ALTERNATIVES TO VELCO'S
NORTHWEST VERMONT RELIABILITY PROJECT

Prepared for VELCO

By

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29 January 2003

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ALTERNATIVES TO VELCO'S NORTHWEST VERMONT RELIABILITY PROJECT

Executive Summary

Vermont Electric Power Company, Inc. (VELCO) retained La Capra Associates (La Capra) to develop and coordinate the study of a set of alternative resource options against which to evaluate the merits of VELCO's proposed Northwest Vermont Reliability Project (NRP or Project). The NRP is a combination of eight transmission upgrades identified by VELCO as necessary to provide reliable transmission service to meet existing and forecasted Vermont electric loads. Reliability studies performed by VELCO reveal that growing Vermont summer loads,[1] an aging transmission infrastructure, limited transmission capacity, and the lack of new Vermont generation, prevent the system from meeting required reliability standards; under certain contingencies the system exposes customers in Northwest Vermont to widespread system outages at today's load levels.

La Capra has examined a broad set of potential alternatives to the NRP, which include system expansion plans composed of utility-scale power plants, distributed generation (DG) installations and demand-side management (DSM) programs. The goal of the study was to develop a robust solution to the transmission reliability problem facing Northwest Vermont. Based upon our analysis, we conclude that the NRP is the most robust solution.

The major NRP Project elements are:

1. Installation of a 115 kV Phase Angle Regulator ("PAR") at VELCO's Blissville substation (Poultney);
2. Installation of a 115 kV PAR at VELCO's Sandbar substation (Milton);

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[1] The VELCO system summer peak load reached 1023 MW in August, 2002, and is expected to grow to 1100 MW by 2005-06, and 1250 MW by 2011, according to the August 5, 2002 Vermont Department of Public Service (DPS or Department) Vermont load forecast.

3. Construction of a new 115 kV line between VELCO's New Haven and Queen City (South Burlington) substations;

4. Installation of 115 kV 24.75 MVAR Cap Bank at VELCO's Hartford substation;

5. Installation of a 115 kV Line Breaker at VELCO's Essex (Williston) substation;

6. Installation of a +/-150 MVAR Dynamic VAR Device (2 stages) and six 24.75 MVAR Static Capacitors at VELCO's Granite (Middlesex) substation;

7. Installation of a PAR and a second 230/115 kV autotransformer at Granite and the re-conductoring of the Granite-Barre line;

8. Construction of a new 35.8 mile, 345 kV Line between VELCO's West Rutland and New Haven substation.

VELCO's "Northwest Vermont Reliability Project Critical Load Milestone Study" issued by the VELCO System Planning Department on 10 December 2002, reveals that many of the NRP upgrade elements, including the Blissville and Sandbar PARs, the 115 kV New Haven to Queen City line, and the Hartford Cap Banks need to be added at existing (and pre-existing) load levels to protect the system against the loss of a critical generation or transmission element under representative contingencies. These elements of the NRP cannot be avoided or displaced by alternative supply or demand-side resources.

The following NRP elements might be displaced by alternative resources.

1. The West Rutland to New Haven 345 kV transmission line;

2. Installation of a PAR and a autotransformer at Granite and the re-conductoring of the Granite-Barre line;

3. A second 115/230 kV, 336 MVA transformer and a +/- 150 MVAR Dynamic VAR Device (1st stage is +/- 75 MVAR) at the Granite substation.

Our analysis reveals that Northwest Vermont currently does not have sufficient resources to meet New England Power Pool (NEPOOL)'s resource adequacy standard loss of load probability criterion, which requires that the power system be designed and operated such that the probability of disconnecting customers is no more than an average of one day in ten years. The current system is exposed to a loss of load probability of ten days in ten years. The results are shown in Table 5, at Chapter II of this report. These calculations reveal that Northwest Vermont will require an additional 89 MW of incremental resources by 2005, and 172 MW by 2011.

In Chapter III of our study we pre-screened commercially available generation technology options (both utility scale and distributed generation) and generally avoided those that are still in developmental stages. This information was combined with aggressive DSM net peak savings potential and program cost data provided to VELCO by Optimal Energy, Inc. (Optimal or OEI), to develop the following five (5) Alternative Resource Configurations (ARCs) against which to test the merits of the NRP. Each ARC is an alternative set of resources designed to meet the same reliability and incremental load serving requirements as the NRP. The ARCs are as follows:

- ARC 1 is composed of 180 MW of simple-cycle combustion turbines (CTs) and approximately 15 MW of distributed generation installations.
- ARC 2 is composed of a 90 MW combined-cycle (CC) and 120 MW of CTs.
- ARC 3 is composed of a 150 MW combined-cycle (CC) and 120 MW of CTs.
- ARC 4 is composed of a 200 MW combined-cycle (CC) and 120 MW of CTs.
- ARC 5 is composed of 120 MW of CTs and 70 MW of DSM-based peak demand savings. The fifth ARC reflects DSM contributions consistent with OEI's maximum achievable (or aggressive) DSM forecast.

In Chapter V of this report, we compared the relative cost effectiveness of each of the five ARCs relative to each other and to the NRP. For each ARC and for the NRP we tracked (1) the option's carrying costs, (2) the net variable costs to serve Vermont's load, and (3) the relative societal benefits. These were calculated, summed and compared under base case conditions.

A summary of the results of the cost comparisons are included at Table 20 of the report as follows:

Present Value Costs of Resource Alternatives, 2005 – 2016

2005 present value [1], $ millions

	NRP	**ARC 1**	**ARC 2**	**ARC 3**	**ARC 4**	**ARC 5**
Carrying Charges	107.5	193.6	242.8	282.7	302.2	314.4
Net Variable Cost to Serve Vermont Load [2]	1,178.1	1,135.2	1,072.9	1,027.3	986.5	1,074.5
Societal Costs/(Benefits) relative to the NRP [3]	-	(2.1)	7.3	11.3	2.6	(182.0)
Total Societal Costs	1,285.5	1,326.6	1,323.1	1,321.3	1,291.2	1,207.0

Notes

[1] The discount rate is 10%.
[2] This includes power supply costs, transmission losses, and capacity value.
[3] For ARC 1 to 4, the monetized value of emissions. For ARC 5, the monetized value of emissions and avoided distribution and sub-transmission investment.

The NRP requires the lowest total present value capital outlay between 2005 and 2016 ($107.5 million), and ARC 5 (the Maximum Achievable DSM case) the highest, $314.4 million. The NRP case features the lowest total annual transmission losses. ARC 1, the generation based alternative with the lowest capital cost, requires a total capital outlay of about $193.6 million across the study period.

Though the societal benefits of ARC 5 exceed those of the NRP and ARCs 1 through 4, our analysis shows that the costs of the DSM program required to defer a small piece of the NRP are large compared to the cost of the NRP element deferred (see Chapter V, section C). Whether or not to require the expenditure of such substantial amounts to obtain these benefits will ultimately be a matter for the Vermont Public Service Board. Our conclusion, in this context, is that the DSM resource commitments considered here cannot be justified by the need to remedy the specific electric system reliability problem in Northwest Vermont. Thus ARC 5 is excluded from additional detailed analysis.

As for ARC a 2 though 4, although they have slightly lower societal costs, we are of the view that they face implementation obstacles that limit their viability as alternatives to the NRP. Recall that ARCs 2 - 4, in addition to 120 MW of CTs, include the installation of a combined-cycle plant requiring a capital investment from $50 to $110 Million greater than that in ARC 1. Due to siting constraints, ARCs 2 - 4 require the development of two sites for power generation. In addition, these ARCs result in surplus installed capacity of 15 to 125 MWs. Their apparent societal cost advantage is a function of depressed LMPs due to transmission congestion that results in trapped generation. Finally, these ARCs increase both overall regional and local emissions. Consequently, ARC 1 is the only alternative that receives additional quantitative treatment.

As part of the assessment of the robustness of the identified least-cost alternative to the NRP, we analyzed the performance of ARC 1 and the NRP under a series of stress cases. Note, however, that all of the generation based ARCs are subject to many of the same uncertainties as ARC 1 (see Chapter V, section E). Thus the performance of ARCs 2 - 4 under uncertainty will be similar to that of ARC 1. In addition, many of the same implementation issues apply (see Chapter VI).

The NRP provides lower total societal costs than that does ARC 1 under all stress scenarios. On a ten year present value basis, the total societal cost of the NRP is $20 million to $100 million lower than the expected total cost of ARC 1. However, with the exception of Stress 2: High Gas, this amount represents only a small fraction (approximately 2 to 4 %) of the total cost of each option. While the differences are not trivial, neither are they very large. There are sufficient uncertainties in the inputs to preclude the selection of either the NRP or ARC 1 solely on the basis of the expected value *pro-forma* economic analysis presented thus far. The decision as to which project provides a more robust solution to the reliability problem is dependent largely on professional judgments regarding both the relative cost and implementation uncertainties. As summarized in the table above, the NRP has fewer cost and implementation related uncertainties than does ARC 1.

Summary Comparison of the NRP to ARC 1

Items of Comparison	NRP	ARC 1
Capital Costs	$150 Million	$195 Million
PV Carrying Charges (2005-2016)	$107.5 Million	$193.6 Million
PV Net Variable Costs to Serve Vermont Load	$1,178.1 Million	$ 1,135.2 Million
Financing and Cost Recovery	VELCO Rates; Possible PTF Treatment in NEPOOL RNS	Uncertain
Environmental Impact	No material emissions impact	Net decrease in regional emission relative to NRP; 10 % increase in local NO_X and CO_2 emissions
Installation and O & M	Costs are fairly well understood; transmission O & M costs are relatively small	Generation interconnection costs uncertain; O&M costs subject to greater uncertainty given nature of rotating machines
Rate Impacts	Potentially small	Generally larger
Reliability Equivalence	N/A	ARC equivalent assuming pro-forma 6% forced outage rates are realized. If actual rates higher, additional machines may be required.
Availability of Sites	VELCO owns or has access to most required land, requires some additional ROW	Few ideal sites; All require extensive improvements
Fuel Infrastructure	N/A	Extensive expansion of VGS delivery infrastructure
Fuel Availability/ Natural Gas Dependence	N/A	Generators 100% NG dependent; ARC reliability a function of the gas delivery system's reliability
Transmission Interconnection and Integration Costs	N/A	Uncertain; estimated to be $100/kW
Timetable	Most elements required now; little flexibility in timing of adding required elements	Generators must be on or before years indicated in schedule to ensure reliability.
Penetration	N/A	DG penetration rates may or may not meet forecast.
Program Implementation	N/A	DG program implementation should not be difficult, but results are uncertain since such a program would be new to VT.

Each of the alternative resource configurations includes the construction of CTs to meet need in 2005. The NRP is not completed until 2007. Thus, if only the NRP is constructed, there is a risk of high congestion costs and possible power shortages in 2005 and 2006. This risk may be exacerbated by the need to take parts of the system out of service in order to complete construction of the NRP. Consequently, we recommend that in addition to the proposed NRP elements, that VELCO investigate the benefits of installing CTs on a temporary basis to provide additional reliability during the summer peak periods in 2005 and 2006. The benefit of using temporary units is that the appropriate number of MWs to install can be determined closer to the time of need without incurring a large up-front expense and without taking on an unnecessary long term commitment. Moreover, the use of temporary units, rather than the purchase and installation of fixed assets, would prevent a potential surplus capacity condition from developing upon the completion of the West Rutland to New Haven 345 kV line in 2007.

Should load growth slow as represented in the Low Vermont Load scenario (see Chapter V, section E), the need for the majority of the NRP elements to be installed and in service by summer 2005 is unchanged. A drop-off in demand growth would allow the construction of the West Rutland to New Haven 345 kV line to be delayed for no more than a couple of years. However, we believe that the line will be needed and that the risk (and costs) of not having the line in service in a timely manner far outweigh the three or four years of avoided carrying charges.

Finally, we have concluded that the proposed Northwest Vermont Reliability Project is the best means to address the region's reliability problems and to meet incremental load requirements.

ALTERNATIVES TO VELCO'S
NORTHWEST VERMONT RELIABILITY PROJECT

I. Introduction

Vermont Electric Power Company, Inc. (VELCO) retained La Capra Associates (La Capra) to develop and coordinate the study of a set of alternative resource options against which to evaluate the merits of VELCO's proposed Northwest Vermont Reliability Project (NRP or Project). La Capra Associates has examined a broad set of alternatives to the NRP, which include system expansion plans composed of utility-scale power plants, distributed generation (DG) installations and demand-side management (DSM) programs. The goal of the study is to develop a robust solution to the reliability and power needs of Vermont that optimizes the expected power supply costs and risk mitigation objectives of the State.

This study has seven chapters. Chapter I outlines the report. Chapter II characterizes the need for additional resources in Northwest Vermont. Chapter III summarizes the results of a preliminary screening of potential supply alternatives to the NRP. Chapter IV presents the analysis conducted to assemble a set of preferred supply and demand-side options to test against the NRP. Chapter V presents the comparative cost analysis of the preferred alternative resource options and the results of an analysis of the performance of the NRP; it also compares the best potential alternative configuration to the NRP under a series of stress cases. Chapter VI outlines the uncertainties and challenges to successful implementation of the best alternative plan. Chapter VII outlines our conclusions and recommendations. The Appendices that follow this report contain supplemental information on our methods and assumptions.

A. The Northwest Reliability Project

VELCO has proposed the Northwest Reliability Project to resolve transmission reliability problems and to serve incremental load on its bulk power system. The components of the NRP fall broadly into two categories: those elements that are required to ensure the secure operation of the system independent of current or future load levels in Northwest Vermont; and those elements that are required to increase the throughput of the system in order to serve incremental loads. The major elements of the NRP are as follows:

1. Installation of a 115 kV Phase Angle Regulator ("PAR") at VELCO's Blissville substation (Poultney)
2. Installation of a 115 kV PAR at VELCO's Sandbar substation (Milton)
3. Construction of a new 115 kV line between VELCO's New Haven and Queen City (South Burlington) substations
4. Installation of a 115 kV 24.75 MVAr Cap Bank at VELCO's Hartford substation
5. Installation of a 115 kV Line Breaker at VELCO's Essex (Williston) substation
6. Installation of a +/-150 MVAR Dynamic VAR Device and six 24.75 MVAR Static Capacitors at VELCO's Granite (Middlesex) substation
7. Installation of a PAR and a second 230/115 kV autotransformer at Granite and the re-conductoring of the Granite-Barre line
8. Construction of a new 35.8 mile, 345 kV Line between VELCO's West Rutland and New Haven substations

For the purpose of this study, we have focused our efforts on developing sets of alternative resources that might displace -- or defer until loads exceed the 1,200 MW critical load level -- the Project elements intended to increase the ability of the transmission system to serve incremental loads in Northwest Vermont.[2] The majority of the elements listed above are intended to control voltage, ensure system stability, or direct flows to prevent thermal overload post-contingency. Those elements required to protect system security irrespective of current or future load levels cannot be displaced simply by adding generation or demand side programs in Northwest Vermont; hence, they are considered common to all resource alternatives.

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[2] The NRP is designed to reliably serve load up to a statewide summer peak customer demand level of 1,200 MW.

The following elements might be displaced by alternative resources.

1. Construction of a new, 35.8 mile, 345 kV transmission line adjacent to VELCO's existing 115 kV transmission line located between VELCO's West Rutland and New Haven substations;

2. The installation of a 230 kV PAR and an autotransformer at Granite and the re-conductoring of the 115 kV Granite – Barre line;

3. Installation of a second 115/230 kV, 336 MVA transformer and a +/- 150 MVAR Dynamic VAR Device (1st stage is +/- 75 MVAR) at the Granite substation.

B. Study Framework – The Stipulation Agreement

This study has been conducted pursuant to the requirements of the Stipulation Agreement entered into between VELCO and the Department of Public Service (Department or DPS). Section 3 of the Stipulation established that VELCO will provide to the Department the following analyses and information:

i. An analysis of the economic value of project deferral reflecting, at least, the capital investment of the West Rutland to Williston project multiplied by the carrying charge, plus operations and maintenance costs, net of the value of the change in losses;

ii. An analysis of the level of generation and DSM combination, per year, that defers or avoids the West Rutland to Williston upgrade;

iii. A description of other transmission projects, including their costs and required lead times, which alone, or in combination with generation and DSM, could avoid or defer the upgrade;

iv. The characteristics (including availability rate and location) of generation options required to avoid or defer the upgrade;

v. An assessment of the generation options, including but not limited to distributed generation, that have appropriate characteristics and that are economically viable given the economic values identified above;

vi. Identification of existing generation that could be upgraded, and identification of existing generation sites that could be utilized for new generation, that could economically avoid or defer the West Rutland to Williston project;

vii. A least-cost strategy for meeting the stated need, taking into account the analysis; and

viii. A multi-year strategic plan for implementing the identified least-cost strategy.

