2011 Vermont Electric Plan Addendum

Sections 3, 4, and 5 of the *2011 Comprehensive Energy Plan* are the *2011 Vermont Electric Plan*. The first portion of this addendum serves to provide a general set of guidelines that should be helpful in development of utility Integrated Resource Plans ("IRPs"). The second portion briefly discusses the process the Public Service Department ("Department") uses under 30 V.S.A. §202(f) in determining whether a proposal is consistent with the *Vermont Electric Plan*.

Addendum A: Integrated Resource Planning Guidelines

Introduction

Pursuant to 30 V.S.A. §218c[1] each regulated electric or gas company is required to prepare and implement a least cost integrated plan (also called an integrated resource plan, or IRP) for provision of energy services to its Vermont customers. The *Vermont Electric Plan* and Public Service Board ("PSB" or "Board") Orders, beginning with Docket 5270, define requirements that a distribution utility's complete IRP should meet in order to pass the Department's review and comply with the Board's approval requirements.[2] The IRP process and the implementation of each Vermont utility's

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[1] 30 V.S.A. §218c. Least cost integrated planning

(a)(1) A "least cost integrated plan" for a regulated electric or gas utility is a plan for meeting the public's need for energy services, after safety concerns are addressed, at the lowest present value life cycle cost, including environmental and economic costs, through a strategy combining investments and expenditures on energy supply, transmission and distribution capacity, transmission and distribution efficiency, and comprehensive energy efficiency programs. Economic costs shall be assessed with due regard to:

(A) the greenhouse gas inventory developed under the provisions of 10 V.S.A. § 582;

(B) the state's progress in meeting its greenhouse gas reduction goals;

(C) the value of the financial risks associated with greenhouse gas emissions from various power sources; and

(D) consistency with section 8001 (renewable energy goals) of this title.

(2) "Comprehensive energy efficiency programs" shall mean a coordinated set of investments or program expenditures made by a regulated electric or gas utility or other entity as approved by the board pursuant to subsection 209(d) of this title to meet the public's need for energy services through efficiency, conservation or load management in all customer classes and areas of opportunity which is designed to acquire the full amount of cost effective savings from such investments or programs.

(b) Each regulated electric or gas company shall prepare and implement a least cost integrated plan for the provision of energy services to its Vermont customers. At least every third year on a schedule directed by the public service board, each such company shall submit a proposed plan to the department of public service and the public service board. The board, after notice and opportunity for hearing, may approve a company's least cost integrated plan if it determines that the company's plan complies with the requirements of subdivision (a)(1) of this section and is reasonably consistent with achieving the goals and targets of subsection 8005(d) (2017 SPEED goal; total renewables targets) of this title.

[2] Natural gas utilities (of which there is only one in Vermont at this time) are also subject to §218c, but not to §202 which establishes the Electric Plan.

approved plan are intended to meet the public's need for energy services, after safety concerns are addressed, at the lowest present value life cycle cost, including environmental and economic costs, through a strategy combining investments and expenditures on energy supply, transmission and distribution capacity, transmission and distribution efficiency, and comprehensive energy efficiency programs. (30 V.S.A. §218c) The cost and benefit factors to be considered include both direct monetary costs and benefits, and indirect impacts such as environmental and other societal effects.

This addendum establishes guidelines for the development of integrated resource plans; however the ultimate content and organization of an electric distribution utility's plan will be unique to each individual utility. The IRP process is intended, in part, to facilitate information exchange among utilities, regulatory agencies, and the public. These guidelines are intended to highlight areas of importance to the Public Service Department and facilitate further discussion between stakeholders. Where this addendum suggests "consideration" of a topic, the topic may be addressed in the written IRP, discussed with the Department prior to submission of the IRP, or both.

IRP FILING AND APPROVAL PROCESS

FILING SCHEDULE AND REVIEW

Utilities are required to undertake a complete revision of the entire IRP at least every 3 years, on a schedule directed by the PSB. The document should reference applicable background reports, analyses, and supporting materials and the utility should hold these for public and Department review. The utility should file an IRP with the Board that is complete and in accordance with the guidelines contained in this Electric Plan and Board Orders.

DEPARTMENT REVIEW

During the three years prior to the utility filing its IRP with the Board, the utility and the Department should meet periodically and work together with the goal of the utility filing an IRP that is supported by the Department. In addition to reviewing whether the IRP meets requirements described in state statute, Board Orders, and the *Vermont Electric Plan*, the Department will review the methodologies used by the utility in undertaking least cost integrated planning and make recommendations as to the soundness of those methodologies. The Department's recommendation of approval or non-approval of the IRP is independent of the particular conclusions of the plan, and contingent only on the efficacy of the employed methodology and consistency with statutes, Board orders, and the *Vermont Electric Plan*. Open communication and interaction between the Department and the utility early in the IRP process should allow the Department to evaluate and support a range planning methodologies.

The Department's review will encompass multiple areas of expertise. For example, the Department's Engineering Division will meet with the utility's engineers to discuss the portions of the plan related to transmission and distribution infrastructure, while load forecasts or power portfolio analysis are the subject of discussions with the Department's Planning and Energy Resources Division. Timely review and potential support of the IRP depends on effective and engaged communication from both the utility and the Department during these parallel conversations.

