radial elements), and that this standard is not the standard contemplated under the company's Least-Cost Integrated Resource Plan ("IRP") or Asset Management Plan that CVPS uses to manage its system resources.

    Central Vermont's strategy for managing subsystem reliability is described in the Company's 2007 IRP which provides:

    > With increased emphasis on reliability performance, CVPS's T&D planning analysis has increasingly focused on studies designed to improve system operation under contingency situations. In the past, analysis focused on all lines in service adequacy. This is no longer an acceptable criterion and, therefore, CVPS has expanded its focus to include adequacy under first contingency. The planning methodologies deployed by CVPS include both deterministic and probabilistic reviews in reliability analysis. The deterministic planning analysis involves the review of system performance on the basis of computer simulations. System performance criteria are typically 0.95 per unit minimum voltage level for all lines in service and 0.90 per unit minimum voltage level for contingency situations with no thermal overloading of equipment. The probabilistic planning analysis places more emphasis on the likelihood of the

occurrence of a contingency and the severity should it occur. This analysis analyzes factors of frequency, duration, unserved load, and historical trends.

In its 2003 IRP, CVPS cited its observance of a general planning philosophy described as “most for less” where the Company tries to obtain most of the benefits of strict N-1 planning for significantly less cost by combining both deterministic and probabilistic approaches. Since then, this philosophy has led CVPS to develop a formal subtransmission network reliability criterion known as the *Equal Slope Criterion*. The relationship between the “most for less” philosophy and the equal slope criterion is explained in Appendix V.C.13.

In short, this new planning criterion recognizes that the strict reliability criteria governing bulk systems may not be cost-justified and may therefore be inappropriate for less critical nonbulk networks. Accordingly, it takes a more nuanced approach to defining “adequate reliability”, recognizing the exposures and consequent probabilities of load loss, as well as the omnipresent condition of diminishing investment return. Its ultimate objective is to devote an optimal level of investment to any given network system - not so little as to create undue hardship or business risk for customers, but not so much as to burden them with unnecessarily high rates. The desire to avoid excessive investment is particularly acute if the funds in question may be devoted to more cost-effective means of improving reliability such as better right-of-way vegetation management or demand side management programs.

Of significance, the equal slope criterion provides the Company’s T&D Planners more flexibility in implementing planning solutions than a N-1 or N-2 criteria. VELCO is required to meet strict reliability standards for the bulk transmission system. These strict standards limit the flexibility for the timing of system upgrades. When a system constraint is identified a solution must be implemented to assure that compliance is met. The equal slope criterion allows the acceptance of some added risk associated with system improvement delay in exchange for the benefits of capital deferrals. The acceptance of a short-term increase in risk may allow for implementation of NTA’s, facilitating the deferral of traditional T&D upgrades.

It is the Company’s belief that the objective of the integrated resource planning process is to assure that the T&D system will deliver electricity safely, reliably and economically. Achieving adequate reliability at least cost requires balancing costs, benefits and risks. This philosophy also recognizes that some added risk may be acceptable in order to decrease

> expected cost. A load duration curve is often used to help visualize this concept.

2007 CVPS IRP at 48-49. The 2007 CVPS IRP is pending approval before the Board in Docket No. 7284.

The 2007 CVPS IRP builds upon prior CVPS IRP reliability analysis. The Company's 2003 IRP provides:

> Combining both deterministic and probabilistic approaches allows CVPS T&D Planning to endorse a "Most for Less" philosophy when doing planning analysis. This is the philosophy where we try to obtain most of the benefits of a traditional planning approach for less cost. It is the Company's belief that the objective of the integrated resource planning process is to assure that the T&D system must deliver electricity safely, reliably and economically. Achieving both reliability and least cost requires balancing of costs and benefits and risks. This philosophy also asks whether it is appropriate to accept some risk in order to decrease expected cost. A load duration curve is often used to help visualize this concept.

2003 CVPS IRP at 34-35. The 2003 CVPS IRP was approved with conditions by Order of the Board on September 6, 2005 in Docket No. 6854. Most recently, CVPS relied on the *Equal Slope Criterion* to developed solutions approved by the Board to address subsystem reliability issues affecting the Company's 46 kV Southern Loop System. A copy of Docket No. 7373, Exhibit Petitioners KJ/LK-4(E) is appended to these comments and incorporated by reference.

The Docket No. 7081 MOU places responsibility for determining the standards applicable to the assessment of subsystem elements with the affected utilities. Paragraph 16 of the Docket No. 7081 MOU provides:

> For each potential Reliability Deficiency described in the draft Plan that is Subsystem or Predominantly Subsystem, each Affected Utility shall confirm the existence and description of such potential Reliability Deficiency or provide VELCO with a statement of the reasons for its determination that the potential Reliability Deficiency does not constitute a Reliability Deficiency. Where the Affected Utility or Utilities conclude that a matter does not in fact constitute a Reliability Deficiency, the Plan shall state this conclusion and the supporting reasons and the Plan need not characterize the matter as a Reliability Deficiency. Nothing in this MOU or the approval thereof constitutes a waiver by the Board or any Party that is not the Affected Utility or Utilities of any right to disagree with the conclusion so stated.

Id. at 7. As used in this section, Paragraph 113(b) describes an "Affected Utility" as:

> i. During Steps 1 through 6, above, a Vermont Utility, the facilities or load of which cause, contribute to, or would experience an impact from, a Reliability Deficiency, and
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> ii. During Steps 7 through 9, above, 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.

Id. at 43. Under the MOU, Steps 1 and 2 are the preparation and review of the Draft Plan including the determination of applicable subsystem reliability and operating criteria. Id. at 3. While CVPS recognizes that VELCO needed to apply a standard to complete its technical assessment, VELCO's subsystem findings only identify areas were their study criteria may have been violated. These findings do not constitute a determination that these areas suffer from a "reliability deficiency" or that applicable subsystem design or operating criteria are subject to an existing or forecasted violation.

Paragraph 113(ii) of the Docket No. 7081 MOU defines a "reliability deficiency" as existing or forecasted violation, pre- or post-contingency, of applicable Bulk Transmission System or Subsystem design or operating criteria, with consideration given to the reliability and availability of individual system elements." Id. at 47. As a consequence, the use of the appropriate subsystem design and operating criteria is of critical importance to the characterization of any issue as a "deficiency". CVPS stresses that the role of the Draft Plan's findings in the VSPC planning process needs to be clarified in the final version of the Draft Plan to explain that the Plan's characterization of subsystem issues does not constitute a determination that the issue constitutes a reliability deficiency in any planning, legal or regulatory proceedings involving the affected utilities. This is a significant concern for CVPS as strict adherence to the N-1 criteria is at odds with the company's IRP planning strategies and because the study findings of the Draft Plan should not result in the creation of presumptions regarding the existence of subsystem reliability deficiencies.

In subsequent draft 20-year reliability analysis and long-range plans, VELCO should adopt appropriate terminology to describe subsystem issues that are identified using VELCO's study criteria. Further VSPC engagement to clarify this aspect of the development of long range transmission planning is also recommended.

2. System performance with Highgate decommissioned. At page IV the Plan states:

> The capacity terms of the Hydro Québec energy contracts delivered over the Highgate HVdc converter will be gradually reduced from 200 MW in

2015 to 31 MW in 2016, 6 MW in 2017, and 0 MW in 2018. Therefore, starting in 2016, the converter may be disconnected with the contract to deliver 31 MW flowing on the Stanstead radial line to supply part of the Newport block load.

