

Appendix B: Guidance for Integrated Resource Plans and 202(f) Determination Requests

The first portion of this appendix 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*.

The *2016 Comprehensive Energy Plan* (2016 CEP) incorporates the Electric Plan. Where the Electric Plan is referenced in statute, the relevant document is the 2016 CEP¹.

Especially relevant to electric utility IRP planning and consistency determinations under 30 V.S.A. §202(f) are Chapters 9, 10, and 11 which directly address electric power. Chapters 12 and 13 outline the state’s approach to particular energy resource types (e.g. solar, wind, natural gas, etc.). Natural Gas utilities should see the natural gas section of Chapter 13 for information about the Department’s approach to natural gas.

Although those chapters are most relevant, the entire 2016 CEP is the Electric Plan. IRPs and other utility actions that must be consistent with the electric plan should be consistent with 2016 CEP more broadly.

¹ The *2016 Comprehensive Energy Plan* is available on the Department’s website at https://outside.vermont.gov/sov/webservices/Shared%20Documents/2016CEP_Final.pdf

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Part A: Integrated Resource Planning Guidelines

Introduction

Pursuant to 30 V.S.A. §218c², 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.³

The IRP process and the implementation of each Vermont utility's 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

² 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.

³ 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.

individual utility. The IRP process is intended, in part, to facilitate information exchange among utilities, regulatory agencies, and the public.

Utilities should use the IRP process to address questions that are the most relevant to the utility at the time of the IRP. Where issues or considerations listed in this document are not germane to the utility, the Department and the utility should, in advance of the utility filing, discuss whether those issues should be included. Also, IRP planning should be conducted with other planning exercises, such as the construction work plan or RUS requirements, in mind. Where a forecast or analysis would serve the purpose of meeting multiple planning obligations, utilities should not be obligated to perform multiple analyses. IRPs will reflect the wide range of planning capacity at Vermont's utilities.

Utilities should use the IRP process to develop methods they will use to evaluate competing investment and purchase decisions to meet customer demand. The range of options available to utilities to balance supply and demand are expanding as new generation, load control, storage, and smart grid technologies become available and affordable. The characteristics of supply and demand resources are changing as well. Historically load was viewed as a fixed obligation which utilities planned to meet with dispatchable supply. Higher penetration of intermittent generation and controllable loads mean that utilities must begin to plan for a future in which both demand and supply have some controllable and some uncontrollable aspects. Grid operators must prepare for more complex grid choreography to balance supply and demand.

Act 56 of 2015 created a Renewable Energy Standard (RES) for electric utilities that requires renewable energy totaling 55% of retail electric sales in 2017, with that requirement growing 4% every three years to 75% in 2032 (Tier 1). Of these renewable resources, some (1% of retail sales in 2017 growing to 10% in 2032) are required to be new, small, distributed generators connected to Vermont's distribution grid (Tier 2). The Act also requires utilities to assist their customers in reducing fossil fuel consumption (Tier 3). Implementation of Tier 3 may result in some electrification of transportation and heating which will impact both overall demand and the daily load profiles of various customer classes. The RES will have significant effects on how utilities plan to balance supply and demand within their portfolios.

In this context, utilities should use the IRP process to demonstrate the underlying methodology and a set of specific tools they will use to evaluate options for balancing supply and demand at the lowest present value life cycle cost as they arise. Because the operating environment is rapidly evolving, using the IRP process as an opportunity to develop, test, and demonstrate these methodologies will allow utilities to react with a greater degree of flexibility as economic and technological conditions in the industry change.

The 2016 edition of this document reflects several important changes to the IRP process:

- An emphasis on using methods for load forecasting and evaluating supply options which can effectively account for uncertainty in emerging technologies.
- The addition of an optional financial analysis which anticipates changes to a utility's cost of service under different scenarios.
- Guidance about how utilities should consider higher penetration of distributed energy resources and increased electrification.
- Discussion of the implications of the RES for load forecasting and supply planning.

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.

Filing and Approval Process

Filing Schedule and Review

Utilities are required to complete a new 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 2016 CEP, including this appendix, and Board Orders.

Utilities in Vermont vary widely in geographic size, sales, and staffing levels. Utilities should produce IRPs which reflect the complexity and size of their operations.

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. 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. Cost of service and financial implications will bring in the Finance and Economics 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.