Within 30 calendar days after the utility files the IRP with the Board, the Department will file a letter with the Board either: 1) recommending approval of the IRP as filed; 2) describing areas of the IRP where the utility and Department could not reach agreement; or 3) if the utility did not afford the Department adequate time to review the IRP prior to filing, proposing a schedule for Department review and discussions with the utility.

PSB REVIEW AND APPROVAL

Although not required, the Department recommends utilities seek PSB approval of their IRP. Section 248 approvals for utility purchase, investment, or construction require evaluation of whether the proposed action is “consistent with the principles for resource acquisition expressed in that company’s *approved* least cost integrated plan”[3] (emphasis added). If PSB approval is not sought, future utility actions risk being judged against an outdated plan, which is not in the best interests of the utility or its ratepayers.

PSB review may include a hearing, and based on the evidence of record, a determination as to whether a utility's IRP is consistent with 30 V.S.A. §218c, Docket 5270, and other relevant PSB Orders. The PSB will also consider if the energy supply portfolio and methodologies described in the plan are reasonably consistent with achieving the goals and targets of 30 V.S.A. §8005(d)(4)[4]. The Board may approve the IRP, approve it in part and reject it in part (with or without conditions), or fully reject it. Robust proposals that have included engagement with the Department will improve the likelihood of a swift approval process.

DISTRIBUTION OF THE IRP

Utilities should file copies of the IRP and any revisions or updates with the Board and the Department; electronically and three hard copies with Department, and such filing with the Board as it may require. Electronic copies should be made available to the Department, the PSB, and the public. Hard copies of the IRP should be made available upon request (at a price not to exceed publication and mailing costs) to parties that intervene in the IRP proceeding and interested citizens of Vermont. The most current IRP should be available on the utility’s website.

DOCUMENTATION

A robust IRP should contain the following elements:

1. Executive summary suitable for distribution to the public, with an overview of the major components of the IRP.

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[3] 30 V.S.A. §248(b)(6)

[4] 30 V.S.A. §8005 Sustainably Priced Energy Enterprise Development (SPEED) Program; Total Renewables Targets
(d) Goals and targets
…
(4) Total renewables targets. This subdivision establishes, as percentages of annual electric sales, target amounts of total renewable energy within the supply portfolio of each renewable electricity provider.
(A) The target amounts of total renewable energy established by this subsection shall be 55 percent of each retail electricity provider’s annual electric sales during the year beginning January 1, 2017, increasing by an additional four percent each third January 1 thereafter, until reaching 75 percent on and after January 1, 2032.
(B) Each retail electricity provider shall manage its supply portfolio to be reasonably consistent with the target amounts established by this subdivision (4). The board shall consider such consistency during the course of reviewing a retail electricity provider’s charges and rates under this title, integrated resource plans under section 218c of this title, and petitions under section 248 (new gas and electric purchases, investments, and facilities) of this title. However, nothing in this subdivision (4) shall relieve a retail electricity provider from the obligations of section 8004 (renewable portfolio standards) of this title.

2. The components described below, including the utility's energy and peak demand forecast, the resource assessment, supply resources, DSM resources, T&D assessment, an integration section, and an implementation or action plan.
3. Technical appendices that contain information that would enable the Department, the Board, and intervening parties to understand, with sufficient detail and clarity to verify the results, how the plan was developed, to verify the accuracy and consistency of information used, and to understand assumptions made in developing the plan. Technical appendices should also include documentation and explanations of all data, assumptions, models, and outputs used in development of the plan; outputs from such models; results of uncertainty analysis; and references to all significant sources of information used in the development of the IRP.

ENERGY AND PEAK DEMAND FORECASTS

The IRP is founded and developed on a Resource Needs Assessment which, in turn, starts with a review of the existing resource mix, a load forecast, and future resource alternatives. The Department recognizes that utility load forecasts continue to evolve due to many factors including changes in overall economic growth, differential growth across ratepayer groups, volatility in power supply fuel costs, and policy actions to create greater energy efficiency or to encourage strategic use of electricity in new sectors such as transportation. Methodologies used to produce forecasts also continue to evolve as more tools are developed and data become available. Given that historical relationships between these assumptions have changed and are likely to keep changing, the following long-term forecasting guidelines are provided.

SUMMARY OF FORECAST GUIDELINES

Forecast Review

Since the forward-looking forecast is founded on historic patterns of energy demand, the utility is encouraged to review prior IRP load forecasts and evaluate their accuracy in predicting load. This could include identifying forecast components or tools that worked, and those that failed to lead to accurate predictions. The forecast review may reveal changing behavioral characteristics, structural changes, and/or the occurrence of unforeseen or unanticipated events.

Baseline forecast methodology

A clear and complete description of the forecast methodology and assumptions should be provided, along with a discussion of the methods and sources used to derive assumptions. If separate models are developed and used for short-term and long-term forecasting, the utility is responsible for providing adequate support for both, along with a clear explanation of methods used by the utility in combining the forecasts.

The utility is expected to provide long term forecasts for energy and seasonal (winter and/or summer, as appropriate) peaks, accounting for extreme weather possibilities, to ensure that adequate resources are available to meet customer needs.

Weather and Probability

Even though Vermont's annual energy use has historically been significantly less temperature sensitive than other regions, the effects of weather events are a significant factor in developing forecasts of peak demand load. The IRP should include a description for the methodology chosen to incorporate weather into the peak demand forecast. For example, the utility may use historical weather data to create predictions of "average" and "extreme" weather conditions or the utility may develop or use an industry standard 90/10 forecast (a forecast with a 90 percent probability that the actual peak demand will be at or lower than the forecast).