CVPS believes that this is a very unlikely scenario and should not be used as the base assumption for reliability analysis. The Highgate converter is currently rolled into the RNS service in the ISO-NE tariff, so there is no incremental charge for import/export use of the Highgate interface. Since use of other interfaces is known to be supported by the spot market even with incremental costs, and since additional interfaces with Hydro Québec are being proposed, it is likely that the Highgate converter will remain in service independent of the term of Vermont's contract with HQ. For example, other entities could schedule deliveries of power from HQ over the Highgate Converter. Moreover, there exist various emergency operating agreements that can be implemented to secure deliveries from HQ. Likewise, utilities could work with HQ to arrange for the wheeling of power to Vermont delivery points via HQ. Accordingly, Central Vermont contends that there are other reasons to assume that flows from HQ may continue in the absence of the existing power contracts, and the Company therefore recommends that the Plan contain an assessment of this probable outcome and recognize that the converter will likely remain in service upon the termination of the existing contracts.

3. <u>Nason Street to Nason V Tie Overload</u>. At page VII the Draft Plan explains that with all lines in the Nason Street to Nason V tie is overloaded in the St. Albans area with the loss of certain subtransmission elements. The Nason Street facilities are located with the CVPS service area and are parts of Central Vermont's subtransmission system. CVPS advises VELCO that the fix for this concern was completed in 2003 and was not properly depicted in the CVPS or VELCO load flow analysis used in the preparation of the Plan. The fix, made as a part of the Company's St. Albans reliability project, was to upgrade the bus to a No.1 copper bus with a summer rating of 67.8 MVA. Recognition of this upgrade should be made throughout the Plan where there is a reference to the Nason Street to Nason V Tie overload.

4. <u>Role of Portable Substation Facilities</u>. At page VII of the Draft Plan when discussing the results obtained through the assessment of subsystem elements, VELCO states that "[b]ecause transformer outages tend to be long-term, the system is exposed to the potential for another transformer outage before a spare transformer can be installed." While CVPS concurs that a transformer outage can create a reliability deficiency, it notes that VELCO has portable substation equipment that it maintains as a part of its strategy for reducing the duration of outages. The Draft Plan makes no reference to the existence or use of such devices and, as such, may paint an overly pessimistic assessment of the time frame associated with a transformer failure. CVPS recommends that the existence and use of portable substations should be taken into account in the long-term reliability analysis and in future draft plans submitted to the VSPC for comment.

5. Assessment of Subtransmission Systems. At page VII the Draft Plan provides: "With all lines in, voltages were below 0.95 pu near Ascutney, Blissville, and St. Johnsbury. Voltages were below 0.9 pu for loss of a sub-transmission line or with a sub-transmission breaker open near St Albans, Chelsea, Hartford, Ascutney, Rutland, Cold River, and Blissville." With respect to this statement, CVPS advises that this assessment was made at peak load and does not take into account the duration of such exposure since this contingencies may only occur for *de minimis* periods of time. As such, these issues may not violate applicable subsystem reliability criteria and should be recognized in the Plan's analysis.

6. Prioritization of Deficiencies and Solutions. At page VII the Draft Plan contains a discussion which introduces VELCO's proposed prioritization of transmission deficiencies and proposed conceptual solutions. CVPS notes that the prioritization criteria developed by VELCO are limited to "the planning stage of the project, the load exposure, and the expected need date." However this list of criteria is too narrow and does not take into account the full range of factors that a distribution utility needs to consider when prioritizing reliability deficiencies and possible solutions. In this regard, DUs must also take into consideration such factors as risk, applicable regulatory requirements, customer reliability impacts, rate impacts, IRP requirements, compliance with company asset management plans, and project benefit to cost ratios. Stated otherwise, a decision to prioritize a reliability deficiency or solution is not a rote matter but rather requires the exercise of expert judgment that must take into account the totality of the matters then at issue. The Draft Plan should be modified to recognize this essential Distribution Utility reality.

7. Summary Table Presentation. At page 8 the Plan contains a summary table that describes VELCO's findings. In addition to the information contained in the Plan, CVPS recommends that the Table be amended to include a column that identifies the "affected systems" not just whether it is bulk, predominately bulk or subsystem. Additionally, CVPS notes that this Table reflects both a year of need and a load level. This is very useful information. CVPS recommends that wherever the Plan identifies a year of need it should also state the load level. This would help to make sure that the information is most useful and can be used effectively should loads not grow as contemplated under the VELCO load forecast.

8. Study Assumptions. Section 1.3 at page 3 of the Draft Plan describes the Study Assumption utilized by VELCO in the conduct of its reliability analysis. Central Vermont offers the following comments regarding the study assumptions:

   a. Load. Central Vermont notes that the 2008 90/10 load value in the forecast used in the reliability analysis is significantly higher than the actual 2008 load value even when adjusted to 90/10. Moreover, for the periods subsequent to 2008 CVPS forecasts declining to flat loads while the forecast used in the analysis shows increasing loads. At the December meeting of the VSPC, similar concerns were expressed and the issues were referred to the VSPC forecasting committee. CVPS reiterates this concern and advises that the forecast be further reviewed by the VSPC and that the results of such analysis be presented as an addendum to the plan.

b. DSM. At page 3 the Draft Plan explains that the load forecast used in the analysis "includes the effects of expected changes to efficiency due to new regulations, such as the increased use of compact fluorescent lighting in the near future. The load forecast includes the effects of ongoing DSM because historical load levels include the effects of past DSM. However, the effects of additional DSM due to an increased budget were not included in the load forecast, which makes it possible for a simple subtraction of the DSM forecast from the load forecast." As such, the forecast used in the plan may not accurately reflect the additional DSM that may be implemented in Vermont. Central Vermont believes that the potential for DSM to reduce loads beyond those reflected in the Draft Plan's analysis need to be taken into account that findings and conclusions set out in the plan that may be altered on account of the acquisition of incremental DSM should be noted. These changes would help users to better and more accurately understand the conclusions described in the plan.

9. Figure 2 Vermont Load Forecasts. At page 7, the Plan discusses the Vermont Load Forecasts. CVPS recommends that this section be amended as follows:

> Figure 2 below shows the historical summer peak loads, the load forecast prepared by ITRON for VELCO and the load forecast prepared by ISO-NE. The ITRON forecast was used to grow the Vermont load. ~~Three trend lines were added to the graph. The first trend line was based on the highest historical peaks; the second trend line was based on the moderate historical peaks; and the third trend line was based on the lowest historical peaks. It can be seen that both forecasts start higher in the beginning years, but approach the moderate peak trend line near 2016. This, albeit, simple analysis suggests that the 2023 peak could occur as early as 2017 if the high trend is followed, or as late as 2028 if the low trend is followed. Primarily, this graph reflects that load forecasting is not an exact science. The level of accuracy of a forecast decreases the farther out the horizon for which it is prepared. When the load uncertainty is superimposed on other changeable factors, such as generation, system topology, system operation, regulatory requirements, and so on, a study beyond the 10-yr time frame should be taken as one that provides additional data to better inform decisions made for the system within the 10-yr time frame. Although expressed as an extreme weather forecast, the ITRON forecast appears to be a middle of the road forecast because it is closer to the average summer peak trend line. The results for the 2028 load level may well be relevant because the 2028 load level may be reached earlier than suggested by the ITRON forecast, and the system should be designed with~~

~~enough margin to serve higher load levels should they occur earlier than projected.~~

Central Vermont recommends that this trend line analysis be deleted. CVPS believes that the methodology described in the Plan is unfounded and misleading. If VELCO wants to put the forecast into perspective relative to history it should weather normalize the historic summer peaks. VELCO could, for example, create 90/10, 50/50 and 10/90 historical peaks using the Vermont adjustments (not the ISO-NE adjustments) in the CELT 2008 Forecast detail spreadsheet. But the Company maintains that there should not be linear trends superimposed on the forecast from the historical data since known structural changes suggest that the load growth rates are going to be suppressed for various reasons including but not limited to: increasing EEU budgets post-2000; Demand Response programs being installed per the ISO-NE programs in response to the Forward Capacity Market; and customer response to higher summer rates after the elimination of higher winter rates. Since Vermont summer peaks coincident with the ISO-NE summer peak drive the DUs' FCM costs, VELCO should also expect the DUs to create summer peak reductions to reduce their costs. For example, Burlington is setting up Demand Response systems to pro-actively reduce its summer peaks. Utilities are also pursuing the implementation of advanced metering systems ("AMI") that will enable additional time-based rates and load control programs.