C. Summary of Approach

The approach used in this study is summarized as follows.

1. **Characterizing Northwest Vermont's Resource Needs -** The study begins with an assessment of Vermont's incremental resource need based on an analysis of the expected peak demands, the characteristics of the existing supply and demand-side resources, and the capabilities of the existing transmission system.

2. **Pre-Screening Generation Options -** Given the broad range of potential generation technologies available to meet the identified need, we pre-screen various generation options in order to exclude from detailed consideration those technologies that are not either economically or technically feasible.

3. **Constructing Alternative Resource Configurations (ARCs) -** A detailed *pro-forma* assessment of the economics of those supply resources (both utility scale and distributed generation) that remained after pre-screening is made to determine which supply technologies will form the component parts of the proposed alternative resource configurations. This information is combined with DSM savings potential and program cost data to develop a set of alternative resource configurations to test against the NRP.

4. **Comparing the NRP to the Alternatives -** For each ARC and for the NRP, the following costs were compared on a net present value basis (2005-2016, with 2005 present value), (1) the option's carrying costs, (2) the net variable costs to serve Vermont's load, (3) net societal costs. Each of these costs is calculated and summed under Base DSM case load conditions. The ARC with the lowest total societal cost and the NRP are then tested and compared under a series of stress cases to evaluate their relative performance under uncertainty. The alternative with the best expected economic and societal performance and distribution of outcomes - whether the NRP or an alternative resource configuration - under base case and stress case conditions is the preferred option.

5. **Implementation Challenges Facing the Least Cost ARC and the NRP –** Because the implementation of any option, including that which may be best on a *pro-forma* basis, has some uncertainties, non-economic variables must be addressed in order to determine which option is, in fact, the most robust means of meeting Northwest Vermont' needs.

II. Identifying Northwest Vermont's Incremental Resource Need

A. Planning Criteria

The need for additional facilities, programs, or procedures to ensure a safe, reliable, and economic electricity supply to customers in Northwest Vermont is defined largely by two interrelated planning and design criteria established by the Northeast Power Coordinating Council (NPCC) and the New England Power Pool (NEPOOL). The transmission design criterion, the so-called N-1 criterion, requires that the bulk power system be designed with sufficient transmission capacity to serve loads after the loss of any critical system element and that within 30 minutes it be able to sustain the loss of the next most critical element. A critical system element might be a generator, a transmission line, a transformer, a phase angle regulator, or some other element. Analysis performed by VELCO Planning indicates that Northwest Vermont currently fails to meet this standard.

The second regional reliability criterion, the resource adequacy design criterion, requires that the electric system be designed such that the probability of disconnecting non-interruptible customers is no more than, on average, once in ten years. Traditionally, utilities in Vermont have evaluated loss of load probability relative to their NEPOOL Capability Responsibility. NEPOOL has, for many years, calculated an Objective Capability for New England, indicating the amount of capacity (MWs) required to ensure that adequate generating capacity (i.e., plant in service) is installed within (or is available to) the Region to meet peak loads with an appropriate reserve margin.

Vermont's Capability Responsibility typically is calculated as its load-ratio share of NEPOOL's overall Objective Capability. This approach assumes a region-wide perspective. That is, Vermont is judged to have achieved its Capability Responsibility if the Vermont utilities own or have under contract sufficient generating capacity to meet their share of the Region's capacity requirement, regardless of where in New England or elsewhere that capacity is located. Importantly, capacity that may not be deliverable to loads in Vermont because of transmission constraints is still credited toward the State's installed capacity balance in a Capability Responsibility assessment.

In recent months, ISO New England has taken steps to refine its planning processes to ensure that transmission constraints do not cause load pockets in which reliability levels fall below the NEPOOL/NPCC once-in-ten-years standard. As part of the Regional Transmission Planning process, ISO New England has evaluated the ability of the power system to reliably deliver power to each of thirteen sub-regions in New England.

La Capra Associates' assessment of resource need in Northwest Vermont is consistent with ISO New England's evolving approach toward regional resource planning. The goal is to identify the amount of incremental load carrying capability that must be installed in Northwest Vermont to serve summer peak demand with a loss of load probability of at most once-in-ten-years. The size and expected forced outage rates of generating units are inputs to estimating loss of load probability. Because Northwest Vermont's generating resources are less than its peak load, the region must depend on transmission ties to other regions for meeting this criterion. Hence, the size and expected outage rates of transmission ties are also critical.

La Capra's calculations reveal that Northwest Vermont currently does not have sufficient resources to meet the loss of load probability standard and that it is, today, approximately ten days in ten years. Given projected load growth, current generating unit forced outage rates, and known transmission constraints, the situation will deteriorate further, unless remedial steps are taken.

B. Load Forecast

Customer loads in VELCO's service area (including 25 to 30 MW from the upper Connecticut Valley in southeast New Hampshire) have been growing at an average annual rate of 2.1% over the last decade, hitting a peak load of 1023 MW in the summer of 2002. The Department's Vermont regional load forecast (issued 5 August 2002) forecasts that, absent load control programs, load will continue to grow steadily (2.2% per year average) over the next twelve years, reaching 1250 MW by 2011.

About one-half of VELCO's summer peak demand (574 MW in 2002) is located in the Northwest Zone, a semi-circular region bounded generally by the New Haven substation to the south, the Granite substation to the east, the Highgate substation to the north and Lake Champlain to the west. Refer to Appendix 3 for a map of the Vermont Load Zones. VELCO has prepared a peak load forecast for the Northwest Zone through 2011 based on the DPS's Vermont regional load forecast.

The DPS forecast excludes load reductions from *future* DSM installations under existing Efficiency Vermont (EVT) and Burlington Electric Department (BED) programs. Optimal Energy, Inc. (OEI or Optimal Energy) has provided a forecast of the load reductions expected over the study period from incremental installations under existing DSM Programs; the reductions are estimated to reach approximately 31 MW by 2011 in Northwest Vermont. In subsequent sections of this report we refer to future load reductions expected from the foregoing as "Base DSM".

Also, the DPS and OEI forecasts reflect loads at the customer meter. Consequently, we have adjusted VELCO's peak load values for sub-transmission and distribution losses. Table 1 shows the load forecast for Northwest Vermont with these adjustments. Growth within this region is projected to average 2.0 % per year over the next twelve years, resulting in a summer peak load of 672 MW by 2011.

Table 1: Northwest Vermont Load Forecast

	NW VT Customer Load Forecast (MW)	Base DSM Cumulative (MW)	Distribution and Sub-Transmission Losses (MW)	Net Forecast Load (MW)
	(1)	(2)	(3)	(4) = (1) - (2) +(3)
2002	530	3	34	561
2005	563	10	36	586
2008	617	20	39	636
2011	662	31	41	672

Our adjusted load forecast for Northwest Vermont divides it into several sub-zones. Based on telemetry data provided by VELCO, we have allocated the Northwest Vermont peak to each subzone. Of these sub-zones, the so-called Inner Zone, comprising the City of Burlington and Chittenden County, has about 30 percent (320 MW) of VELCO's current total system load. Refer to the Vermont Zone Map, Appendix 3. This zone is forecast to have the highest average annual growth rate within the region, 2.6%, resulting in a peak load of 404 MW by 2011, as shown in Table 2. If load actually grows as forecast, it will clearly exacerbate the reliability problems existing with today's system.

Table 2: Inner Zone Load Forecast

	Inner Metro Zone Customer Load Forecast (MW)	Cumulative Base DSM (MW)	Distribution and Sub-Transmission Losses (MW)	Net Inner Metro Zone Forecast Load (MW)
	(1)	(2)	(3)	(4) = (1) - (2) +(3)
2002	301	2	19	318
2005	331	6	21	346
2008	368	12	23	379
2011	398	19	25	404

C. Inventory of Existing Resources

1. Existing Transmission Facilities Serving Northwest Vermont

Transmission facilities transport power to Northwest Vermont along four major routes. Power is transported from Northern New York via the 115 kV "PV20" transmission line that connects Grand Isle to Plattsburg. Power reaches Northwest Vermont from New Hampshire via the 230 kV "line F206" extending from Comerford to Granite, and then along the 115 kV "line K26" from Granite to Barre. Power enters from Canada through the Highgate Converter, which in turn connects to a 115 kV line to Burlington. Power from Southern New England moves along the 345 kV "line 340" connecting Southern Vermont to Coolidge, from Coolidge to West Rutland along a line recently upgraded to 345 kV, and from West Rutland to New Haven along a 115 kV line.

The VELCO system within Chittenden County currently consists of three 115 kV radial feeds with terminals at the East Avenue, Queen City and Essex substations, respectively. Green Mountain Power takes power from the Queen City and East Avenue substations, and Burlington Electric Department takes power from the Queen City and Essex substations for delivery to their respective customers in Burlington, South Burlington, and surrounding communities.

2. Existing Demand-Side Resources in Northwest Vermont

Vermont utilities have for years supported the installation of DSM programs that have served to reduce system peak loads. That effort has more recently been led by Efficiency Vermont (EVT), which administers statewide DSM programs. BED administers its own DSM programs. As noted earlier, together, we refer to these, together, as "Base DSM." Tables 1 and 2 above show peak load reductions from Base DSM in the Northwest Vermont Zone and the Inner Zone, respectively.

3. Existing Generating Facilities in Northwest Vermont

The generating facilities located in the Northwest Zone include a number of thermal and hydropower units. These are identified in Table 3, below. The total of their summer capacity ratings is 214 MW. Of that total, 94 MW is located in the Inner Zone.

Table 3: Existing Generating Facilities in Northwest Vermont

UNIT NAME	ZONE	SUMMER MW	TYPE	FUEL
Gorge 1 Diesel	Inner	7.0	GT	FO2
Essex 19 Hydro	Inner	7.8	HY	Water
Gorge 18 Hydro	Inner	3.3	HY	Water
Essex Diesels	Inner	4.0	IC	FO2
Burlington GT	Inner	20.0	JE	FO2
JC McNeil	Inner	52.0	ST	Wood
Bolton Falls	Metro	7.8	HY	Water
Vergennes Hydro	Metro	2.1	HY	Water
Winooski 1	Metro	7.3	HY	Water
Vergennes 5, 6 Diesels	Metro	4.0	IC	FO2
Marshfield 6 Hydro	Outer NWE	4.7	HY	Water
Middlesex 2	Outer NWE	2.3	HY	Water
Waterbury 22	Outer NWE	2.8	HY	Water
Berlin 1 GT	Outer NWE	35.0	JE	FO2
Highgate Falls	Outer NWN	9.3	HY	Water
Lower Lamoille	Outer NWN	15.8	HY	Water
Sheldon Springs	Outer NWN	14.8	HY	Water
Beldens	Outer NWS	4.6	HY	Water
Huntington Falls	Outer NWS	4.4	HY	Water
Middlebury Composite	Outer NWS	4.6	HY	Water

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The probability that a given generating facility will be able to "deliver" its capacity on peak is a function of its expected forced outage rate. Thus, the amount of megawatts that the region's generating facilities can be expected to contribute toward meeting the peak must reflect those unit outages. In order to do so, the load carrying capability of the generators in the region is calculated. Load carrying capability is the amount of load that a set of generators, given their forced outage rates and capacity ratings, can serve with an assumed probability. The results provide a probabilistic view of the peak load that can be reliably served by the generating facilities in Northwest Vermont.

For the purpose of calculating the load carrying capability of the set of resources in Northwest Vermont, the Highgate Converter is treated as a generating facility (of 200 MW). The Highgate Converter is a critical resource that is connected to loads in Northwest Vermont by a radial 115 kV line, and the system must be operated so as to provide reserves to cover the loss of the converter. In addition, Highgate has a historical forced outage rate that is more like that of a generating facility than that of a transmission facility.

Given their installed capacities and forced outage characteristics, the 322 MW of thermal generation (including Highgate) in Northwest Vermont can serve a peak demand of 82 MW with loss of load probability (LOLP) of no more than once-in-ten-years.[3] Refer to Table 4 for a summary of the Load Carrying Capability calculation.

The contribution of the hydro facilities in Northwest Vermont to loads carried was assumed equal to the average of their median July and August production levels. The total hydro contribution is approximately 34 MW. Note that the hydro assumption implicitly assumes that the hydro facilities will be available and have sufficient water to operate (at median summer conditions) during the peak. This is likely a conservative assumption. VELCO planning reports that historically Vermont hydro has generated approximately 15 MWs on average during the hours when summer loads have peaked in Vermont.

Table 4: Summary of Northwest Vermont Load Carrying Capability

Load Zone	Installed Thermal MW	Thermal LCC Allocation	Hydro MW	Total Dependable MW
Inner	83.0	36.8	3.5	40.3
Metro S	4.0	1.9	5.4	7.3
Metro E	0.0	0.0	0.0	0.0
NW-East	35.0	9.2	3.8	13.0
NW-North[1]	200.0	34.2	16.3	50.5
NW-South	0.0	0.0	5.2	5.2
Total NW Zone	322.0	82.0	34.2	116.2

[1] Highgate Converter is treated as a Generator in NW-North Zone

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[3] The NPCC and NEPOOL supply adequacy standard requires that the bulk power system be designed with an LOLP not exceeding once-in-10-years. If the standard were, say, once-in-one-year, for example, then the load carrying capability of the thermal resources in Northwest Vermont would be approximately 122 MW.

D. Northwest Vermont's Need for Additional Resources

There are several options for solving the transmission reliability problems facing Northwest Vermont. These include the installation of additional transmission facilities, increased DSM initiatives, and the installation of generating resources, either distributed or centrally located. Analysis presented by VELCO in the "Northwest Vermont Reliability Project Critical Load Milestone Study" (the "Critical Load Report") identifies transmission system additions necessary to bring the Vermont transmission system into compliance with regional planning and design criteria.

The majority of the Project elements are intended to control voltage, ensure system stability, or direct flows to prevent thermal overload, post-contingency. Generation is generally not the optimal means of supplying these services to the grid, from either a cost or an operational perspective. The one possible exception is the proposed 115 kV line from New Haven to Queen City, which serves a dual purpose. At loads above 900 MW, this line is required to protect against the loss of the existing Williston to Queen City 115 kV line and will be required to maximize the flows on the proposed West Rutland to New Haven 345 kV line. Assuming the 345 kV line were displaced by generation, a generator could theoretically be installed at Queen City to provide pre- and post-contingency protection against the loss of the existing 115 kV line. However, the Queen City substation abuts a residential area and there is insufficient land to accommodate the required amounts of generation (50 to 75 MWs). Consequently, building generation to displace the New Haven to Queen City 115 kV line is not viable.

Recall from above that the elements that might be displaced by alternative resources include the following.

1. Construction of a new, 35.8 mile, 345 kV transmission line adjacent to VELCO's existing 115 kV transmission line located between VELCO's West Rutland and New Haven substations;
2. Installation of a 230 kV PAR and autotransformer at Granite and the Granite – Barre 115 kV reconductoring;

3. Installation of a second 115/230 kV, 336 MVA transformer and a +/- 150 MVAR Dynamic VAR Device (1st stage is +/- 75 MVAR) at the Granite substation.

The following assessment of the incremental resource requirements assumes that the balance of the Project elements are installed by 2005, as proposed. Table 5 below contains a summary calculation of Northwest Vermont's need for incremental resources, consistent with the once-in-ten-years reliability standard. Refer to Appendix 4 for the Need Analysis Model. From the net forecast load developed earlier in Table 1, two items are subtracted:

- The normal transfer capability of VELCO's existing 115 kV system into Northwest Vermont, as described above; and
- The load carrying capability of the existing generators in Northwest Vermont, as shown in Table 4.

La Capra's loss of load probability (LOLP) calculations reveal that Northwest Vermont currently does not have sufficient resources to meet the resource adequacy standard requiring a loss of load probability not to exceed once-in-ten-years, but rather has, today, an LOLP of approximately ten days in ten years. Given projected load growth and generation and transmission constraints, the situation will deteriorate further, unless immediate remedial steps are taken.

Table 5: Northwest Vermont's Need for Additional Resources

	Net Forecast Load (from Table 1) (MW)	NW VT Existing Import Capability (MW)	NW VT Existing Generation Load Carrying Capability (MW)	Net Need (MW)
	(1)	(2)	(3)	(4) = (1) - (2) - (3)
2002	564	384	117	64
2005	589	384	117	89
2008	635	384	117	135
2011	672	384	117	172

E. Inner Metro Zone's Need for Additional Resources

The transmission system that serves Northwest Vermont is capable of transporting roughly 384 MW into the Northwest Zone during peak load conditions. Additional constraints within the Northwest Zone further limit the ability to move power into and among the several sub-zones. Table 5 was developed without consideration of transfer capability constraints within the Northwest Vermont region. However, as a practical matter, the Inner Zone requires additional resources above those shown in Table 5, due to constraints. The problems exist primarily at the sub-transmission level and ultimately manifest themselves as transmission congestion, which results in out-of-merit generation at high loads.