Economic Assumptions

Most IRPs will use a commercially available macroeconomic forecast to 'drive' the utility forecast, or at a minimum provide forecasts of key drivers in the model. In doing so, the utility should:

1. Consider referencing one or more alternative forecasts to solicit a range of future outcomes. Alternative forecasts could be averaged to generate a baseline forecast or the spread between forecasts might form the basis for a range in possible economic outcomes;
2. Consider coordinating long term forecasts and planning scenarios by using a baseline forecast that references forecasts by ISO-NE and/or VELCO or uses similar methodology;
3. Consider the relationship between statewide macroeconomic forecasts and economic activity in the utility's service territory. In other words, consider whether there are significant differences in economic structure and performance in the service territory, such as clear and present seasonal differences from the statewide forecast. If so, the utility should develop proxies for 'local' economic conditions prior to estimating the load forecast;
4. Incorporate into its forecast model economic and structural variables. These variables may include electricity prices, prices and availability of fuel substitution, measures of ability to pay, demographic changes, economic output, or government policy actions;
5. Clearly identify key indicators that drive electric load or efficiency; and
6. Clearly document the vintage of any macroeconomic forecast used.

Policy, Codes & Standards Assumptions

State and Federal building codes and appliance standards affect the amount of overall electricity consumption in the state, both annually and during peak demand periods. Where appropriate, forecast adjustments should be made to incorporate the predicted energy effects of building code updates occurring on a three year basis. Federal appliance and lighting efficiency standards have been established, have known effective dates, and are subject to continual revision. The utility is encouraged to consider, and incorporate where appropriate, the effects of these standards on both energy consumption and available efficiency savings. The codes and standards assumptions and resulting forecast adjustments should be clear and well defined.

Customer class definitions

Disaggregating the energy forecast by customer classes often improves forecast performance and understanding of changing structural relationships that affect energy and demand. Therefore the utility is encouraged to, where appropriate:

1. Clearly define customer classes;
2. Conduct customer class forecasts; and
3. Forecast customer counts independently from the demand characteristics of customers within each customer class.

Demand-Side Management Forecast

Since 2000, energy efficiency services in Vermont have been delivered for most utilities by Efficiency Vermont (EVT), a third party program administrator. EVT forecasts its "statewide" energy and summer peak demand savings with Public Service Board approved planning budgets.

For all utilities that do not act as an energy efficiency utility providing efficiency services to its own ratepayers, the IRP should show an understanding of EVT's 20 year forecasted energy savings, and provide discussion detailing how the utility expects EVT's forecasted energy efficiency savings to affect its load forecast.

For utilities that deliver their own electric efficiency services, but have specific Board approved planning budgets and savings forecasts, the utility should incorporate those forecasts into the base case and provide a discussion detailing how the utility expects its forecasted energy efficiency savings to affect its load forecast.

In both cases, utilities should consider:

1. If and how forecasted efficiency savings will materialize in the utility's customer territory; and
2. How much efficiency investment is embedded in the utility's historical data, affecting its base load forecast.

Utilities may also consider inclusion of alternate scenarios of energy efficiency that depart from the Public Service Board approved 20-year planning budgets.

Independent of efficiency forecasts, the utility should forecast, to the extent applicable and consistent with the planned use of these resources:

1. Demand response resources forecasted to be available,
2. Demand impacts of other load management resources (e.g. rate design), and
3. Energy and power supplied by net metered generators.

The utility should consider inclusion of low and high case forecasts for these resources on its system. Where applicable, the forecast should also include projected impacts on load due to or enabled by the adoption of advanced metering infrastructure or other grid modernization technologies.

Other Assumptions

The utility should explicitly describe its consideration of the expected impact of plug-in electric vehicles on its demand forecast, and how these loads affect its supply and T&D planning.

The utility should also describe its expectations for the adoption of any other new technologies that may increase or decrease energy and power needs, such as advanced meters or other "grid modernization" technologies, an increase in the saturation of energy storage, or increased use of heat pumps or other fuel switching technology.

INFORMATION FOR FORECASTING

In developing forecasts, utility should utilize relevant historical data. The development of forecasts for the 20-year planning period should include consideration of the following information:

1. Customer counts, by class;
2. Total sales of electricity by customer class (annual or by season, as appropriate);
3. Peak load (annual or by season, as appropriate); and
4. Annual sales and coincident system peak contribution for each major customer class.

The IRP or its technical appendices should also document:

1. Source and vintage of independent economic models employed:
2. Description of the forecast model including the relevant variables, coefficients, and the form

of the final model;
3. All historic values used in estimating model coefficients;
4. Summary statistics and diagnostics performed on the final model;
5. Characterization of the process used in the development of the final model including variables considered and rejected;
6. Description, including sources, for assumptions including end use detail where applicable;
7. Reason(s) for including any qualitative (dummy) variables, composite variables, and trend variables used in the model; and
8. Historic and forecast values for independent drivers of the forecast, fully documenting the basis for projecting them.

To aid in review, numerical data should be made available in electronic formats usable by the Department and Board upon request.

UPDATING THE FORECAST

Economic and load forecasts should be updated on a regular basis and as significant changes in the environment require (e.g., economic conditions or government policies that may significantly affect future demand, such as standards or taxes). Utilities should also revise forecasts that demonstrate poor performance.