As a consequence, this aspect of the Plan should be reconsidered and the plot in Figure 2 should corrected to eliminate the blue line connecting the 2008 actual load and the 2009 forecast since the blue line is used for history. That change will highlight the dramatic increase of the 2009 90/10 forecast from the 2008 actual load. This is another reason why the weather correction suggested above would be valuable. The history and the 90/10 forecast are not amenable to comparison without weather correcting the history. The forecast is also suspect in the near term since the recession was not included in the Itron forecast and appears to be significantly reducing loads (*i.e.*, producing negative growth). Thus the statement "[t]he level of accuracy of a forecast decreases the farther out the horizon for which it is prepared" could stand for the proposition that forecasting the future is difficult and errors will grow where there is evidence that the near term forecast is inaccurate due to its starting point. For all the reasons cited above, the text of the Plan should reflect the load levels that trigger reliability concerns not the expected year that the load level occurs in the VELCO 20 Year Load Forecast.

10. <u>Table 6 Thermal and Voltage Criteria</u>. Table 6 on page 18 of the Draft Plan contains thermal and voltage criteria used in the development of the Draft Plan. The text at page 18 introducing the table provides that these criteria "are based on common good utility practices and the current understanding by ISO-NE and the New England transmission owners." While these statements may apply to the facilities at or above 115 kV, Central Vermont reiterates its concern that these criteria do not apply to substation elements with voltages below 115kv. For example, the CVPS criterion for its subsystem facilities is 0.9 pu to 1.1 pu, not the 0.95 pu to 1.05 pu reflected in the table. As described in comment

number 1 above, the determination of these criteria should be made by the affected utility and the Draft Plan should not characterize subsystem facilities as a reliability deficiency based on the characterizations of applicable criteria made by VELCO. This concerns should be addressed in this and future version of the plan.

11. Recognition of the Merchant Transmission Project. CVPS notes that the Draft Plan nowhere discusses proposed merchant transmission projects and the impacts such projects could have on transmission planning in Vermont. While these projects are not certain, CVPS nonetheless believes that it is inappropriate to ignore their potential impacts in the plan. CVPS recommends that subsequent versions of the Plan consider the potential impacts of merchant transmission projects to the extent that information is available and the projects have advanced beyond mere discussion.

12. Line F-206 Out of Service. Page 32 of the Plan discusses loss of the F-206 and K-31 Lines. CVPS advises that its Wallingford to Mt. Holly facilities have been reconductored from #1 CU to 477 ACSR and that the Mt. Holly to Cavendish facilities are scheduled for re-conductoring in 2011. The 477 ACSR conductor has a summer rating of 49.7 MVA. In addition, a Mt. Holly breaker is being added in 2009 and can address issues until the line is reconductored. As a result, CVPS believes that these factors need to be considered in connection with the issues associated with the loss of the F-206 and K-31 Lines and reflected in further versions of the Plan.

13. 370 Line Out of Service. Page 32 of the Plan discusses issues raised by the loss of the 370 and K-30 Lines. CVPS advises that it is planning to add a breaker in Brandon with SCADA control in 2009. This breaker will allow for opening of the subtransmission system and avoid overload of the identified 46 kV lines. The reliability impacts attributable to this upgrade should be reflected in the Plan and considered in connection with the loss of the 370 and K-30 Lines.

14. 340 Line Out of Service. At page 32 the Plan discusses issues associated with the loss of the 340 and 3220 Lines. CVPS notes that it has the capability to open the loop in certain situations or to transfer load to the G-33 which could help to off load North Brattleboro thereby allowing the Vernon Road 115/46 kV transformer to handle more of the affected load. Moreover, the Southern Loop is currently an area that is receiving intensified geo-targeted energy efficiency services. As a result, CVPS believes that these factors need to be considered in connection with the issues associated with the Loss of the 340 and 3220 Lines and reflected in further versions of the Plan.

15. 350 Line Out of Service. Page 32 of the Plan discusses the loss of the 350 and K-32 Lines. CVPS advises that the North Rutland to East Rutland 46 kV Line is scheduled to be reconductored in 2009. This line will be reconductored to 477 ASCR with a 49.7 MVA summer rating. This project was identified as an efficiency upgrade but should also help to solve reliability concerns affecting this area. CVPS recommends that the impacts attributable to this reconductoring project should be reflected in the Plan. Also

see comment 12 above. In addition page 32 of the Plan discussed the loss of the 350 Line in conjunction with the loss of the K-37 Line. Central Vermont observes that the Brandon Breaker Project (discussed in connection with the loss of the 370 and K-30 Lines) will mitigate reliability concerns under this contingency. The Company recommends that the impacts of the Brandon Breaker be recognized in this analysis and reflected in the revised Plan.

16. Subtransmission Analysis. At page 51, CVPS recommends that Section 3 of the Plan be amended to state: "The N-1 standard was applied to the sub-transmission system regardless of the owner of the system. However, N-1 violations noted in this report may be considered acceptable after a review by the utility whose customers are impacted by ~~owns~~ the affected equipment."

17. Post Contingency Flows. At page 51, the Plan should be revised to state: "Post-contingency voltages should be no lower than 0.9~~5~~ pu and no higher than 1.10~~5~~ pu. A change in voltage, delta V, due to a contingency should be no greater than 10%."

18. Loss of the K-31 Line. At page 52 the Plan describes problems that arise with the loss of the K-31 Line. As CVPS reported in comment 12 above it is implementing a reconductoring project which will resolve the 46 kV line overload problems identified in the Plan between Wallingford and Ludlow that arise from the Loss of the K-31. This effort should be reflected in the analysis.

19. Loss of the K-37 Line. At page 52 the Plan describes the problems that arise with the loss of the K-37 Line. CVPS notes, however that the analysis reveals that the K-37 Line is only overloaded by 1 % at peak, therefore the Plan should reflect that this problem should be considered a low probability and low priority event based on its inherent risk of occurrence and the fact that Rutland is now an areas that is receiving geo-targeted energy efficiency which may help to address this matter.

20. Loss of the K-42 Line. At page 52 the Plan discusses issues associated with the loss of the K-42 Line. In connection with this concern CVPS notes that the issues associated with this contingency will be studied under the detailed joint study of the St. Albans-Georgia area begin conducted by CVPS and VELCO. Accordingly, CVPS recommends that the Plan be amended to withhold recommendations concerning this matter until the detailed joint study is completed.

21. Loss of the K-60 Line. At page 52 the Plan describes problems that arise with the loss of the K-60 Line. CVPS reports that the Lyndonville Project now being undertaken should resolve the issues associated with the loss of the K-60 Line and recommends that this effort be acknowledged in the analysis.

22. N-1-1 Performance of the Subtransmission System. Section 3.2.2 of the Plan at page 52 describes the analysis of the subtransmission system undertaken as a part of the analysis

of bulk transmission N-1-1 contingencies. From Central Vermont's perspective, this analysis has the effect of testing the subtransmission system using reliability criteria that are significantly stricter than the criteria used to design these subsystem facilities. Subtransmission systems have not and are not generally designed to survive N-1-1 contingencies on the Bulk System. While this information may be of interest to planners, any assessment of subsystem performance under these contingencies should not be considered to be evidence of subsystem inadequacy under applicable reliability criteria. As a consequence, CVPS questions the need for the discussion of these alleged deficiencies in the Plan and notes that the Plan need make no recommendations to address subsystem issues based on this assessment.

