2007
Integrated Resource Plan

GREEN MOUNTAIN POWER

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1: Executive Summary

Overview

Green Mountain Power presents the results of our 2007 Integrated Resource Planning process. Through this process we met several objectives.

The first — and most important — objective is that we thoughtfully examined the potential strategies that GMP could deploy to secure the resources necessary to meet the needs of our customers in a way that provides the most value to customers, based on current and anticipated regulatory policies, price projections, and risks. GMP evaluated the various strategic options from several perspectives: projected costs, air emissions, flexibility, financial feasibility, and flexibility to adapt to the changing environments in which our customers live and conduct their businesses.

A second objective is to form a basis for establishing dialogue with the Vermont Public Service Board, the Department of Public Service, the Vermont Legislature, the executive administration, and other government agencies. In this objective, we comply with the requirement for all utilities in Vermont to periodically file an Integrated Resource Plan.

The third objective is one that is gaining visibility and priority within the Vermont community. GMP hopes that this report and other insights and information developed within the IRP analysis provide context to the public outreach efforts being conducted by the Department of Public Service. As such, GMP has adopted a decision and information presentation process that brings more stakeholders with diverse perspectives into the strategic planning process. To do this, we incorporated a process known as a Multi-Attribute Trade-off analysis (see “Results of the Multi-Attribute Trade-off Analysis” on page 10 for details).

Planning Objectives

Based in part on the results of our analysis, GMP continues to pursue the following goals:

- Keep our revenue requirements low, both in procuring and delivering power.
- Maintain our environmental stewardship by continuing to purchase energy principally from non-emitting or low-emitting sources.
- Manage our supply and generation risk, including support of the highest level of economic energy efficiency and investing in a judicious amount of economic renewable sources. All these options help create a diverse portfolio of resources.
- Continue strengthening our financial position.

Sections of the IRP

This IRP consists of several sections.

Section 1: Executive Summary reviews the entire report and presents its conclusions.

Section 2: Background Information addresses the current situation in the electric industry — regionally, nationally, and for GMP in particular — and summarizes our investment in renewable power sources.

Section 3: Demand and Resources presents forecasts of load growth, discusses the effects of energy efficiency initiatives on growth, describes GMP's current sources of generation, and describes various methods of planning and associated studies conducted.

Section 4: Energy Resource Planning presents the analytical framework for identifying a least-cost mix of resources; and describes four alternative scenarios GMP might face over the next twenty years, evaluating potential supply portfolios and comparing those portfolios across the various potential future outcomes based on appropriate ranking criteria. We determined the portfolio best suited to meet GMP's incremental needs and evaluated whether GMP's existing portfolio should be adjusted or replaced. This section also describes previously performed studies concerning the capacity, reliability, and efficiency of GMP's sub-transmission and distribution system.

The final **Section 5: Action Plan** describes the proposed plan for implementing the conclusions presented in this IRP.

We at GMP are confident that other stakeholders will find the insights gained from this report and our process valuable and more importantly useful. Our Integrated Resource Plan is, and should be, a living plan intended to provide current direction for our resource management activities while being adaptive to the evolving global energy world and changing customer preferences. In addition, this effort provides GMP with an analytical framework to use for further refining the plan as we implement it.

As all stakeholders on Vermont's energy future recognize, the value of all planning exercises depends on a myriad of assumptions for evaluating how decisions could, would, and should turn out. GMP recognizes this uncertainty by testing key assumptions as well as by creating a living plan that can be evaluated and tested as we gain more information. This information could come in the form of clarity in environmental regulations, a change in the direction of the price and availability of fossil fuels, and revisions to the cost estimates for new efficient electric generating facilities, as well as from the evolving priorities of stakeholders as they affect GMP's provision of reliable electric power to the customers in our service territory.

This plan complies with the orders of the Vermont Public Service Board (PSB) in Docket No. 6290, to with the requirements of 30 V.S.A. §218c. That section defines an IRP as:

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.

This IRP, along with steps that GMP has taken since 2003, also addresses a number of specific items contained in stipulations associated with GMP's 2003 IRP. Appendix I summarizes these items, and where they are addressed.

The Details of the Plan

Four Scenarios

We based much of the portfolio analysis and energy efficiency savings forecasts in this Integrated Resource Plan on four scenarios, called:

- Fortress America
- Green Focus
- Back to Business
- Green Growth

Please note: Much of the information in this report is based on projected figures and statistics. While much effort and considerable forethought has been exerted, no one can accurately predict the future. As such, the actual numbers and future outcomes are likely to be different. Please consider this fact when reading this report.

These scenarios were initially identified in the February 2003 Vermont Integrated Resource Planning Scenario Development Report submitted on behalf of GMP, Central Vermont Public Service Company (CVPS), and Citizens Communications Company doing business as CES, the Citizens Energy Services.

Figure 1 depicts these four scenarios with respect to geopolitical and economic factors (horizontal axis) and environmental regulation factors (vertical axis).

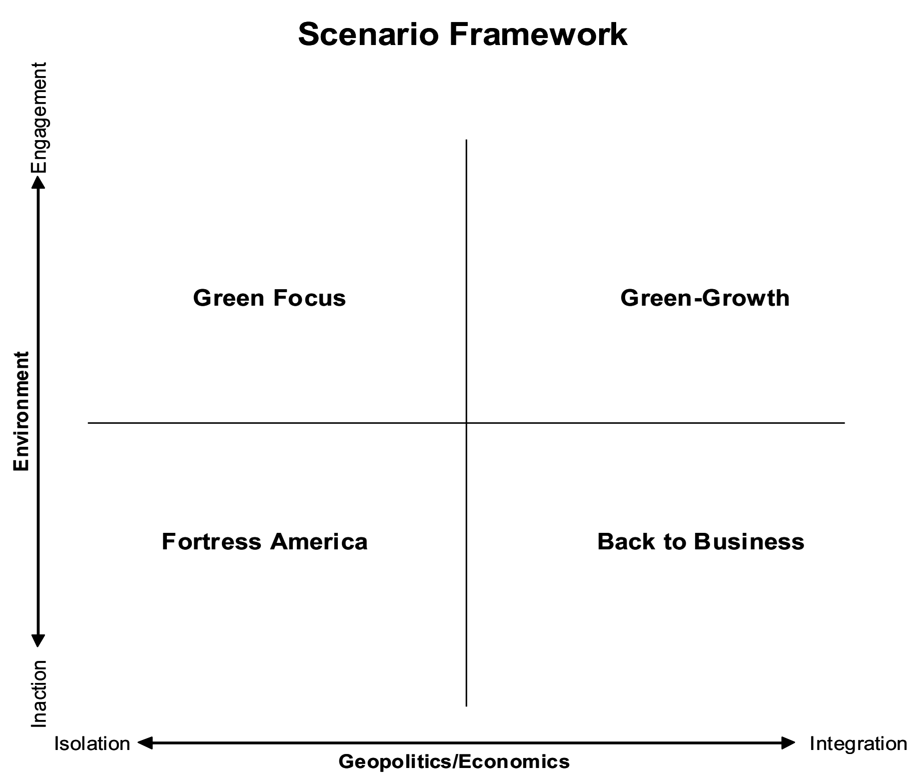

Figure 1: Framework for Future Condition Scenarios

GMP analyzed three variations of each strategy against six portfolio choices, providing for an overall analysis of 18 resource portfolio strategies. The heart of GMP's analysis is referred to as Scenario Planning whereby each of these strategies is modeled and evaluated under four different scenarios for the energy future of the state, regional, and global marketplaces.

The four scenarios can be summarized as follows:

Fortress America

- Highest fuel prices, then moderation
- Low load growth
- Security and reliability spending stagnates economy
- Little progress made toward tighter environmental regulations
- Local supply commands a premium
- Second strongest demand-side management (DSM) investment scenario

Green Focus

- High fuel price trends
- Low load growth
- High DSM, strong renewables growth
- Stronger environmental regulation

Back to Business

- Robust load and economic growth
- A share of fuel price downturn followed by moderation in price growth, hence the lowest fuel price scenario in fuel prices
- Modest levels for DSM funding levels and renewable portfolio standards (RPS)
- Limited evolution in environmental regulation

Green Growth

- Moderate load growth, strong economy
- A small fuel price decline followed then by inflationary growth
- Moderate enhancements to environmental regulations
- Slow growth in DSM
- Federal RPS, but slow implementation

Planning Resources

GMP faces a resource planning imperative over the next ten years. We forecast three alternatives with respect to growth in electricity demand (which inherently assumes some degree of energy efficiency programs in determining its growth rate) over the next 20 years:

- Base peak, based on a 1% annual growth.
- Low peak, based on a 0.6% annual growth.
- High peak, based on a 1.6% annual growth.

We considered the effects of economic trends, statistical analyses, and energy efficiency programs on all three growth rates. Figure 2 depicts these growth rates.

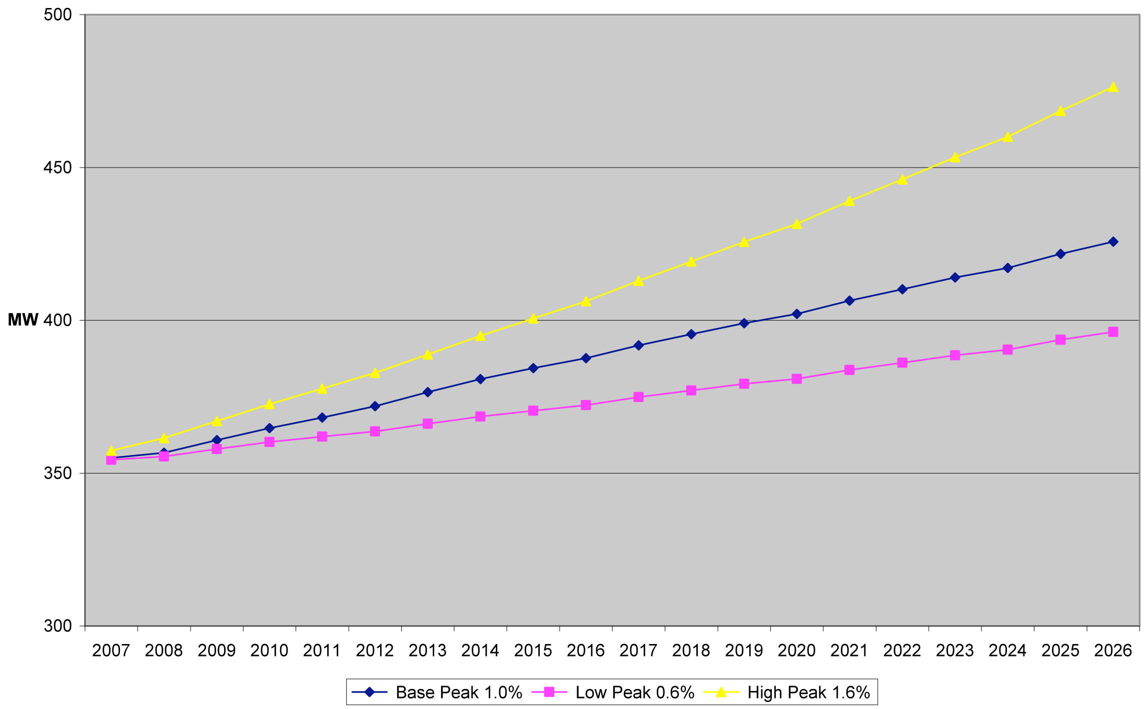

Figure 2: GMP's Annual Peak Demand Before DSM Program Influence

Funding Energy Efficiency Programs

The responsibility of planning for and implementing energy efficiency programs across Vermont lies with the organization Efficiency Vermont (EVT). This 'utility' provides consistent and focused efforts in designing programs and implementing energy efficiency improvements in existing structures, replacement appliances and equipment, and new construction. Efficiency Vermont thus provides energy efficiency services to GMP customers as part of a statewide effort supervised by the VPSB, which is funded through surcharges to utility bills.

We examined different levels of potential future energy efficiency program funding across the four scenarios (presented in Figure 1). This analysis combines savings from the reduction of peak demand and energy use. It is based on consumer financial impacts, technical and economic analysis, and the collaboration and input of many Vermont electric utility stakeholders. Based in part on information from Efficiency Vermont's annual reports, we created hypothetical future statewide efficiency budgets for each scenario. We then forecasted the energy efficiencies that might occur with these hypothetical spending levels over the next two decades. For each level of funding, we estimated the summer peak savings, winter peak savings, and annual energy savings associated with energy efficiency.