ASSESSMENT OF RESOURCES

The utility is expected to model the integration of new resource alternatives with existing supply assets leading to the selection of a preferred portfolio that is the most cost-effective resource mix (including economic and environmental costs) after considering risk, supply reliability, uncertainty, and statutory requirements. In general, utilities are expected to:

1. Identify a broad range of supply-side options along with their unique operating characteristics. This may include consideration of wide range of supply resources to promote diversity of generation by fuel and technology; transmission service; supply contracts; and procurement from DSM, DR and customer-sited generation.
2. Use multiple evaluation criteria that include total cost and rate impacts, environmental impacts, and risk management to compare specific resource plans or strategies.
3. Incorporate uncertainties into the planning process, such as the uncertainty associated with the future demand for electricity, fuel prices, and the enactment of future environmental regulations.

Utilities should investigate supply side resources that may reasonably be available in the 20-year planning period. This investigation should consider utility needs for baseload, intermediate load, and peaking capacity, in the context of ISO-New England’s management of the bulk power system. Total capacity requirements include peak load and reserve margin requirements.

ASSESSMENT OF EXISTING RESOURCES

The utility’s IRP should:

1. Describe existing and committed base case generating capacity and firm power transactions currently under contract;
2. Identify potential changes to existing resource commitments, including, but not limited to, re-powering, fuel switching, and life extension of power plants or power contracts,

loss reduction in transmission and distribution systems, and improvements in generation and/or T&D areas;

3. Define existing renewable resources;
4. Delineate utility construction and jointly developed projects;
5. Describe purchases, including purchases through the SPEED program or any other Board approved bid solicitation programs, including:
    a. Purchases from independent power producers;
    b. Purchases from other utilities;
    c. Customer owned generating capacity that is not a qualifying facility or independent power facility; and
    d. Resources developed through pooling, wheeling, coordination arrangements, or through other mechanisms.

SUPPLY OPTIONS INVENTORY

In describing supply options to consider over the planning period of the IRP, the utility should identify options in some or all of the following classes:

1. Existing utility owned resources that will serve as future resources should be described, including potential costs
2. New supply resources that a utility has considered should be discussed, including construction cost, construction schedule, and expected in-service date.
3. Power pooling, power agreements and inter-utility coordination. Opportunities to purchase energy and/or capacity from other utilities should be identified, including a description of the resource potential and costs. Also list planned purchases necessary to meet reserve margin requirements, and note planned energy hedge trades which provide price certainty and reduce exposure to volatility.
4. Existing non-utility generation in the utility's service territory, including customers with generation capability for self-generation, peak shaving, or emergency back-up, which may reduce the need for new capacity.
5. New non-utility owned generating facilities or technologies available, along with options likely to be available during the planning period. It may be appropriate to consider generic examples of particular technologies, rather than specific potential facilities. The utility should also describe the potential for such facilities by technology and fuel type, the likely amounts of capacity and energy available from such facilities at various prices, ownership, the environmental impacts of such facilities, and the availability of such capacity and energy during the 20-year planning period.
6. Interruptible service offerings to improve system capacity utilization that could improve system capacity utilization.
7. Off-system sales contracts when the utility has excess capacity. When a utility has excess capacity, analysis should be provided in the IRP concerning how it intends to increase efficiency and pursue least-cost service through management of off system sales.

ASSESSMENT OF ALTERNATIVE RESOURCES

For potential generating facilities and technologies identified as credible options for meeting load during the planning period, the following additional information should be provided. For consideration of a generic resource and technology (e.g. solar PV, utility-scale wind, natural gas combined cycle, or market purchases) rather than consideration of a particular facility, generic assessments of these characteristics may be appropriate.

1. Description of supply resource – Where available, list the name, location of each station, unit number, type of unit, installation year, heat rate, rated capacity and net capability, capacity factors, net (dependable) summer and winter capability, and installed environmental protection measures. Also list units grouped by fuel type and heat rate.
2. Availability of resource – Delineate the planned and unplanned outage rates and capacity factors of the units or technologies assessed in the IRP.
3. Operating Costs – Describe the costs to acquire, operate, and maintain the technology (in addition to fuel costs). The utility should identify historic, fixed, and variable costs for producing energy for the past five years, and projected fixed and variable costs of producing energy over the planning horizon.
4. Maintenance Requirements **-** A comprehensive maintenance program is important in providing reliable, low-cost service. The utility should identify expected remaining useful life, maintenance requirements and outages for base load, intermediate and peaking units.
5. Fuel Supply – The utility should specify and describe fuel types, fuel procurement policies, and potential for fuel switching/substitution.
6. Fuel Supply reliability – The utility should describe its contingency plan regarding potential supply disruptions, and strategy to meet the goal of having a reliable supply of low cost fuel.
7. Fuel Prices – Describe historical fuel prices for the past five years and projected fuel prices over the planning horizon (the fuel forecast should be consistent with the range of load forecasts). The price forecast methodology should be clearly stated and defined.
8. Condition Assessment – For resources owned and/or maintained by the utility, describe the utility's plan to maintain and operate supply resources, where economically feasible, at their current levels of efficiency and reliability.

When assessing resource options to develop a least cost portfolio, utilities should incorporate both economic and environmental costs. This includes assessment of the economic risks associated with environmental costs. Where applicable, the utility should identify the quantities of air pollutants, liquid wastes, and solid wastes that are produced by any generation option per unit of electricity produced. In addition, the utility should identify the environmental risks/regulatory changes affecting existing and alternative supply resources.