23. Step-Down Transformer Contingency Performance. Starting at page 55, the Plan discusses the performance of Step-Down Transformers under various contingencies. As a part of the discussion, the Plan explains that installing a spare transformer can take 1 to 5 days. While this may be true if a transformer needs to be transported to a remote location, VELCO keeps and maintains portable substations as a part of its ordinary equipment and processes. As a consequence, the time to restore service after the failure of a step-down transformer can be much shorter, measured in hours and not days. Given that VELCO has tools like portable substations, the existence and use of these tools should be reflected in the analysis and a more realistic time frame to restore service should be recognized in the Plan. See also comment 4 above.

24. Loss of Middlebury Transformer. At page 56 the Plan discusses problems that arise with the loss of the Middlebury transformer. CVPS reports that it has identified a 46 kV solution to address the Middlebury problems and efforts are now underway to pursue the implementation of the solution. Accordingly the Company believes that this reliability project and its impacts on area reliability should be reflected in the Plan's analysis.

25. Loss of the Blissville Transformer. At page 56 the Plan discusses problems that arise with the loss of the Blissville transformer. CVPS notes that the issues described arise due to the "at peak" nature of the analysis. To assess the issues associated with the Blissville Transformer, CVPS conducted an analysis applying its "equal slope" criteria. That analysis did not confirm a reliability deficiency. As a consequence, the Plan should reflect Central Vermont's findings and should not identify a reliability deficiency with respect to the Blissville Transformer. In addition, there is a cold stand-by transformer at Blissville that should be acknowledged in the analysis.

26. Loss of the Hartford Transformer. At page 56 the Plan discusses problems that arise with the loss of the Hartford transformer. To assess the issues associated with the Hartford Transformer, CVPS is conducting an analysis applying its "equal slope" criteria.

27. Loss of the Chelsea Transformer. At page 56 of the Plan discusses problems that arise with the lost of the Chelsea Transformer. CVPS notes that under the study assumptions,

these problems do not arise until 2013. Accordingly, CVPS is assessing this issue under its applicable reliability criteria.

28. Loss of the St. Albans Transformer. At page 56 the Plan discusses problems arising in connection with the loss of the St. Albans Transformer. CVPS notes that the issues described arise due to the "at peak" nature of analysis. The Company also recognizes that these issues are currently being assessed under the joint CVPS-VELCO St. Albans-Georgia Study now being undertaken by these parties and recommends that the Plan reflect the same.

29. Loss of Rutland Area Transformers. At pages 56 and 57 the Plan describes various reliability concerns affecting Rutland due to loss of transformers. In part, these issues were identified in the 2007 VELCO Long-Range Plan. CVPS recommends that the Plan be updated to reflect that the Company is planning to conduct a detailed joint CVPS-VELCO Rutland Reliability Study in 2009.

30. Loss of the Ascutney Transformer. At page 57 the Plan describes problems associated with the loss of the Ascutney Transformer. CVPS will assess this issue under its applicable reliability criteria.

31. Loss of the Windsor Transformer. At page 57 the Plan describes problems that can overload the Windsor to Highbridge 46 kV Line. However, the Plan does not consider the affects to this area from the planned addition of capacitors at the Bridge Street substation. CVPS understands that this capacitor addition should help this problem and that the project should be recognized in the Plan. CVPS will assess this issue under its applicable reliability criteria.

32. Plan Recommendations Regarding Substations. At page 60 the Plan offers recommendations based on its conclusion that some substation locations do not have adequate transformation capacity to prevent thermal and voltage violations. With respect to these recommendations CVPS offer the following:

    a. Substation Configuration. The Plan recommends that at each location where a transformer is proposed to be added, the substation should be upgraded to a ring or breaker-and-a-half configuration. However, CVPS has found that at the low voltage sizes, a ring design may not be cost-effective. Cost-effectiveness concerns need to be taken into account when solutions to reliability issues are considered. The Plan should be amended to reflect that a ring design needs to be tested for cost-effectiveness as a part of the design of substation upgrades.

    b. Middlebury Transformer. CVPS disagrees with the Plan's recommendations regarding the Middlebury transformer. Rather, CVPS has an alternate 46 kV solution to address this and other area concerns. The Plan should acknowledge the CVPS solution now in the works rather than the proposal presently described for this area.

c. Blissville Transformer. Central Vermont's assessment using applicable reliability criteria does not support the conclusion that the Blissville transformer violates the Company's reliability criteria.

d. Hartford Transformer. Central Vermont is assessing this issue under applicable reliability criteria.

e. St. Albans-Georgia Study. The assessment of issues affect the St. Albans area is currently the subject of a detailed joint study being conducted by CVPS and VELCO in accordance with the Docket No. 7081 MOU. Conclusions about the upgrades to be implemented to resolve reliability deficiencies affecting this area should be made as a part of this process and it is premature to recommend a specific solution until this effort is complete.

f. Loss of Rutland Transformers. Rather than describe the proposal to solve the identified Rutland issues, CVPS recommends that the Plan be updated to reflect that the Company is planning to conduct a detailed joint CVPS-VELCO Rutland Reliability Study in 2009.

g. Loss of Ascutney Transformer. Central Vermont is assessing this issue under applicable reliability criteria.

h. Loss of Chelsea Transformer. Central Vermont is assessing this issue under applicable reliability criteria.

33. Subtransmission Contingency Performance. Page 61 of the Plan describes various matters concerning subtransmission contingency performance. CVPS offers the following:

a. B-11 Upgrade. CVPS plan to reconductor the North St. Albans to National Carbide Line in 2009 to 477 ASCR with a summer rating of 49.7 mVA. The affects of this upgrade should be taken into account and the recommendations concerning the St. Albans area should be reconsidered as a part of the ongoing study of the St. Albans-Georgia area.

b. B-14 Upgrade. CVPS plans to reconductor the North Rutland to East Rutland Line in 2009 to 477 ASCR with a summer rating of 49.7 mVA. The North Rutland to East Rutland Line upgrade was identified in Central Vermont's last IRP as an efficiency project. This should be reflected in the Plan and the affects of this upgrade should be taken into account.

c. Rutland NTA Efforts. By Order of November 4, 2008, the Public Service Board expanded the scope of geographic-targeting energy efficiency efforts being undertaken by Efficiency Vermont to include the Rutland area. These efforts will have an impact on area loads. CVPS therefore recommends that the analysis of the Rutland area be reconsidered to reflect the impacts of targeted energy efficiency efforts and their effects on the B-14 (East Rutland to South Rutland). CVPS has implemented procedures to monitor loads in this area and will continue to assess the area to determine if further measures are necessary.

d. B-5 Upgrade. The B-5 Fairfax to Milton Line is being upgraded to 477 ASCR with a summer rating 49.7 MVA in accordance with Central Vermont's Asset Management Plan to address issues arising because of the age of this plant. The upgrade for this facility is currently budgeted for completion in 2012. The status of this project and its reliability impacts should be recognized in the Plan.

e. East Middlebury to Salisbury. Depending on load levels, CVPS can open the network with the Salisbury or Brandon Breakers (2009). This can help resolve issues affecting East Middlebury to Salisbury 46 kV.

34. Subtransmisssion System Recommendations. Section 3.4.1 of the Plan at page 64 sets out recommendations regarding the need for additional reactive support at various subsystem locations. With respect to these recommendations CVPS comments as follows:

a. B-5 Fairfax Falls to Milton. CVPS has scheduled a reconductoring project for Milton in 2012 which should be reflected in the Plan. See comment 33(d) above.

b. Nason St. to Nason V Tie. CVPS has already implemented a solution to this issue and therefore reference to this matter should be omitted from the Plan. Also see comment 3 above.

c. B-11 North St. Albans to National Carbide. A detailed joint study of the St. Albans-Georgia area is being conducted by CVPS and VELCO. Any recommendations concerning this area should be reconsidered as a party of that study and the Plan should reflect that the study is currently in the works. See comment 33(a) above.

d. B-14 North Rutland to East Rutland to South Rutland. North Rutland to East Rutland is being reconductored in 2009 and South Rutland area is now the subject of geo-targeted energy efficiency efforts by the Efficiency Vermont. These efforts should be reflected in the Plan and any recommendations concerning South Rutland should be reevaluated to take into account Central Vermont's monitoring efforts directed at this area as well as the effects of the additional energy efficiency be provided to customers in this target area. See comments 33(b) and (c) above.