Figure 3 depicts the four basic levels of funding that we explored.

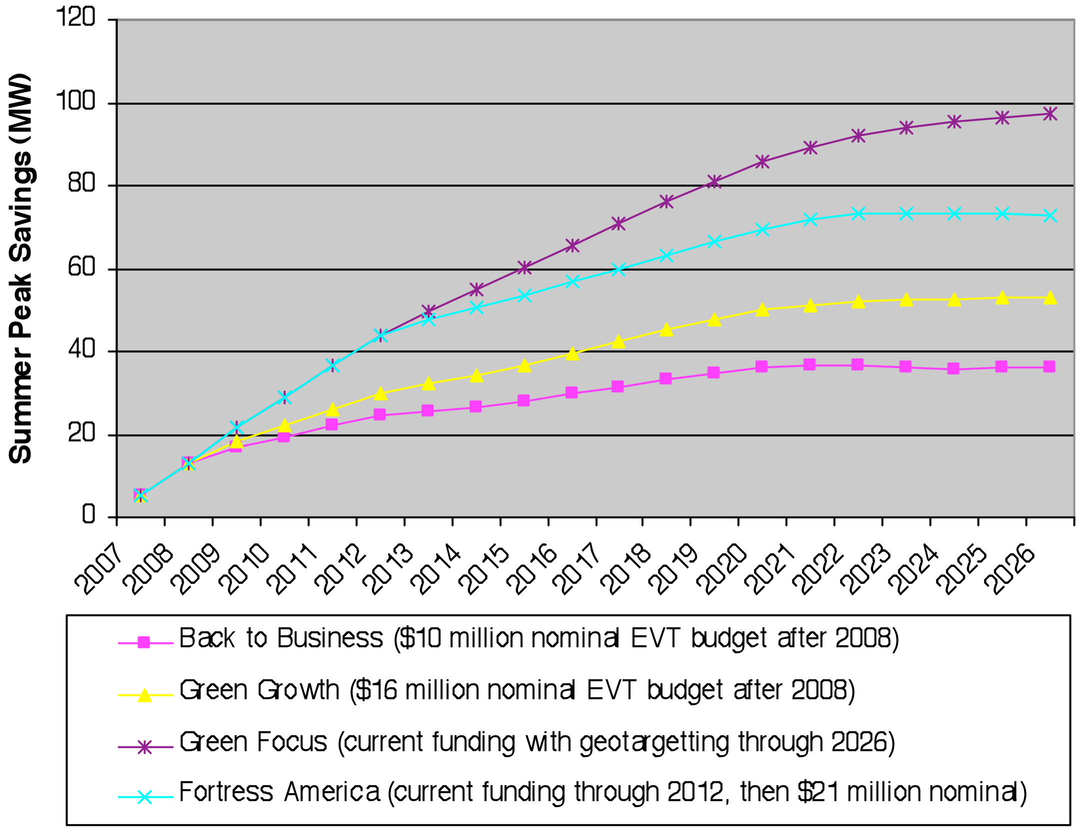

Figure 3: Efficiency Vermont Summer Peak Demand Reduction Forecasts

Future Demand and Capacity

Figure 4 compares GMP's projected future capacity resources to the range of summer peak requirements (that is, projected summer peak demand less energy efficiency savings) described above. The expirations of agreements with Entergy to supply power from Vermont Yankee in 2012 and the long-term Hydro-Québec Vermont Joint Owners contract schedules in 2015 result in a majority of GMP's resource portfolio needing to be replaced during the next decade.

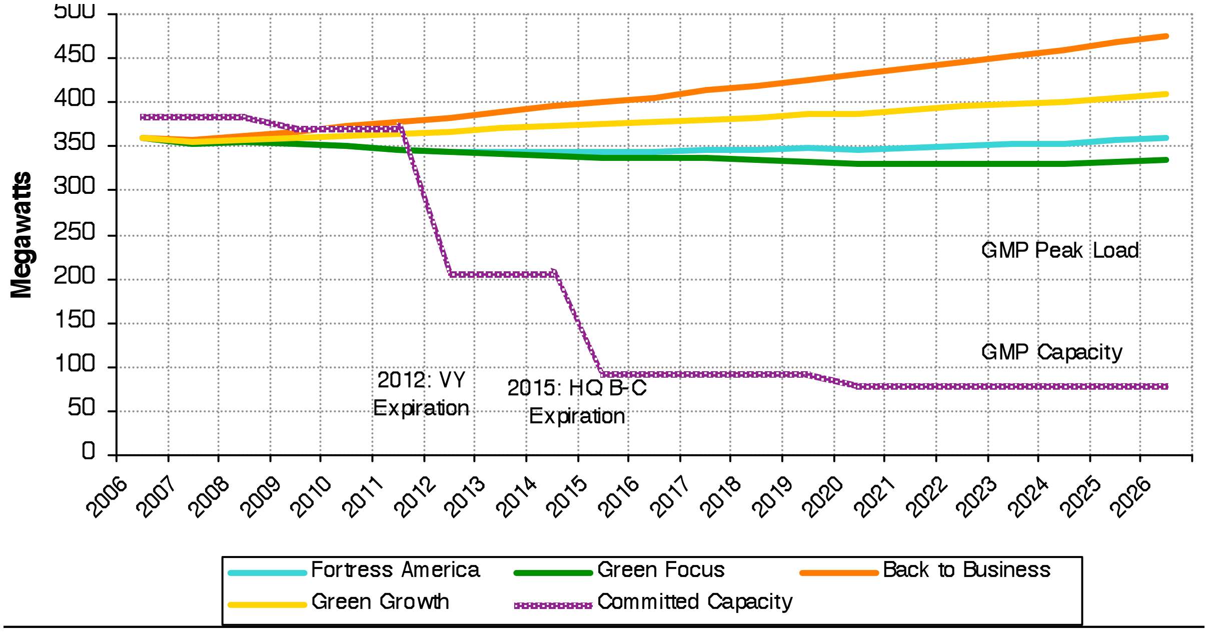

Figure 4: Comparing GMP's Future Demand and Capacity

Potential Portfolios

GMP developed and analyzed six distinct portfolios to replace its expiring resources and meet the growing needs of its customers.

- Portfolio 1 maintains the type of price stability and environmental impact mix of supply as current portfolio choices.
- Portfolio 2 features substantial new renewable energy from regional RPS-qualifying facilities, in amounts that reach 20% of GMP's energy supply in 2020. The emphasis on clean power results in a new Hydro-Québec contract or negotiation of a similar contract with one or more low-emission suppliers.
- Portfolio 3 purchases output from new or existing natural gas-fired combined cycles for a 15-year contract as its primary component.
- A major component of Portfolio 4 is building or buying into new or existing peaking capacity for a 15-year contract with emphasis on a location within Vermont.
- Much of Portfolio 5 is buying output from new base load facilities for a 15-year contract using Regional Clean Coal (IGCC) as a proxy.

- Portfolio 6 consists of market contracts with 1-, 3-, and 5-years duration for capacity and energy, the regional Forward Capacity Market (FCM) for capacity, and short-term or spot market purchases for peaking energy.
- Table 1 summarizes the resource additions that are featured in the six portfolios. Note that in all the portfolios, committed resources (for example, owned hydroelectric units for base load, owned peaking and intermediate capacity) will provide some of GMP's long-term needs.

#	Portfolio	Resource Additions Providing Operating Duty		
		Base Load	**Intermediate Load**	**Peaking Load**
1	Current Portfolio Energy Path	Long-term contract extensions with Vermont Yankee and Hydro-Québec or replacements with alternative counterparties	Short-term Market Energy	FCM Capacity, Short-term Market Energy
2	Renewable Emphasis	Renewables, New Hydro-Québec	Bilateral Contract	FCM Capacity, Short-term Market Energy
3	Combined Cycle Unit Contract	Combined Cycle	Combined Cycle	FCM Capacity, Short-term Market Energy
4	Peaking Capacity Unit Contract	Peaking Capacity, Bilateral Energy Contract	Peaking Capacity, Bilateral Energy Contract	Peaking Capacity, Short-term Market Energy
5	Base Load Capacity Unit Contract	New Base Load (IGCC)	FCM Capacity, Bilateral Energy Contract	FCM Capacity, Short-term Market Energy
6	Market Contracting	Bilateral Contracts — Capacity and Energy	Bilateral Contracts — Capacity and Energy	FCM Capacity, Short-term Market Energy

Table 1: Portfolios Studied in the 2007 IRP

Results of the Multi-Attribute Trade-off Analysis

In this analysis, we analyzed six attributes for each of the six portfolio strategies using three variations for each of the four scenarios to determine any trade-offs in their results that could be made. These six attributes — called impact attributes — that GMP felt were important enough to influence a recommended strategy to most benefit our customers are:

- Net present value revenue requirement: 20 years (native values reduce revenue requirements and are thus beneficial to GMP customers)
- Societal net present value (revenue requirements plus externalities costs): 20 years
- Short-term market and fuel price exposure: the percent of energy exposed to natural gas prices
- Long-term hedged percentage: the percent of energy with fixed costs or prices fixed for terms greater than five years
- Imputed debt: the amount of debt that is implied to be addressed in a utility's financial statements due to its power contracting activities
- Emissions: tons of CO_2 (carbon dioxide), NOx (nitrogen oxide), and SO_2 (sulfur dioxide)

The results suggest that the most robust resource portfolio will contain a combination of large long-term contracts with regional base load facilities, one or more replacement long-term imported power contract, a significant amount of renewable generation (to the extent it can be purchased or developed in cost effective projects), a significant amount of energy efficiency through Efficiency Vermont, and, if appropriate, capitalize on the evolving ISO New England Forward Capacity Market with strategic development of and contracting for combined cycle and peaking capacity. We will give priority to options that can be cost effective and developed within Vermont over those in other areas of New England.

Figure 5 indicates that GMP might not incur much higher expected power supply costs in order to insulate its portfolio against potential long-term market price movements. The better portfolios (that provide the most benefit in reducing revenue requirements) also appear to provide the highest degree of long-term fuel and market price hedge combined with low emissions. The Current Portfolio Energy Path portfolio has high hedging capability and generally equal-to-or-better revenue requirements than the other portfolios. We note, however, that long-term fixed price commitments can (in retrospect) turn out to cost noticeably above or below future market prices. In evaluating actual long-term resource options, GMP will therefore need to consider the relative financial stability of its suppliers (that is, their ability to actually deliver on a below-market contract) and the performance assurance terms that suppliers will require of GMP (in the event that the contract turns out to be above-market).

Another notable indication from Figure 5 is that several of the portfolios — particularly the Current Portfolio Energy Path, Renewable Emphasis, and Combined Cycle — feature fairly similar projected costs. The relative rankings for these resources (and the appropriate amounts to include in GMP's portfolio) could therefore evolve as GMP obtains specific proposals from potential suppliers and future market conditions change. As a result, this

IRP's action plan emphasizes steps to identify and evaluate potential resource options as opposed to prescribing specific volumes and timing for targeted resources.

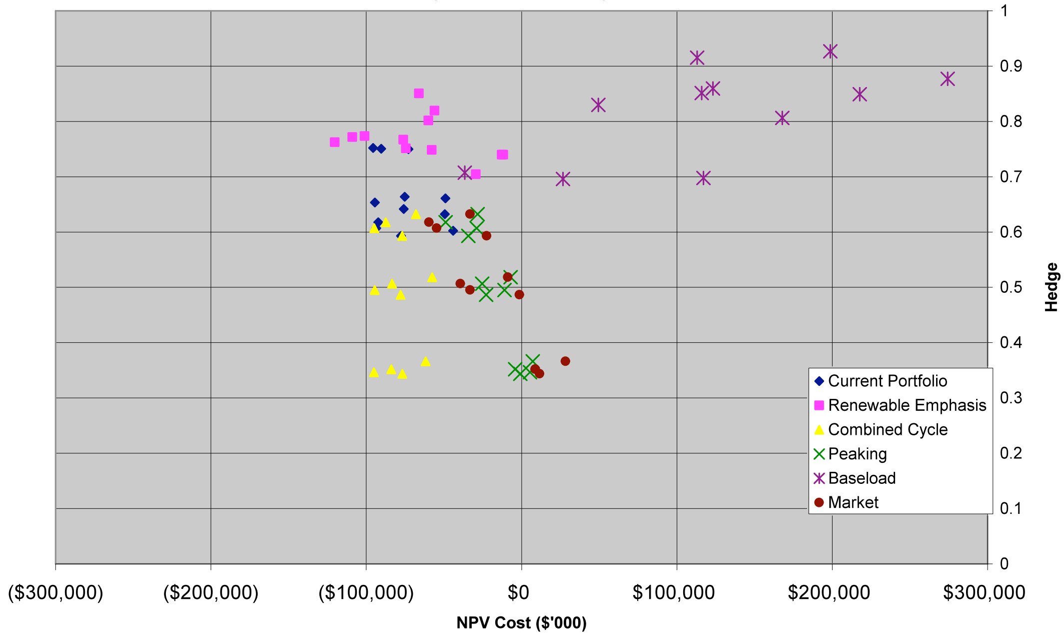

Figure 5: Twenty-Year Net Present Value Requirement Portfolio Cost versus 20-Year Term Hedge against Market and Fuel Price Changes

Figure 6 shows that the portfolio strategies based on either market- or coal-based resources have the highest CO_2 emissions and do not perform particularly well on the cost attributes.