Public Service Board Review and Approval

Each regulated electric company shall submit a proposed plan to the Department and the Public Service Board. PSB review will include notice and opportunity for 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 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 approval.

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.

Required Elements

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.

The executive summary should also include a description of the utility's current business and system including information such as the number of customers, peak load, which towns the utility serves, the number of substations and circuit miles, current sources of power etc.

2. **Table of Contents** which gives titles and page numbers for sections as well as sub-sections.
3. **Forecasts and Scenarios** which includes load forecasts and alternative scenarios.
4. **Assessment of Resources** which reviews the existing resource mix, identifies a broad range of supply-side options, models the integration of new resources, and leads to the selection of a preferred portfolio.
5. **Financial Assessment** which presents the utility's business plan for the future while providing information on changes in its overall cost of service and electric rates.
6. **Assessment of the Transmission and Distribution System** which evaluates options for improving system efficiency and reliability and presents plans for bulk transmission, grid modernization, and vegetation management.
7. **Assessment of Environmental Impact** which quantifies, assigns a value to, and then considers any significant environmental attributes of the resource portfolio.
8. **Integrated Analysis and Plan of Action** that looks across demand, supply, finances, and transmission and distribution, to identify a least-cost portfolio and a preferred plan of action.

1. Forecasts and Scenarios

IRP analysis begins with a load forecast along with the development of several alternative scenarios. Load forecasting is a long-standing practice of estimating a utility's load based on a range of economic, technological, and weather data. Scenario planning on the other hand considers dynamic or surprising futures that can result from rapidly changing circumstances such as economic downturns, large-scale deployment of new technologies, or changes in customer behavior.

Both forecasting and scenario planning help utilities develop tools to evaluate how they should react to changes in the electric power sector on an ongoing basis in a world where many factors influencing supply and demand are complex and uncertain.

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. 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.

1.1. Demand Forecasting

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.

a. Base Case Forecast

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.

b. Weather and Probability

The IRP should include a description for the methodology chosen to incorporate weather into the peak demand forecast. The effects of weather events are a significant factor in developing forecasts of peak demand load. 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).

c. 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, VELCO, the Vermont System Planning Committee (VSPC) and/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; and
- 6) Clearly document the vintage of any macroeconomic forecast used.

d. Policy, Codes & Standards

State and federal policy has a significant impact on electric load. 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.

e. Renewable Energy Standard (RES) Compliance for Tiers 2 and 3

The Renewable Energy Standard (RES) requires that utilities acquire supply from distributed resources and engage in energy transformation projects to reduce their customers' use of fossil fuels. As of this writing, the Public Service Board has not issued a ruling specifying how utilities should implement the RES; however, the RES makes clear that under Tier 2 utilities are required to obtain significant supply resources from distributed generation. Some of these resources will be "behind the meter" projects that impact net load on an annual, seasonal, and daily basis. For example wide-scale deployment of behind the meter solar both reduces net demand and shifts summer peaks to later in the day.

Under Tier 3 utilities will be aiding customers to reduce their fossil fuel use through a variety of “transformation” projects. These projects may include some efficiency measures that could affect electricity usage as well as fossil fuel usage and they may include measures designed to shift energy use in transportation and heating from liquid and gas fossil fuels to electric-based technology. The addition of these new technologies may drive load upward and shift consumption to different times of day or different seasons. For example, wide-scale adoption of electric heat pumps may increase winter demand for electricity.

When forecasting load, utilities should explicitly consider how their plans for Tier 2 and 3 compliance may impact load from the perspective of total annual sales, and also seasonal and daily use patterns.

f. 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 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 discuss how it expects forecasted energy efficiency savings to affect load.

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:

- 1) Demand response resources forecasted to be available;
- 2) Demand impacts of other load management strategies such as rate design; and
- 3) Energy and power supplied by net metered generators.
- 4) 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.

The utility should consider inclusion of low and high case forecasts for these resources on its system.

g. Emerging Technologies

The utility should explicitly describe its consideration of the expected impact of emerging technologies on its demand forecast, as well as planning for supply and T&D. The utility should also describe its expectations for the adoption of any other new technologies that may increase energy and power needs.