35. Conclusions and Recommendations re: Middlebury Project. Section 4 of the Plan at Page 64 states that "[e]xcept for the Lyndonville proposed project, none of the deficiencies have a planned transmission solution at this time." However, CVPS has a proposed transmission solution for its Middlebury area and the Company has had a public hearing and the solution is in the process of being pursued and permitted. This CVPS subtransmission project is being designed in accordance with the Company's equal slope reliability criteria and will solve this problem for 10 years under current planning assumptions. This conclusion is also restated at page 66. Accordingly, CVPS recommends that the Plan recognize the efforts underway in connection with the Middlebury Project.

36. Conclusions and Recommendations re: Deficiency 5. At page 68 the Plan describes VELCO's conclusions regarding Deficiency 5. Since this area is currently the subject of a detailed joint CVPS-VELCO 2009 study, the Plan should acknowledge the study and indicate that the recommendations should be updated in accordance with the study results.

37. Conclusions and Recommendations re: Deficiency 6. At page 68 the Plan discusses recommendations concerning Deficiency 6 which can affect loads in Windsor, Vermont. As such, CVPS recommends that the list of affected utilities include Green Mountain Power Corporation.

38. Conclusions and Recommendations re: Deficiency 10. At page 71 the Plan discusses recommendations regarding Deficiency 10. Deficiency 10 is the Lyndonville Project that is currently being planned and implemented by the affected utilitites. The Plan should recognize this effort and reflect the fact that final designs remain a work in progress subject to the efforts of the affected utilitites.

39. Conclusions and Recommendations re: Deficiency 11. At page 72 the Plan discusses recommendations concerning Deficiency 11. CVPS observes that Deficiency 11 could be part of the Company's Vernon Road Breaker Project. The Plan should reflect that CVPS is currently assessing the synergies associated with the inclusion of work on this Deficiency with its efforts to plan the Vernon Road Breaker Project.

40. Conclusions and Recommendations re: Deficiency 17. At page 75 the Plan discusses conclusions regarding Deficiency 17. As part of the recommendations, the Plan states that "one should consider operating the sub-transmission system open or increasing the voltage of the sub-transmission system to 69 kV or 115 kV because that system is unable to remain connected when a transmission line opens." CVPS does not believe that it is appropriate to open its subtransmission system in a pre-contingency mode but may open the system in the event of an outage on the parallel high voltage facilities. Additionally,

before building or upgrading facilities to 69 kV or 115 kV voltages in these rights-of-way, the Company would look at sectionalizing and other system protection schemes to cost-effectively maintain reliability. Central Vermont recommends that these comments be reflected in the Plan.

41. Conclusions and Recommendations re: Deficiency 18. At page 75 the Plan discusses conclusions regarding Deficiency 18. As part of the recommendations regarding Deficiency 18, the Plan recommends that capacitor banks be added to address various conditions. Depending on the circumstances CVPS will continue to work with VELCO to identify the most cost-effective locations for capacitor bank additions on its subsystem and distribution facilities.

42. Issues Associated with NTA Screening. Where NTA screening is presented affecting the CVPS loads, the use of projected 2009 load may be a problem due to the Company's concerns with the VELCO forecast. In addition, projects affecting CVPS's subsystem should not be tested using N-1-1 bulk system reliability criteria. As a consequence of these concerns, there may be more time and opportunity for NTAs to be effective than would otherwise be suggested.

Central Vermont appreciates the opportunity to provide comments on the Draft Plan. Should you have questions regarding these comments, please contact CVPS Engineering. Thank you for your attention to this matter.

Attachment

A foundation for, and the establishment of a *probabilistic* reliability guideline for the Southern Loop

L. R. Kirby
April 2005

Entities that build transmission facilities comprising a part of the New England bulk transmission network have an inherent obligation to meet the minimum reliability standards recognized by the various owners and operators of that system. Failure to meet such standards may not only jeopardize the entity's own transmission system, but those of the interconnected entities as well.

The tightly woven connectivity of higher-voltage bulk networks is something of a double-edged sword. On the one hand, if unanimously operated to prudent standards and with ample margins, they are robust throughout. On the other hand, if any part is operated to lesser standards or with poor margins, the resulting risk is imposed not just locally, but over a broad area. NPCC's recognized standards for reliability on bulk power transmission networks in the Northeastern US are *deterministic* in nature, and are generally known as *N-1* or *N-2*. These terms refer to the ability of a system to continue operating acceptably with one less (or two less) than the normal number of system components (i.e. lines, transformers, and generators). This requirement extends all the way up to the peak load of the system or subsystem in question.

However, the NPCC standards also allow for a level of reliability lower than the N-1 or N-2 standard on lower-voltage systems, in cases where the failure of that system does not jeopardize the bulk system[13]. Typically, the failure of lower-voltage local networks (or radials) served by a higher-voltage bulk network, does not jeopardize the bulk network itself, but only those load centers served by the lower voltage system(s). Therefore, entities operating or building such systems are not necessarily required to adhere to the N-1 or N-2 standards, as is the case for the bulk transmission system. The appropriate level of reliability on such underlying systems is instead, determined by relative economic costs and benefits.

Logically then, the appropriate level of reliability for such systems is not a fixed parameter (as with deterministic standards) but is a function of cost. This leads naturally to a discussion of a typical cost-benefit characteristic (see Figure 1). The law of diminishing returns dictates that the characteristic typically rises rapidly at first, then gradually flattens out. Solution options near the extreme left have relatively low costs and relatively high benefit-to-cost ratios (i.e. the slope of the characteristic) but minimal overall benefits. Solution options near the extreme right have higher overall benefits but very high cost and poor benefit-to-cost ratios. Deterministic standards are often so rigorous as to result in solution options that fall within this undesirable high-cost region. More desirable solutions, with a reasonable cost/benefit tradeoff tend to exist near the "knee of the curve" as indicated in Figure 2. CVPS strives to achieve a reasonable balance between total benefit levels and benefit-to-cost ratios. In other words, the Company seeks solutions that tend to fall near the middle of the cost-benefit tradeoff curve. At CVPS, this cost/benefit philosophy is often referred to as a "most for less" approach, that is, *most* of the benefit of a deterministic standard but at substantially *less* cost.

In terms of utility reliability standards, the approach which best achieves this balance is the *probabilistic* approach, which is flexible and may be cost-based, as opposed to the *deterministic*

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[13] Section 2.1 *Design Criteria* of the NPCC's *Basic Criteria for Design and Operation of Interconnected Power Systems* document states "It is …recognized that the Basic Criteria are not necessarily applicable to those **elements** that are not a part of the **bulk power system** or in the portions of a member system where instability or overloads will not jeopardize the reliability of the **bulk power system.**"

approach, which is rigid and technically-based. The probabilistic approach to reliability is inherently more cost-effective than the deterministic approach because it concentrates capital resources on the greatest threats until the cost becomes prohibitive, whereas the deterministic approach basically assumes that capital resources are limitless and will be expended until the N-1 or N-2 standard is satisfied. Furthermore, although the deterministic approach *does* recognize cost in choosing an option from among those that meet the reliability standard, it does not recognize cost as a determining factor in the development of the standard itself[14].

Thus far, we have established a probabilistic reliability *philosophy* (i.e. "most for less") but have yet to develop a quantitative *standard or guideline* based on that philosophy. The development of such a guideline begins with an examination of a typical load duration curve. Figure 3 is a generic load duration curve for an area or subsystem that may be defined by a closed interface.