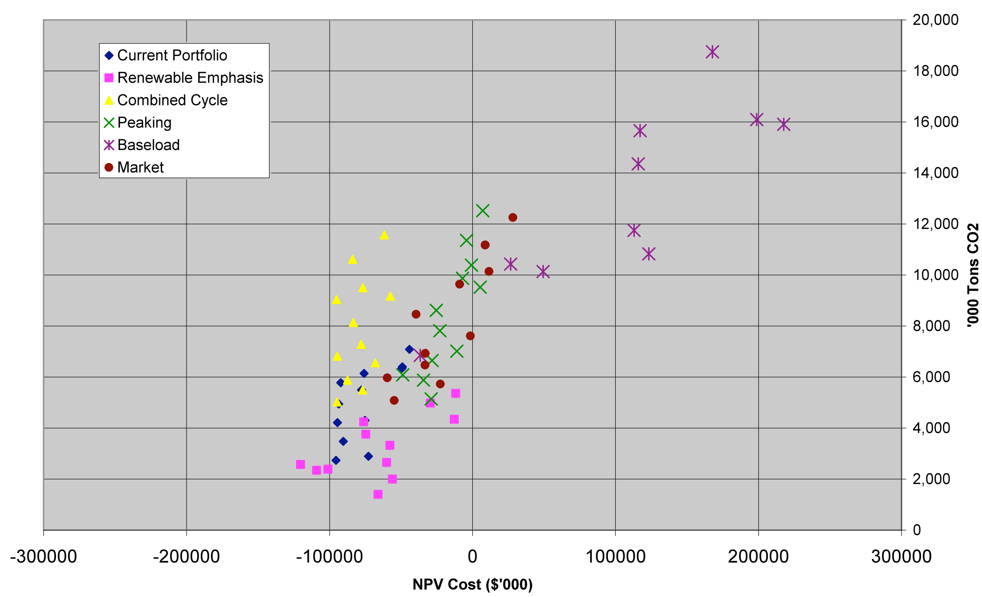

Figure 6: Twenty-Year Net Present Value Requirement Portfolio Cost versus Carbon Dioxide Emissions from New Resources

Based in part on this study's results and consistent with least cost planning principles, GMP intends to seek to meet as much of the energy shortfall as possible with non-emitting or low-emitting resources. Obtaining long-term arrangements from non-emitting resources can reduce supply risks, particularly in view of the potential for increasing regional and national regulation of emissions including greenhouse gases. At present, our most promising replacement portfolio includes favorable renegotiated contracts with one or both of the major expiring resources. We are fully aware, however, that there are alternative means of securing long-term contracts from other counterparties that can deliver similar low-emitting profiles to Vermont.

Other potential resources using conventional technologies that require the construction of new generating capacity exist: in-state capacity burning natural gas and/or oil, and regional capacity burning natural gas or coal.

Stress Testing

As a final step in the analysis, we stress tested the better scenarios on the basis of a 2020 snapshot. The stress tests included a:

- 10% increase in electric market energy prices.
- 25% increase and decrease in market energy and fuel prices.
- One-year temporary loss of the Vermont Yankee resource.
- The stress testing for 2007 produces three additional attributes in the trade-offs discussed above. We refer to these attributes as the Resiliency Attributes since they test the beneficial nature of the portfolios in a more dynamic environment. These attributes are:
- 2020 revenue requirements portfolio value impact.
- 2020 total retail price volatility: percent and cents per kilowatt hour.
- Stressed fuel price volatility exposure: percent of energy exposed to short-term market.
- Figure 7 compares the change in the portfolio value (relative to market) in 2020 to the original scenario value (that is, without the stress test change). The least net change in average retail price of electricity occurs in the most highly leveraged portfolio, which is the Renewable Emphasis portfolio. This helps us demonstrate the benefits of longer term fixed pricing in PPAs and renewable generation *contracted at the right price* can be beneficial to minimize costs, reduce environmental impact, and maximize hedge. Our general observations from the stress testing process are:

- These portfolios, with strong elements of Vermont Yankee, Hydro-Québec, and renewable energy generation, can continue to dramatically reduce fuel price exposures. They do, however, expose GMP to power costs above the regional market should future market prices turn out relatively low.
- A 25% increase in fuel prices would only result in about a 5% or less change in retail rates, with the Renewable Emphasis portfolio being close to 100% hedged.
- A loss of the largest resource, Vermont Yankee, does impact the annual portfolio economics in the future since that resource is expected to be priced close to market initially and then escalate to provide further savings.

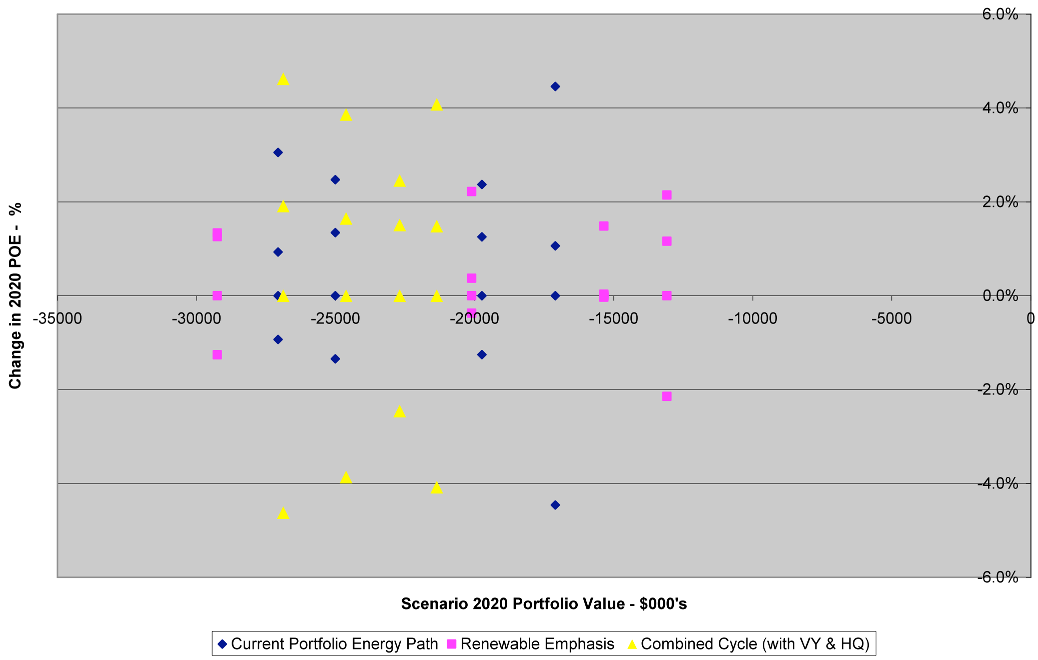

Figure 7: 2020 Portfolio Value versus Percent Change in the Retail Price of Electricity

This analysis suggests that the portfolio GMP choose include significant elements of Vermont Yankee, Hydro-Québec, and renewable energy generation. It is important to note that the actual amounts of these and other resource within the portfolio depend on price negotiations as well as other contract terms, and on renewable project costs.

Leverage Advantages and Opportunities

There are several areas where GMP has leverage in the marketplace to potentially provide resources at below market cost when actually purchased. The need for Vermont approval of a Vermont Yankee license extension, and possible value sharing with its owner could provide GMP with an early opportunity for beneficial power supply. In addition of the long-term capital recovery perspective of a cost-of-service regulated utility on behalf of its customers may compare favorably to a market based on merchant financing costs and risk perspectives. As an integrated utility, GMP should have the ability to capture all the economic advantages of generation that location, reliability, and T&D savings might create. GMP's ability and willingness to enter into long-term supply contracts with existing or new generation facilities could potentially provide leverage in negotiating with project developers.

This can lead to several opportunities for GMP. One is developing utility-owned local peaking generation with 'wires' benefits, in coordination with VELCO analysis and planning. GMP also has the ability, albeit difficult, to join or form a consortium of vertically integrated utilities within New England to jointly develop resources and purchase from large resources in order to capture economies of scale or buying power advantages.

The results of this analysis establish several resources as having priority in the GMP planning over the next few years. These resources are:

- Vermont Yankee and other nuclear owners
- Hydro-Québec and/or other import opportunities
- Renewable generation
- Natural gas combined cycle participation
- In-state peaking or combined cycle capacity

Implementation Timeline for Actions

The 2007 IRP Action Plan focuses on early development and negotiations activities with the objective to either acquire resource commitments or firm up the estimated cost and availability of future generation facilities.

Date	**Activity**
2007	Prepare IRP. Monitor and participate in the Vermont DPS public outreach process.
2007 to 2008	Explore opportunities for renewable energy resource PPAs, to assess their potential role in the resource portfolio. Begin soliciting or negotiating for renewables.
2007 to 2008	Conduct discussions for replacing our nuclear contract after its expiration in 2012. Also discuss potential future contract opportunities with Hydro-Québec. Review the long-term market alternatives to both of these resources.
2007 to 2008	Test the potential for cost-effective long-term contracts with existing and new natural gas combined cycle capacity. Inventory the potential for contracting with these resources for discrete entitlements (less than 50 megawatts).
2007	Guide and participate in the joint utility Vermont generation siting study.
2007 to 2009	Review FCM auction results to determine if GMP has a financial advantage or can leverage its vertical integration when facilitating the development of in-state capacity.
2009 to 2011	Gorge gas turbine is retired and replaced with a newer 25 megawatt unit.
2010 to 2012	Vergennes diesel retirement is reviewed: evaluate life extension and replacement with a newer unit.
2011 to 2015	Berlin is retired. Its replacement may be evaluated in the context of participation in a statewide process.
2012	Vermont Yankee contract expires.
2013 to 2015	Potentially take positions in short- and medium-term base/intermediate load contracts up to the expected net short in 2015/2016. Hydro-Québec VJO Schedule B contract expires.
Post 2015	Replace and add contracts as needed, consistent with GMP's Risk Management Policy.

Table 2: Implementation Timeline

2: Background Information

The Electric Industry

Since Green Mountain Power's (GMP) last Integrated Resource Plan (IRP) in 2003, the electric industry — wholesale, retail, and reseller — has experienced both incremental as well as monumental changes, some unprecedented. This section discusses the changes that occurred over these last four years.

A Perspective on the National Situation

The wholesale electric marketplace weathered early public (the energy crisis in California) and private (the ignominious fall of Enron) deregulation problems and moved toward a more mature profile. Beginning in 2004, the market began to resolve the liquidity crisis that had occurred in the two subsequent years throughout the merchant-generation and power marketing businesses. Large financial companies, many of whom had been left holding the assets of the bankrupt developers and failed merchant companies, brought much needed financial support. These companies — Morgan Stanley and Goldman Sachs (J. Aron) among them — extended the experience they gained in global commodities trading to power trading. By the next year, these two companies ranked among the top five electric power traders; Merrill Lynch was thirtieth.

The Federal Energy Regulatory Commission's (FERC) Standard Market Design requirements caused the areas of the country that have wholesale power markets and prices administered by an Independent System Operator (ISO) or Regional Transmission Organization (RTO) to expand. Between 2002 and 2005, both PJM (the ISO for Pennsylvania, New Jersey, and Maryland) and MISO (Midwest ISO) substantially grew their control areas: PJM expanded west to Illinois and south to North Carolina; MISO expanded west to include most of Minnesota and all of the Ameran service areas in Missouri and Illinois. FERC encourages independent transmission companies to participate in these RTOs by offering higher return rates that can expand non-discriminatory access to transmission facilities and improve the efficient use of existing infrastructure. In areas with an RTO or ISO, many of the market designs are beginning to coalesce around certain standard characteristics (such as hourly day-ahead and real-time pricing, loss and congestion pricing, and ancillary service settlements), albeit all with varying terminology and billing practices.