TRANSMISSION AND DISTRIBUTION SYSTEM IMPROVEMENT

A utility should plan and conduct a comprehensive study evaluating options for improving transmission and distribution (T&D) system efficiency and reliability. Based on the findings of that study, it should then implement a program to bring its T&D system to the level of electrical efficiency that is optimal on a present value of life cycle cost basis within a reasonable period of time. These studies and action plans should be reviewed and updated at reasonable intervals. Finally, each utility should implement a program, as part of its IRP, to maintain T&D efficiency improvements on an ongoing basis.

T&D SYSTEM EVALUATION

Each utility should evaluate individual T&D circuits to identify the optimum economic and engineering configuration for each circuit, while meeting appropriate reliability and safety criteria. The IRP should contain a detailed description of how and when the utility will carry out these evaluations.

Decisions regarding some facilities may affect more than one utility. In such instances, utilities should work together so that their evaluations reflect not only their individual interests, but also the interests of ratepayers generally.

The standard for establishing optimum T&D system configurations and for selecting transmission and distribution equipment is the net present value of life cycle cost. This life cycle cost should be evaluated on both a societal and utility/ratepayer basis. This standard requires consideration of a project's capital costs and life cycle operating costs, as well as benefits resulting from the construction of enhanced system configurations and the installation of energy efficient T&D components. These benefits include avoided operation and maintenance costs, and avoided energy and capacity costs. Avoided energy costs include the direct costs for energy, the costs for energy consumed as line losses, and T&D delivery costs. Avoided capacity costs include fixed costs and capacity charges for power including on peak line losses, fixed costs and capacity charges for T&D, the cost of Capability Responsibility reserve obligations, the deferral of T&D investments. Other benefits of T&D system efficiency include reduced environmental externalities and reduced market prices due to reduced demand for energy and capacity.

Evaluations should identify and compare all technically feasible investments to improve system reliability and efficiency. At a minimum, evaluations should include (and assess the economics and technical feasibility where appropriate) the following measures:

1. The current power factor of the system, and any plans for power factor correction;
2. Distribution circuit configuration, phase balancing, voltage upgrades where appropriate, and opportunities for feeder back-up;
3. Subtransmission and distribution system protection practices and methodologies;
4. The utility's planned or existing "smart grid" initiatives such as advanced metering infrastructure or distribution automation;
5. Re-conductor lines with lower loss conductors;
6. Replacement of conventional transformers with higher efficiency transformers;
7. Conservation voltage regulation;
8. Implementation of a distribution transformer load management (DTLM) or similar program (See Equipment Selection and Utilization Standards below);
9. A list of the locations of all substations that fall within the 100 and 500 year flood plains, and a plan for protection or relocation of these facilities.
10. A current copy of the utility underground Damage Prevention Plan (DPP) (or provide a plan to develop and implement a DPP, if none exists);

T&D EQUIPMENT SELECTION AND UTILIZATION STANDARDS

Utilities should develop and adopt any necessary procedures to meet the following standards:

1. All transformer selection and purchase decisions fully reflect the value of projected capacity and energy losses over the equipment lifetime with due regard for expected loadings and duty cycles;
2. Inventory of transformers in use and on hand is to be managed to match transformer loss characteristics with customer load factors[5]; and

[5] This program should first establish a link between the utility customer or meter accounts and the

3. An ongoing system to monitor and adjust transformer loading for optimal economic benefit is in place.

Implementation of T&D Efficiency Improvements

As individual circuit evaluations are completed, utilities should schedule the implementation of all cost-effective measures within a reasonable period of time. A utility's IRP should note any progress-to-date in the evaluation of circuits, the development of implementation plans for circuits in which evaluations have been completed, and the completion of efficiency measure installations.

Maintenance of T&D System Efficiency

Transmission and distribution systems are dynamic in nature, i.e., their configurations and capacities change over time to meet the changing needs of customers. Consequently, the implementation of a set of efficiency measures on a given circuit should not mark the end of the attention given to that circuit. Rather, T&D system optimization should be pursued as an ongoing effort.

Utilities should, as part of their planning efforts, set out a program for maintaining optimal T&D efficiency. This program and progress in it should be reported thoroughly in the utility's IRP and describe, through operating procedures, design criteria, equipment replacement standards, etc., the manner in which optimal T&D efficiency will be maintained. All subsequent cost-effectiveness analyses performed under this program should maintain the standard of present value of life cycle costs.

OTHER T&D IMPROVEMENTS

In addition to the improvements outlined above, utilities should comply with the following T&D-related improvements, which address several areas important to T&D least cost planning and system reliability.