The 2016 Comprehensive Energy Plan explicitly aims to increase electrification in transportation and heating. The RES also creates a Tier 3 obligations will directly impact not only the total amount of energy utilities must provide, but may alter the load shapes of many customer classes. Utilities should consider:

- 1) Distributed, net-metered generation;
- 2) Plug-in electric vehicles;
- 3) Heat pumps;
- 4) Energy storage; and
- 5) Other fuel switching technology.

h. Updating the Forecast

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

1.2. Alternative Scenarios

In some previous IRPs, scenarios have been developed by adjusting the base-case demand forecast both upward and downward, but without the consideration of disruptive exogenous forces or the possibility of the utility controlling or shaping load itself. Emerging technologies in the electricity sector have the potential to fundamentally reshape how electric power is generated, delivered, consumed, and paid for within the 20-year planning horizon of the IRP. Utilities should use the IRP process as an opportunity to consider not only how load will incrementally grow or shrink, but to evaluate whether and how new technologies and socio-economic forces that are uncertain and outside of the utility's control will impact it and its customers, as well as how new kinds of utility interventions could influence when customers use electricity and how much they use.

Utilities are encouraged to choose a methodology which has sufficient flexibility to evaluate these potentially disruptive and transformative trends for both load forecasting and evaluating supply options. The specific issues the utility considers, and the methodologies it employs to do so are left up to the utility. However, that methodology must be capable of fully addressing uncertainties in electrification, distributed generation, storage, controllable loads and other emerging technologies that may radically change load, supply, and financial solvency of the utility.

One potential method utilities could employ is scenario planning.⁴ Scenarios are not predictions of what will happen, but plausible futures that may happen. Utilities can use scenario planning to consider how some of these possible futures may play out and develop tools that will help them react to changing circumstances as they evolve, and actively shape the conditions they will face. Each utility faces a different set of concerns, so scenarios developed by that utility should reflect its unique characteristics.

As utilities consider possible alternative futures, the Department is interested in knowing not necessarily how exactly the utility might respond, but *what tools and methods* it will use to decide how to respond. These tools will likely include modeling as well as decision-making processes, customer/member engagement, and new innovative programs.

a. Sources of Uncertainty

There are many sources of uncertainty for utilities across the 20-year planning horizon. Some are related to emerging technologies and others are related to exogenous economic forces, weather, or demographics, etc. Methods developed by utilities should include ways to evaluate sources of uncertainty. Scenario planning is one such method, but not the only one.

Because the Comprehensive Energy Plan and the RES call for increased distributed energy resources as well as significant electrification in transportation and heating, utilities should use their IRPs to consider how these state-level policies will impact load and supply, as well as the utility's own role in shaping and managing load. Therefore, methods chosen by the utility to forecast load and compare supply options should be capable of considering the best course of action for the utility under a "high DER (distributed energy resources) and electrification scenario." Utilities should consider the rapid development of high levels of behind the meter generation, storage, and controllable loads as well as significant electrification in the transportation and building heat sectors. Distributed energy resources and electrification will impact *both* supply and demand.

Methods developed by the utility should also consider areas of particular relevance to that utility. The list below is provided to stimulate thinking about possible futures which differ significantly from base case scenarios.

- 1) The cost of energy, capacity, and RNS charges at the regional level is either significantly greater or significantly less than current levels.
- 2) Small-scale solar generation continues to rapidly deploy, constituting an accelerating percentage of the utility's supply; or changes in various incentives cause a slow-down in solar development.
- 3) The value proposition for electric storage, at either the utility scale or for end-users, improves significantly, for example such that it can be used to more

⁴ For a description of scenario planning in the context of electric utilities, see NARUC's Scenario Planning in a Utility Regulatory Context. Available at <http://www.naruc.org/Publications/FINAL%20Full%20Colorado%20SERCAT.pdf>.

closely coordinate intermittent supply with demand; or electric storage for end-users remains out of reach.

- 4) Customers can significantly reduce their net load to the grid by procuring their own generation and storage and they do so in increasing numbers; or customers continue to purchase the vast majority of their needs from the grid, but play a larger role in supply, load control, and/or storage. Note that this could vary significantly by rate class.
- 5) Electric load grows significantly as transportation and heating are electrified; or penetration of electric cars and heat pumps remains low.
- 6) Socio-economic forces cause a dramatic increase or decrease in load because of either economic boom or bust.
- 7) There is an increase in dramatic weather events which cause many more outages and require greater emergency response from the utility.

b. Impacts to Utility Operations

After the utility has identified relevant future scenarios, it should develop methods to consider how it will balance supply and demand, while maintaining or enhancing power quality and reliability. Unlike incremental changes to load, disruptive circumstances will impact the timing and scale of system peak and total energy usage. For example, increased solar production is shifting net peak demand later in the day and may require resources or infrastructure to be planned for later in the day.