A load duration curve is simply a graphical representation of the range of loads that are experienced by an area or subsystem over a period of time, typically one year. The parameters of load and duration may be expressed as percentages (up to 100%), or as absolute values (e.g. megawatts on the vertical axis and hours on the horizontal axis). Note that the slope of the curve is related to the duration spent at or near a given load value - the flatter the slope, the greater the amount of time spent at or near that load. Load duration curves are widely used by planning engineers to understand systems' load behavior, and to determine the probabilities of being within specific load ranges.

Before embarking on an explanation of a *probabilistic* standard or guideline, it may be useful to first explain a *deterministic* standard using the load duration curve. Figure 4 provides the same load duration curve as in Figure 3 but with the minimum load-serving capability required to meet an N-1 deterministic standard, indicated by the horizontal green line. Note that it intersects the curve at 100% of peak load, in other words, it requires that the system operate acceptably for any first contingency up to peak load.

Now we may expand our discussion by considering once again the diminishing return on investment that is inherent in the cost benefit characteristic. The reasons for the law of diminishing returns are varied, but in the case of transmission planning, one of its leading causes may be observed in a typical load duration curve. When approaching its left-hand extreme, the load duration curve accelerates dramatically upward, culminating in a near-vertical termination. The electrical infrastructure required to satisfy the N-1 criterion all the way to peak load may be quite expensive, but the duration of time spent near this peak (and therefore the probable exposure to a critical contingency) increases much more slowly than the increase in load itself. Therefore, the reliability benefit of meeting the N-1 criterion on this last upward stretch of the load duration curve quickly diminishes, contributing greatly to the characteristic non-linearity of the cost-benefit curve. An effective probabilistic reliability guideline must recognize this important relationship.

Therefore, we should avoid requirements for load-serving capability that extend all the way to peak load, but we should also avoid overall lax requirements that result in few reliability benefits. Accordingly, it makes sense to require first-contingency coverage for the load levels in the "shoulder" region of the load duration curve (i.e. the broad middle region between the upward and

[3] Note that a deterministic reliability standard (specifically known as N-1) was used in the assessment of each Southern Loop DR option, so as to provide *equal* reliability performance, thereby permitting an equitable comparison of differing capital costs, losses, aesthetics, and other attributes. The N-1 standard serves as a convenient yardstick for such comparisons, but its use in this limited way should not be viewed as a general endorsement of its use for the Southern Loop. To the contrary, the probabilistic method, mentioned above, is endorsed as the appropriate reliability approach for non-bulk transmission network planning.

downward curvatures) where the % increase in load almost always occurs more slowly than the % increase in duration. In this region, reasonable gains in reliability (through reductions in probable contingency exposure) may be achieved by capital investment[15]. But as the load duration curve begins to shift toward vertical near the extreme left-hand side, the incentive for continued investment quickly diminishes.

At what point does this relationship "break even", that is, at what point are we effectively indifferent to the expenditure of the next increment of capital to achieve the next increment of load-serving capability? The answer will differ depending on the specifics of the system under consideration, the criticality of the load it serves, and other factors. However, a logical guideline would be the point at which the rate of change of load (on a percent basis) begins to exceed the rate of change of duration (on a percent basis). Any significant movement to the left of this point on the load duration curve will lead to a rapidly-diminishing return on investment. Yet, such a guideline will still capture all of the "shoulder" region of the curve where the percent change in load is usually lower than the percent change in duration, and where reliability investment tends to be gainful.

Figure 5 presents this concept graphically, using the same load duration curve as in Figures 3 and 4. A diagonal line connecting the peak load at zero duration to the minimum load at full duration has a slope equal to one (on a percent basis), and thus all along this line the rate of change of load percentage is equal to the rate of change of duration percentage. This slope may then be shifted until it is tangent to the curved portion of the left-hand side of the load duration curve. This point of tangency defines the required *load-serving capability* of the system during the worst contingency, as well as the acceptable level of *exposure duration* (i.e. the percent of time that the system would not be able to withstand the contingency without load-shedding). In our generic example, these values are 80.5% of peak load and 7.5% duration, respectively.

The proposed probabilistic reliability guideline may therefore be summarized as follows:

> *The (minimum) reliability guideline for **non-bulk network transmission** is such that the system or subsystem in question must be able to survive the worst single contingency with minimally acceptable performance, for the load level at which the system's marginal load percentage is equal to its marginal duration percentage, within its load duration characteristic. Generally there are two such points on any load duration characteristic. The right-hand point is trivial; the left-hand point is that to which this guideline applies.*

This probability-based reliability guideline may be referred to as the "equal slope criterion" for short.

It must be recognized that capital investments in utility infrastructure are not always scalable, but may instead be "lumpy", in the parlance of utility planners. This means that achieving the equal slope criterion with perfect precision may not be practical or even possible in some cases. This may leave the utility planner having to decide between overshooting or undershooting the prescribed load-serving capability, with the resulting upward or downward deviation yielding a less than desirable cost-benefit tradeoff either way. Nonetheless, a rational guideline that may be difficult to achieve is better than no guideline at all, and at least provides a frame of reference for making the decision. It is suggested however, that the guideline be treated as a desired *minimum,*

[15] If contingency coverage of even the shoulder hours is deemed to be too expensive, then the next lower reliability standard for networked transmission systems is effectively N-0, also known as "all lines in service". Although used in some parts of the world, US utilities and regulatory authorities are generally reluctant to accept this standard, viewing it as too lax for transmission networks.

as noted within the parentheses above. This resolves the difficulty of deciding whether to overshoot or undershoot the criterion, and errs on the side of overshooting it in cases where it cannot be achieved with exactitude.

Until this point, the discussion has focused on the development of a probabilistic reliability guideline, with generic examples of its application. But what of its application to the Southern Loop specifically? Figure 6 presents the present-day load duration curve for a closed interface around the Southern Loop, including Bennington and Brattleboro. Note that the software developed for this assessment cannot draw a perfectly smooth curve, as revealed by a close examination of Figure 6. However, an ancillary assessment was done with a load duration curve hand-drawn by a French curve to enhance its smoothness. The application of the equal slope criterion to this curve results in a (minimum) post-contingency **load-serving requirement of 73.5%** of the present-day peak load, or 85 Mw. This corresponds to a desired **exposure duration of no more than 8.8%**, or 771 hours per year.