Table 6 compares the Northwest Vermont resource need with and without accounting for Inner Metro congestion. Although sub-transmission solutions may address the Inner Metro Zone congestion issue, they will do nothing to ease the broader Northwest Vermont resource need. However, the inverse could be true for solutions to the broader Northwest Vermont resource need. That is, if sited correctly, they could also ease the Inner Zone congestion problem.

Table 6: Additional Resource Need Due to Inner Zone Congestion

	NW VT Resource Need without Inner Metro Congestion (MW)	NW VT Resource Need with Inner Metro Congestion (MW)	Increased Deficiency due to Inner Metro Congestion (MW)
2002	64	89	25
2005	89	112	23
2008	135	155	20
2011	172	188	16

Table 6 should not be interpreted to mean that congestion is declining through time. To the contrary, the total congestion into the Northwest Zone is increasing, reducing the apparent contribution of the Inner Zone to the congestion problem in the Northwest part of the state. Consequently, absent sub-transmission upgrades targeting Inner Zone constraints, there may be advantages to locating any new resources within the Inner Zone. Of course, sub-transmission constraints could be either eased or worsened by the siting of new generators local to the constraint, depending upon the specific local line configurations. While we add generation to meet the need on VELCO's bulk transmission system, we seek to site generation or implement DSM programs that might also ease local congestion.

F. Congestion Costs in Vermont

Under the current Standard Market Design, the State of Vermont will be considered a single load zone for congestion pricing purposes. Consequently, all load serving entities in Vermont will be subject to a common clearing price equal to the load-weighted average nodal Locational Marginal Prices (LMPs) at all Vermont nodes. This methodology effectively socializes congestion across the state.

As discussed above, congestion is greatest in the Inner Zone. However, the entire Northwest Vermont zone is subject to congestion. The majority of prices in Vermont are similar to those at the New England Hub – essentially the unconstrained price. This implies that minimal congestion is expected in most of the State. However, assuming no changes to the existing infrastructure and the base case load forecast, the Vermont LMP zone will become among the highest priced locations in New England. A projection of regional prices and of total congestion costs in Vermont is presented below in Tables 7 and 8 respectively. Congestion costs climb post-2006. This result is consistent with the fact that, due to inadequate supply, the number of hours in which load is unserved increases steadily after 2006.

Table 7: Projection of Locational Marginal Prices
under Status-Quo Conditions (Annual Average $/MWh)

	Vermont LMP Zone	New England HUB
2005	35.10	33.21
2008	37.33	34.91
2011	44.22	40.36

Table 8: Projection of Total Vermont Annual Congestion Costs under Status-Quo Conditions

	Vermont LMP Zone
2005	$12.6 million
2008	$17.2 million
2011	$28.8 million

III. Pre-Screening of Generation Technology Options

The pre-screening process focuses on commercially-available generation technology options, generally avoiding those that are still in developmental stages. While research continues into ways to improve the economics and operational performance of virtually all generation technologies, a least-cost, reliable transmission system in Northwest Vermont is necessary in the appropriate time-frame. This means that the NRP should be tested against proven, commercially available, generation alternatives.

The pre-screening process narrows the generation technology options to a subset of those that are most promising. The technology options -- together with their typical fuel types, unit sizes and modes of deployment -- are discussed below and summarized in Table 9.

Table 9: Generation Technologies Options

Technology Type	Fuel Type	Typical Unit Sizes	Typical Deployment
Distributed Generation:			
Reciprocating Engines	Gas or Oil	Up to 1,000 kW	Distributed Applications
Microturbines	Gas or Oil	Up to 250 kW	Distributed Applications
Industrial CTs	Gas or Oil	Up to 1,000 kW	Distributed Applications
Fuel Cells	Gas or Oil	Up to 200 kW	Distributed Applications
Renewable Energy:			
Wind Turbines	Wind Power	Up to 6 MW	Central or Distributed
Biomass Combustion	Biomass	Up to 50 MW	Central or Distributed
Photovoltaics	Solar Energy	Up to 100 kW	Central or Distributed
Solar Thermal	Solar Energy	Up to 50 MW	Central or Distributed
Landfill Gas	Methane	Up to 5 MW	Distributed Applications
Bulk Generation:			
Combined Cycle	Gas or Oil	100 to 250 MW	Central Station
Combustion Turbine	Gas or Oil	12.5 to 50 MW	Central or Distributed
Coal-Fired Steam	Coal	100 to 600 MW	Central Station
Nuclear	Uranium	500 MW and Up	Central Station
Oil or Gas-Fired Steam	Gas or Oil	50 to 600 MW	Central Station
Hydro	Water Power	Up to 200 MW	Central or Distributed
Municipal Solid Waste	Refuse	Up to 50 MW	Central Station
Internal Comb. Engines	Gas or Oil	5 to 25 MW	Central or Distributed

A. Distributed Generation Technologies

There is a range of commercially-available distributed generation (DG) technologies, including reciprocating engines, microturbines, industrial combustion turbines, and fuel cells. For each DG technology, a rough cost estimate is developed so as to establish a starting point for the evaluation of the merits of each.

1. Cost Factors

The screening process focuses on the following *pro forma* set of cost and performance parameters, which include the following:

- **Equipment and Installation Costs** – the costs that a developer would incur to purchase and install a given generation facility.
- **Operating and Maintenance Costs** – the total of the various fixed and variable operating and maintenance costs incurred to operate the facility.
- **Heat Rates** – the heat rates that can be achieved by different generation technologies, which are indicative of relative fuel efficiencies and expected fuel costs.
- **Emissions Costs** – the costs that can be attributed to the production of emissions (i.e., SO_2, NOx, CO, CO_2, and volatile organic compounds) from a given facility, as calculated using $/MWh externality cost factors based on those in the Department's *Power to Save* report and other similar sources.

These costs do not apply to specific DG installations, but, rather, to typical units within each technology type. The results are summarized Table 10.

Table 10: Typical Unit Cost Estimates -- Distributed Generation Technologies

	Reciprocating Engines	Micro Turbines	Industrial CTs	Fuel Cells
Size Considered (kW)	25 to 1,000	25 to 1,000	1,000	100 to 200
Equipment & Installation Costs ($/kW)	$1,000 to $1,300	$700 to $1,900	$1,000	$3,500
Operating & Maintenance ($/kW-yr)	$75 to $85	$35 to $100	$25 to $50	$25
Heat Rate (Btus/kWh)	10,000 to 15,000	12,000 to 19,000	12,000	5,700 to 8,500
Sample Fuel Cost ($/MMBtu)	$3.5	$3.5	$3.5	$3.5
Emissions Costs ($/MWh)	$30 to $45	$10 to $16	$15	$10 to 20
Typical Capacity Factor (%)	75%	75%	25%	75%
Typical Production Cost ($/MWh)	$100 to $140	$70 to $141	$145 to $155	$120 to $140

2. Distributed Generation Screening Evaluation

The estimates of costs for reciprocating engines, microturbines and industrial combustion turbines indicate that all three distributed generation technologies merit consideration in later phases of our study. Each has an established track record in DG applications and is commercially available. Their estimated equipment and installation costs are all in the vicinity of 10¢/kWh to 15¢/kWh. Their heat rates are generally comparable, although the range for microturbines is a quite wide. We include the reciprocating engine, microturbine and industrial combustion turbine technologies in subsequent phases of the study.

Fuel cells are an emerging, very clean, distributed generation technology with considerable promise. Because there is no fuel combustion, some emissions by-products (e.g., NOx) are avoided. However, at present the equipment and installation costs are quite high – i.e., in the range of $3,500 per kW - which, with the associated lengthy investment payback period, makes fuel cells an unlikely choice relative to other distributed generation technology options. This is exacerbated by the fact that fuel cells are largely untested in consumer power generation applications. Based on these considerations, fuel cells are not assessed further in subsequent phases of the study.

B. Renewable Energy Technologies

1. Cost Factors

As with distributed generation technologies, the evaluation of the merits of various renewable energy technologies begins with rough estimates of their costs and related characteristics, which are, for each: (1) equipment and installation costs, (2) operating and maintenance costs, (3) heat rate, where appropriate; and (4) emissions costs. The typical cost estimates are summarized in Table 11.

Table 11: Typical Unit Cost Estimates:
Renewable Energy Generation Technologies

	Wind Turbines	Biomass	Photo-voltaics	Solar Thermal	Landfill Gas
Size Considered (kW)	500-2,000	100,000	20-200	100,000	500-20,000
Equipment & Installation Costs ($/kW)	$1,000 to $1,600	$1,500 to $2,000	$6,000 to $6,500	$4,000	$1,400 to $1,800
Operating & Maintenance ($/kW-yr)	$25 to $50	$50 to $60	N/A	$50 to $60	$75 to $80
Heat Rate (btus/kWh)	N/A	8,911	N/A	N/A	11,000 to 13,000
Sample Fuel Cost ($/MMBtu)	N/A	$2.5	N/A	N/A	N/A
Emissions Costs ($/MWh)	N/A	$5 - $20	N/A	N/A	$30 to $130
Typical Capacity Factor (%)	30%	65%	25%	25%	85%
Typical Production Cost ($/MWh)	$75 to $105	$80 to $110	$450 to $500	$325 to $330	$70 to $180

2. Renewable Generation Technologies

Wind Turbines

Improvements in wind turbine technologies continue to make this power generation resource increasingly attractive. In recent years, developers have explored opportunities to establish wind farms in promising New England locations. Mountain ridge lines in Western Maine and, most recently, Nantucket Sound off the coast of Cape Cod are among the locations that have been the focus of serious inquiry. A recent report prepared for the U.S. Department of Energy's Office of Energy Efficiency and Renewable Energy suggests that Vermont has "more than enough potential 'technical' wind resource to meet this study's target [750 MW] of 'high penetration' on Vermont's power grid …."[4] The report emphasizes that this conclusion was reached without considering the economic or siting feasibility issues at any given location.

Our cost estimates suggest that the economic viability of the technology is still in question with respect to Vermont locations. The cost data indicate that the equipment and installation costs of wind turbines range up to $3,000 per kW for smaller generating units. Even larger facilities have equipment and installation costs in the range of $1,000 per kW, which is high considering that wind turbine capacity factors are typically in the range of about 30 percent, even at optimal sites. As a consequence, the cost of energy from wind turbines is typically well above prevailing prices in New England's power markets.

Perhaps more importantly, with respect to the evaluation of wind power as an alternative to the NRP, it is necessary to recognize the intrinsic nature of the available wind resource. Wind is a variable and unpredictable source of power, although the extent is obviously site specific. If wind speed is not sufficient to turn the shaft in the generator, electricity is not produced. First, most of the best sites for wind generation in the State are outside of (i.e., in electrical terms) Northwest Vermont. Second, the wind resource is best in the winter, off-peak. By contrast,

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[4] *Wind and Biomass Integration Scenarios in Vermont: Summary of First Phase Research: Wind Energy Resource Analysis.* Princeton Energy Resources International, LLC. March 2002. Pg. 6.

Northwest Vermont's reliability problem has, as its root, an insufficient power supply during the summer peak load months. Indeed, summer peaks are most likely to occur during hottest of days when winds are very light. As a result, wind power is not a practical solution to the problem at hand, and will not provide the Reliability Equivalence needed to solve the Northwest Vermont transmission problem. Hence, wind turbines are not considered further. Refer to the wind resource map in Appendix 4.

Biomass

The combustion of biomass is a viable approach to power generation in Vermont. Both the McNeil and Ryegate generating units burn wood as a primary fuel. In concept, additional biomass could be collected in Vermont (or transported from other states or Canada) to fuel additional biomass plants.

However, several factors raise questions regarding its merits as part of the recommended solution to Northwest Vermont's near-term reliability problem. First, our analysis suggests that the economics of such facilities are marginal. Plant equipment and installation costs are high. In addition, high O&M costs and low efficiencies contribute to high per kWh prices (104/kWh to 124/kWh). Moreover the installation of a biomass facility in Northwest Vermont would require solving a number of location-specific logistical problems, including the identification and transportation of a cost-effective and reliable fuel supply.

It is beyond the scope of our study to review the range of factors that should be carefully assessed to determine whether a viable biomass facility could be installed in Northwest Vermont. Nonetheless, absent more attractive economics, and at least some evidence that logistical problems could be resolved, we do not recommend the biomass technology as a prudent approach to solving Northwest Vermont's near-term reliability problem. Therefore, this technology is not included in further phases of the study.

Photovoltaics and Solar Thermal

Solar power technologies can be applied at large, central station facilities. These would include solar thermal facilities that can exceed 100 MW in size. Solar technologies are also used in smaller, distributed applications, often on customer premises and with capacities measured in kilowatts. Vermont participates in the Million Solar Roofs initiative announced in 1997, which pursues both photovoltaic and solar thermal applications at the distribution level.

As with wind resources, solar powered generating facilities must be located where there is an adequate solar resource, which depends on climatic and geographic considerations. Equipment and installation costs are high. Our rough cost estimates for photovoltaic and solar thermal technologies suggests that their "per kWh" costs also would be quite high, largely because of the much reduced levels of solar radiation during Vermont's winter months. It is noteworthy that large, central station applications, including photovoltaic and solar thermal types, have not proven cost-effective at higher latitudes. By contrast, smaller units have been valuable in limited applications in northern states, usually where unique circumstances justify the costs of their deployment.

In the absence of an established "northern states" track record for large central solar facilities, one cannot reasonably propose such facilities as part of the solution to Northwest Vermont's reliability problem. Moreover, while we anticipate some limited contributions from distributed, small-scale photovoltaic and solar thermal installations, the associated capacity contributions will not materially affect the resource need calculations. Therefore, neither photovoltaics nor solar thermal resources are evaluated further.

Landfill Gas and Farm Methane Recovery

Various forms of methane recovery are being explored as potential fuel sources for electricity generation. The U.S. Environmental Protection Agency ("EPA") maintains a listing of landfill gas sites that have (and have not) been developed for electric power generation through its Landfill Methane Outreach Program. The EPA listing indicates that the Burlington landfill has been developed as a 0.7 MW power generation site, but identifies no other existing landfills in Chittenden County. While new landfill facilities might be opened in Northwest Vermont, the two existing landfill gas facilities in Vermont (i.e., the Burlington and Brattleboro landfills) have an average generating capacity of 0.6 MW. We conclude that potential new landfills likely will not, during the study period, be a substantial incremental source of capacity in Northwest Vermont.

Farm waste streams are another potential source of methane. The Vermont Methane Pilot Project is a joint project between the Vermont Departments of Public Service and Agriculture, and the U.S. Department of Agriculture. A report addressing the potential to produce electricity from the methane resulting from the digestion of farm waste (i.e., dairy cow manure) concludes that sufficient waste is produced in Vermont to support almost 30 MW of power generation. Related documents on the Department's website and elsewhere suggest that this technology is in developmental stages, with significant barriers (including the capital costs of methane recovery and power generation equipment, and technological barriers in digestion processes). The very limited track record for these devices indicates that there is considerable uncertainty regarding both the operating and maintenance costs in the long term, as well as the life expectancies of such facilities. There is evidence that facilities that are multiple megawatts in size can be fueled by farm waste methane; however, larger facilities require quantities of farm waste that considerably exceed those of Vermont's biggest dairy farms.

Given the barriers, power generation from farm methane recovery will not be a solution to Northwest Vermont's near-term reliability problem. Therefore, this technology is not considered in subsequent phases of the study.

C. Bulk Generation Technologies

The commercially-available technologies include combustion turbine, combined-cycle, coal, nuclear, oil-and natural gas-fired steam turbines, municipal solid waste, internal combustion engines and hydropower facilities. The rough cost estimates for the bulk generation technology options are based on data from a number of sources and are summarized in Appendix 4. The factors considered in our rough cost estimates are discussed below. Note that the costs and related characteristics do not include those for hydropower facilities. The capacities of such facilities can run from less than one to hundreds of megawatts, and the costs are highly site-specific.

1. Cost Factors

Once again, each is evaluated in terms of (1) equipment and installation costs, (2) operating and maintenance costs (in this instance, both "fixed" and "variable" O&M), (3) heat rate; and (4) emissions costs. The results are summarized in Table 12.