BULK TRANSMISSION

VELCO, as the responsible planner for Vermont's bulk transmission system on behalf of Vermont ratepayers and utilities, should give special consideration not only to the efficiency of its own facilities, but also to the impact its actions may have on the efficiency of sub-transmission and distribution. Where appropriate, VELCO should support and cooperate with others, including the state's electric distribution utilities, in undertaking regional T&D optimization studies. The societal test coupled with suitable reliability analysis and attention to strategic planning issues should form the basis for planning and technical evaluation. Where additional transmission capacity is determined to be required following consideration of all non-transmission alternatives, the preferred method for increasing transmission capacity should be through the upgrading of existing facilities within existing

distribution transformer that provide services to these customers. This is to enable utilities to monitor monthly energy demand on each transformer, and to provide data that will enable utilities to estimate peak transformer demand. (This could be accomplished through advanced metering infrastructure (AMI) or distribution transformer load management software.) This information will permit utilities to manage transformer loading more efficiently and postpone transformer replacement or pinpoint overloaded or inefficient units in service. These efforts will also be useful in conjunction with voltage conversion or other programs that involve significant investment. For transformer replacement, this program has the potential to provide significant benefits permitting utilities to match transformer capacity and loss characteristics more closely to customer load characteristics.

transmission corridors unless it can be demonstrated that such a measure would have a substantial adverse impact on the electric system or societal costs. The utility's IRP should describe the process undertaken to facilitate inter-utility coordination relative to transmission planning. Transmission projects are reviewed by the Vermont System Planning Committee (VSPC) established pursuant to PSB Docket 7081. Active utility participation and information sharing in the VSPC should increase the state's ability to meet reliability requirements in a least-cost manner.

SUB-TRANSMISSION

Sub-transmission planning should take into account broader interests than those of individual utilities. Where appropriate, integrated regional reliability improvements and transmission system optimization should form the basis for the basic planning and technical evaluation criteria. Utilities should cooperate as needed to assure efficient operation and installation of sub-transmission plant while also assuring an acceptable level of reliability, justified by suitable probabilistic analysis. If necessary, joint utility or utility-regulatory processes should be established to coordinate this activity; collaboration under the auspices of the VSPC may facilitate this coordination. The utility's IRP should describe the actions taken facilitate inter-utility coordination relative to sub-transmission planning.

DISTRIBUTION

The Board is authorized by statute (30 V.S.A. § 249) to designate exclusive service territories for electric utilities in order to reduce or eliminate the existence of duplicate electric facilities. Where duplicate electric facilities exist, the companies responsible should seek to eliminate the duplication to the extent possible.

In the process of building, rebuilding or relocating lines to roadside, electric utilities should coordinate with the appropriate telephone and cable TV companies during the planning and construction phases to ensure that, wherever possible, no permanent duplicate facilities are installed along the same road and that the transfer of existing facilities to new or replaced poles is done in an expeditious manner. The Department encourages all utilities to use the NJUNS software to track transfer of utilities and dual pole removal. The utility's IRP should describe the efforts undertaken to ensure coordination with relevant telephone and cable companies relative to transmission and distribution planning.

While there can be significant benefits from roadside relocation of distribution lines, this activity can have a significant adverse impact on Vermont's scenic landscape. Therefore, companies proposing extensive roadside relocation programs should work with all interested stakeholders (ANR Department of Forests, Parks and Recreation; Public Service Department; Regional Planning Commissions; local governments; and the Agency of Transportation as appropriate) to address aesthetic concerns, including techniques or approaches that mitigate the impact on aesthetics. Where the relocation would have only a minimal impact on visual resources, little or no mitigation may be required. However, for projects in areas with high-value visual resources more extensive mitigation procedures should be considered including:

1. Relocation to the less sensitive side of the road;
2. Use of alternative construction techniques such as spacer cable, armless construction, and relocation underground;
3. Development of a site specific vegetation management plan; and
4. Alternative routing.

These discussions should also consider other important factors such as cost, reliability, and worker and public safety.

GRID MODERNIZATION

"Grid Modernization" and "Smart Grid" generally refer to a class of technology that is being used to modernize utility electricity delivery systems by implementing measurements of circuit parameters, two-way communications technology, and computer processing. This technology includes "advanced meters" which are digital meters that play a key role in grid modernization by measuring voltage, demand (kW), and energy (kWh) at hourly or sub-hourly intervals, and by enabling two way communications. For example, utilities could use these voltage measurements to optimize the voltage on a distribution circuit, and employ conservation voltage reduction where appropriate. The potential benefits are that a smart grid would enable utilities and their customers to track and manage the flow of energy more effectively (including the cost of electricity at a given time), curb peak demand, lower energy bills, reduce blackouts, and integrate renewable energy sources and storage to the grid (including electric and plug-in hybrid vehicle batteries). The smart grid also has the potential to increase energy efficiency, thereby reducing environmental impacts of energy consumption, and empower consumers to manage their energy choices. Distribution Automation is also a term that includes technologies that enable a utility to remotely monitor and operate its distribution system, which should result in improved reliability and operational efficiencies. The Department encourages utilities to investigate grid modernization technologies and to implement those that are cost effective.

VEGETATION MANAGEMENT PLAN

In their IRPs, all utilities should describe their current vegetation management plan and, if they have not already done so, they should evaluate the merits of implementing a systematic vegetative management plan. Some of the information required in this section may be common to several of the smaller utilities, providing a potential opportunity for these utilities to share in the cost of collecting the information for their respective reports. However, each utility should submit its own report because each utility is responsible for ensuring that the vegetation management program in its service territory is undertaken in a least cost manner.

A utility may find it useful to work with the Department of Forests, Parks and Recreation to improve the utility's line clearing standards, train utility clearing crews, and update its vegetation management plan. Public information and education is an area in which materials developed by one utility could be shared by other utilities, thus reducing costs. It is important for utilities to make their customers aware of the dangers of trimming near utility lines and the importance of planting low-growing species beneath power lines.