Depending on how these sources of uncertainty play out, the least-cost path to balancing demand and supply while ensuring safety, reliability, and power quality will create impacts and require the utility to acquire a different portfolio of resources (broadly defined). To balance supply and demand, utilities should consider both traditional centralized supply solutions as well as distributed energy resources. Utilities should take an integrated look, considering not only the cost of the resource, but the impact of that resource on the grid including any necessary or avoided upgrades.

The IRP should present strategies to address the impact of future scenarios on the following aspects of utility operations:

- 1) Seasonal load profiles for different types of rate classes;
- 2) Power supply portfolios on summer and winter peaking days;
- 3) Timing and magnitude of system peak;
- 4) Transmission and distribution system upgrades;
- 5) Recovery of sunk costs;
- 6) Rates;
- 7) Total load and supply;
- 8) RES compliance.

c. Ongoing Application

The utility should develop methods to consider the various possible futures they develop which can be deployed between IRP cycles to evaluate demand, supply, business model, and infrastructure options as they are evolving. These tools might include cost of service models, decision trees for selecting least cost options, methods for considering attributes such as resilience or microgrids, and geo-targeting of efficiency or other DER measures. These methods and tools should be deployed when utilities make major decisions about power supply, load control, and system upgrades.

1.3. Data, Models, and Information

a. Data and Models

In developing forecasts and scenarios, utility should utilize relevant historical data. To aid in review, numerical data should be made available in electronic formats usable by the Department and Board.

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.

2. Assessment of Resources

The assessment of resources provides an inventory of existing resources and presents supply options along with relevant information about the characteristics of that supply. Throughout the resources section of the IRP, utilities should integrate their plans to meet RES obligations under Tiers 1, 2, and 3.

2.1. Existing Resources

A complete assessment of the utility's existing resources should include an evaluation of the following:

- 1) Existing and committed base case generating capacity and firm power transactions currently under contract;
- 2) Potential changes to existing resource commitments, including, but not limited to, re-powering, fuel switching, and life extension of power plants or power contracts;
- 3) Loss reduction in transmission and distribution systems, and improvements in generation and/or T&D areas;
- 4) Existing renewable resources;
- 5) Utility construction and jointly developed projects;
- 6) Power and REC purchases, including:
 - Purchases through the Standard Offer program;
 - Purchases to satisfy utility RES obligations under Tiers 1 and 2;
 - Purchases from independent power producers;
 - Purchases from other utilities;
 - Customer owned generating capacity;
 - Resources developed through pooling, wheeling, coordination arrangements, or through other mechanisms; and
 - Any other Board approved bid solicitation programs.

2.2. Supply Options Inventory

In describing supply options to consider over the planning period, 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.
- 4) Opportunities to purchase energy and/or capacity from other utilities or entities should be identified, including a description of the resource potential and costs.
- 5) Planned purchases necessary to meet reserve margin requirements, and planned energy hedge trades which provide price certainty and reduce exposure to volatility.
- 6) 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.
- 7) 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.
- 8) Interruptible service offerings to improve system capacity utilization.
- 9) 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.

2.3. Assessment of Alternative Resources

For potential generating facilities and technologies identified as credible options for meeting load during the planning period, the utility should provide the specific information in items 1-10 below.

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 and 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.
- 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.
- 9) RES compliance – Whether the resource satisfies Tier 1, Tier 2, or Tier 3 requirements.
- 10) 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 affecting existing and alternative supply resources.

2.4. Smart Rates

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.

The *2016 Comprehensive Energy Plan* requires utilities with AMI infrastructure to develop a plan to move to smart rates as the standard option. Smart rates could include time-of-use rates, critical peak pricing, dynamic peak pricing, peak-time rebates, and real-time pricing. The IRP should include such plans for smart rate deployment and estimate the impact smart rates may have on total demand, peak demand, and infrastructure requirements.

A utility's choice of one of these pricing structures for its customer classes could have significant impacts on the demand for both capacity and energy, 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 how the utility plans to incorporate new dynamic pricing structures or rate designs or qualify for the exception outlined in the 2016 CEP (p. 226). 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.