Table 12: Typical Unit Cost Estimates:
Bulk Generation Technologies

	CT	CC	Coal Steam	Gas Steam	Oil Steam	Nuclear	MSW	ICU
Size Considered (MW)	20-50	100-250	100-1,000	100-250	100-250	500 to 1,200	25-50	25
Equipment & Installation Costs ($/kW)	$600 to $850	$600 to $800	$1,200 to $1,500	$1,000	$1,000	$2,000	$1,200	$1,000
Fixed Operating & Maintenance ($/kW-yr)	$15 to $25	$20 to $40	$45	$20 to $35	$30 to $40	$75 to $100	$60 to $75	$1
Variable Operating & Maintenance ($/MWh)	$1	$1 - $2	$2	$1.5	$2	N/A	$2	$25
Heat Rate (btus/kWh)	10,000 to 11,000	6,500 to 8,000	9,000 to 10,000	9,500	9,500	N/A	12,000	8,500
Sample Fuel Cost ($/MMBtu)	$3.50	$3.50	$1.50	$3.50	$3.50	N/A	N/A	$3.50
Emissions Costs ($/MWh)	$15	$7	$40	$10	$30	N/A	$50	$10 to $15
Typical Capacity Factor (%)	25%	75%	75%	75%	75%	75%	75%	75%
Typical Production Cost ($/MWh)	$105 to $130	$55-$70	$90-$100	$75-$80	$95 to $100	$60-$65	$90	$115 to $120

2. Bulk Generation Screening Evaluation

Coal

Coal technologies do not offer a practical response to Northwest Vermont's reliability problem. The region's need is primarily for intermediate peaking power supplies. Coal is economic in baseload applications where relatively high equipment and installation costs can be recovered across large kWh sales volumes. The adverse economic pressures increase as facility sizes diminish to levels consistent with Northwest Vermont's need. Primarily for this reason, coal-fired facilities with capacities below several hundred megawatts are rare today.

Coal-fired generation technologies also present substantial environmental challenges. As with other fossil-fueled generation technologies, coal combustion results in the production of a number of emissions that must be controlled to meet state and federal air emissions. However, coal-fired generating plants typically have the highest air emissions of the fossil-fueled technologies on a per kWh basis, and their emissions are generally the most expensive to mitigate. Water use impacts also are receiving increasing attention from state and federal regulators. Water can serve both as the working fluid in the thermodynamic process of a steam cycle and as a coolant. In steam turbine applications, large amounts of water typically are required; any water losses must constantly be replenished. As a coolant, heat 'pollution' of water bodies can occur where discharge temperatures exceed intake temperatures.

The permitting process for a coal-fired generating facility would obviously include scrutiny of emissions and water impacts. Under current Vermont law and regulation, the developers of a new generating facility must obtain a Certificate of Public Good from the Public Service Board pursuant to 30 V.S.A. § 248. Pursuant to that statute, the Board is required to consider the recommendations of (a) the Agency of Natural Resources (ANR), (b) affected municipal and regional planning commissions, (c) municipal legislative bodies, and the land conservation measures of any affected municipality. The statute requires the Board to seek to ensure that a new generation facility will not have an undue adverse impact on aesthetics, historic sites, air and water purity, the natural environment and the public health and safety. In addition, the Vermont ANR, the EPA and other federal agencies impose a number of regulations, focused primarily on air and water impacts.

La Capra anticipates that achieving siting approval would be difficult for the proponents of a coal-fired generating facility in Northwest Vermont. Notwithstanding any developers' commitments (and ultimately their legal obligations) to control air emissions to meet all established standards, our experience regarding proposals for coal-fired generation in New

England indicates that it is extremely difficult to obtain public acceptance. It is unlikely that any power plant developer would obtain (or even seek to obtain) the requisite approvals to site a new coal-fired generating facility in Vermont within the necessary time frame.

In addition, cost and the other identified considerations exacerbate the situation and lead to the conclusion that coal-fired generation technologies would not be viable as a solution (or part thereof) to Northwest Vermont's reliability problem. Therefore, coal-fired generation is eliminated from further consideration.

Nuclear

Nuclear generation does not offer a practical solution to Northwest Vermont's transmission reliability problem. First, the technology is very expensive. Plant equipment and installation costs are very high relative to other bulk generation options and the nuclear industry has a long history of substantial cost overruns.

Second, the commercial reactors that have been constructed in the United States have been considerably larger than Northwest Vermont's projected capacity need levels. With nameplate capacities typically well above 500 MW, a 'traditional' nuclear generating facility would introduce immediate concerns relative to transmission contingency planning standards. That is, it would be designated as a contingency in N-1 tests, and would thus provide little if any improvement in transmission reliability. In addition, units of such size would almost certainly have a significant operational impact on the transmission system, which could require substantial and costly upgrades.

La Capra is aware that designs for new, smaller, modular nuclear generating facilities are being developed. However, no such design has yet been implemented commercially in the U.S.

Finally, there are challenging legal review processes that a nuclear generation facility would have to overcome to obtain siting approvals. As discussed above, the developers of a new generating facility must engage regulatory review processes under 30 V.S.A. § 248. Moreover, before a nuclear generating facility can be sited, Vermont Law requires that the matter be put to a vote of the Legislature. In light of the foregoing, nuclear generation is not well-suited to Northwest Vermont's bulk power system or the identified resource need.

Oil and Natural Gas-Fired Steam Plants

Steam turbines and oil- or natural gas-fired boilers are not among the better alternatives to the Northern Reliability Project. As a result of advances in combustion turbine and combined-cycle technologies, these have a substantial cost advantage (both capital and operating) over boiler-based, steam turbine technologies. In addition, combustion turbines and combined-cycle generation technologies also have better emission rates than conventional steam technologies, which further contribute to their cost advantage and make them more environmentally appealing. Indeed, virtually all of the generating facilities sited in New England during the past decade have been combustion turbine and combined-cycle units. For these reasons, we have eliminated oil- and natural gas-fired steam turbines from further consideration.

Hydropower

Hydropower has a long history as a successful contributor to the generation supply mix in Vermont. However, several factors affect its merits as a viable alternative to the NRP. First, although several rivers, which in concept could support hydro facilities, flow through Northwest Vermont -- including the Missisquoi, Lamoille and Winooski rivers -- an assessment of the potential for new hydropower development would require extensive geological, hydrological and climatic studies. We are not aware that any such study has been performed and, thus, we cannot confirm that there are good sites for new hydropower development in Northwest Vermont. Moreover, even if such sites were known to exist, we would anticipate that the proponents of a new hydropower facility would face intense scrutiny and considerable public resistance in obtaining the necessary siting approvals.

Second, the production from hydropower facilities is significantly affected by hydrological conditions. Experience in New England indicates that local hydropower resources may be difficult to predict, particularly prior to the completion of the requisite studies. Reservoirs that support hydropower generation are most susceptible to low water conditions during the summer months. Moreover, new hydropower generation would likely arrive in the form of run-of-the-river facilities. Consequently, we find it unlikely, based upon the information presently available, that new hydropower will offer a significant and dependable capacity contribution during peak conditions in Northwest Vermont. We do not evaluate this resource option in subsequent phases of our study.[5]

Municipal Solid Waste

To date, no power generation facilities fueled by municipal solid waste (MSW) have been developed in Vermont. Nevertheless, there is no technical reason that refuse from residences and businesses in Vermont cannot be collected (or transported from other states or Canada) for such use. However, several factors affect the merits of biomass generation technologies as part of the solution to Northwest Vermont's reliability problem. First, the economics of such facilities are marginal. Plant equipment and installation costs are quite high, as are their O&M costs. In practice, MSW facilities are rarely constructed unless a community cannot obtain access to a landfill.

Second, the installation of an MSW facility in Northwest Vermont would require the solution of a number of logistical problems, including the identification and transportation of a cost-effective and reliable fuel supply (i.e., waste stream). Siting and environmental permitting processes also can be complicated by the more complex emissions of MSW boilers, stemming from the wide range of substances and materials occasionally placed into waste streams.

It is beyond the scope of our study to review the range of factors necessary to determine whether a viable MSW facility could be installed in Northwest Vermont. Nonetheless, absent more attractive economics and evidence that the various logistical problems could be resolved, we do not recommend MSW generation as a prudent approach to solving Northwest Vermont's reliability problem. Therefore, this technology is not included in further phases of our study.

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[5] We note that hydropower is a very well-established resource in New England, with a substantial industry supporting it. We are skeptical that a meaningful hydropower option that has been overlooked to date in Northwest Vermont will emerge in the course of this study.

Internal Combustion Engines

Our cost analysis indicates that Internal Combustion Engines (ICEs) do not compare well to competing resource options. ICEs are typically deployed in response to distributed baseload needs, where transmission transfer capabilities are limited. However, they are not competitive in peaking applications because of their high capital costs relative to combustion turbines. As such, we believe that CTs are the technology of choice for peaking applications, and eliminate ICEs from further consideration.

D. Results of Pre-Screening Process

Listed below are the most promising generation technology options. More specifically, these generation technologies are the "building blocks" with which the Alternative Resource Configurations (ARCs) are constructed and subsequently compared to the NRP. The most promising generation technologies are as follows:

- Combustion turbine generating facilities;
- Combined-cycle generating facilities;
- Reciprocating engines (DG);
- Microturbines (DG);
- Industrial combustion turbines (DG).

This list is considerably shorter than that which was set forth at the start of this chapter. The reason, to summarize the foregoing discussion, is that various resource options were set aside for one or several of the following: (1) they currently are not cost-competitive with other options; (2) they are a poor fit relative to Northwest Vermont's need; (3) they are available only in unit sizes (MW) that exceed the need to an extent that would present problems relative to transmission planning standards; (4) their developmental status is such that they are problematic as potential solutions to the significant reliability problems confronting Northwest Vermont; and (5) others.

This screening approach was driven by an important objective: to ensure that the economic tests framed for the NRP are both rigorous and realistic. As noted earlier, in order to draw conclusions regarding what is least-cost and robust under a range of alternate planning scenarios, the economic performance of the NRP was examined relative to system expansion plans that include various generation alternatives. The results are themselves more robust if the generation technologies are, with some measure of confidence, viable in Northwest Vermont. Generation technologies with demonstrably poor economics, or those that are not realistic options in the appropriate time-frame, should not be considered in this exercise.

Although a number of generation technologies have been excluded, this is not intended to mean that these resources may not play a role in Vermont's energy future. Indeed, if it is determined that a generation expansion plan is preferred relative to the NRP, each generating option should be scrutinized as it approaches the point at which investment dollars must be committed. Research is currently underway for virtually all generation technologies that may, particularly in the longer-term, affect their relative economics and operational performance.

Fuel cells, for example, are not represented in our ARCs, largely because they are not now competitive economically. However, a considerable research effort has led to significant advances in recent years. If the economics of fuel cells continue to change, they may become appealing to large commercial and industrial loads. Certain of the ARCs include estimated capacity contributions from distributed generation technologies at commercial and industrial customer locations. If, in coming years, fuel cells can compete economically with the DG technologies on which our capacity and cost estimates are based, they may supplant those other technologies. Similarly, the economics of solar or wind power could improve such that those technologies begin to be installed with some frequency at select, distributed locations in Northwest Vermont. In such instances, the associated capacity contributions may, perhaps, lead to modest adjustments to load forecasts and the timing of new investments.

Finally, any significant near-term changes to the economics of the various generation technology options could have a bearing on the results of our analysis. In this context we recommend that close attention be paid to the effects that state renewable portfolio standards (RPS) could have on the economic landscape for renewables. Renewable portfolio standards are being implemented by several New England states and others have, from time to time, considered introducing such legislation.

As load serving entities across New England increase the demand for supplies from renewable energy sources to meet state mandated RPS obligations, the prices paid for renewable attributes from qualified renewable resources in Vermont might rise significantly relative to market energy prices.[6] Under such circumstances, renewable resources could have improved cost-effectiveness relative to other resource options. Depending on both the path that has been selected as the appropriate response to the NRP and on the commitments that have been made along that path, a revised look at the expansion plan may be warranted.

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[6] Typically the location of a renewable facility is not an issue, provided that its "renewable" attribute can be tracked.

IV. Constructing Alternative Resource Configurations

Each Alternative Resource Configuration (ARC) is composed of a set of new resources that complement the existing resource base. At the end of this section, we present five ARCs as possible alternatives to the NRP.

In order to establish a simple, consistent convention for making cost comparisons, we assume that any potential alternative to the NRP – whether a DSM, distributed generation or bulk generation option – will be constructed, owned and operated by a Special Purpose Entity (SPE) that has access to utility-like financing and cost recovery mechanisms.[7] Accordingly, the evaluation of the cost components of the potential alternatives to the NRP includes the direct costs and benefits of each option to the SPE and, separately, the avoided costs and benefits that would accrue to Vermont.

The evaluation of each component of the five potential alternate resource configurations incorporates all costs that would be incurred to develop, operate, and/or purchase the incremental resources that are necessary to meet Northwest Vermont's identified need. Each ARC is composed of one or more of the following:

- Incremental DSM programs,
- Distributed generation installations, and
- Utility scale generation additions.

A. Demand-Side Resources

As discussed earlier, the DSM resource assumed in this analysis is based on a study performed by Optimal Energy for VELCO. The OEI study assessed the potential for investments in end-use energy efficiency improvements to reduce the growing peak loads in Northwestern Vermont. In addition to its assessment of Base DSM savings, OEI also examined the maximum contribution

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[7] This is a simplifying convention for analytical purposes. Should a non-transmission alternative prove least-cost, the issue of what entity will build, own and operate the facilities or administer the programs, financing and cost recovery will become central. These issues are discussed in the strategic implementation section.

that an aggressive energy efficiency program targeted at this capacity constrained region could make to reduce summer peak loads during the next 10 years.

The DSM programs would focus on key residential, commercial and industrial markets in Northwest Vermont. These initiatives would extend the similar, but significantly smaller-scale, Base DSM Programs that Efficiency Vermont is now conducting statewide and that the Burlington Electric Department is conducting in its service territory. It is anticipated that, if undertaken, it would be jointly with the emerging distribution utility initiatives resulting from the current distributed utility planning process.

The OEI study estimates that net peak savings from the aggressive programs would by 2007 amount to 27.1 MW in the Inner and Outer Metro zones and 11.3 MW in the Northwest zones;[8] by 2011, the amounts would be 65.3 MW and 33.3 MW, respectively. These load reductions are net of (that is, in addition to) Base DSM peak load reductions projected to be achieved by Efficiency Vermont's and Burlington Electric Department's existing Base DSM programs. Refer to Table 13, below, for a summary of projected savings and costs.

The OEI study estimates potential savings in three residential markets – retail products and appliances, retrofit applications, and new construction – and two commercial/industrial markets – existing buildings and new construction. For the three residential markets, the study provides separate estimates for measures that make both comparatively high and comparatively low peak load contributions. Drawing on a statewide potential study completed in 2002 for the DPS, OEI assesses dozens of efficiency technologies that may be applied to all major end-uses across the full range of building types. The savings estimates include both the energy savings each efficiency technology offers and the time required to get the technology in place (i.e., market penetration rates).

OEI also estimates the "societal benefits and costs" of the aggressive efficiency program and concludes that the societal benefits exceed the societal costs. The societal costs include the costs to market, administer, purchase and deliver the energy efficiency technology over the next

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[8] OEI forecasts Northwest/Central; we examine only Northwest.

decade. The societal benefits include avoided transmission, generation, capacity, and operating costs, including avoided environmental costs. OEI's analysis indicates that, from a societal perspective, this program is cost-effective without consideration of avoided transmission benefits. That is, the combined value of the non-transmission related societal benefits alone exceed the societal cost of the aggressive efficiency program in each market.

Table 13: Cumulative Summer Peak Savings (MW) and Costs ($ Millions)
Northwest Vermont Load Zones *

Year	Inner Metro Zone		Outer Metro Zone		Outer Northwest Zone	
	MW Savings	Utility Costs	MW Savings	Utility Costs	MW Savings	Utility Costs
2004	1.1	$8.1	0.1	$0.7	0.6	$4.4
2005	5.7	$25.2	0.7	$3.1	2.7	$11.9
2006	13.9	$54.2	1.5	$5.9	6.2	$24.2
2007	24.5	$85.2	2.6	$9.1	11.3	$39.6
2008	36.0	$117.8	3.8	$12.6	17.9	$59.1
2009	45.0	$143.0	4.7	$14.9	23.7	$74.8
2010	52.9	$166.1	5.4	$17.0	28.8	$90.4
2011	59.1	$186.9	6.2	$19.6	33.3	$105.2
2012	63.9	$206.5	6.6	$21.4	36.8	$118.9
2013	67.4	$225.9	6.8	$22.8	39.2	$131.3

* Based on analysis performed by OEI. Savings estimates adjusted forward one year.

B. Distributed Generation

Distributed generation facilities are facilities that are sited at the customer level, (e.g., at a residential customer's home or business customer's office), at the distribution level (e.g., on an electric distribution sub-station at distribution-level voltage), or at the transmission level (e.g., on a transmission company's property connected to the power grid at a transmission-level voltage). For the purpose of our DG assessment, we evaluated only those facilities that may be installed on a customer site. In this study, distribution and transmission level generation installations are considered to be utility-scale generation.

The evaluation of the potential for DG installations in Northwest Vermont focuses on commercial and industrial loads within the Inner and Metro Zones. The following building categories are probable hosts for DG: colleges and schools, grocery stores, health facilities, places of lodging, office buildings, restaurants, retail space, warehouses, and light-manufacturing facilities. Within each of these categories, we examined the potential DG applications for two types of buildings, those with and those without natural gas service. In buildings without gas service, it is assumed that DG installations would be fueled by propane.