All U.S. wholesale energy markets continued to experience large price increases and substantial volatility, driven largely by increasing oil and natural gas prices. Notably, long-term price expectations for natural gas (which directly affects electricity prices in many areas of the country) have increased significantly. This, in turn, has stimulated considerable interest in alternatives to gas- and oil-fired generation in many regions of the country.

Construction of natural gas-fired generation, once the dominant new construction, has stagnated recently. Utilities outside of the Northeast are increasingly proposing coal-fired power plants; installed and proposed wind capacity has increased significantly.

Even with all these changes and progress, the most notable change occurred in 2005 when Congress passed the Energy Policy Act of 2005. Among other things, this Act repealed the Public Utility Holding Company Act (PUHCA) while streamlining the process for some interstate transmission projects and providing incentives for new coal technology. With the repeal of PUHCA, most of the country experienced significant merger activity leading to speculation that the current 100 major United States utilities will be reduced to 50 within a few years.

An Overview of New England's Electric Market

New England's electric market serves 14 million people living the 68,000 square-mile area encompassing Vermont, New Hampshire, Maine, Massachusetts, Connecticut, and Rhode Island. More than 350 generating units, connected to the 8,000 miles of high-voltage transmission line, represent approximately 31,000 megawatts of installed summer generating capacity. The area continues to experience its highest loads in summer months. During a period of region-wide extreme temperatures and humidity, the area reached a new system peak of 28,130 megawatts in August of 2006, fairly close to the installed capacity.

ISO New England

ISO New England continues to be the entity charged with running the region's wholesale electricity market. It dispatches generation and transmission assets, and ensures that New England complies with national standards for electric reliability. In February 2005, the ISO became an RTO. In this role, the ISO continues to perform its current functions and responsibilities. Because the stakeholder committees that previously directed the ISO mission have now become advisory, the ISO has gained more operation independence.

The region's wholesale electricity market continues to evolve in stages: from 1999's hourly markets and bid-based pricing; to 2003's Standard Market Design which incorporated localized price calculations for congestion and losses; to today's focus on providing more efficient investment signals for generators, transmission upgrades, and conservation.

During the five years following the opening of wholesale markets in 1999, New England's installed capacity increased by 40 percent. This significantly improved reliability margins and made possible genuine competition among generating resources. Unfortunately, absent localized price differences, a significant amount of this installed capacity was sited in Maine and other areas outside of the region's load centers where generation was most needed to reduce highly loaded transmission lines.

The ISO's introduction of Standard Market Design was intended to correct this situation. In actual practice, the complexity of the changes to the energy market (in particular, political resistance to the significant localized price increases associated with the proposed locational capacity market) meant that localized capacity and reserve market changes had to be postponed. To address this shortfall, the ISO has spent the last two years redesigning the region's capacity market to create meaningful incentives for generation to be built where it can make the greatest contribution to the regional infrastructure. In October 2006, a redesigned localized reserve market was introduced to provide focused payments for fast-start resources to support the reliability of the electric system. December 2006 saw the culmination of this effort when New England began the transition to the new Forward Capacity Market (FCM) which employs an auction that generates price signals three to five years into the future (see "Appendix C: ISO New England's Forward Capacity Markets" on page 147). In the next few years, stakeholders will determine if these market-based initiatives spur the required investment in generation capacity generally, and particularly in heavily populated load centers.

The ISO has also improved its Demand and Load Response Programs. These programs provide incentives for customers to reduce their electricity use during periods of high demand or high prices. This has facilitated demand-side participation in the market in hopes of having significant blocks of load than can actively respond to prices during peak periods and alleviate the need for some new peaking generation. The programs have grown in the past three years. Today, more than 600 megawatts are enrolled in New England. In the power-intense summer months, almost 500 megawatts of peak demand can be reduced in a short period of time, improving reliability and reducing emissions from peaking power plants.

Demand Growth Fuels Need for Capacity Upgrade

Acting in its planning capacity, in October 2006 ISO New England issued the Regional System Plan for 2006 (RSP06) which highlights some significant challenges facing the region in the next 10 years. This 200-page plan details load growth, generation supply, transmission upgrade needs, and some demographic data necessary for future planning.

The growth in demand primarily drives the need to upgrade New England's electric power infrastructure. ISO projections indicate that New England's summer-peak demand will grow at an annual rate of 1.5% until 2007 and increase at a brisk 1.9% thereafter. Based on current levels, these projections represent an increase of about 500 to 600 megawatts of peak demand per year. In addition, the region's increased use of air conditioning is expected to continue decreasing the annual load factor. This phenomenon is expected to continue until 2015.

Due to these demand changes as well as supply-side retirements, New England needs new supply and/or demand-side resources within the next few years to provide sufficient system capacity. Specifically, to satisfy these projected needs, the region needs 170 megawatts of new capacity by 2009, and 4,300 megawatts by 2015. The retirement of additional generating units or changes in the import capacity of the external transmission lines to Canada and New York will require additional needs sooner. Some of these additional resources must be sized and located to provide critical system support in areas with limited transmission capability (particularly in import-constrained load pockets).

The region is currently relying more heavily then ever on natural gas-fired power plants to satisfy electrical demand. Today, about 40 percent of the New England's installed capacity uses natural gas as its primary fuel, up from 17 percent in 1999. This trend is expected to continue in the coming years, albeit at a slower pace. The ISO would like a significant amount of the gas-fired generation to be able to use oil as an alternate fuel. This would serve to stabilize costs to consumers throughout the year and to assure that the system is reliable in the winter months, when the natural gas delivery system can experience constraints.

During several days in January 2004, extremely cold temperatures and record heating requirements prevented at least half of the gas-fired plants from operating. This caused extremely high prices for nearly a week and significantly challenged the electric system's reliability. The ISO is concerned that this reliance links the price of electric energy to the price of natural gas in nearly all of the on-peak hours of the year. Such a reliance exposes the market to disruptions to gas supply at any time (as was witnessed during the dramatic run up in electricity prices during the hurricane season of 2005). To reduce this vulnerability, the ISO has a two pronged approach: promoting a balanced mix of fuels for new capacity additions (including nuclear and coal) while encouraging a wider implementation of demand response and energy efficiency initiatives throughout the pool. The effectiveness of the promotion of fuel diversity remains to be seen, as most electric utilities in New England (outside of Vermont) are no longer vertically integrated and they are not understood to be responsible for managing the price of electric supply over the long-term.

Regional Greenhouse Gas Initiatives in New England

New England has made considerable strides in improving the environmental impact of electricity production in the region. While already one of the lowest emission areas in the country, the region is making a considerable effort to reduce the pollution from power plants even further in the next decade. The primary focus of these new initiatives is the region's production of carbon dioxide (CO_2) in response to growing concerns over global warming. The region is also tightening standards on mercury emissions and other harmful emissions on a state by state basis.

The Regional Greenhouse Gas Initiative (RGGI, signed by each of the New England states along with New York, New Jersey, Maryland, and Delaware) targets the production of CO_2 from power plants. Beginning in 2009, RGGI seeks to cap regional power plant emissions at approximately 2005 levels until 2014, then requires a reduction of 10 percent below this level by 2018. The caps would be mandatory for all states signing the agreement. In its Regional System Plan for 2006, the ISO projects achieving the RGGI cap will require the New England states to increase energy efficiency and add low- or zero-emitting generation by as early as 2010. The cost of RGGI allowances and offsets will be reflected in the wholesale electricity markets, presenting a potential upward exposure for future market prices.

Renewable Portfolio Standards (RPS) are in effect in Maine, Massachusetts, Connecticut, and Rhode Island. In these states, companies serving retail customers are required to use specific eligible types of new renewable resources (typically including wind, solar, landfill gas, and low-emission biomass) to produce a certain percentage of the energy supply. The NEPOOL Generation Information System (GIS), supported by each state, tracks these commitments. A bilateral market for RPS-eligible GIS certificates is growing. Because the Massachusetts and Connecticut RPS requirements for new renewables presently exceed the supply of qualifying generation, GIS certificates (also known as Renewable Energy Certificates or RECs) for RPS-eligible generators in New England trade for a near-term price of over $50 per megawatt hour. In the longer term, increasing renewable supply is expected to reach balance with the requirements, leading to more moderate REC prices.

About Green Mountain Power

A Breakdown of GMP's Retail Sales

Green Mountain Power (GMP) is an investor-owned utility. It provides electric services to approximately one-third of the population of Vermont and sells electricity in the wholesale market to other utilities. GMP's service area is both economically and geographically diverse.

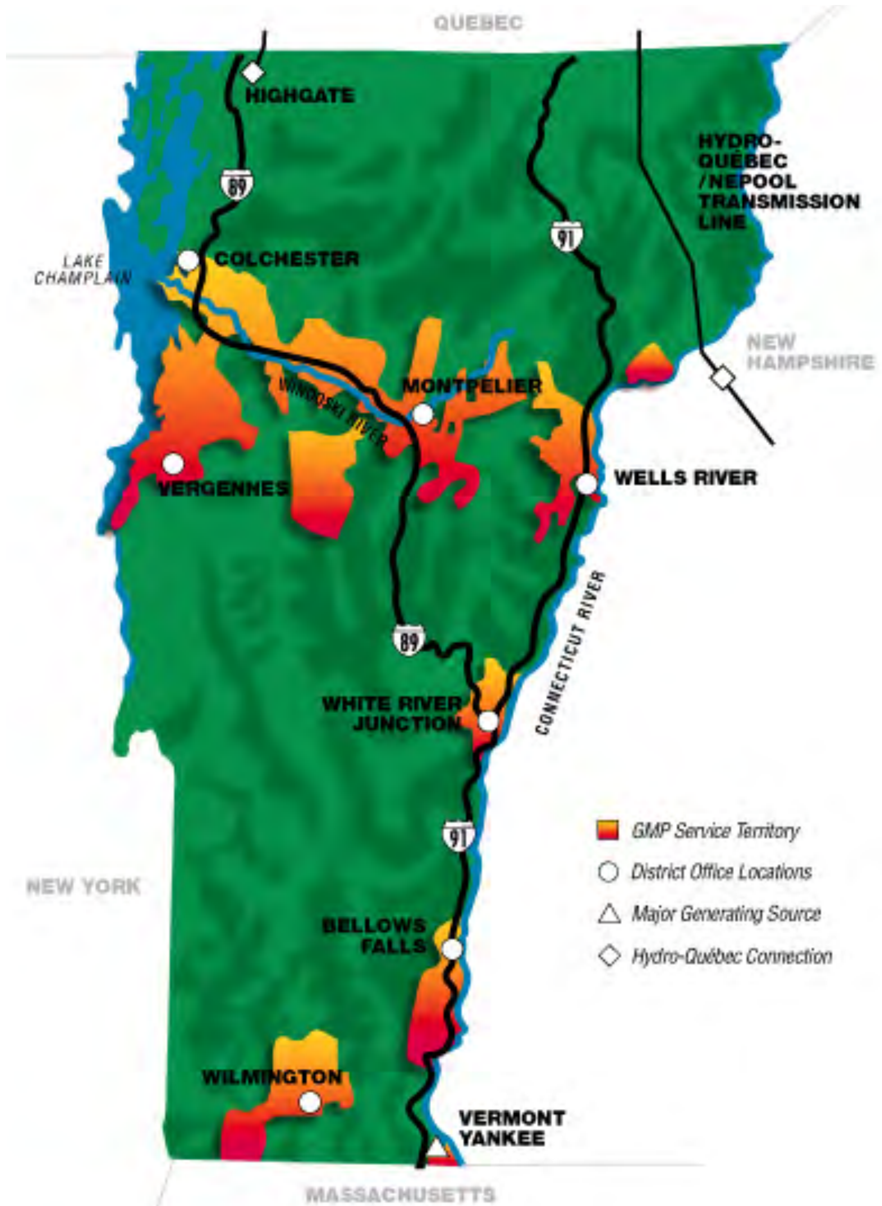

Figure 8: GMP's Service Area in Relation to State Boundaries

Sales Breakdown. Green Mountain Power serves 90,000 customers in nine counties and 122 different communities. GMP serves approximately the following customer mix:

Residential customers 76,500

Small commercial and industrial customers 13,500

Large commercial and industrial customers 24

GMP's retail sales by megawatt hours are almost evenly divided between residential, commercial, and industrial customers.