3. Financial Assessment

The financial assessment, new to this edition of the IRP guidelines, is optional for IRPs completed under this guidance document, although utilities are strongly encouraged to submit a financial assessment as part of their IRPs. The Department anticipates making the financial assessment mandatory for the next planning cycle after reviewing the optional submissions.

Should utilities choose to complete a financial assessment, it should present a strategic direction for business. It should consider the impact of the utility's preferred action plan (see Section 6) on revenue, expenses, income, and financing. The financial assessment should describe the utility's expected cash flow and describe its financing plan for any capital expenditures. It should also present the expected financial results of the utility's business plan while providing information on changes in its overall cost of service and electricity pricing.

Relatively simple 5-year financial projections can be made by applying an inflation rate to known, current business expenses and adding in the cost of any known new capital expansions.

3.1. Cost of Service

A utility has an obligation to its ratepayers to manage risk and minimize its system cost. Utilities should evaluate and balance the expected costs, business risks, and long-run public policy goals in developing and selecting a business model portfolio with the best cost-risk combination.

Resource portfolio analysis provides input to the cost of service model that determines the impact on customer rates of each portfolio. The cost of service model includes the impacts of lost sales in the rate calculations for each portfolio. This allows for the assessment of rate impacts of the resource portfolios.

A utility's cost of service model would recognize a utility's financial objectives while meeting energy resource needs through a balanced, lowest cost portfolio, with supply, demand, and energy efficiency options.

Included in the financial section of a utility's IRP filing should be its expected revenue requirement and cost of service for the next 5 years that could include but would not be limited to:

- 1) Production;
- 2) Transmission;
- 3) Distribution;
- 4) Customer accounts;
- 5) Sales;
- 6) Administration & general;
- 7) Depreciation;
- 8) Taxes other than income taxes;
- 9) Other interest expense;
- 10) Income taxes;
- 11) Cost to finance rate base;
- 12) Total cost of service;
- 13) Expected rate revenues;
- 14) Rate base;
- 15) Financing plans including cash flows and planned capital expenditures.

Information on the utility's financial metrics and ratios over the IRP planning horizon should also be provided. The financial ratios could include but would not be limited to:

- 1) Interest coverage ratio (operating income plus depreciation, divided by interest expense);
- 2) Debt service ratio (operating income plus depreciation, divided by interest expense plus principal payments);
- 3) Equity to debt ratio (total equity divided by the total debt outstanding);
- 4) Return on equity and weighted average cost of capital;
- 5) Credit rating of the firm; and
- 6) Each of its outstanding debt instruments.

4. Assessment of the Transmission and Distribution System

Each electric 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.

4.1. 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 utility's power factor goal(s), the basis for the goal(s), the current power factor of the system, how the utility measures power factor, and any plans for power factor correction;
- 2) Distribution circuit configuration, phase balancing, voltage upgrades where appropriate, and opportunities for feeder back-up;
- 3) Sub-transmission and distribution system protection practices and philosophies;
- 4) The utility's planned or existing "smart grid" initiatives such as advanced metering infrastructure, SCADA, or distribution automation (see Section 4.6);
- 5) Re-conductor lines with lower loss conductors;
- 6) Replacement of conventional transformers with higher efficiency transformers;
- 7) The utility's distribution voltage settings (on a 120 V base), and whether the utility employs, or plans to employ, conservation voltage regulation or volt/VAR optimization;
- 8) Implementation of a distribution transformer load management (DTLM) or similar program (see Section 4.2);

- 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 discussion of whether the utility has an underground Damage Prevention Plan (DPP), or plans to develop and implement a DPP, if none exists;
- 11) The location criteria and extent of the use of animal guards.
- 12) The location criteria and extent of the use of fault indicators, or the plans to install fault indicators, or a discussion as to why fault indicators are not applicable to the specific system.
- 13) A pole inspection program, the plans to implement a pole inspection program, or a discussion as to why a pole inspection program is not appropriate to the specific utility.
- 14) The impact of distributed generation on system stability.

4.2. T&D Equipment Selection and Utilization

Each utility should describe the process(es) used to select all major equipment (not limited to transformers) according to least-cost principles.

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

4.3. 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.

4.4. 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.

4.5. 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.

a. 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 upgrading existing facilities within existing 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 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.

b. Sub-Transmission

Sub-transmission planning should take into account broader interests than those of individual utilities. Where appropriate, integrated regional reliability improvements and sub-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.

b. 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.