For each building category and fuel (natural gas or propane), we considered both the microturbine and reciprocating engine based installations. And for each combination of building category, fuel choice, and technology, the economics of both electric-only and combined heat and power (CHP) schemes are evaluated. In the case of CHP, the economics are assessed under two possible design configurations: that is, where the DG scheme is sized to meet primarily (1) the electrical load, or (2) the thermal load.[9]

In addition, the study distinguishes between the costs and benefits of DG installations at existing buildings versus at new construction. The distribution equipment required to serve the loads of existing facilities has already been incurred, and is thus unavoidable. However, a local distribution company may be able to avoid some distribution costs if its system is planned with the expectation that DG will be installed at certain customer sites. Refer to the discussion of avoided distribution upgrade costs below.

Microtubines and reciprocating engines have different operational characteristics and load following capabilities. Generally, reciprocating engines are able to load-follow reasonably well. Microturbines, by contrast, are not well-suited to load-following and, when running, generally operate at full output. Because the electrical output of reciprocating engines can effectively follow a building's loads, we have assumed that such engines would be sized to meet a customer's peak demand. That is, for example, a building with a peak load of 100 kW would be fitted with a 100 kW reciprocating engine. Microturbines, on the other hand, have been sized to meet the building's average load and, thus, a building with an average load of 50 kW would be fitted with a 50 kW microturbine. A result of this analytical convention is the implicit

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[9] Note that we do not consider application scenarios which anticipate DG sales to the grid. The costs and benefits of such scenarios are highly situation-specific, and are beyond the scope of this analysis.

assumption that the customer with a micro-turbine based DG installation is able to purchase the balance of its electrical requirements from the local distribution utility.

Our analysis shows that the economics of microturbine and reciprocating engine DG schemes vary considerably based on the specific building category, fuel type, and application. The differences arise largely from the relative fit of a given DG scheme to the customer load profile (i.e., electric, thermal, or both) and the relative flexibility of the DG scheme.

Note that the installation of distributed generation has the potential to impose certain costs on the local distribution utility, particularly if DG becomes widespread and DG units are allowed to sell power onto the grid. For example, the distribution utility may incur system upgrade costs to install protective equipment to ensure that distributed generation facilities on a given distribution circuit do not adversely affect the safety or reliability of that circuit.

We have assumed that DG facilities will not feed power back into the grid, and that local distribution utilities will not charge standby rates for the provision of backup supply from the grid. Similarly, the study does not address potential lost revenues (which could recover any “stranded,” and other costs) of a distribution utility. Thus, the analysis is conservative in that it assumes that the distribution utility will incur no incremental costs as a consequence of DG installations.

Beginning with the *pro-forma* costs developed in the DG screening phase (refer to Section IIIA of this report), we developed costs specific to each DG application discussed. For instance, given the load for a specific building type, we determined the size of the DG unit required and therefore were able to adjust our *pro-forma* capital costs accordingly. Specific fuel and operating costs were likewise determined for each application based on building load.

In addition to estimating costs for each of the categories discussed in the screening phase (equipment, O & M, fuel, and a host of other “avoided costs” were included in our analysis, including emissions costs, offsetting these direct costs. For instance, in those applications with CHP, the cost of the equipment for CHP was offset by the value of the natural gas that would have otherwise been purchased for heating in a particular commercial application. More generally, the value of the transmission losses, congestion, emissions, and ancillary services avoided by the distributed generation applications are also included in the analysis.[10]

For each application, the total costs of each DG scheme – direct costs less avoided costs- are summarized on a $/kW-year basis. Note that, where appropriate, adjustments are made for the coincident peaks of DG facilities relative to system peaks; that is, for assumed differences between anticipated DG-facility output (a function of customer load shape) and VELCO's system peak. For example, if a given DG facility is expected to operate during the summer season at roughly half of its peak capacity, we recognize such limitation through a like increase (i.e., twice) in the per unit costs of the facility. This adjustment ensures that *the per unit costs reflect the cost per avoided kilowatt of peak demand.*[11] Refer to Appendix 5 for spreadsheets presenting the DG cost analysis

The results of our analysis of the costs of various potential applications of reciprocating engines and microturbines are summarized in Table 14, with detailed analysis in Appendix 5. As described in Section D, these costs form the basis for determining the amount of distributed generation that would be economic in comparison to the bulk generation alternatives, and therefore the amount of distributed generation that is included in our Alternate Resource Configurations (ARCs).

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[10] For emissions, the direct emissions from the DG unit are offset by the emissions that would have otherwise been created on the bulk system, had the DG unit not existed. See Appendix 5 for detailed spreadsheet with all avoided costs.

[11] Because we are ultimately comparing the DG applications to the NRP, the costs of any DG must be viewed in terms of avoided kW of capacity. For instance, assume a 100 kW DG unit could be installed in a school for, say, $200/kw-year. If the school's coincident peak (relative to VELCO's peak loads) were only 40 kW, such an application would only reduce VELCO's peak by 40 kW. Its "true" cost vis-à-vis the NRP would therefore be $500/kw-year.

Table 14: Distributed Generation Results Summary: Net Cost of Capacity (real-levelized $/kW-year, $2004)

With CHP, Sized to Electrical Load

All Electric Buildings

	New Construction		Existing Buildings/Retrofit	
	Microturbine	Reciprocating Engine	Microturbine	Reciprocating Engine
Grocery	913	393	1,042	523
Health	NA	NA	NA	NA
Lodging	NA	NA	NA	NA
Office	1,238	493	1,367	665
Restaurant	2,007	840	2,135	977
Retail	1,970	245	2,098	392
Warehouse	1,682	1,031	1,810	1,184

Gas Buildings

	New Construction		Existing Buildings/Retrofit	
	Microturbine	Reciprocating Engine	Microturbine	Reciprocating Engine
Grocery	460	129	588	260
Health	305	66	433	195
Lodging	351	52	480	186
Office	419	36	548	166
Restaurant	925	554	1,053	724
Retail	944	316	1,073	455
Warehouse	457	129	585	271

Without CHP, Sized to Electrical Load

All Electric Buildings

	New Construction		Existing Buildings/Retrofit	
	Microturbine	Reciprocating Engine	Microturbine	Reciprocating Engine
Grocery	879	679	1,007	818
Health	NA	NA	NA	NA
Lodging	NA	NA	NA	NA
Office	1,287	1,287	1,437	1,437
Restaurant	1,754	1,697	1,882	1,840
Retail	1,734	1,801	1,862	1,969
Warehouse	1,617	1,316	1,746	1,476

Gas Buildings

	New Construction		Existing Buildings/Retrofit	
	Microturbine	Reciprocating Engine	Microturbine	Reciprocating Engine
Grocery	367	174	496	305
Health	268	110	396	239
Lodging	367	102	496	237
Office	367	71	496	200
Restaurant	933	627	1,061	796
Retail	933	319	1,061	458
Warehouse	367	184	496	325

With CHP, Sized to Thermal Load

All Electric Buildings

	New Construction		Existing Buildings/Retrofit	
	Microturbine	Reciprocating Engine	Microturbine	Reciprocating Engine
Grocery	3,567	2,590	3,695	2,718
Health	NA	NA	NA	NA
Lodging	NA	NA	NA	NA
Office	2,655	3,300	2,805	3,450
Restaurant	3,567	2,904	3,695	3,032
Retail	3,547	3,375	3,675	3,543
Warehouse	3,506	2,844	3,635	2,972

Gas Buildings

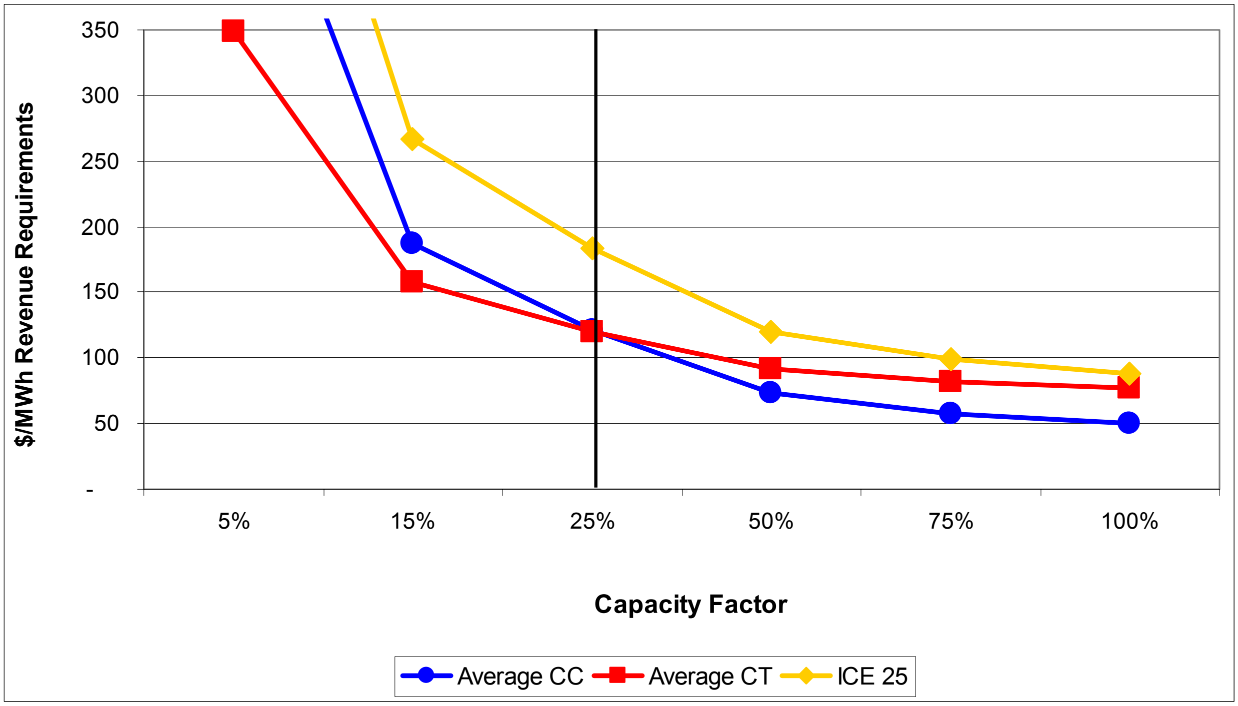
	New Construction		Existing Buildings/Retrofit	
	Microturbine	Reciprocating Engine	Microturbine	Reciprocating Engine
Grocery	867	1,274	995	1,403
Health	224	197	352	325
Lodging	215	229	343	358
Office	494	169	623	298
Restaurant	867	1,274	995	1,402
Retail	886	1,231	1,015	1,359
Warehouse	859	1,217	987	1,345

C. Bulk Generation

The pre-screening in Chapter 3 shows that combined-cycle (CC) and simple-cycle (CT) combustion turbine technologies are the most cost effective utility scale generation options. To develop the optimum mix of CCs and CTs to meet the incremental resource need in Northwest Vermont, one must take into account both the region's peak demand exposure and the shape of the load to be served.

The cost profile of a given facility size and type is a function of its duty cycle (e.g, peaking, intermediate, or base-load). Based on our bulk generation cost analysis, Figure 1 below provides a graphical summary of how duty cycle affects the relative cost per kWh effectiveness of the technologies considered.

Figure 1: All-In Power Costs vs. Capacity Factor



CC=Combined Cycle; CT=Combustion Turbine; ICE=Internal Combustion Engine

Figure 1 shows the estimated all-in costs (fixed and variable) of the bulk generating units operated at various capacity factors on a cost per MWh basis. At capacity factors above 25 percent, combined cycle units are generally more cost-effective than combustion turbines; that is, the lower operating costs of a combined cycle unit outweigh its higher capital costs. In contrast, at capacity factors below this level, combustion turbines are more economic. Hence, cost effectiveness depends largely upon expected operation. Refer to Appendix 6.

To evaluate the MW contribution that each generator makes toward meeting Northwest Vermont's need, we calculated the incremental load carrying capability associated with adding a generator with a given installed capacity rating and forced outage rate. The cost of each possible expansion plan is then evaluated on a dollars per mega-watt of incremental load carried basis. This approach ensures that the expansion plan is not biased in favor of larger units, which may otherwise appear to have an economy of scale advantage on a per MW of installed capacity basis. For example, our calculations show that, although it has 33% more installed capacity, the incremental load carrying capability of a 200 MW unit is only 10% higher than the load carrying capability of a 150 MW facility. Thus, all else equal, the total installed cost of a 200 MW facility would have to be no more than 10% higher than the cost of the 150 MW unit in order for it to be the economic alternative.

Table 15: Sample Incremental Load Carrying Capability Calculations: LOLP is 1-in-10-years

Supply Configurations	Installed Capacity Sum MW	Incremental Installed Sum MW	System LCC MW	Incremental LCC MW
Existing System NW	322.0	0.0	82.0	0.0
1 x CT12.5	332.0	10.0	89.5	7.5
2 x CT12.5	342.0	20.0	98.1	16.1
1 x CT25	342.0	20.0	99.3	17.3
2 x CT25	362.0	40.0	114.8	32.8
1 x CT50	362.0	40.0	114.1	32.1
2 x CT50	402.0	80.0	149.6	67.6
1 x CC100	412.0	90.0	156.6	74.6
1 x CC150	472.0	150.0	214.4	132.4
1 x CC 225	522.0	200.0	227.6	145.6

CC = combined cycle; CT = combustion turbine

D. Assembling Each ARC

Each ARC is characterized by the following:

- Its anticipated DSM contributions (i.e., offsets to peak loads, in MWs, *above* the Base DSM levels forecast by Optimal Energy);
- Its anticipated DG contributions (i.e., offsets to peak loads, in MWs, resulting from specified DG technologies and applications);
- Its bulk generation components (defined in terms of technology types, unit sizes in MWs, timing of unit additions, and facility locations); and

- Its total net present value costs (reflecting consideration of capital, avoided power supply and emissions costs).

The process by which we arrive at each ARC is as follows. First, we construct a set of least cost ARCs incorporating different DSM scenarios — i.e., with and without the Maximum Achievable DSM option. For each ARC, the peak demand (MW) to be met through supply-side resources was reduced by the amount of forecasted incremental DSM savings. Second, a set of bulk generating units with an incremental load carrying capability (LCC) at least equal to the net peak demand was added in the appropriate years. The results of the LCC calculations, our bulk guided the assembly of the bulk generating units necessary to meet the need in Northwest Vermont. The extent to which cost-effective DG might provide deferral value (delay the construction of a generator by one or more years) was then assessed and the ARCs were adjusted to reflect DG as appropriate.[12]

In 2005, the need in Northwest Vermont is forecast to be approximately 87 MW net of base DSM, increasing thereafter in increments of 10 to 20 MW each year. The least cost means of meeting this need is the construction of three 40 MW (summer rating) combustion turbines. Although the combination of two 40 MW CTs and a 20 MW CT would meet the need in 2005, an additional 20 MW CT would be required in 2006. Given economies of scale, efficiency benefits, and to a lesser extent present value effects, it is more economic to install the three 40 MW units. The installation of these units in 2005 displaces the Granite PAR, the Granite-Barre line reconductoring, and the Granite +/- 75 MVAR Dynamic VAR Device, allowing the system to serve loads up through the 1,100 MW critical load level identified by VELCO planning. Each

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[12] The following DG applications are within the range of costs exhibited by the bulk generation options being considered as tentative ARC components (all other DG applications exhibited considerably higher costs; see Appendix 5):

- New construction health facility, with natural gas connection, reciprocating engine
- New construction lodging facility, with natural gas connection, reciprocating engine
- New construction office facility, with natural gas connection, reciprocating engine

of the five ARCs starts with the installation of the three 40 MW CTs in 2005 and meets incremental loads with different combinations of CTs, CCs, DSM and DG.

ARC 1 is composed of 180 MW of CTs and approximately 15 MW of distributed generation installations. This approach yielded an ARC in which the amount of capacity installed in the system closely matched the need. Given the relatively low air emissions (limited hours of operation) and land use impacts (small plant footprint) of the CTs and the relatively short construction time (less than a year), we assume that the siting, permitting, construction, and testing of the first round of CTs could be completed by summer 2005, with subsequent installations proceeding in a timely manner. In addition, we assume that a program to implement

ARCs 2 through 4 include the 120 MW of CTs installed in 2005 and the installation of a combined cycle unit in 2007. Typically in New England, power plant developers have required approximately two years to complete the siting and permitting processes and an additional two to three years to construct and test a combined-cycle plant. Although an expedited siting and permitting process might allow construction to proceed earlier than assumed, the time required for construction and testing are more or less fixed. Thus, even an expedited process cannot be expected to get a new CC on line in less than approximately three and half years. Consequently, the combined cycle-units in ARCs 2 through 4 are put into service in summer 2007 rather than in 2005 to reflect the amount of time that would realistically be required to site, permit, and construct the facilities.