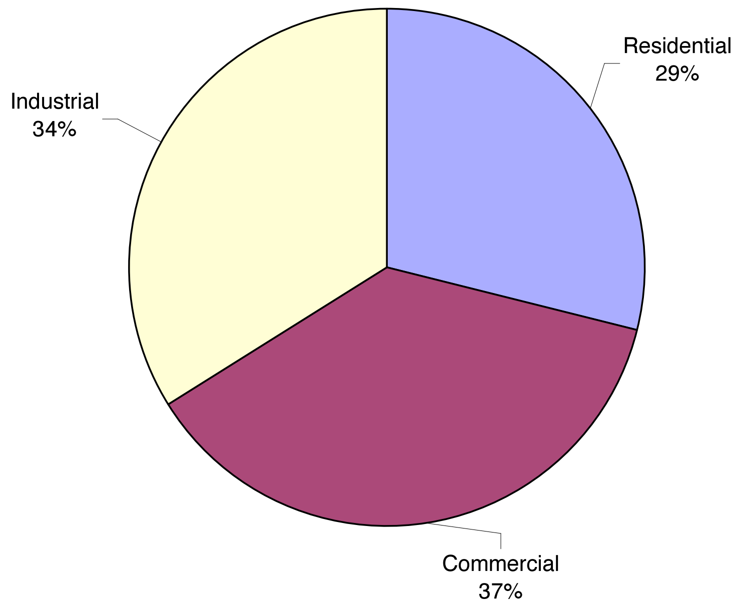

Figure 9: GMP's 2006 Megawatt Hour Sales by Customer Type

Sales Growth. Between 1986 and 1995, GMP's retail sales grew roughly 30 percent. Almost all of that growth, however, took place in the early years between 1986 and 1990. Between 2000 and 2006, GMP's sales have leveled off with a growth rate of slightly more than 0.5%. This is due to three main factors: the slowdown in the Vermont economy, the success of GMP's demand side management programs, and new federal and state energy efficiency standards.

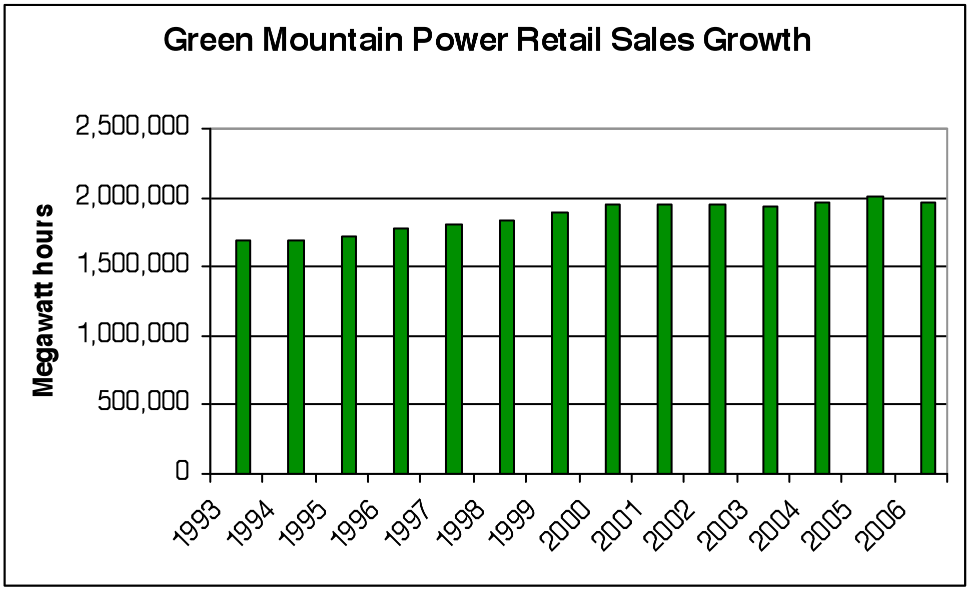

Figure 10: GMP's Retail Sales Growth through 2006

A Mix of Generation and Supply Resources

Generation Facilities

Green Mountain Power owns and operates 11 generation facilities, all of which are located in Vermont. These include:

- One wind plant
- Eight hydro plants (two of which have peaking fossil generation associated with them)
- Two fossil fuel peaking plants

Green Mountain Power also has ownership interest in the:

- McNeil biomass plant in Burlington, Vermont
- Wyman Station in Yarmouth, Maine
- Stonybrook Station in Ludlow, Massachusetts.

Fuel Sources

Green Mountain Power's current fuel source is evidence of our conscious effort to reduce the use of fossil fuels while emphasizing renewable sources. In 2006, approximately 55% of Green Mountain Power's fuel mix came from water, wood, and wind.

GMP 2006 Fuel Sources

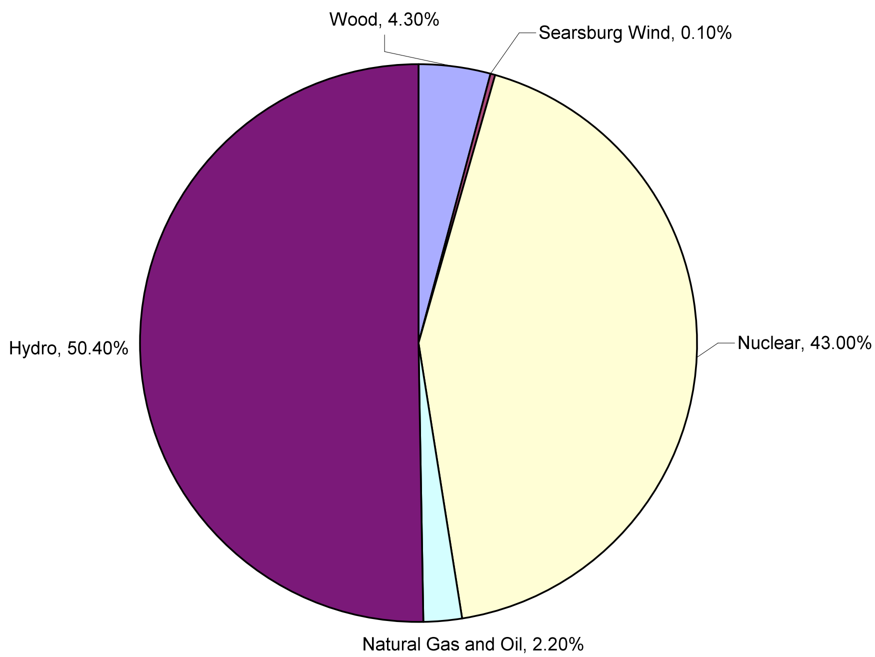

Figure 11: Fuel Sources by Percentage (2006)

This table presents GMP's power supply sources by size.

Percentage	Source
50.4%	Hydro
43.0%	Nuclear
4.3%	Wood
2.2%	Oil and Natural Gas
0.1%	Wind

Table 3: GMP's Power Supply by Size

In recent years, Green Mountain Power has sold some of the RECs associated with its wind generating station in Searsburg. Therefore, rather than assert that 0.6% of Green Mountain Power's energy came from wind in 2006, we claim only 0.1% as wind since the remaining 0.5% is distributed to other sources.

Note: RECs are financial instruments allowing companies to purchase and sell the renewable attributes of qualifying renewable electric generation. Energy produced by renewable generation facilities (such as our wind station) and from which RECs have been sold to others is not counted in our portfolio as wind or renewable generation.

Transmission and Distribution

Green Mountain Power's power delivery system includes approximately 287 miles of sub-transmission line operating at voltage levels ranging from 13.8 to 69.0 kilovolts. These sub-transmission lines are supplied by a combination of Vermont Electric Power Company (VELCO) power supply delivery points, neighboring utility interconnections, and internal generation.

GMP has 63 substations that supply its electric distribution system. The distribution system configuration ranges from 2.4 kilovolts delta to 19.9/34.5 kilovolts grounded wye. GMP has approximately 2,475 miles of overhead and 460 miles of underground distribution lines.

The bulk transmission system serving GMP is tied to the New York, Hydro-Québec, and New Brunswick systems through a number of interconnections. Power is transmitted from the Hydro-Québec system to Vermont by means of the Highgate converter and related facilities, the Phase I and Phase II DC lines, plus other related facilities.

The Highgate facilities have a capacity of 225 megawatts and include:

- An AC-to-DC-to-AC converter that reliably ties together the dissimilar AC systems of Hydro-Québec and New England.
- Seven miles of 115 kilovolt transmission line.

The Phase I facilities are currently being retired at the end of their 30 year life. They consisted of a 450 kilovolt direct-current transmission line running from an AC-DC converter on the Hydro-Québec system (near Sherbrooke, Québec) to a DC-AC converter terminal with a capacity of 690 megawatts (at the Comerford Generating Station in Monroe, New Hampshire). The transmission line in Vermont is owned by the Vermont Electric Transmission Company (VETCO), a subsidiary of VELCO. The remaining facilities — a transmission line and the converter terminal — were constructed and are owned by the New England Electric Transmission Corporation, a wholly owned subsidiary of the New England Electric System.

Phase II facilities consist of an extension of the 450 kilovolt high voltage direct current (HVDC) line south from Comerford, through New Hampshire, into Massachusetts, and include a converter terminal at the Sandy Pond, Massachusetts substation. This project includes modifications and improvements to certain New England Power and Boston Edison transmission lines, as necessitated by the HVDC line's construction. Phase II added 1,310 megawatts of capacity, bringing the total capacity available for imports from Hydro-Québec to 2,000 megawatts. GMP's participation share in Phase I is 2.93242% and in Phase II is 3.1792%. At the maximum 2,000 megawatt rating, this amounts to a total of approximately 61 megawatts to GMP.

Potential issues affecting the economics of these two Hydro-Québec interfaces include:

- Inclusion in NEPOOL Pool Transmission Facilities (PTF).
- Compensation as full PTF component.
- Grandfathering of long-term contract rights for Vermont companies.
- Manner in which ISO treats the capability ratings for the facility.
- Potential future uses of the Phase 1 sight.

Renewable Sources: Looking to the Future

Low Air Emissions. GMP's current power mix is quite low on air emissions since our reliance on fossil fuels is quite low. We do, however, see risks to maintaining that position. Our contract for nuclear generated power from Vermont Yankee expires in 2012, while our contract with Hydro-Québec expires in 2015. Together they account for almost two-thirds of our energy supply. Both have low air emissions. And while there are still challenges posed by nuclear generation, there is no doubt that nuclear power helps keep our air emissions low.

In addition to the environmental benefits of a low reliance on fossil fuels, GMP enjoys (as do its customers) fixed cost arrangements for more than 70% of our power supply. As such, we are not significantly vulnerable to the volatility of oil and natural gas prices. That is much of the reason we were able to avoid significant rate increases between 2001 and January 2007.

Wind Power. Green Mountain Power continually works with wind developers to find new sources of wind generation. In 1997, GMP constructed a six megawatt wind facility on Waldo Mountain in Searsburg, Vermont. Located next to the GMP facility is a site with potential for a thirty megawatt wind generation plant (assuming all necessary federal and state permits can be obtained). We are working with developers to support siting efforts and obtain some of the output of the new wind station.

Renewable Requirements. At this time, Vermont does not feature a mandatory RPS of the same structure as other New England states. The SPEED program, created by the Vermont Legislature in 2005, does establish targets for the purchase of energy from renewable electricity projects and give a financial advantage to Vermont renewable developers. The Public Service Board implemented this program through Rule 4.300 the next year. In particular, utilities are required to buy output from renewable generators (at prices no greater than market prices); no Act 248 showing of need is required for a certificate of public good; and projects are automatically eligible for state-backed VEDA financing. Utilities purchasing energy get credit toward the SPEED requirement even if RECs are retained by the developer or resold to other buyers in the region. This program requires the utilities to increase the amount of renewable energy to match the energy growth that they experience up to 10 percent of total requirements. If new renewable generation delivered by 2012 is insufficient, a more traditional RPS mandate (likely requiring the purchase of both energy and RECs) will go into effect.

"Greener Mountain Power"

In the spring of 2006, Green Mountain Power introduced an option for customers to choose 100% renewable energy sources. Called "Greener Mountain Power", residential and small commercial customers can choose to have us designate renewable resources equal to 25%, 50%, or 100% of their monthly use. Large commercial customers can sign up for 10% of their monthly use and additional 10% increments with GMP permission.

We purchase certified renewable resources or RECs available on the New England power grid equal to the portion of electricity customers have designated. When renewable resources are available from Vermont projects, GMP gives them priority consideration.