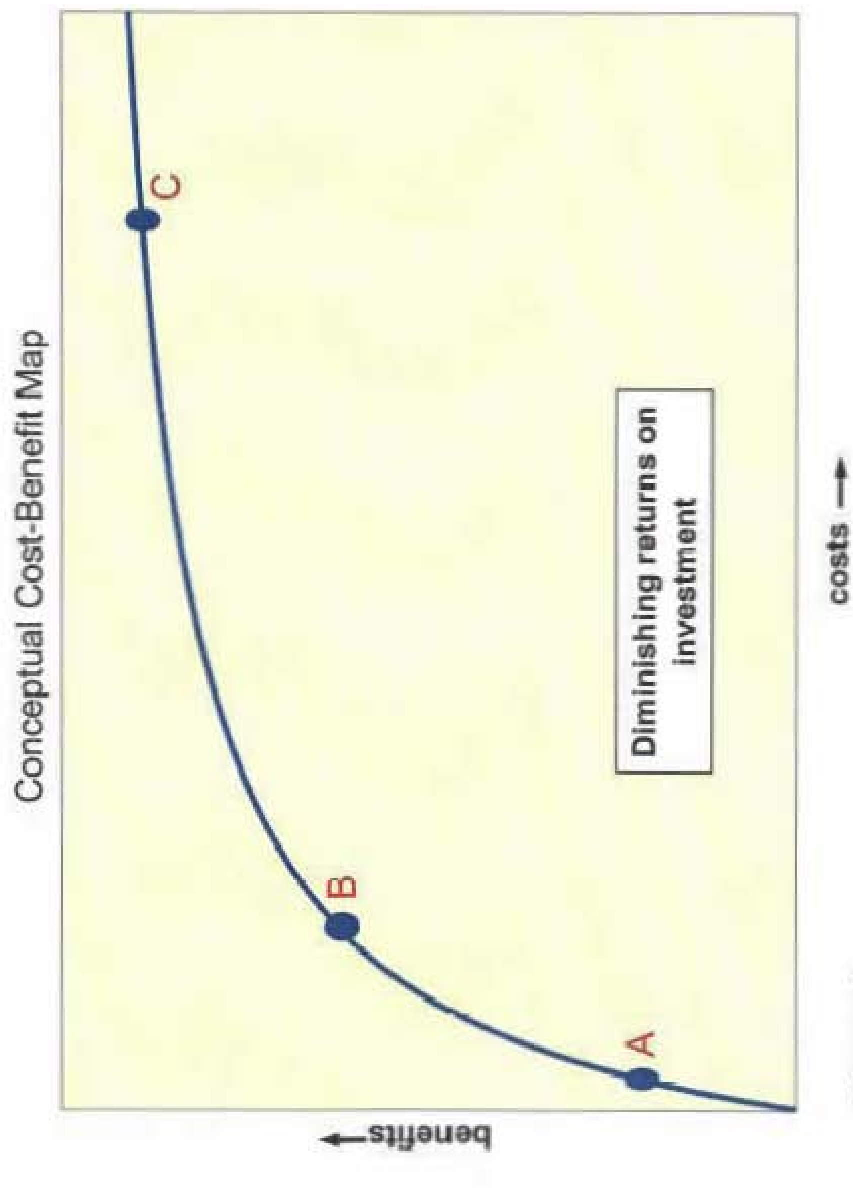

Conceptual Cost-Benefit Map
A
B
C
Diminishing returns on investment
benefits
costs

Figure 1

Conceptual Cost-Benefit Map

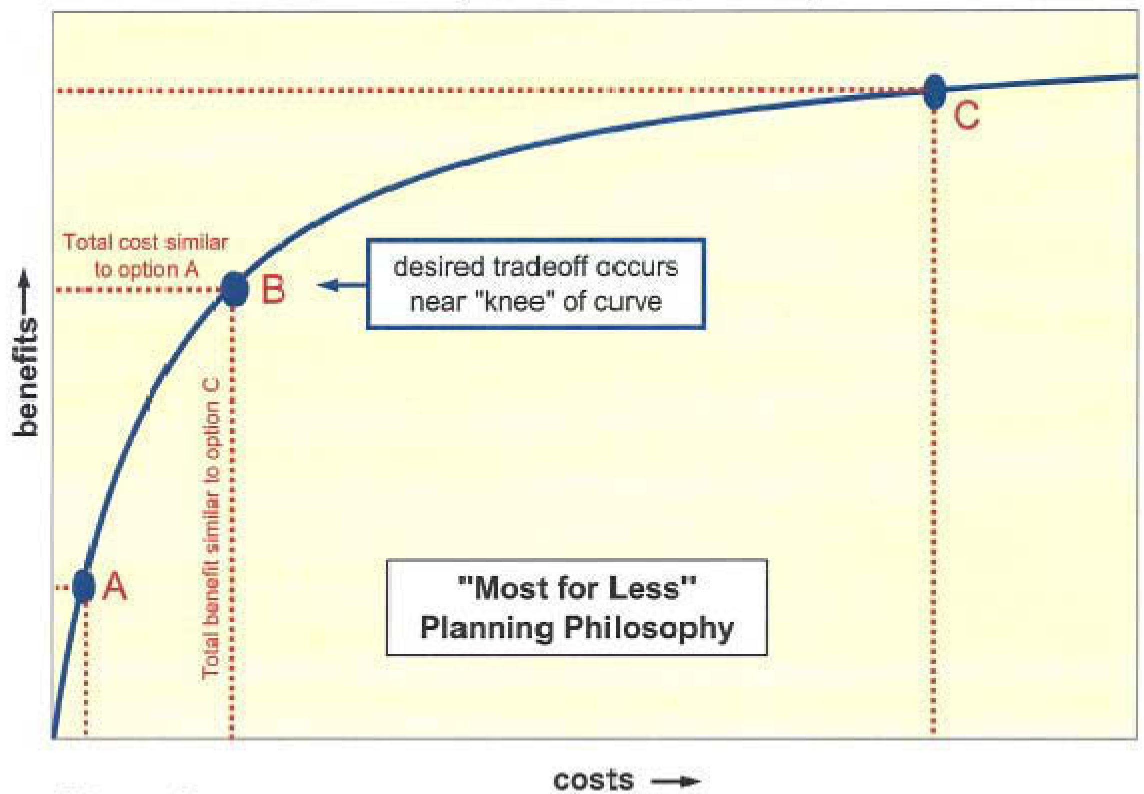


Figure 2

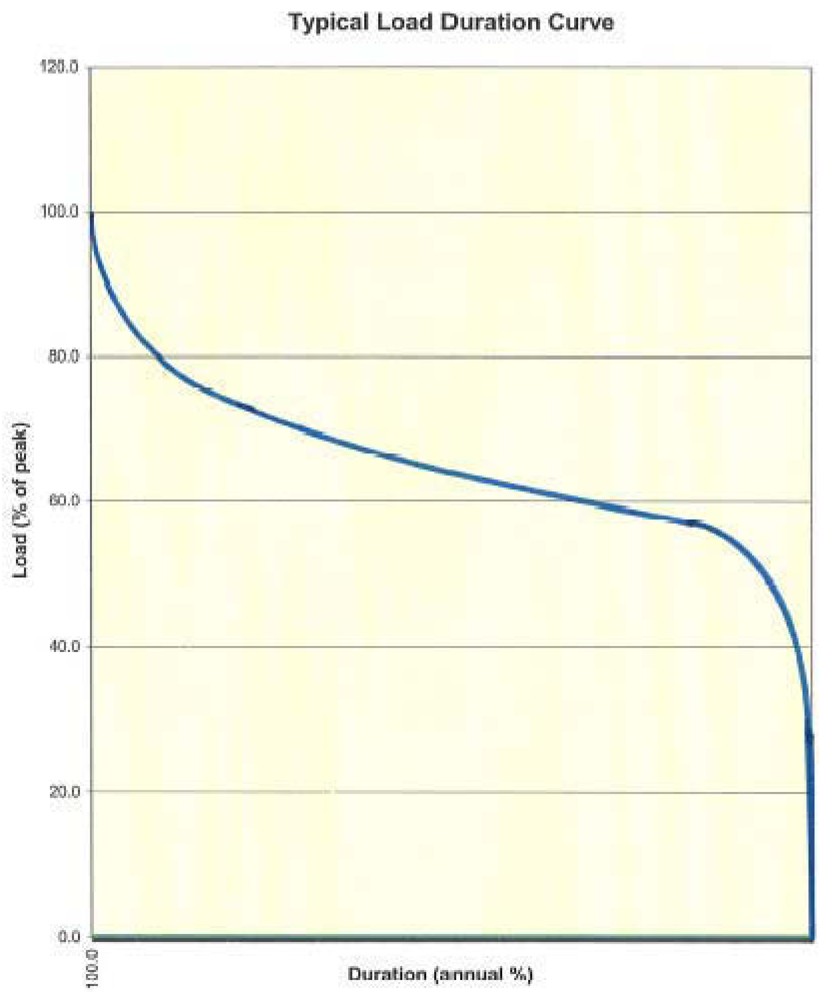

Typical Load Duration Curve
120.0
100.0
80.0
60.0
40.0
20.0
0.0
Load (% of peak)
100.0
Duration (annual %)