Three CC sizes were tested: in ARC 2 a 90 MW CC was added; in ARC 3 a 150 MW CC was added; in ARC 4 a 200 MW CC was added (summer rating). Adding CCs in each of these ARCs results in surplus installed capacity relative to the need. However, because the combined cycle units have higher operating efficiencies that do the CTs in ARC 1, it was not possible to exclude the CCs based simply on an installed cost comparison. Additional analysis was required to assess the performance of these alternatives.

E. Consideration of Incremental DSM

The analysis considers how several different levels of targeted DSM would impact the need for major components of the NRP. The NRP and ARCs 1 - 4 incorporate the peak demand savings achieved by a continuation of the ongoing DSM programs of Efficiency Vermont and the Burlington Electric Department (the base DSM described earlier). ARC 5 considers the impact of fully implementing the targeted DSM programs for the Inner and Metro Zones outlined in the OEI study (i.e., Max Achievable). Below we consider how three other in between levels of DSM contributions may affect the need for the NRP (i.e., 25%, 50%, and 75% of the DSM impacts in considered in ARC 5).

Because DSM impacts are produced in small increments over time, it takes some time to accumulate peak reducing impacts. Table 16 sets forth the peak reducing impacts in the Inner and Metro Zones of these four levels of DSM savings:

Table 16: Estimated Demand Savings from Targeted DSM Programs In the Inner and Metro Zones

Percent of Estimated Potential	100%	75%	50%	25%
Year	(summer peak demand kW)			
2004	1,187	8,90	594	297
2005	6,357	4,768	3,179	1,589
2006	15,425	11,569	7,713	3,856
2007	27,084	20,313	13,542	6,771
2008	39,723	29,792	19,862	9,931
2009	49,685	37,264	24,843	12,421
2010	58,288	43,716	29,144	14,572
2011	65,232	48,924	32,616	16,308
2012	70,514	52,886	35,257	17,629
2013	74,191	55,643	37,096	18,548

Source: 100% value taken from Table 1 from OEI final report; 75%, 50%, and 25% values were calculated from 100% values. All values shifted forward one year.

Given the magnitude of the need in 2005 and the ramp up schedule of the "Max Achievable" DSM savings, either the West Rutland to New Haven 345 kV line or the 120 MW of CTs as proposed for the ARCs above should be installed in 2005. Thus, pursuing incremental DSM does not defer the need to build either transmission or generation in 2005. However, the combination of new generation in 2005 and the implementation of an aggressive DSM program can defer the need to expand the Dynamic VAR Device at Granite to +/- 150 MVAR. Table 14 presents an analysis of the carrying charges associated with implementing a DSM program that would defer the construction of the Dynamic VAR Device from one to eight years.

Table 17: Evaluation of the Deferral Value of Incremental DSM

($ 2005)

% of Max Achievable DSM Program Savings [1]	NRP Elements Deferred	Duration of Deferral	PV Carrying Cost of DSM Program through Deferral Period	PV Carrying Cost of Deferred Element through Deferral Period
100% Inner & Outer Metro Savings	+/- 75 MVAR Dynamic VAR Device	8 years (until 2015)	$271.3 million	$11.2 million
75% Inner & Outer Metro Savings	+/- 75 MVAR Dynamic VAR Device	5 years (until 2012)	$167.5 million	$8.2 million
50% Inner & Outer Metro Savings	+/- 75 MVAR Dynamic VAR Device	3 years (until 2010)	$92.6 million	$5.8 million
25% Inner & Outer Metro Savings	+/- 75 MVAR Dynamic VAR Device	1 year (until 2008)	$35.3 million	$3.1 million

[1] Incremental DSM savings potential per OEI Maximum Achievable DSM Analysis.

Relative to the generation based ARCs - in particular to ARC 1, which has 180 MWs of CTs and 15 MW of DG -- each 25% increase in DSM savings effectively eliminates the need to build a 20 MW CT. Thus, for example, adding a program that achieves 25% of Max DSM savings will eliminate the DG from ARC 1. Adding a program that achieves 50% of Max DSM savings will eliminate the DG and a 20 MW CT from ARC 1.

A program that achieved all of the forecasted DSM savings for the Inner and Metro Zones would defer the need for additional generation approximately six years and for additional transmission approximately eight years. That is, a 10 MW CT would have to be installed in 2013 to reliably serve load up to the 1,140 critical load level. Either a second +/- 75 MVAR Dynamic VAR Device or more generation would have to be added in 2015 to reliably serve loads above that level.

ARC 5 is composed of the 120 MW of CTs and 74 MW of incremental DSM, all of the forecast savings achievable for the Inner & Metro Zones. As described above a less aggressive incremental DSM program provides little deferral value. Thus, the magnitude of the forecasted energy, peak demand savings and other societal benefits warrant examination of the most aggressive program.

F. Results – The Identified ARCs

Tables 14 and 15 summarize the transmission elements required to be installed to ensure reliable system operation and the components of five ARCs that result from the assembly process. Four reflect supply-side expansion plans assuming Optimal Energy's base DSM forecast. The fifth reflects DSM contributions consistent with Optimal Energy's maximum achievable (or aggressive) DSM forecast. All incorporate different combinations of DG and bulk generation resources. These ARCs are the best generation and DSM alternatives to VELCO's proposed NRP. In Chapter VI, we identify the ARC with the lowest expected costs and compare its expected performance to that of the NRP under uncertainty.

Table 18: NRP Elements Required for Reliability in All Proposed Alternative Resource Configurations

Year Installed	Element
2004	Hartford Capacitors
2004	Essex 115 kV Breaker
2005	Blissville PAR
2005	Sandbar PAR
2005	Williston 115 kV Ring Bus
2005	Granite Capacitors
2007	New Haven to Queen City 115 kV Line

ARC 1	2005	2006	2007	2008	2009	2010	2011
VT Critical Load Timing [1]	1,100.0		1,140.0				1,200.0
NW VT Peak Demand [2]	589.3	610.6	624.8	635.4	644.6	657.9	672.2
Incremental DSM [3]	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Dist. Gen. MW [3]	2.4	2.4	2.4	2.4	2.4	2.4	2.4
Revised VT Critical Load Timing	1,100.0			1,140.0			
Adjusted NWVT Peak Demand	586.9	605.8	617.5	625.7	632.5	643.5	655.4
Need	**-86.7**	**-105.6**	**-117.3**	**-125.5**	**-132.3**	**-143.3**	**-155.2**
Bulk Gen. Units Added by Type	3xCT50		1xCT25		1xCT25		1xCT25
Summer MW Installed	120		20		20		20
Bulk Gen. Inc. LCC	107.1		17.1		16.4		19.1
Cumulative LCC	**107.1**	**107.1**	**124.2**	**124.2**	**140.6**	**140.6**	**159.7**

ARC 2	2005	2006	2007	2008	2009	2010	2011
VT Critical Load Timing [1]	1,100.0		1,140.0				1,200.0
NW VT Peak Demand [2]	589.3	610.6	624.8	635.4	644.6	657.9	672.2
Incremental DSM [3]	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Revised VT Critical Load Timing	1,100.0		1,140.0				1,200.0
Adjusted NWVT Peak Demand	589.3	610.6	624.8	635.4	644.6	657.9	672.2
Need	**-89.1**	**-110.4**	**-124.5**	**-135.1**	**-144.4**	**-157.7**	**-172.0**
Bulk Gen. Added	3xCT50		1xCC100				
Summer MW	120		90				
Bulk Gen. Inc. LCC	107.1		67.3				
Cumulative LCC	**107.1**	**107.1**	**174.4**	**174.4**	**174.4**	**174.4**	**174.4**

Table 18-2: Alternative Resource Configurations

ARC 3	2005	2006	2007	2008	2009	2010	2011
VT Critical Load Timing [1]	1,100.0		1,140.0				1,200.0
NW VT Peak Demand [2]	589.3	610.6	624.8	635.4	644.6	657.9	672.2
Incremental DSM [3]	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Revised VT Critical Load Timing	1,100.0		1,140.0				1,200.0
Adjusted NWVT Peak Demand	589.3	610.6	624.8	635.4	644.6	657.9	672.2
Need	**-89.1**	**-110.4**	**-124.5**	**-135.1**	**-144.4**	**-157.7**	**-172.0**
Bulk Gen. Added	3xCT50		1xCC150				
Summer MW	120		150				
Bulk Gen. Inc. LCC	107.1		118.1				
Cumulative LCC	**107.1**	**107.1**	**225.2**	**225.2**	**225.2**	**225.2**	**225.2**

ARC 4	2005	2006	2007	2008	2009	2010	2011
VT Critical Load Timing [1]	1,100.0		1,140.0				1,200.0
NW VT Peak Demand [2]	589.3	610.6	624.8	635.4	644.6	657.9	672.2
Incremental DSM [3]	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Revised VT Critical Load Timing	1,100.0		1,140.0				1,200.0
Adjusted NWVT Peak Demand	589.3	610.6	624.8	635.4	644.6	657.9	672.2
Need	**-89.1**	**-110.4**	**-124.5**	**-135.1**	**-144.4**	**-157.7**	**-172.0**
Bulk Gen. Added	3xCT50		1xCC200				
Summer MW	120		200				
Bulk Gen. Inc. LCC	107.1		125.4				
Cumulative LCC	**107.1**	**107.1**	**232.5**	**232.5**	**232.5**	**232.5**	**232.5**

Table 18-3: Alternative Resource Configurations

ARC 5	2005	2006	2007	2008	2009	2010	2011
VT Critical Load Timing [1]	1,100.0		1,140.0				1,200.0
NW VT Peak Demand [2]	589.3	610.6	624.8	635.4	644.6	657.9	672.2
Incremental DSM [3]	6.8	9.7	12.6	13.7	11.1	9.9	8.6
Revised VT Critical Load Timing	1,100.0						
Adjusted NWVT Peak Demand	582.5	594.1	595.7	592.6	590.7	594.2	600.0
Need	**-82.3**	**-93.9**	**-95.5**	**-92.3**	**-90.5**	**-94.0**	**-99.8**
Bulk Gen. Added	3xCT50						
Summer MW	120						
Bulk Gen. Inc. LCC	107.1						
Cumulative LCC	**107.1**	**107.1**	**107.1**	**107.1**	**107.1**	**107.1**	**107.1**

Notes:

[1] VT-wide native load levels without distribution and sub-transmission losses corresponding to the critical loads presented by VELCO in its "Critical Loads Analysis"

[2] Northwest Vermont native load levels inclusive of distribution and sub-transmission losses.

[3] DSM and DG MWs are adjusted to reflect the benefits of avoided losses.

V. Comparing VELCO's Proposed NRP to the Alternatives

A. Identifying the Preferred ARC

The goal of this analysis was to identify the ARC developed in Chapter 4 and listed in Table 15 that performed best relative to the NRP. For each alternative resource configuration, we have estimated the relative total societal costs: that is, the expected capital cost, net variable cost to supply the balance of Vermont load, and the additional costs and benefits to society, including external environmental costs associated with air emissions from electric generating sources.

The NRP and other alternative resource configurations entail different amounts of generating capacity, different wholesale market prices and (in the case of ARC 5, with the maximum DSM) different load requirements. The PROSYM model was used to simulate the effects of these factors on Vermont's total electricity costs and on the air emissions of the New England electricity system. Refer to Appendix 7 for a discussion of PROSYM and our modeling assumptions. Because the PROSYM analyses are time consuming, they were performed for three sample years: 2005, 2008 and 2011. For each year and each resource configuration, the societal costs were estimated using the following components:

- Fixed costs and capacity value associated with each resource configuration;
- The net variable cost to supply the balance of Vermont's power needs;
- Power costs associated with serving transmission system losses;
- Emission-related externality costs;
- Costs associated with incremental DSM implementation, where applicable.

Summaries of the estimated direct costs, net variable costs to supply balance of Vermont load and societal costs (which include external environmental costs associated with electricity production) are provided in Appendix 9. In addition, Tables 15 and 16 below summarize the results for all resource configurations and scenarios analyzed. The remainder of this section explains how each of these components was derived, and how the results were assembled to estimate the relative total societal costs associated with each alternative resource configuration.

1. Fixed Costs and Capacity Revenues

The fixed costs are calculated for the components of each resource option. Fixed cost items include transmission equipment in the case of the NRP, and utility-scale generation, distributed generation and DSM in the case of the ARCs. DSM program costs are discussed in a later section.

First, a set of annual carrying charges was developed for each resource, based on its economic life. The economic lives assumed in the analysis are 25 years for utility scale generation, 15 years for distributed generation, 13 years for DSM (5 years for recovery of the regulatory asset). The carrying charges for all resource options were developed to reflect utility ownership and financing (i.e., rate base treatment). Second, the annual carrying charges, which feature a somewhat front-loaded pattern, were converted into a set of real-levelized carrying charges that are equivalent in present value terms. The advantage of the economic carrying charge approach is that it captures the end effects associated with cost recovery of equipment with different lives. See Appendix 8 for further detail.

Each of the resource configurations tested as potential alternatives to the NRP will provide power to serve Vermont's needs or, in the case of DSM, will provide savings that reduce Vermont's needs. Each ARC will provide an amount of Installed Capacity (ICAP)[13] value from installed capacity or reduced peak demands. We estimate the market price of Installed Capacity over the long term, based on the revenue requirements of a new utility scale peaking capacity in the New England market. For each ARC, we apply this price to the capacity that it provides, to obtain an offset against the fixed costs associated with the ARC.

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[13] This report refers to this quantity as ICAP value. In actual practice, generators may achieve this value through a combination of the ICAP product and spot market energy price "spikes" above those depicted in our PROSYM analysis.

2. Net Variable Cost to Supply the Balance of Vermont's Power Needs

The net variable cost to supply the balance of Vermont's power needs is also calculated. The inputs to the calculation are the components of Vermont's power supply costs that may vary based on the resource option selected. The first component is the variable costs of Vermont's committed generation sources (i.e., its owned generation resources and long term purchased power contracts). Notable is the cost of power under Vermont's Vermont Yankee buyback contract from Entergy Nuclear, which depends on spot market prices when they are significantly lower than the agreement's fixed price schedule.

The second cost component is future wholesale market transactions. Vermont's committed power sources are, on average, sufficient to serve most, but not all, of the state's forecasted power needs. As a result, Vermont will need to make future purchases, either in the spot market or on a forward basis, to meet some of its requirements. For each resource configuration we use the PROSYM model to forecast the operation of Vermont's committed supplies based on regional market prices. This analysis prices Vermont's additional needs at forecasted spot market prices for the Vermont load-zone, and captures any market price differences between the locations of Vermont's load and its committed sources. Also, to the extent that production from Vermont's committed generation sources exceeds the load, the PROSYM analysis captures the net revenues associated with short term economy sales.

These two components – variable costs of committed Vermont generating sources, and future wholesale power transactions – are added to obtain the total net variable costs associated with Vermont's power supply. Significantly, our analysis does not include the fixed costs associated with Vermont's committed generation sources; these costs will not vary based on the resource configuration that is chosen to address Northwest Vermont's reliability problem. Similarly, we did not calculate the variable cost of power under long term purchases from HQ/VJO and VEPPI, because the volumes and prices under these contracts will not vary based on the chosen resource configuration and can be considered fixed for the purpose of this analysis.

3. Transmission System Losses

Transmission losses[14] associated with each resource configuration are explicitly calculated. Differences in transmission losses among resource configurations may occur due to differences in the amount and type of new Vermont generation, the transfer capability and resistive characteristics of the VELCO system (based on whether or not the NRP is implemented), and retail electricity demand.

As summarized in Appendix 7, Vermont's electrical system is represented in the PROSYM analysis using nine zones containing Vermont's electricity demand and in state generating plants. These zones are appropriately linked with each other, and with the New England, New York, and Hydro-Quebec systems. Electricity flows between the zones take place over the VELCO transmission system. Transmission losses are estimated within the PROSYM model based on the simulated hourly flows between the zones, using the assumption that losses vary with the square of the flow. This method produces estimated annual losses of about 2 percent of the Vermont load if the NRP is constructed, and slightly higher losses under each alternative resource configuration. Because these losses are part of the total energy requirements that Vermont utilities must serve under the ISO-NE market system, we have estimated the cost of serving the losses based on the projected spot market energy price for the Vermont zone. The lower losses associated with the NRP may also produce some ICAP value, but these appear to be limited and we have not quantified them here.