More than 350 customers signed up in the first few months of the program. We anticipate signing up 500 customers a year and are currently planning an expanded marketing program to help us reach that goal.

Fighting Global Warming

Green Mountain Power is fully committed to fighting global warming. We recognize the direct link between climate change and our actions as an electric utility. We were one of the first utilities in the country to offer our customers the opportunity to participate in CoolHome (www.cleanair-coolplanet.org), an innovative program to fight global warming.

GMP has also assumed a leadership role in committing to a clean power supply by joining the Chicago Climate Exchange (CCX), a self-regulated exchange that administers the world's first multi-national and multi-sector marketplace for reducing and trading greenhouse gas emissions. Participants receive credits for emissions reductions and those credits may be sold. CCX provides a market for buying and selling credits so that reductions can be achieved in the most cost-effective way.

We were the first electric utility in the northeast to join CCX. We voluntarily committed to either reduce greenhouse gas emissions by 4% from our 1998–2001 baseline average by 2006 or to purchase greenhouse gas credits to achieve the equivalent result. CCX has relied on GMP to educate other businesses in Vermont and New England about joining the exchange. The result: we reduced our emissions by a considerable amount, largely through power plant operations, and met our 2006 goal.

In addition, GMP encouraged the creation of, and strongly supports, the Vermont Energy Efficiency Utility (EEU). We serve on its board. EEU is a customer-funded statewide utility that provides energy efficiency services for Vermonters. Harvard University recently recognized the EEU as one of the most innovative state government programs in the nation. GMP works closely with the EEU as a way to help our customers use energy wisely.

Regional Greenhouse Gas Initiative

Green Mountain Power supports Vermont's agreement to participate in the Regional Greenhouse Gas Initiative (RGGI) summarized above. The only existing Green GMP facility that would be affected by the initiative is the Berlin #5 gas turbine.

Investing in Renewable Power Sources

Every year, Green Mountain Power receives financial distributions from the Nuclear Electric Insurance Limited (NEIL) as a term of the sale of the Vermont Yankee plant to Entergy. GMP maintains an ongoing plan for investing these distributions in renewable resources.

GMP's Board, on June 13, 2002 and November 24, 2003, described the objectives of these investments:

- Obtain the greatest tangible financial benefit to Green Mountain Power ratepayers.
- Apply a significant portion of these benefits towards developing and using renewable resources.
- Account for both the principal and the time value of the financial distribution.

GMP's 2003/2004 Renewables Support Plan distributed that year's NEIL credit as follows: 60% for renewables projects developed by GMP, 30% paid into the Vermont Solar and Small Wind Incentive Program (established under Act 69 of the 2003 legislative session), and 10% to develop an optional renewable pricing program.

GMP's 2005 Renewables Support Plan provided that 55% of that year's NEIL credit would be applied to GMP renewables projects, 35% for the Solar & Wind Incentive Program, and 10% for the renewables pricing program (green tariff).

The 2006 Plan addressed the interests of various participants to the process, promoted a consensus of those participants, and minimized administrative costs to ensure that as much of the credit as possible directly benefit these goals. We applied the 2006 NEIL credits for essentially the same three purposes and in the same proportions as the 2005 Plan, with several additions.

We allocated approximately $15,000 in a low impact, "micro-hydro" generation project located in Barre ($15,000) by a third party. We allocated another $10,000 for assistance in connecting to the power grid for a modular agricultural waste digester and biogas generator at a dairy farm in Charlotte. All unexpended funds are kept in an interest-bearing bank account and detailed expense accounts are maintained for each project.

Our 2007 plan (which we will soon file) accounts for just under $300,000 in NEIL credits. We will allocate part or all of these credits to establish a program working with farms in our service territory to install anaerobic digestors for producing renewable energy. We anticipate working with the farms to fund a study and interconnection costs for these farms. We expect to purchase excess output and sell the renewable energy certificates to our customers to satisfy Green Rate requirements or potentially other expanded renewable offerings.

GMP's projects funded by NEIL receipts include:

The **Vergennes Project** consists of rewinding the generator at Vergennes #1 hydro station while the plant is out of service to replace the turbine. GMP expects to complete the permit process and begin in 2006. We plan to use $95,000 of the NEIL funds for the Vergennes Project.

The **Essex Project** consists of refurbishing the old exciter penstock at the Essex hydro plant and adding a turbine-generator using a bypass flow necessary to oxygenate fish downstream. This project is expected to produce an additional 566 megawatt hours per year for an estimated cost of $401,000.

The **Commercial Load Management (CLM) Project** puts in place a control program that can automate management of selected loads at commercial customer sites. It provides consultations, audits, and installation of associated equipment at customer locations. GMP began operation in June 2006.

The **Tafts Corners Solar Project** calls for installing 25 kilowatts for about $200,000. The contractor, Solarworks, has an established track record of similar installations for Hannafords grocery stores and is presently working through details with their management.

3: Demand and Resources

The Market Demand for Electricity

Demand and Energy Growth

Green Mountain Power contracted with Itron, Inc. to complete the 2007 energy and demand forecast. Itron built the base case energy and peak demand forecast on GMP's sales forecast generated in November 2006. Here we describe and summarize the forecasting method, forecast drivers, and the sales forecast results.

Itron derived the energy forecasts by first translating the sales forecasts on a billing cycle and projected them to a calendar month. GMP then summarized and adjusted the annual calendar sales for line losses to produce a long-term energy forecast.

Itron combined this annual energy forecast with system hourly load forecast using *MetrixLT* (Itron's long-term hourly modeling software). This generates an initial 8,760 hour system load forecast. Itron derived the peak forecast by calibrating the initial peak forecast from the initial hourly system load forecast against actual monthly system peak demand. They then combined the final calibrated peak forecast with the monthly energy and hourly system load profile to generate a consistent long-term hourly load forecast. Figure 12 and Figure 13 depict these results.

Figure 12 shows the forecasted system hourly load for 2011 (by season).

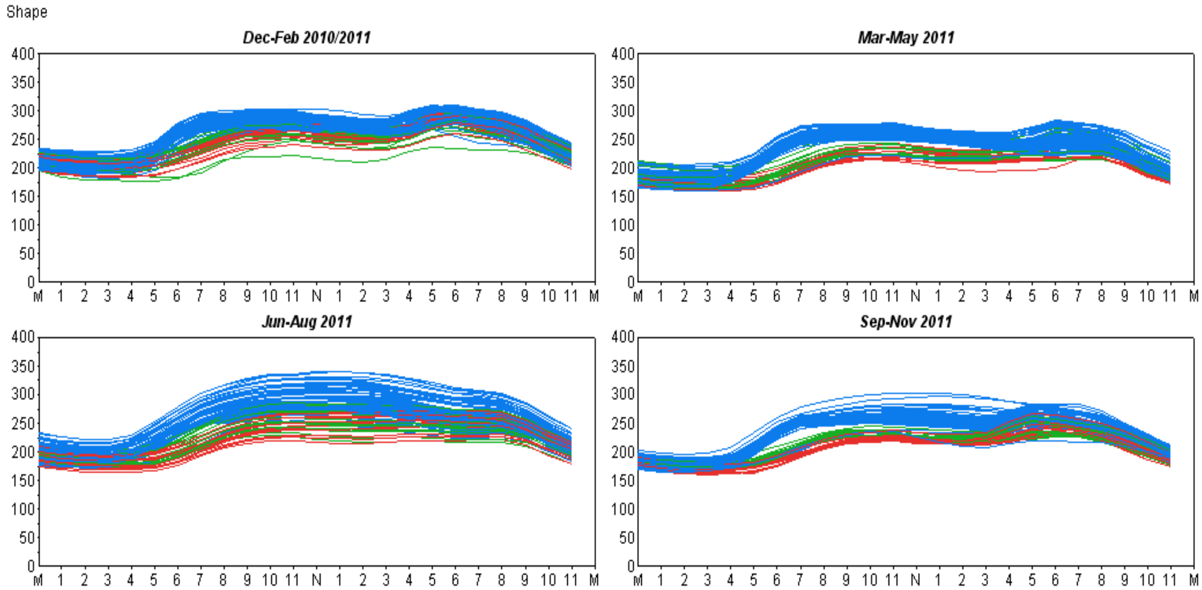

Figure 12: GMP Forecasted System Hourly Load 2011

Figure 13 shows the forecasted system hourly load for the summer peak week of 2011.

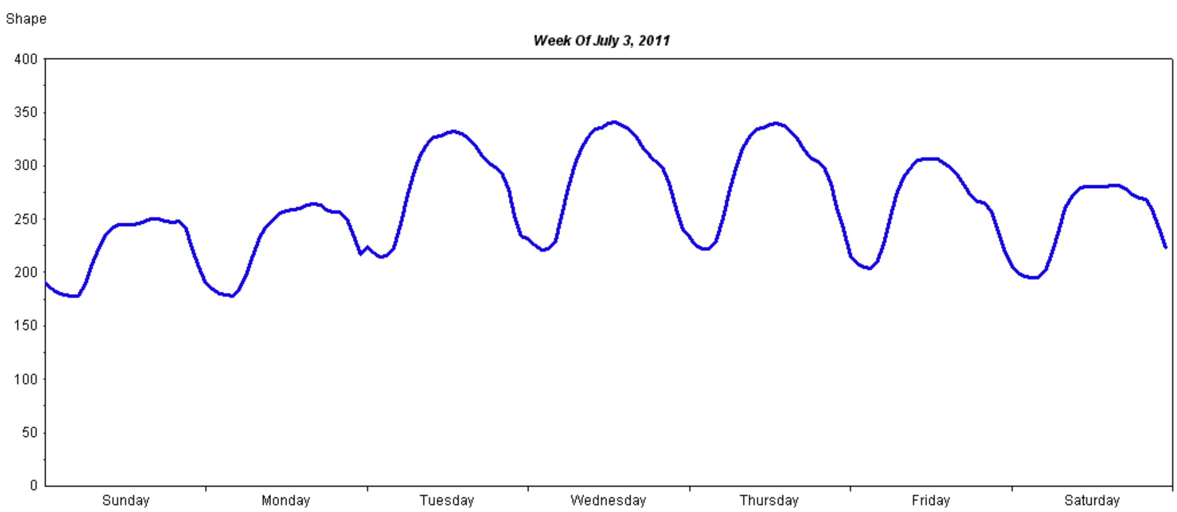

Figure 13: GMP System Hourly Load – Summer Peak Week 2011

Table 4 summarizes the forecasted base case energy demand and summer and winter peak demands for the next twenty years.

Year	Energy (GWh)	Summer Peak (MW)	Winter Peak (MW)
2007	2,101.0	355.0	315.7
2011	2,180.3	368.2	327.3
2016	2,304.3	387.6	344.5
2021	2,410.9	406.5	361.1
2026	2,527.2	425.8	378.1
CAGR (2007–2026)	1.0%	1.0%	1.0%

Table 4: Reference Forecast

Table 4 shows calculated growth rates based on the year 2007. This shows a weather normalized growth rate for energy and peaks equal to 1.0% through the study period. The forecasted summer peak occurs in July and the forecasted winter peak falls in January.

"Appendix A: 2007 Long-Term Energy and Peak Forecasts" (on page 107) contains more details.

- "Customer Class Sales Forecast" (page 107) presents an overview of the sales forecasting method, forecast drivers, and results.
- "Energy and Demand Forecast" (page 123) gives an overview of the energy and demand forecast method, and resulting long-term energy and demand forecast.
- "Model Statistics and Coefficients" (page 133) describes the method and presents results from the scenario analysis.

Energy Efficiency Forecasts

Green Mountain Power developed energy efficiency savings forecasts for this Integrated Resource Plan. Much of the analysis to develop the forecasts relied on information from Efficiency Vermont's (EVT) annual reports. Efficiency Vermont presented this information to the Public Service Board (PSB) during ACT 61 workshops in 2006 concerning the impact increased funding would have on energy efficiency savings and contained in the PSB's August 2, 2006 order increasing the funding for the Energy Efficiency Utility (EEU)[1].

The energy efficiency forecasts were applied to four plausible economic scenarios called Fortress America, Green Focus, Back to Business, and Green Growth. We created hypothetical budgets for each scenario, basing them on the current Efficiency Vermont budget (which also includes a budget for geotargeting). We then forecasted the energy efficiency savings that might occur with these hypothetical spending levels over the next two decades.