Figure 3

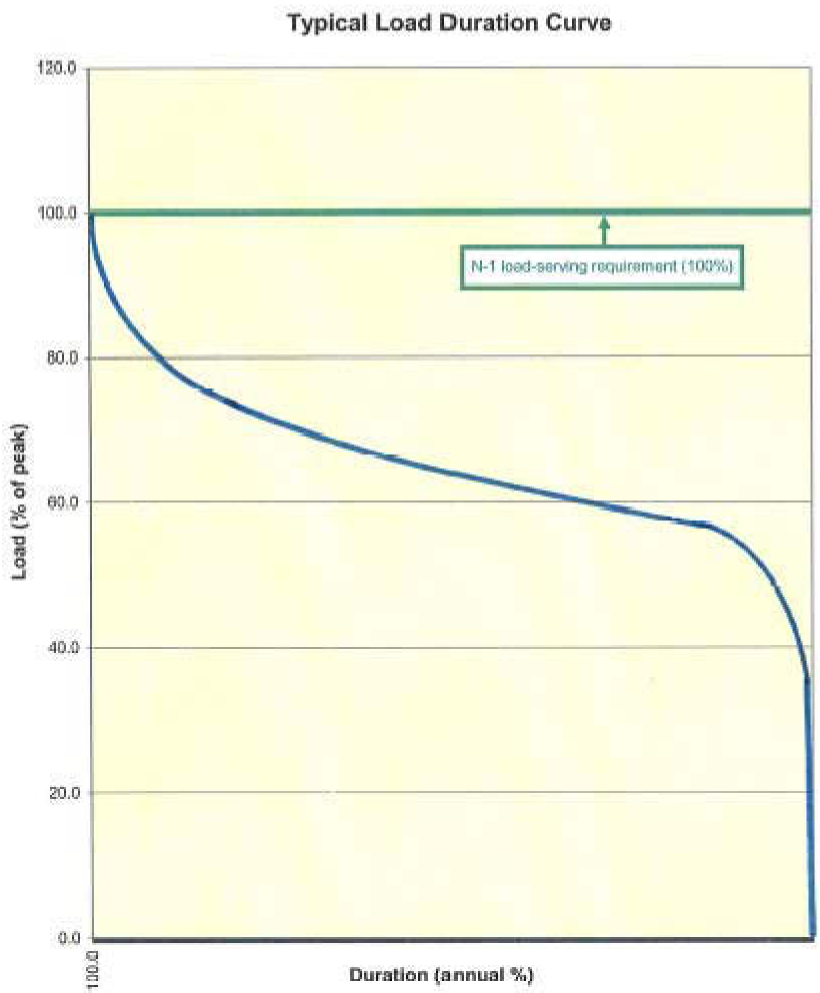

Typical Load Duration Curve
120.0
100.0
80.0
60.0
40.0
20.0
0.0
Load (% of peak)
N-1 load-serving requirement (100%)
100.0
Duration (annual %)

Figure 4

Typical Load Duration Curve

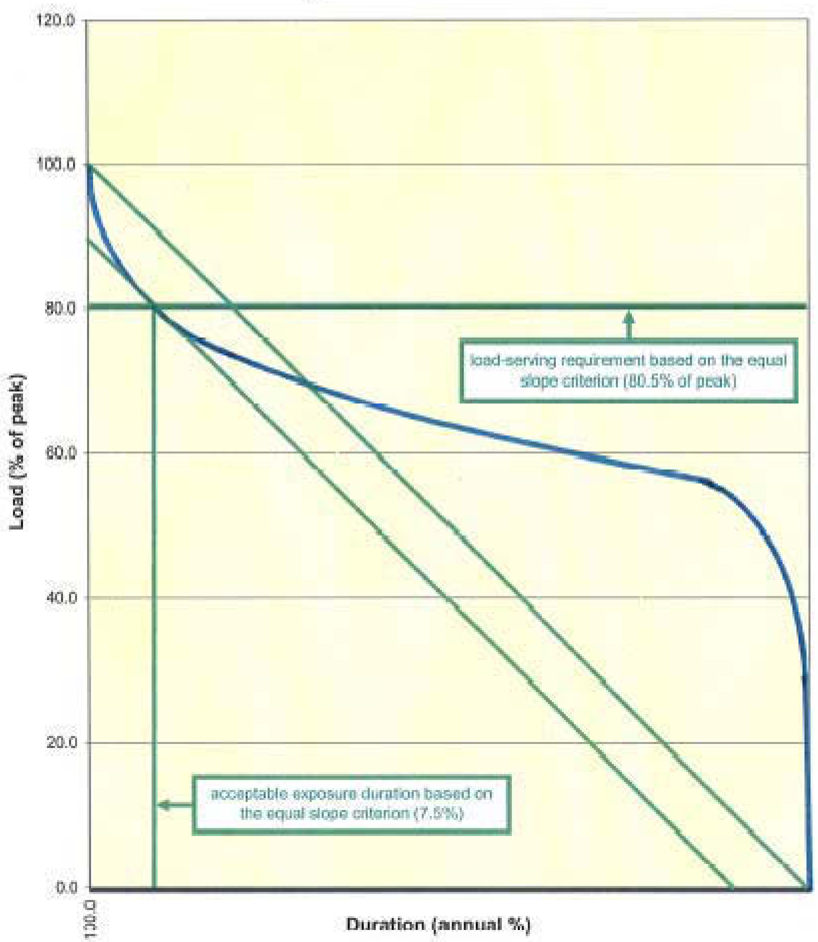
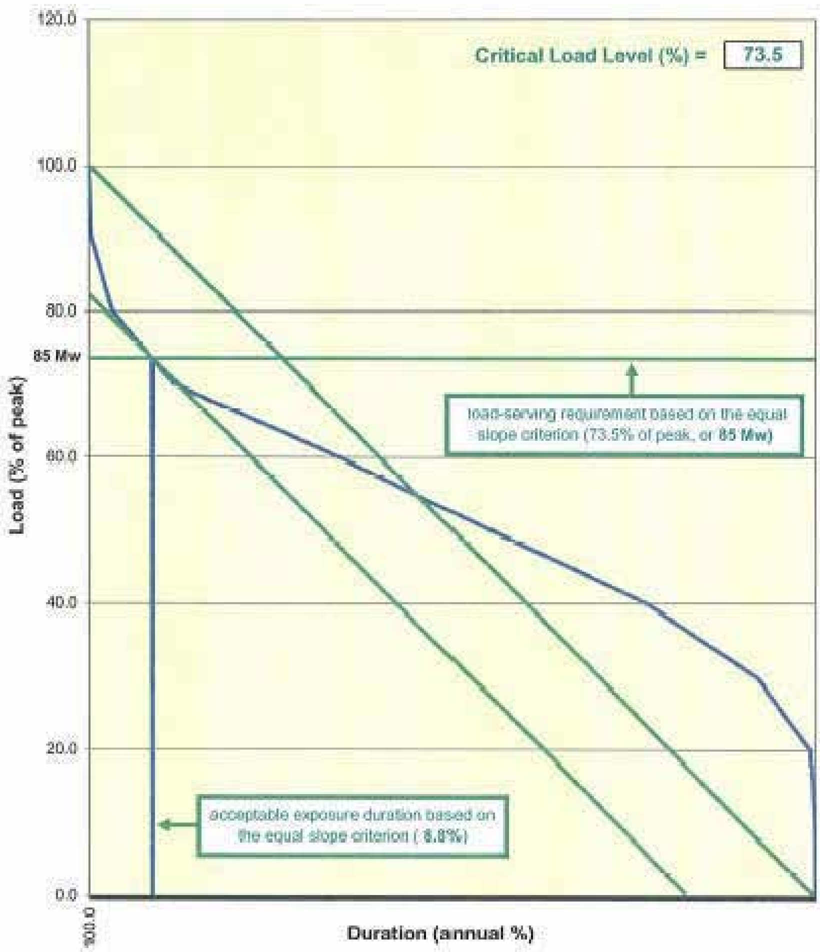


Figure 5

Southern Loop / Brattleboro Load Duration Curves
Blue = 2000/01 (assumed to be the existing LDC)



Peak Load of Base Curve (**MW**) = 116.0

Exposure Duration of Base Curve (%) = 8.8

Load Factor of Base Curve (%) = 52.3

Figure 6