4. Emission-Related Externality Costs

The external environmental costs associated with electricity production are monetized. For each resource configuration, we have estimated the total New England emissions of SO_2, NO_x, and CO_2 using the PROSYM model. To account for the external environmental costs associated with these emissions, we apply $/ton costs for each of the three emissions. The relative costs of emissions for the pollutants are derived from the Department's "Power to Save" document, and

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[14] Distribution and subtransmission losses are tracked in our analysis as part of the load requirements served by Vermont utilities, and are represented as a constant percentage of retail load.

these values were scaled so that the total external environmental costs associated with a gas-fired combined cycle plant are approximately \$7 per MWh.[15]

Note that the monetized value of total air emissions associated with New England electric generation is much larger than the gross and net costs associated with the NRP and its alternatives. For presentation purposes, we therefore show the estimated cost of emissions for each resource configuration *relative to the emissions associated with the NRP case*.

Projected air emissions do not differ strongly among the resource configurations (including the NRP) that include only Base DSM, so that differences in emission-related societal costs do not strongly affect the results for these cases. However, the projected air emissions for the Maximum DSM case, ARC 5, are noticeably lower, producing significant societal cost savings compared to the other cases.

5. Incremental DSM Implementation Costs

In ARC 5, we have reflected load reductions resulting from the implementation of Maximum Achievable DSM as projected by OEI. As noted earlier, implementation of the Maximum Achievable DSM in the Inner and Metro Zones combined with the installation of 120 MWs of CTs in 2005 and a 10 MW CT in 2013 effectively displaces the West Rutland to New Haven 345 kW line and defers the Granite Dynamic VAR Device until 2015. As modeled, the incremental DSM effort is implemented only in these zones. The appropriate DSM program costs therefore are the Maximum Achievable DSM costs that OEI has projected for the Inner and Metro zones through 2011. To determine the annual costs, we have assumed that the annual utility costs will be treated as regulatory assets to be recovered over 5 years. We have added to these costs annual societal costs.[16] We computed the real-levelized value of these costs based on the 13 year average life of the measures.

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[15] The \$7 per MWh (in \$1997) is consistent with the settlement figure that was utilized in VPSB Docket 5980 (Statewide Energy Efficiency Plan).

[16] The OEI report tables provided program societal costs by zone for the entire period, and the entire DSM program, including EVT/BED. We have allocated these Inner/Metro costs to the incremental program based on their share of total program costs, and have spread them over the years on the basis of incremental program annual costs.

6. Summary of Results

For each resource configuration, the cost categories above were summed to produce a total annual cost figure for each of the three simulation years (2005, 2008 and 2011). We then converted these annual results into a real-levelized stream that, when escalated from 2005 at the rate of general inflation, yields an equivalent in present value. The results for each resource configuration are summarized in terms of their total installed costs (Table 19) and their carrying costs and total societal costs (Table 20).

Table 19: Total Installed Cost of Each Option ($ 2005)

NRP	ARC 1	ARC 2	ARC 3	ARC 4	ARC 5 *
$157 million	$240 million	$282 million	$330 million	$357 million	$406 million

* Includes DSM program and measure costs through 2011.

Table 20: Present Value Costs of Resource Alternatives, 2005 – 2016
2005 present value [1], $ millions

	NRP	ARC 1	ARC 2	ARC 3	ARC 4	ARC 5
Carrying Charges	107.5	193.6	242.8	282.7	302.2	314.4
Net Cost to Serve Vermont Load [2]	1,178.1	1,135.2	1,072.9	1,027.3	986.5	1,074.5
Societal Costs/(Benefits) relative to the NRP) [3]	-	(2.1)	7.3	11.3	2.6	(182.0)
Total Societal Costs	1,285.5	1,326.6	1,323.1	1,321.3	1,291.2	1,207.0

Notes

[1] The discount Rate is 10%.
[2] This includes power supply costs, transmission losses, and capacity value.
[3] For ARC 1 to 4 societal benefits is the monetized value of emissions. For ARC 5 societal benefits includes the monetized value of emissions and avoided distribution and sub-transmission.

B. Discussion of Results

The five ARC cases, the NRP and the resource alternatives produce similar total societal costs, with a more pronounced difference in present value sum of annual carrying charges and net variable cost to supply Vermont ratepayers. The NRP requires the lowest total present value capital outlay between 2005 and 2016 ($107.5 million) and ARC 5 (the maximum DSM case) the highest, $314.4 million. ARC 1, the generation based alternative with the lowest capital cost has carrying charges of about $193.6 million across the study period. Some key observations are discussed below.

- The NRP is projected to produce somewhat lower spot market prices in the Vermont load zone, reducing the cost of serving uncommitted load. The NRP effectively eliminates transmission constraints into Northwest Vermont, thereby improving access to regional supplies. This impact is captured in the direct cost to serve Vermont load.

- The NRP has lower total annual transmission losses than ARC 1 and slightly higher total losses than ARCs 2 through 5.

- Vermont's power supply situation will change noticeably after 2012 as large power purchases from Vermont Yankee, Hydro-Quebec and VEPPI expire. Together, these purchases amount to several million MWh per year and provide almost half of Vermont's current and projected power needs. After 2011, Vermont's needs for new power sources will be much more substantial and the lower Locational Marginal Prices (LMPs) associated with the NRP case will likely produce greater savings for Vermont than can be had under the alternative resource configurations – including the heavily DSM dependent ARC 5.

- Compared to the ARCs, the NRP has a higher net variable cost to supply the balance of Vermont's load. The primary reason for this is that the ARCs 1 through 5 have capacity value in the New England market, where the NRP, a transmission project, does not have capacity market value. Capacity revenues offset, in large part, the annual carrying charges of the ARCs, producing lower net fixed costs. In addition, the DSM programs in ARC 5 greatly reduce the total load served under than case.

- That the societal costs of ARC 1 and ARCs 2 through 4 are approximately equal masks the fact that, relative to the need, ARCs 2 though 4 have from 15 to 125 MW of excess installed capacity. As a consequence, ARCs 2 through 4 are more sensitive to the capacity price than is ARC 1. The lower net variable cost to serve Vermont load is a function of the operation of significant trapped generation in Northwest Vermont suppressing regional LMPs. If, in the future, transmission were built either for reliability or economic purposes (to give this generation access to the broader New England market) the depressed LMP effect would be lost.

- The calculated environmental cost of generation is based on total New England air emissions from electric power production. From this perspective, the NRP and ARC 1 are roughly comparable. Due in large part to dispatch inefficiencies, ARCs 2 though 4 have a negative impact on regional emissions. Although not captured in th societal costs, on an in-state basis, ARC 1 increases local NO_X and CO_2 emissions by 10% and 12% respectively; ARC 2 increases local NO_X and CO_2 emissions by 7% and 17% respectively; ARC 3 increases local NO_X and CO_2 emissions by 7% and 25% respectively; and ARC 4 increases local NO_X and CO_2 emissions by 5% and 27% respectively.

C. Assessment of DSM-Based ARC 5

Alternative Resource Configuration 5, which includes 74 MW of DSM-based peak demand savings, provides large net societal benefits compared to the other options considered (Table 17 includes the Societal Benefits of the NWP and each ARC). However, the value of peak demand reductions comprises only a small share of these social benefits. Examined from the perspective of the amount of direct investment needed to achieve the peak reductions, the annual carrying cost of the targeted DSM programs is prohibitively high – i.e., the DSM programs in the Inner and Metro Area are projected to cost approximately $3,650 per saved kW, compared to a range of $160 to $180 per delivered kW for the generation-based options or $120/kW for the transmission project.

Pursuing the full potential of DSM to defer peak demand would require an unprecedented DSM program; one that seeks to capture all the efficiency improvements the OEI study identifies as available. Although the OEI study has estimated reasonably what an aggressive energy efficiency investment program could achieve, as the OEI report observes, a program that seeks to reduce peak demand this sharply over a limited period of time has not been attempted on such a large scale anywhere. This is not to say that it cannot be done. But this would be a massive and unprecedented effort with substantial implementation risks and risks that the savings will either not be achieved or will not be achieved when necessary. This translates into the risk that load will continue to grow past critical levels, exposing Northwest Vermont to high congestion costs and to capacity shortages

When considering targeted DSM programs that achieve less than 100% of peak demand savings identified as feasible by OEI, we observed earlier that:

- the 25% DSM option could defer for one year one comparatively small component of the NRP (the +/- 75 Dynamic VAR Device at Granite) or avoid the equivalent of only 15 of DG capacity or about 20 MW of CT capacity;
- the 50% DSM option could defer this transmission component for three years or avoid the equivalent of only 35 MW of DG and CT capacity;
- the 75% DSM option could defer this transmission component for eight years or avoid the equivalent of only 55 MW of DG and CT capacity.

Table 21: Summary of the Carrying Cost of Incremental DSM that Defers NRP Transmission or ARC 1 Generation through the Deferral Period ($ 2005)

% of Max Achievable DSM Program Savings [1]	PV Carrying Cost of DSM Program	PV Carrying Cost of Deferred NRP Element	PV Carrying Cost of Deferred Generation
75% Inner & Outer Metro Savings	$167.5 Million	$8.2 Million	$21.3 Million
50% Inner & Outer Metro Savings	$92.6 Million	$5.8 Million	$10.1 Million
25% Inner & Outer Metro Savings	$35.3 Million	$3.1 Million	$5.1 Million

The Stipulation requires that we determine the amount of DSM that can either defer or displace elements of the NRP. The above analysis shows the costs of the DSM program required to defer a small piece of the NRP are large compared to the cost of the NRP element deferred. In all cases, though, the societal benefits of ARC 5 exceed those of the NRP and ARCs 1 through 4, even without consideration of the cost savings associated with some deferred transmission investments. Whether or not to require the expenditure of such substantial amounts to obtain these benefits will ultimately be a matter for the Vermont Public Service Board.[17] Our conclusion, in this context, is that the DSM resource commitments considered here cannot be justified by the need to remedy the specific electric system reliability problem in Northwest Vermont.

D. Selecting the Preferred ARC

For reasons outlined in section C above, ARC 5 is not analyzed further in this study. As for ARCs 2 though 4, although they have slightly lower societal costs, we are of the view that they face implementation obstacles that challenge their viability as alternatives to the NRP. Recall that ARCs 2 - 4, in addition to 120 MW of CTs, include the installation of a Combined Cycle

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[17] We observe that in the recent EVT funding case, when presented with statewide maximum achievable DSM savings and costs of a similar magnitude to those presented here, the Board opted not to aggressively increase EVT's funding.

plant requiring a capital investment from $50 to $110 Million greater than that in ARC 1. Due to siting constraints, ARCs 2 - 4 require the development of two sites for power generation. In addition, these ARCs result in surplus installed capacity of 15 to 125 MWs. Their apparent societal cost advantage is a function of depressed LMPs due to transmission congestion that results in trapped generation. Finally, these ARCs increase both overall regional and local emissions.

Consequently, ARC 1 is the only alternative that receives additional quantitative treatment. Note, however, that all of the generation based ARCs are subject to many of the same uncertainties as ARC 1. Thus the performance of ARCs 2 - 4 under uncertainty will be similar to that of ARC 1. In addition, many of the implementation issues discussed in chapter VI apply.

E. Stress Cases: NRP and ARC 1

The quantitative result of our comparison of the NRP to ARC 1 under base case conditions offers a great deal of, albeit not complete, insight into the robustness of ARC 1 and the NRP as a least-cost solution to Northwest Vermont's reliability problem. The base case conditions that we model reflect the expected set of future conditions to which Vermont will be exposed. However, there is always a degree of uncertainty regarding the actual future values of various inputs. The risk that the inputs will vary from the expected values has two forms. The first is the probability that the actual values at any time will lie not at their expected value, which we have modeled, but somewhere else on the distribution. The second is that the fundamentals that drive the input assumptions will have changed, leading to a secular change in the distribution of outcomes.

As part of the assessment of the robustness of the identified least-cost alternative to the NRP, we analyze the performance of ARC 1 and the NRP under a series of stress cases. The secular risks that we analyze are outlined below.

- **High Oil Prices –** We assume a $5.00 per barrel increase in crude oil prices over the base case, from roughly $22.00/Bbl to $27.00/Bbl in 2005, while natural gas prices remain constant at base case levels. Fuel oil and natural gas are the marginal fuels on-peak in New England. An increase in the cost of fuel oil will raise regional on-peak prices, but will have no effect on the fuel cost of the generation added under ARC 1. This scenario tests which alternative, ARC 1 or the NRP, provides a better hedge against a secular rise in fuel oil prices.

- **High Natural Gas Prices –** We assume a doubling of U.S. well-head natural gas prices, from roughly $2.50/MMbtu in 2005 to $5.00/MMBtu, while oil prices remain constant at base case levels. This price increase is consistent with natural gas futures prices currently trading in the NYMEX market. Natural gas has become an important fuel both on and off peak. An increase in the cost of natural gas will likely raise regional power prices across all-hours. Moreover, because the generation added under ARC 1 is natural gas fueled, an increase in gas prices will also increase the fuel cost of the generation added under ARC 1. This scenario tests which alternative, ARC 1 or the NRP, provides a better hedge against a secular rise in natural gas prices.

- **Release of SEMA/RI Trapped Generation –** At present, due to insufficient transmission capability, some 6,000 MW of generation is trapped in Southeast Massachusetts and Rhode Island (SEMA/RI). ISO-NE has recognized this problem and proposals for addressing the transmission deficiency are included in the 2002 Regional Transmission Expansion Plan. This scenario tests which alternative, ARC 1 or the NRP, provides lower overall power supply costs to Vermont should the surplus generation in SEMA/RI become available to the region.

- **Low Vermont Load Growth --** We assume that load remains flat through 2007 and grows at half the base case rate thereafter. Analogous to the High Vermont Load Growth Scenario, this scenario tests which alternative, ARC 1 or the NRP, provides a better hedge against a secular decline in load growth in Vermont.

As a result of the Low Load growth assumption, the Vermont-wide summer peak does not reach the 1,200 MW critical load level during the study period. The 1,100 MW critical load level at which the West Rutland to New Haven 345 kV line must be in service moves from 2007 to 2011. The second +/- 75 MVAR Dynamic VAR Device required at the 1,140 critical load level is not needed within the study period. The balance of the NRP elements is required in service according to the Base Case implementation schedule. The ARC design has been modified accordingly to reflect the change in need resulting from the Low Load assumption.

Table 22: Revised NRP Installation Schedule – Low Load Conditions

Base Case Year Installed	Low Load Case Year Installed	Element
2004	2004	Hartford Capacitors
2004	2004	Essex 115 kV Breaker
2005	2005	Blissville PAR
2005	2005	Sandbar PAR
2005	2005	Williston 115 kV Ring Bus
2006	2006	Granite PAR
2006	2006	Granite – Barre Reconductoring
2007	2007	Granite +/- 75 MVAR Dynamic VAR Device (1st Stage)
2007	2011	West Rutland to New Haven 345 kV
2007	2017	Granite +/- 75 MVAR Dynamic VAR Device (2nd Stage)

Table 23: Alternate Resource Configuration -- Low Load Scenario

ARC LL	2005	2006	2007	2008	2009	2010	2011
VT Critical Load Timing [1]							1,100.0
NW VT Peak Demand [2]	564.1	564.1	564.1	569.8	575.5	581.2	587.0
Incremental DSM [3]	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Dist. Gen. MW [3]	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Revised VT Critical Load Timing							1,100.0
Adjusted NWVT Peak Demand	564.1	564.1	564.1	569.8	575.5	581.2	587.0
Need	**-63.9**	**-63.9**	**-63.9**	**-69.6**	**-75.3**	**-81.0**	**-86.8**
Bulk Gen. Added	2xCT50				1xCT12.5		1xCT12.5
Summer MW	80				10		10
Bulk Gen. Inc. LCC	67.6				10		9.9
Cumulative LCC	**67.6**	**67.6**	**67.6**	**67.6**	**77.6**	**77.6**	**87.5**

Notes:

[1] VT-wide native load levels without distribution and sub-transmission losses corresponding to the critical loads presented by VELCO in its "Critical Loads Analysis"

[2] Northwest Vermont native load levels inclusive of distribution and sub-transmission losses.

[3] DSM and DG MWs are adjusted to reflect the benefits of avoided losses.

- **High Vermont Load Growth --** We assume that the summer peak grows at a rate from half to one percentage point greater than under the base case and that energy load grows at a rate 0.5 percentage points greater than under the base case. As a result of the High Load growth assumption, the Vermont-wide summer peak reaches the 1,200 MW critical load level in 2009. The NRP and ARC 1 have been designed to reliably serve load up to the 1,200 MW critical load level. This scenario tests which alternative, ARC 1 or the NRP, provides a better hedge against a secular increase in load growth in Vermont.

Table 24: High Load Scenario – Revised Critical Load Timing

	2005	2006	2007	2008	2009	2010	2011
VT Critical Load Timing [1]		1,140.0			1,200.0		
NW VT Peak Demand [2]	600.0	625.0	642.8	657.1	670.0	687.0	705.0

Notes:

[1] VT-wide native load levels without distribution and sub-transmission losses corresponding to the critical loads presented by VELCO in its "Critical Loads Analysis"

[2] Northwest Vermont native load levels inclusive of distribution and sub-transmission losses.