We developed three energy efficiency forecasts for each scenario:

- Summer peak savings
- Winter peak savings
- Annual energy savings

We also disaggregated the annual energy savings forecast into seasonal on- and off-peak energy savings forecasts, and described the amount of funding that determined the energy savings achieved by each of the four scenarios. The recently approved budgets through 2008 are used for each scenario. These scenarios, their names, and their hypothetical budgets are:

Fortress America. This scenario has the high energy prices through 2012. As such, the Energy Efficiency budget remains nominally at $28 million dollar per year, including the geotargeting funding, through 2012. From then until 2026, the budget moderates to about $21 million, reflecting the drop in energy prices.

Green Focus. Since this scenario has the highest energy prices throughout the study period (until 2026), the Efficiency Vermont budget remains nominally at the $28 million dollar per year, including the geotargeting funding, through 2026.

Back to Business. This scenario has the lowest energy prices, thus the budget for Efficiency Vermont after 2008 is assumed to return to the early historical program funding levels of about $10 million per year through 2026.

Green Growth. Since this scenario has moderate energy prices, the budget for Efficiency Vermont after 2008 drops to about $16 million. This funding level is approximately the level of funding that occurred though the first half of this decade. This scenario continues program funding at the nominal $16 million average through 2026.

[1] The EEU budget and the Efficiency Vermont budget are separate and distinct. The EEU budget includes funding for Burlington Electric Department's efficiency programs, and the Department of Public Service's budget for monitoring and evaluation activities.

The following table shows a summary of the energy efficiency savings that would be achieved in GMP's service area under each scenario for the years 2007, 2016, and 2026.

Fortress America			
Year	**2007**	**2016**	**2026**
Summer Peak (MW)	5.3	56.8	72.7
Winter Peak (MW)	4.8	51.1	65.3
Annual Energy (MWh)	31,848	340,077	434,589
Green Focus			
Year	**2007**	**2016**	**2026**
Summer Peak (MW)	5.3	65.5	97.5
Winter Peak (MW)	4.8	59.0	87.6
Annual Energy (MWh)	31,848	392,535	582,986
Back to Business			
Year	**2007**	**2016**	**2026**
Summer Peak (MW)	5.3	29.6	35.9
Winter Peak (MW)	4.8	26.6	32.3
Annual Energy (MWh)	31,848	177,023	215,069
Green Growth			
Year	**2007**	**2016**	**2026**
Summer Peak (MW)	5.3	39.7	53.1
Winter Peak (MW)	4.8	35.7	47.8
Annual Energy (MWh)	31,848	237,255	317,895

Table 5: Summary of Energy Savings

Review a graph of this data on Figure 17: Efficiency Vermont Summer Peak Demand Reduction Forecasts on page 58.

We discuss these scenarios in greater detail in "Four Potential Scenarios" beginning on page 52.

Rate Design

Innovative rate design promotes efficient energy use and other important policy goals. It can closely match wholesale purchase obligations with retail sales obligations to effectively hedge supply-related price and volume risk.

GMP encourages large customers to use energy efficiently by offering rates with time-differentiated energy and demand charges. Last year, GMP introduced a critical peak rate for large customers. This rate offers reduced energy and investment charges combined with higher energy and investment charges during critical peak hours; customers can avoid these higher charges by reducing critical-peak loads. GMP limits critical events to 150 hours per year and notifies customers the day before the event by email, facsimile, or phone. Customers with interruptible demands greater than 100 kilowatts can participate in GMP's load management programs.

GMP's legacy Curtailable Rider program charges for peak demand only during periods when energy costs are high or when reliability is threatened. At times when energy market prices are high (but GMP system loads are not near peak levels), customers can choose to "buy through" with their discretionary consumption priced at estimated locational marginal energy prices. All customers in this program have 15-minute interval meters that are read every 30 days for billing and profiling usage.

GMP implements the ISO Price Response program through our Load Response Rider. GMP compensates participating customers for reductions in load during high cost periods, as compared to a ten-day moving average, at the marginal clearing price. All ISO Price Response customers have 15-minute interval meters that are read every 30 days. GMP then sends this data to ISO New England.

In July 2006, GMP began targeting commercial customers through an addition to our load control programs. Customer service and load management specialists work with Control Technology Inc (a private partner located in South Burlington with expertise in industrial load controls) to help customers participate. The "Energy Management Alliance" takes a three-pronged approach to:

- Promote lower billing on current rates.
- Advocate for either the ISO New England Voluntary Price Response or Mandatory Demand Response program.
- Assess whether the customer would benefit from GMP's critical peak rate.

These specialists assess whether customers are suitable for this program, then schedule a technical audit (in a walkthrough) to estimate their full potential. If significant energy savings potential exists beyond load management, we involve Efficiency Vermont. Depending on customer characteristics, Efficiency Vermont can work jointly with us from the start.

GMP is working to make a "virtual choice" option available to its largest customers. This rate allows certain customers to purchase energy service from a third-party supplier, with GMP providing only "wheeling" services. Customers with the capability to shop for power can benefit by choosing their own attribute trade-offs of price, environmental impact, price volatility, and flexibility of their power supply. At the same time, this program may reduce GMP's financial risk profile.

Supply Resources

Green Mountain Power's Generating Resources

GMP's existing supply portfolio (summarized in Table 6 and based on ISO New England's seasonal unforced capacity ratings) consists of:

- 20 megawatts of owned hydro-electric plants.
- 57 megawatts of internal combustion peaking plants.
- 5.5 megawatts of the McNeil station.
- A 114 megawatt entitlement in schedules B and C of the Hydro-Québec Vermont Joint Owners (VJO) contract.
- A 106 megawatt unit contract for the output of Vermont Yankee.
- A 6.8 megawatt unit contract for the output of Wyman unit 4.
- A 38 megawatt unit contract for the output of Stonybrook combined cycle gas turbine.
- 17.7 megawatts of VEPPI and other PURPA QF power.

These values represent summer claimed capacity. The actual capacity to GMP varies based on periodic audits and their availability during critical peak periods. GMP also purchases from JP Morgan an intermediate term energy contract with a shaped energy profile to meet average hourly demands in each month. This resource does not provide capacity value.

Unit	Fuel	GMP Capability (Summer Claimed Capability MW)	Imminent Unit Retirement /Contract Expiration Year
VEPPI Hydro	Water	12.1	
VEPPI Wood	Wood	6.6	
VT Yankee PPA	Nuclear	105.8	2012
Wells River Hydro	Water	0.5	
Searsburg	Wind	0.5	
JP Morgan	System	0.0	2010
Wyman #4	Oil #6	6.8	
Stonybrook	Oil #2, Gas	38.3	
Berlin #5	Oil 31, Ker	37.7	2012
Gorge 1	Oil #2	13.5	2009
Vergennes #9	Oil #2	3.9	
Essex Diesel	Oil #2	7.9	
Hydro-Québec	System	114.0	2015
Utility Hydro	Water	19.8	
McNeil	Wood, Gas, Oil #2	5.5	
Total		372.9	

Table 6: Green Mountain Power's Existing Supply Portfolio

Generation Investments

As discussed in Chapter 4, several existing GMP generating units are approaching the end of their economic lives. In addition to the evaluation of retirement and replacement of these units, GMP regularly invests in its hydroelectric and thermal generating units for purposes that include: increasing plant output or efficiency; equipment replacement; maintaining safety; and compliance with regulatory requirements. Appendix E lists generation improvement projects that may be implemented in 2007, along with their primary type. While the projects that GMP actually implements may vary from this list, it is intended to provide a flavor of the type and scope of generation projects that GMP evaluates.

Local Power Delivery System

Planning the Delivery of Power

Green Mountain Power has developed the following planning criteria to assure that its power delivery system achieves satisfactory performance. The planning criteria uses 4/0 ACSR (aluminum clad steel reinforced conductor) and 477 KCM (thousand circular mils, the conductor size) ACSR for its main overhead three phase lines. The standard conductor sizes for underground lines include 1/0, 350 KCM AL and 750 KCM AL. GMP's standard transmission system voltage in the Western and Central Division areas is 34.5 kilovolts. The 34.5 kilovolt system delivers power from the VELCO delivery points to GMP's distribution substations, wholesale customers, and large industrial customers. GMP also uses 46 and 69 kilovolt systems in the Southern Division.

GMP's standard distribution system voltage is 7.2/12.5 kilovolts grounded wye. We have a limited amount of 19.9/34.5 kilovolts distribution system facilities in service, but are restricting its use to high growth industrial areas because of operating difficulties with underground 34.5 kilovolt equipment.

Green Mountain Power allows 5–8% maximum voltage drop on the transmission system during normal operation and 10% maximum voltage drop during first contingency operation. We limit the drop in distribution system voltage to 5% during all types of operation.

Each element in the power delivery system has a design load limit, which reflects the load at which the element begins to overheat and fail. GMP applies a 100% maximum load limit on all elements during normal operation. We allow overloading in specific cases for limited periods of time during first contingency operation, but only when service must be maintained or restored.

Transmission and Distribution Studies and Improvements

Monitoring Transmission and Distribution

GMP monitors its transmission and distribution system to identify feeders that might need improvements or potentially be subject to distributed utility planning (DUP[2]). We use data gathered from these sources to update forecasts for feeders and substations. The data sources include:

- The Supervisory Control and Data Acquisition (SCADA) database for load (MW), reactive (MVAR), and unbalance (Amps) data for the feeders connected to the SCADA system. Only a small number of the smaller feeders are not on SCADA.
- Thermal Demand Ampmeters and revenue meters for feeders not on SCADA.
- Line extension requests.
- Act 250 letters.
- Customer complaints.
- MV-90 data.
- Data loggers.
- Customer outage database to determine the worst sections of line.
- GIS to locate certain types of wire and cable that are routinely replaced to increase their reliability.

GMP Transmission and Distribution Efficiency Study

In a comprehensive 1998 T&D efficiency study, GMP identified 183 projects on 94 circuits that represented cost-effective efficiency improvements to GMP's distribution system. In 2006, GMP re-evaluated these 183 projects using current data and found we could implement 153 of these projects with a total estimated cost of $8.67 million. The remaining projects were either already completed or the circuits had changed so dramatically that the projects no longer would make the circuits more efficient.

GMP agreed to provide a report to the Department of Public Service by January 9, 2006 describing the results of its review. In addition, GMP agreed to complete its review and provide follow up reports to the DPS on April 21, 2006, July 25, 2006 and October 30, 2006. GMP fulfilled these obligations and the follow up reports were provided to the DPS ahead of schedule.

Only 25 of the 153 projects (with an estimated cost of $122,000) would result in enough energy savings to justify their costs. All of the larger projects (which involved reconductoring circuits or extending three-phase lines) were too costly to justify any

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[2] Distributed utility planning (DUP) involves modular electrical generation and storage technologies, and specifically targeted demand-side management (DSM) programs, strategically sited and operated to supplement central station generation plans and the transmission and distribution grid to cost-effectively obtain both location-specific and system-wide customer benefits.

saving from increased efficiency of the system. These 25 cost-effective projects involve phase balancing, additional capacitors, and load transfers. These projects are generally completed in conjunction with other maintenance and construction projects. GMP has completed fourteen of these projects to date and plans to complete the remaining eleven projects in 2007.

The most cost effective projects identified in the efficiency study were either adding capacitors to the system or balancing circuits. As such, GMP is currently conducting two additional studies; one addresses VAR issues (see *GMP System VAR Study* below) and the other addresses balancing circuits (see “Balancing Circuits” on page 41).

As part of the periodic meetings between GMP and the DPS (held about once a quarter), GMP regularly reviews the progress being made on T&D efficiency study projects with the DPS.

Replacing Conductor

The T&D efficiency study also determined that replacing conductor based purely on loss savings was not cost effective. GMP will, however, replace existing, undersized conductors when a circuit is experiencing voltage or reliability issues. GMP will also replace conductors to lower losses when replacing a series of poles or extending three-phase circuits. Under these situations, replacing conductor is cost effective because we perform these replacements in conjunction with other work.

GMP is currently replacing all of its 6SCP conductor — also known as ammaductor. This type of wire, manufactured in the 1940s, was inexpensive to make. It consists of two strands of copper wrapped around an ungalvanized steel core. The wire has not aged well and has a high mechanical failure rate. GMP has identified all the remaining ammaductor on its circuits and plans on replacing the conductor over the next several years.

GMP System VAR Study

ISO New England has instituted a new rule that severely limits reactive VAR flow between reliability regions. As a result, VELCO and other transmission companies are strictly limiting power factors at GMP’s delivery points.

To help meet these limitations, GMP increased the minimum power factor required for customers to avoid a penalty under its commercial and industrial time-of-use tariff (Rate 63). We also plan to add capacitors to the distribution system to help meet these limits. Adding capacitors as close to the load as possible will ensure the greatest efficiency improvements and assist meeting the delivery point power factor requirements.