In describing its current vegetation management plan, each utility should provide the information specified in the table below (or in an alternative format acceptable to the Department). In addition, the utility should provide a detailed explanation of why its current vegetation management program represents the least cost program, including details on the relative composition of tree species present in its service territory, the annual growth rates of these species, and the vegetation management techniques used (including when, where, and how herbicides are used). As a means to evaluate the effectiveness of the vegetation management program, utilities should monitor the number of tree related outages as compared to the total number of outages, and provide this information in their IRPs.

	Total Miles	Miles Needing Trimming	Trimming Cycle
Transmission			
Distribution			

	Y-2	Y-1	Y	Y+1	Y+2	Y+3
Amount Budgeted						
Amount Spent						
Miles Trimmed						

Note: Y = the last full calendar year.

STUDIES AND PLANNING

Each utility should include in its IRP a description of all engineering and operational studies conducted since its last IRP, and all studies planned for the next three years. The utility should also include a list of all capital projects completed since its last IRP or in progress. Capital projects planned for at least the next three years should be included in the IRP Action Plan.

ELECTRICITY PRICING

IRPs should discuss whether current rate designs for each major customer class are consistent with other components of the IRP, and consider how potential future changes in rate design could facilitate IRP goals. Load control programs should be compared for cost-effectiveness with alternative resources.

As utilities deploy, or plan to deploy, advanced metering infrastructure and other smart grid technologies, the technical potential exists for new rate designs. Potential rate designs that could be enabled by these technologies include time-of-use rates, critical peak pricing, dynamic peak pricing, peak-time rebates, and real-time pricing. A utility’s choice of one of these pricing structures for all or some of its customer classes could have significant impacts on the demand for both energy and power, the relationship between components in a power supply portfolio, and the necessary transmission and distribution infrastructure to deliver the required energy to customers. An IRP should address whether the utility plans to incorporate new dynamic pricing structures or rate designs. If the utility has such plans, the IRP should discuss the expected or projected impact of these planned or potential rate structures on load, power portfolios, and infrastructure requirements, or describe plans to characterize these impacts.

ENVIRONMENTAL IMPACT

The IRP should demonstrate an understanding and due consideration of any significant environmental attributes of the resource portfolio, current or planned. These impacts should be quantified where possible. This includes, at a minimum, consideration of CO_2, NOx, and SOx emissions, along with any other environmental impact such as waste disposal. The utility should clearly demonstrate the derivation of the values used to estimate environmental impacts, including emissions rates, lifetime emissions, and the dollar value of emissions or other environmental costs. 30 V.S.A. section 218c requires due regard of the financial risks associated with greenhouse gas emissions, and the value of such risks should be incorporated into least cost planning where possible.

INTEGRATION

The IRP should integrate its use of existing and planned supply resources, T&D improvements, and demand-side resources into a consistent plan that meets the need for energy and capacity. The plan should minimize total costs relative to benefits, showing all financial, regulatory, and other significant assumptions including how environmental externalities have been considered. Utilities should, to the extent feasible, report the expected results of their IRP in at least the following areas:

- Expected capital and operating costs of the resource plan and its effect on utility revenue requirements;
- Impact on costs passed to customers;
- Impact on the environment;
- Effects on fuel and technology diversity and other factors affecting the plan's ability to respond to unforeseen changes;
- Increased coordination between T&D planning and power portfolio planning;
- Impact on reliability of the system;
- Impact on the utility's financial condition;
- Impact on the state and local economies, to the extent feasible; and
- Use of renewable resources and trajectory for achieving statutory and other targets or goals;

RISK AND UNCERTAINTY ANALYSIS

IRP analysis should characterize the principal sources of uncertainty and the associated risks to utilities and their customers. It should go beyond uncertainties in load to consider other factors that may present risks to the utility and its customers such as fuel prices, loss of a major source of supply, and other key forecast drivers and assumptions behind the base case forecast and resource mix. Where analysis reveals unacceptable levels of risk to the utility and its customers with its present portfolio, the utility should characterize avenues for addressing such concerns.

Analyses should be conducted to examine the risks and uncertainties associated with meeting the customers' energy service needs. The IRP should discuss such analyses which are particularly informative to the development of the action plan. Discussion with the Department during the preparation of the IRP may include discussion of risks not included in the final IRP document. Risks and uncertainties to be considered include, but are not limited to:

1. Fuel prices for electricity production and for customer end-uses;
2. Assessment of current economic conditions;
3. Variation in economic factors;
4. In service dates of supply and demand resources;
5. Unit availability;
6. Market penetration rates for, and the cost-effectiveness of, demand-side programs;
7. Inflation in plant construction costs and the cost of capital;
8. Changes in discount rates;
9. Possible federal or state legislation or regulation;
10. New technological developments; and

11. Unit decommissioning or dismantlement costs.

IDENTIFICATION OF LEAST COST PORTFOLIO

Utilities should evaluate a variety of portfolio strategies, noting the uncertainty and sensitivity of each. Strategies that deliver the lowest cost under optimal conditions, but are highly sensitive to the operating environment, may not be the most appropriate choice. Strategies that achieve a relatively low cost under a variety of contingencies may be preferable. Utilities should explicitly account for the critical interactions among potential supply options.