4.6. 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.

4.7. Vegetation Management Plan

Each utility should describe its current vegetation management plan (including both cyclic ROW trimming and hazard/danger tree removal) or, if they have not already done so, they should evaluate the merits of implementing a systematic vegetation 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. 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). Each utility should discuss in its IRP the means used to evaluate the effectiveness of the vegetation management program, including monitoring the number of tree related outages as compared to the total number of outages, and analyzing and comparing the cost of proactive vegetation management versus the cost of responding to storms.

	Total Miles		Miles Needing Trimming		Trimming Cycle (years)	
Sub-transmission						
Distribution						
	Y-2	Y-1	Y	Y+1	Y+2	Y+3
Amount Budgeted						
Amount Spent				X	X	X
Miles Trimmed						

Note: Y = the last full calendar year.

4.8. Studies and Planning

Each utility should include 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 action plan (see Section 6.4).

4.9. Emergency Preparedness and Response

In its IRP, each utility should describe storm/emergency procedures, such as securing contract crews, dispatch center, participating in utility conference calls, and updating vtoutages.com. This should include a discussion regarding how often vtoutages.com is updated, and, if applicable, what could be done to update it more frequently. Also discuss the utility's operating procedure for internal and external public notifications of planned and unplanned outages.

4.10. Reliability

Each utility should provide in its IRP the data for the last five full calendar years for CAIDI and SAIFI as reported pursuant to PSB Rule 4.900 (i.e., without major storms excluded). These data may be presented in either tabular or graphical format. The utility should discuss the trends of these data, and, if applicable, what additional actions may need to be taken.

5. Assessment of 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 could include consideration of greenhouse gas emissions, NOx, and SOx, along with any other environmental impact such as waste

disposal. The utility should consider any environmental impacts that it deems material to the outcome of its load management and supply portfolio analysis. If it chooses to exclude any particular pollutants or impacts from analysis, should give an explanation as to why it chose to do so. 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.

The RES internalizes the cost of many of the externalities associated with greenhouse gas emissions; although the requirements of the RES phase in over time and do not fully eliminate greenhouse gas emissions from the utility portfolio. As the RES phases in, the externalized costs of greenhouse gas emissions should be reduced in IRPs to coincide with reductions of greenhouse gas emissions in the portfolio.

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. The statute requires that:

“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.”

6. Integrated Analysis and Plan of Action

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 results of their IRPs in at least the following areas:

- 1) Expected capital and operating costs of the resource plan and its effect on utility revenue requirements;
- 2) Impact on costs passed to customers;
- 3) Impact on the environment;
- 4) Effects on fuel and technology diversity;
- 5) Increased coordination between T&D planning and power portfolio planning;
- 6) Impact on reliability of the system;

- 7) Impact on the utility's financial condition;
- 8) Impact on the state and local economies, to the extent feasible; and
- 9) Use of renewable resources and trajectory for achieving statutory and other targets or goals.

6.1. 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.

6.2. 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 and distributed energy 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.

6.3. 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.

6.4. 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:
 - General procedures for implementing, monitoring, and evaluating the project;
 - General work plan for the project; and
 - 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.

6.5. 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.

Part 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*, which is the *2016 Comprehensive Energy Plan* (2016 CEP). Companies contemplating proposals for actions subject to PSB approval under 30 V.S.A. §108 or §248(b) should also request a determination in writing from the Director of Planning and Energy Resources under 30 V.S.A. §202(f).

In addition to determining consistency with the specific text of the *Comprehensive Energy Plan*, the Department will look for consistency with statutory state policies, goals, and requirements, including the goals and policies established in 30 V.S.A. sections 202a(1), 202a(2), 218c, 218e, and 8001.

1. Process

a. 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;
- 2) The nature of the arrangements being proposed;
- 3) The capacity and/or energy and the terms of the arrangements being proposed;
- 4) An explanation of the objectives the company seeks to accomplish with the proposed action;
- 5) How it relates to the company's short and long-range power supply plans;
- 6) How it relates to the 2016 CEP; and,
- 7) Any other relevant information.

b. 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.

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.

2. Filing Components

Typical information needed for utility power supply projects or purchases includes the following components. Other actions are likely to require different kinds of information.

a. 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.

b. 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.

c. 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.