Table 25 summarizes the results of the stress cases. See Appendix 9 for more details.

Table 25: Present Value Costs of ARC 1 & NRP Stress Cases 2005 – 2011

2005 present value, $ millions

	Base Case		Stress 1: High Oil Prices		Stress 2: High Gas Prices	
	NRP	ARC 1	NRP	ARC 1	NRP	ARC 1
Net Variable Cost to Serve Vermont Load	$1,285.50	$1,328.8	$1,300.5	$1,347.5	$1,350.9	$1,419.9
Total Societal Costs	$1,285.50	$1,326.6	$1,300.5	$1,325.8	$1,350.9	$1,449.3

	Stress 3: Release of SEMA/RI Trapped Gen		Stress 4: Low Vermont Load	
	NRP	ARC 1	NRP	ARC 1
Net Variable Cost to Serve Vermont Load	$1,269.5	$1,310.3	$1,040.9	$1,064.1
Total Societal Costs	$1,269.5	$1,309.3	$1,040.9	$1,068.4

F. Discussion of Stress Case Results

The NRP base case provides lower total societal costs than that does ARC 1 under all stress scenarios. On a ten year present value basis, the total societal cost of the NRP is $20 million to $100 million lower than the expected total cost of ARC 1. However, with the exception of Stress 2: High Gas, this amount represents only a small fraction (approximately 2 to 4 %) of the total cost of each option. While the differences are not trivial, neither are they very large. There are sufficient uncertainties in the inputs to preclude the selection of either the NRP or ARC 1 solely on the basis of the expected value *pro-forma* economic analysis presented thus far.

Should load growth increase as represented in the High Vermont Load scenario, all of the NRP or ARC 1 elements would have to be installed and in service as soon as possible. In this scenario, although not quantitatively captured, the physics of the power system would favor the NRP. Transmission elements are limited by thermal and voltage constraints. Generation is limited by its capacity. If load were to grow as in the High Vermont Load scenario, the VELCO operators could likely implement emergency procedures that would allow them to run the transmission system so as to serve load for a couple of years until additional transmission, generation or demand-side measures were implemented. The generation-based ARC 1 is capacity limited and would not be able to serve loads above the 1,200 MW critical load level. Thus, if one expected loads to rise as in the High Vermont Load scenario, plans to install additional generation would have to be made up front to ensure the reliability of the system past 2009.

Should load growth slow as represented in the Low Vermont Load scenario, the need for the majority of the NRP elements to be installed and in service by summer 2005 is unchanged. A drop-off in demand growth could allow the construction of the West Rutland to New Haven 345 kV line to be delayed for no more that a few years. However, we are of the view that the line will be needed and that the risk (and costs) of on not having the line in service in a timely manner far outweigh the three or four years of avoided carrying charges.

VI. Implementation Issues

On an expected value basis using *pro-forma* cost assumptions, the proposed Northwest Reliability Project and Alternate Resource Configuration 1 are effectively equal. The decision about which project provides the most cost effective and robust means of meeting Vermont's need will depend largely on non-cost considerations, notably the feasibility of siting and constructing transmission versus generation in a timely manner in Northwest Vermont. Delays in the implementation of either scenario will adversely impact the ability of Vermont to resolve the present reliability problems.

In any case, in the event of delays, analysis shows that the additional congestion costs (independent of an assessment of the value of lost load) could exceed $10 million per year. This is approximately equal to the annual fixed carrying costs of 100 MW of CTs and half as much as the annual carrying cost of the NRP.

A. Implementing ARC 1

In order for ARC 1 to be implemented, the following issues must be addressed and satisfactorily resolved.

1. Combustion Turbines

- The study assumes that a Special Purpose Entity with access to utility-like financing and cost recovery mechanisms will build, own and operate the facilities. This is clearly a simplifying convention. The facilities could be built, owned, and operated by a third party and the power purchased by the Vermont utilities pursuant to a PPA, or the Vermont utilities could jointly develop the resources with a single utility as operator. These issues are secondary, however, to the issues of financing and cost recovery.

  The NRP, if built, will go into VELCO's rates and be recovered from all users of the VELCO transmission system. If the NRP receives PTF treatment, the majority of the NRP's costs would go into the New England regional network rate with only a fraction, about 5%, of the project costs charged directly to Vermont.

  The NRP is proposed to remedy reliability problems and serve incremental load in Northwest Vermont. At present, there is available no rate treatment that would either recover the costs of generation from all of the ratepayers in Vermont (VELCO rate treatment), or spread the cost across all of the ratepayers in New England (RNS treatment). Rather, the utilities in Northwest Vermont (CVPS, VEC, BED, GMP) would likely pay the full cost of implementing ARC 1. Although the CTs constructed under ARC 1 provide a reasonable alternative to the NRP, it is not clear whether 175 MW of CTs is the best complement to the utilities' existing power supply portfolios or, in fact, whether they require that much additional supply. Thus, if the utilities build the units, they may be taking on the risk of a sub-optimal power supply portfolio or excess supply resources.

- A fundamental assumption underlying ARC 1 (in fact all of the generation-based ARCs) is that there are sufficient suitable locations at which to site the required generation. Preliminary inspection of existing VELCO substations suggests that the Georgia site and perhaps the Champlain site are best suited for siting utility scale generation. However, land is limited at these locations and it is uncertain how many turbines could be accommodated at each location. Moreover, adding more than 80 MW at the Georgia site will require the construction of additional transmission infrastructure in order to allow all the power to be evacuated when Highgate and PV20 are in service. In addition, substantial site preparation, substation and line upgrades will be required to interconnect multiple generators at the Champlain site.

- Existing generator sites, such as the McNeil and the Burlington Turbine sites, do not provide viable locations for new generation. Extensive sub-transmission upgrades would be required to evacuate additional power from the McNeil site. There is insufficient land to accommodate additional turbines at the Burlington Turbine location, and if an additional generator could be sited, substantial sub-transmission upgrades would be required to evacuate incremental power from that location.

- The costs to expand the Vermont Gas system to allow for the operation of significant generation additions are uncertain. Without conducting studies to evaluate the specific location and gas requirements of the added generation relative to their existing infrastructure, VGS is unable to provide more than crude estimates of system expansion costs. For all locations adjacent to VELCO substations on which generation does not already sit, the VGS system would have to be upgraded. Such upgrades will include, at least, additional compression and the construction of radial spurs to serve the generators. Using a *pro-forma* cost of $1 million per mile of new gas pipeline, we have assumed $10 million worth of gas pipeline upgrades would be required to bring a gas pipeline to the Georgia site. The farther south in the Inner and Outer Metro zones the plant is located the more extensive and expensive is the required gas pipeline investment. Thus, based on distance, to bring a pipe to the Champlain site we estimate a cost of $25 million. Without a system impact study and cost estimate of the required upgrades, these number remains speculative.

- The analysis assumes that CTs can be constructed and put in service for summer 2005. However, VGS estimates that approximately 36 months would be required to site, permit and complete a major pipeline upgrade. While clearly a rough estimate, it raises questions regarding the feasibility of bringing a natural gas fired facility on-line by summer 2005.

- As with the costs to expand the gas system, the cost of integrating these facilities into the transmission grid is speculative. For the purpose of this study, we have limited transmission interconnection costs to substation upgrades and line upgrades of limited scope. We assume facilities will be built adjacent to existing VELCO substations, eliminating the need to build long evacuation lines. We assume that an investment of $100/kW is required for full transmission interconnection and system integration. It is possible, however, that a system impact study will reveal that full-integration will require more extensive upgrades on the VELCO system, or perhaps will require upgrades on sub-transmission system of one or more of the distribution utilities.

- In order for ARC 1 to reliably serve the need, the generation additions have to be made according to an implementation schedule that closely follows that laid out in Table 13 (every two years). The successful implementation of ARC 1 will require, therefore, the timely siting and permitting of each facility, conducting the necessary transmission and gas system impact studies, construction of gas and transmission infrastructure, acquisition of the turbine and associated equipment, bidding and selection of an EPC contractor, and construction and testing of the facility. While much of the above might be accomplished in parallel, it represents a significant regulatory, administrative, engineering, and financing effort.

- The generation constructed under ARC 1 is natural gas fired. We do not assume that the facilities are dual-fuel capable, and thus do not include any costs associated with dual-fuel capability or on-site liquid fuel storage. Adding these costs would increase the fixed costs of the ARC relative to the NRP. Because the generators must burn natural gas, the reliability of the ARC is in part a function of the reliability of the natural gas delivery system. We have not assessed the probability of fuel interruptions due either to interruptions on the TransCanada pipeline or the potential for failure of any component of the VGS delivery system.

2. Distributed Generation (CHP)

- The *pro-forma* assessment of the contribution of distributed generation to meet the resource need in Northwest Vermont implicitly assumes a coordinated effort to identify promising loads and install the schemes that are economic. Such an effort has, to date, not been attempted; however, there are questions regarding the logistics of administering such a program. To first order, the administration of such a program is likely to be conceptually similar to the logistics of administering DSM programs. The costs of running such a program -- such as the cost of identifying likely loads, contacting potential customers, analyzing customer usage and engineering the CHP scheme -- have not been estimated or included in the CHP cost analysis presented in this study.

- This study assumes that the SPE will build, own and operate the CHP scheme on the customer site and sell the heat and electricity to the customer. In practice, some customers may wish to operate and maintain their own equipment, although there is anecdotal evidence that, because power generation is not a core business function, most customers do not do so. Because the distribution utilities do not have experience installing CHP schemes, as a practical matter the facilities will likely be installed by a third party contractor. Similarly, the utilities will likely contract with a third party to perform CHP operations and maintenance.

- The CHP schemes installed under ARC 1 are economic within the context of the overall resource option, but, in general, are not economic on a stand-alone basis. Thus, customers are not likely to purchase the facilities based on their intrinsic economic merits. The utility may have to offer a subsidy to potential CHP customers. This subsidy has not been included in the societal costs of ARC 1. However, we do not believe it would have to be large. The study assumes that the utility will finance the CHP installations and put them into rate base for cost recovery.

- The study does not address potential rate impacts associated with CHP. We have assumed that any power requirements not purchased from the CHP installation will be purchased from the grid. However, we have not assumed that the customer will face a special backup rate that reflects the customer's residual load shape post installation of the CHP facility. In addition, the installation of the CHP schemes will lower the total kW and kWh across which the distribution utilities' revenue requirement is currently recovered. The study does not address the stranded costs or cost shifting implications of the CHP program.

- The study assumes that all possible CHP installations that are economic within the context of the ARC are installed. In practice, the utility will have to convince the customer that it is in his or her interest to have the CHP equipment on his or her site. Also, the analysis implicitly assumes that customers for which CHP appears economic have adequate space to accommodate the CHP installation.

- The cost of engineering and installing actual CHP schemes to meet the needs of actual customers versus the costs of meeting the needs of *pro-forma* customers with *pro-forma* installations can vary considerably. In general, CHP installations are custom engineered to meet the needs of a given customer. Although there are broad similarities among schemes, unique requirements can have large cost impacts. Consequently, we expect that the variance between the *pro-forma* contribution from CHP assumed in ARC 1 and the actual contribution may be significant.

- ARC 1 assumes that some 2 MW of CHP is installed each year across the study period. Although ARC 1 is fairly insensitive to small perturbations in the installation schedule, large deviations would directly impact the reliability of ARC 1 and render it a nonviable alternative to the NRP.

B. Implementing the NRP

As with ARC 1, in order for the NRP to be implemented, several issues must be addressed and satisfactorily resolved.

- For most of the proposed project, VELCO has adequate right-of-way or the required easements. However, there are segments of proposed line for which additional right-of way must be obtained.
- As with ARC 1, the NRP costs used in this study are *pro-forma* estimates and are subject to some uncertainty.
- There is some uncertainty regarding rate treatment. Depending largely on FERC decisions regarding transmission funding, the NRP, if built, may go into VELCO's rates and be recovered only from users of the VELCO transmission system or it may go into the New England regional network rate with only a fraction, about 5%, of the project costs charged directly to Vermont.
- During construction, generation in Northwest Vermont may have to be must-run to protect against outages. The analysis has not included any costs associated with possible must-run generation during construction. In addition, it is possible that the existing generation in Northwest Vermont will not be adequate to provide proper reliability levels during construction and that temporary generation will have to be brought into the region. The costs associated with securing and operating temporary generation during construction are not included in the analysis.
- The NRP construction schedule is a *pro-forma* estimate. As with the generation and other infrastructure upgrades required for ARC 1, there is some risk that the NRP cannot be completed according to the schedule assumed in this analysis. As with ARC 1, if NRP completion were delayed, Northwest Vermont would be exposed to high congestion costs and the possibility of power shortages.

C. Summary

On an expected value basis, assuming *pro-forma* cost assumptions, the proposed Northwest Reliability Project and Alternate Resource Configuration 1 are effectively equal. The decision about which project provides the most cost effective and robust means of meeting Vermont's need must, therefore, depend largely on non-cost considerations. Because delays in the implementation of an effective remedy to the present reliability problems will result in high congestion costs and the increasing potential for outages during the summer peak period, a solution must be selected and implemented as soon as possible. Based on the discussion above, it is our view that that the NRP has fewer, and less difficult, implementation issues to resolve in order to move forward.

Table 26: Summary Comparison of NRP to ARC 1

Items of Comparison	NRP	ARC 1
Capital Costs	$150 Million	$195 Million
PV Carrying Charges (2005-2016)	$107.5 Million	$193.6 Million
PV Net Variable Costs to Serve Vermont Load	$1,178.1 Million	$ 1,135.2 Million
Financing and Cost Recovery	VELCO Rates; Possible PTF Treatment in NEPOOL RNS	Uncertain
Environmental Impact	No material emissions impact	Net decrease in regional emission relative to NRP; 10 % increase in local NO_X and CO_2 emissions
Installation and O & M	Costs are fairly well understood; transmission O & M costs are relatively small	Generation interconnection costs uncertain; O&M costs subject to greater uncertainty given nature of rotating machines
Rate Impacts	Potentially Small	Generally Larger
Reliability Equivalence	N/A	ARC equivalent assuming pro-forma 6% forced outage rates are realized. If actual rates higher, additional machines may be required.
Availability of Sites	VELCO owns or has access to most required land, requires some additional ROW	Few ideal sites; All require extensive improvements
Fuel Infrastructure	N/A	Extensive expansion of VGS delivery infrastructure
Fuel Availability/ Natural Gas Dependence	N/A	Generators 100% NG dependent; ARC reliability a function of the gas delivery system's reliability
Transmission Interconnection and Integration Costs	N/A	Uncertain; estimated to be $100/kW
Timetable	Most elements required now; there is little flexibility in the timing of adding required elements	Generators must be on or before years indicated in schedule to ensure reliability.
Penetration	N/A	DG penetration rates may or may not meet forecast.
Program Implementation	N/A	DG program implementation should not be difficult, but results are uncertain since such a program would be new to VT.

VII. Recommendations

The quantitative study results do not point conclusively to a preferred solution to the Northwest Vermont reliability problem. The NRP and the alternative resource configurations analyzed have similar costs under most conditions. The decision as to which project provides a more robust solution to the reliability problem is dependent largely on professional judgments regarding both the relative cost and implementation uncertainties. Based on the discussion presented above, we are of the view that, in addition to lower *pro-forma* costs, the NRP has fewer cost and implementation related uncertainties than does ARC 1.

Each of the alternative resource configurations includes the construction of CTs to meet need in 2005. The NRP is not completed until 2007. Thus, if only the NRP is constructed, there is the risk of high congestion costs and possible power shortages in 2005 and 2006. This risk may be exacerbated by the need to take parts of the system out of service in order to complete construction of the NRP. Consequently, we recommend that in addition to the proposed NRP elements, that VELCO investigate the benefits of installing CTs on a temporary basis to provide additional reliability during the summer peak periods in 2005 and 2006. The benefits of using temporary units is that the appropriate number of MWs to install can be determined closer to the time of need without incurring a large up-front expense and without taking on an unnecessary long term commitment. Moreover, the use of temporary units, rather than the purchase and installation of fixed assets, would prevent a potential surplus capacity condition from developing upon the completion of the West Rutland to New Haven 345 kV line in 2007.

Should load growth slow as represented in the Low Vermont Load scenario, the need for the majority of the NRP elements to be installed and in service by summer 2005 is unchanged. A drop-off in demand growth would allow the construction of the West Rutland to New Haven 345 kV line to be delayed for no more that a couple of years. However, we believe that the line will be needed and that the risk (and costs) of on not having the line in service in a timely manner far outweigh the three or four years of avoided carrying charges.

Finally, we have concluded that the proposed Northwest Vermont Reliability Project is the best means to address the region's reliability problems and to meet incremental load requirements.