The critical requirement in developing a least cost portfolio of resources is to maintain an unbiased evaluation of options to increase supply and modify demand and to fairly balance costs, risks, and societal impacts. Given the uncertainties inherent in this process, there may be a variety of projects available with identifiable costs and benefits that do not differ widely. Benefits and costs should be evaluated using both a societal test and a utility or ratepayer test; other tests or metrics (such as rate impacts or robustness to uncertainty) may also be appropriate to include.

The integration section of a complete and robust IRP includes a thorough discussion of the following:

1. Identification of an optimal portfolio of supply resources, bulk transmission, T&D, and rate design projects, with a summary of the expected annual energy and capacity costs or savings contribution of each selected option over the planning horizon. Significant concerns of managing the optimal portfolio that relate to financing, project timing, line loss and reserve requirements, and organizational factors should be identified along with any critical externalities that influenced inclusion of the option.
2. Discussion of the methodology and assumptions used to derive the optimum portfolio, with discussion of the sensitivity of results to important assumptions.
3. Discussion of reasonably competitive projects not included in the optimum portfolio, including reasons for exclusion, and whether or not projects will be available for consideration if the strategic environment changes.
4. Discussion of contingency plans associated with the higher risk components of the selected portfolio, including events that would alter the portfolio and trigger a utility's decision to either adopt or terminate a measure.

PREFERRED PLAN

A complete IRP develops a preferred least-cost plan that fully explains, justifies, and documents the manner in which it was developed, including an explanation of how it ensured internal consistency in avoided costs and retail electricity prices. Where the utility's preferred plan does not minimize net societal costs, the IRP should discuss the utility’s reasoning for pursuing the plan selected.

IMPLEMENTATION OR ACTION PLAN

A complete IRP includes effective strategies for implementing the least-cost integrated portfolio identified in the preferred plan. Provisions for research and data collection necessary to improve planning performance (saturation surveys, supply and demand marketing studies, distribution system mapping) can also be included as proposed action items.

A sound and complete implementation plan should include the following:

1. An overview of the preferred least cost portfolio, briefly discussing how it will be administered and updated.

2. For each near-term program project identified in the preferred plan and scheduled for implementation within three years, provide the following:
    a. General procedures for implementing, monitoring, and evaluating the project;
    b. General work plan for the project; and
    c. Identification of important contingencies that may arise as the strategic environment changes and projects evolve, including adjustment to project plans that should be made to minimize adverse impacts.
3. For any program project identified in the preferred plan and scheduled for implementation after three years, provide a list of expected decision points.

ONGOING MAINTENANCE AND EVALUATION

After its IRP is approved, a utility is responsible for administering approved projects, evaluating and reporting on progress, and effectively maintaining its IRP.

Addendum B: Consistency Determination

The Department under 30 V.S.A. §202(f) reviews certain proposed actions by electric utilities to determine the consistency of those actions with the current adopted version of the *Vermont Electric Plan*. Companies contemplating proposals for actions subject to PSB approval under 30 V.S.A. §108 or §248(b) should also request in writing the Director of Planning and Energy Resources' determination under 30 V.S.A. §202(f).

In addition to determining consistency with the specific text of Sections 3, 4 and 5 of Volume 2 of the *Comprehensive Energy Plan* (which are the *Electric Plan*), the Department will look for consistency with the summary statements of policy contained in Volume 1 of the Comprehensive Energy Plan and the statutory state policies, goals, and requirements summarized in section 1.2 of Volume 2 of the *Comprehensive Energy Plan*. This includes the goals and policies established in 30 V.S.A. sections 202a(1), 202a(2), and 8001.

Notification

Any company making such a proposal should notify the Director at least 60 days in advance of the proposed action and include, at a minimum, the following information:

1. A description of the proposed action; the nature of the arrangements being proposed; the capacity and/or energy and the terms of the arrangements being proposed; and other relevant information.
2. An explanation of the objectives the company seeks to accomplish with the proposed action, and how it relates to the company's short and long-range power supply plans, as well as to this Plan.

Regulatory Response

The Department will advise the company if additional information on the proposed action will be needed. If so, the Department will make appropriate information requests. The Department will issue the resulting determination as quickly as feasible following the receipt of requested information. Typical information needed for utility power supply projects or purchases includes:

ECONOMIC ANALYSIS

Calculation of the societal costs and benefits of a proposed supply action and of the supply and DSM alternatives the utility has considered. The underlying data, including production simulations and DSM program data, should be included. Submitted analysis should also include discussion (and where possible, calculation) of the opportunity cost of the proposed action.

SENSITIVITY ANALYSIS

Since the results of societal test analyses are highly sensitive to key assumptions that may be hard to predict, it is necessary to determine how varying those assumptions may alter the competitiveness of the proposed action. For this reason, the utility should conduct additional studies incorporating variations of those assumptions (utilizing tools such as Monte Carlo or scenario analysis and including correlations among variables where practicable). All assumptions subject to changes that would have a significant impact on the analysis results should be reviewed. The variations to be studied may be developed with the Department in advance of filing.

DIVERSITY CALCULATIONS

To help gauge the degree of dependence on the proposed project, a utility's analysis should show the percentage of its energy and capacity requirements the proposed action will provide during the project's life, based on production simulation results.

Similar calculations should be shown for the aggregate energy and capacity from the proposal plus all other entitlements of the utility that use similar technology and fuel.

Other actions are likely to require different kinds of information.

The Department wishes to expedite the review and determination process in every way compatible with its responsibility to conduct a thorough review of proposed actions. For that reason, companies are encouraged to initiate discussion of major proposed actions at an early date.