GMP is also reviewing the power factors on all circuits with VAR data to determine whether we should improve and increase power factors. We prioritized these circuits by the magnitude of VARs consumed and analyzed each circuit’s annual VAR demand. From this, we determined whether existing capacitor banks are operating properly and whether we should install additional banks involving either switched or fixed capacitors.

GMP’s system VAR study is analyzing 69 circuits. For years 2007 and 2008 (the first two years of the project), we will address 36 of these 69 circuits. We will complete the remaining 33 circuits in 2009 and 2010. We expect that less than half of these remaining 33 circuits will require capacitors. For the 36 circuits on the project list that we will address: GMP has ordered capacitors for the first 18 circuits on the project list; we plan to implement these projects by the end of 2007. We analyzed the next 18 circuits this year; 13 of these next 18 circuits needed capacitors. We will implement solutions for them in 2008.

Balancing Circuits

GMP developed a list of unbalanced circuits (beyond those identified in the updated T&D efficiency study) and, starting from the most unbalanced, has evaluated these circuits for possible action. We screen circuit balance at peak load. We then examine significantly unbalanced circuits for possible phase balancing.

Replacing and Adding Transformers

GMP continually replaces transformers for a variety of reasons including, but not limited to, voltage conversions, additional customers added to a transformer, maintenance, and storm damage. When a transformer must be replaced or added, GMP installs the most cost effective and efficient transformer possible. We determine the most efficient transformer using an Excel®-based analytical tool (developed in collaboration with the Department of Public Service). The tool considers life cycle, capital cost, no-load loss, and peak-load loss to determine the most inexpensive transformer that best fits the situation.

GMP classified 53 distribution transformers in its system as PCB contaminated (greater than 50 and less than 500 ppm). We are working on a plan to replace these transformers. When replacing a transformer, we will evaluate the load to determine the most energy efficient transformer to install based on current system loads. GMP has a number of distribution transformers purchased before 1980 that have not been tested for PCBs. Some of these are likely to be classified as either PCB contaminated transformers (>50 and <500 ppm) or PCB transformers (>500 ppm).

Distribution Circuit Reconfiguration/Voltage Conversion

As load grows, system capacity must also increase. GMP responds by reconfiguring distribution circuits, upgrading transformers, and converting voltages to meet this increased need while maintaining system efficiency. We exhaust these options before proposing new substations.

The "On-Going ASC Projects" (page 170) and "Non-ASC Transmission and Distribution Upgrade Projects" (page 172) sections discuss GMP's current and proposed projects, many of which involve upgrades to distribution circuit reconfiguration transformers and voltage conversion.

Automating Transmission and Distribution

GMP incorporates the vast majority of GMP's feeders, hydro facilities, and sub-transmission breakers and sectionalizing load break switches into our Supervisory Control and Data Acquisition (SCADA) system. We continue to increase the use of our SCADA system as antiquated equipment is upgraded and able to accept remote control functions.

In the near future, GMP expects to evaluate automating distribution in high load areas. We continue to expand computer access to VELCO SCADA data as needed.

Power Quality

Power quality issues mainly arise due to distribution or sub-transmission issues.

On distribution, a customer issue causes us to review power quality: low or high voltage, unbalance, or a number of other items. We install power quality recording devices at the specific customer's location for a period of time, and then analyze them for any power quality issues.

On sub-transmission, power quality issues can arise during contingencies or (sometimes) during heavy loading periods under normal operation. A dispatcher notices this through our SCADA system. Our Engineering Department handles the power quality issue by using a power quality device and by reviewing and analyzing existing sub-transmission equipment.

In both instances, if a power quality issue related to the utility system exists, we immediately develop and implement a solution.

Transmission and Distribution System Studies

Economic Assumptions Used in T&D Studies

For DUP projects, GMP follows the guidelines in the MOU agreed to in Docket 6290. We updated the energy and capacity costs with the values represented in the 2005 Avoided Energy Supply Component (AESC) Study Group report. GMP still uses the avoided T&D costs and the additional environmental compliance adders agreed to in Docket 6290.

For T&D efficiency projects that are not subject to DUP analysis, GMP uses the societal test to determine the cost effectiveness of a T&D efficiency upgrade. More specifically, the analysis compares the net present value of the levelized carrying cost of the project to that of the net present value capacity and energy savings that would be achieved by installing the upgraded equipment. We use the latest avoided costs contained in the AESC Study Group report to determine the value of the energy and capacity savings. The avoided T&D values are those that were agreed to in Docket 6290. In its analysis, GMP also uses the environmental externality values agreed to in Docket 6290. We generally do not consider risk in these analyses.

For a project to be considered cost effective, the net present value of the energy, capacity, and T&D savings (including environmental externalities) must exceed the net present value of the levelized capital cost of the project.

Transmission and Distribution Reliability

GMP focuses a significant amount of our planning, engineering, and construction activities on increasing the reliability of our system. We also focus on mitigating any factors that have a negative impact on reliability.

Weather Events. Certain weather events impact GMP's system reliability. And weather events usually occur with only 24 to 72 hours notice, placing a premium on our ability to react quickly. Towards this end, we have infused a culture of preparing for weather events, and successfully created an appreciation for reacting quickly. We educate all employees about the different functions they will perform, and when and how to perform them.

In order to evaluate our performance, GMP has created and uses Storm Preparedness Planning Guidelines. We exercise the guidelines with each weather event, then evaluate ways to improve the process after each event. We incorporate "lessons learned" into the guidelines which then become part of future responses to weather events.

GMP recognizes that certain weather events can predicate power outages. We take a proactive stance, subscribing to a weather monitoring service in which GMP Dispatchers receive inclement weather alerts and forward them to operations management by email and a Storm Pager. This early warning system allows us the time necessary to mobilize the Storm Team, field assessors, and field crews before an outage occurs. This proactive process has significantly minimized the duration of outages.

Technology plays a significant role in managing a storm event. GMP uses several interrelated systems when restoring power. This allows us to efficiently answer high volumes of customer calls and to maximize the use of every available resource.

GMP's Storm Director on-call rotation continues to be a vital component of restoring power during an outage. The Storm Director on-call "owns" the successful handling of a storm, including calling pre-storm assessment and planning meetings, securing resources, assigning individuals to specific roles, scheduling a succession of staff (if the restoration effort is forecasted to last more than 24 hours), and wrapping up after a storm.

Trimming Trees. The location of trees and branches also impact GMP's reliability. We implemented a comprehensive vegetation management plan in June 1999; it focused efforts on pruning trees that encroached on GMP facilities the most. We first trimmed out circuits with the highest number of tree-related outages and customer outage hours (as determined by outage statistics generated from Service Interruption Reports). In 2006, 392 miles of GMP distribution lines and 568 acres of transmission line rights-of-way were trimmed.

GMP strategically focused on removing "danger trees" — trees that are near power lines, but outside rights of way which are removed for public safety and system reliability. We must get permission from property owner's before removing danger trees. In 2006, we had 5,466 danger trees removed. In late 2004, we completed our first cycle for transmission vegetation management; in 2006, we completed a seven-year cycle of distribution vegetation management. We are now on the second cycle of trimming.

Pole Inspections. GMP inspects and treats its transmission poles every 10 years. We look for splits, holes, and abrasions to the pole. We excavate soil from around the pole's base to look for "ground line" rot. We then "sound" and "bore" the pole to determine if the inside has been compromised or if voids have developed. Finally, we wrap the pole with an antifungal compound.

GMP last inspected poles during the years 2000 to 2003. We plan to inspect poles again beginning in 2010.

Infrared Scans. GMP performs infrared scan of its entire sub-transmission system. Infrared scans help identify elements of the electric system that are stressed or destined to fail. GMP also performs aerial transmission inspections in the spring and fall to look for danger trees, broken cross arms, "floating phases", and other items that have the potential to affect system reliability. These slow and meticulous aerial inspections catch items as subtle as hair line cracks in insulators and cotter pins that are working their way free. As part of post-storm assessments, GMP regularly evaluates parts of its system looking for issues.

GMP will continue performing "close in" aerial scans to identify critical transmission lines or sections of lines to better catch problems before they surface.

Analyzing Outage Events

Table 7 compares 2006 outage events to the historical five year average[3].

Cause Code Series	Cause Code Description	Average (2002–2006)		2006	
		Events	% of Total	Events	% of Total
10/11	Other / Unknown	140	7%	109	5%
1	Trees	650	31%	746	35%
2	Weather	303	14%	267	12%
3	GMP Initiated	88	4%	75	4%
4	Equipment Failure	471	22%	465	22%
5	Operator Error	16	1%	16	1%
6	Accidents	81	4%	78	4%
7	Animals	357	17%	361	17%
8	Power Suppliers	14	1%	24	1%
Totals		2,120	100%	2,141	100%

Table 7: Outage Events Analysis

[3] Average data compiled over the five year period 2002 to 2006.

Analyzing Customer Hours Outages

Table 8 compares 2006 customer hours out to the historical five year average[3].

Cause Code Series	Cause Code Description	Average (2002–2006)		2006	
		CHO	% of Total	CHO	% of Total
10/11	Other / Unknown	7,961	3%	2,370	1%
1	Trees	98,191	43%	114,855	37%
2	Weather	27,923	12%	38,493	12%
3	GMP Initiated	2,753	1%	2,875	1%
4	Equipment Failure	35,246	15%	35,166	11%
5	Operator Error	1,056	0%	456	0%
6	Accidents	11,409	5%	18,202	6%
7	Animals	19,867	9%	12,354	4%
8	Power Suppliers	25,441	11%	83,545	27%
Totals		229,847	100%	308,315	100%

Table 8: Customer Hours Out Analysis

Referring to Table 8, one of the biggest variances in 2006 was in terms of supplier related outages. Based on historical averages, we can anticipate approximately 11% of our customer hours out for the year to be attributed to suppliers. In 2006, supplier related outages accounted for 27% of the total customer hours out for the year and were the result of 24 separate outage events. This represents an increase in customer hours out of 145% and an increase in the number of events of 71%, when compared to the average.

Supplier	CHO	Events
VELCO	3,756	8
New England Power	68,062	13
Other	11,726	3
Total	83,545	24

These outages were the result of various causes. They had the largest impact on our Dover and Wilmington substations where 85% of the 83,545 customer hours out (CHO) were recorded.

Every year since 2002, GMP has identified its worst performing circuits and implemented plans to improve their service reliability. We have created a priority list that ranks each circuit by the number of outage events and the total customer outage hours. This list allows GMP to focus its limited resources on the least reliable areas of the power system, improving overall performance. Coupled with a system-wide focus on preparedness, technology, and proactive vegetation management, GMP creates a comprehensive approach to advancing the reliability of our power system.

GMP will continue to make significant investments into the improvement of its electric system. Projects aimed at improving reliability include whole coordinating circuit fuses, moving “cross country” lines roadside, installing new line reclosers, upgrading SCADA controls, and replacing end-of-life plants.

We note that since 2000, GMP has made a tremendous investment in vegetation management. Annually, we invest approximately $2.7 million in tree trimming. Our goal is to be on a seven year trim cycle for distribution lines and five year cycle for transmission lines. Last year we achieved this goal and we are now onto our “second trim cycle”. Anecdotally, we feel the trimming has made a major difference, so that winds that would have caused significant outages in the past now more often blow through with little or no effect.

Planning Coordination with VELCO and Other Utilities

GMP regularly communicates with VELCO and other utilities in the state to review the need for VELCO’s bulk transmission services. VELCO maintains a base case Positive Sequential Load Flow (PSLF) model of Vermont’s transmission system. All Vermont utilities have access to the model and continually update it. The model simulates load flows on Vermont’s bulk transmission and sub-transmission system and is used for planning studies.

When requested, GMP forecasts loads for VELCO. The Burlington Waterfront ASC (discussed on page 170 of “Appendix F: Transmission and Distribution Planning”) is a good example of the coordination efforts between VELCO, GMP, and other utilities.

Current and Planned Use of Automated Meter Reading

GMP uses a multi-media approach to ensure the most cost effective and efficient methods for automatically reading meters. We reduce the cost of reading meters by implementing lower-cost, one-way radio frequency methods. We use these methods primarily in remote, rural areas (such as Wilmington and Vergennes). We implement a two-way metering system to obtain timely consumption information and better manage outages. We use this method primarily in less rural areas (such as Colchester, Barre, and Montpelier).

In 2005, Green Mountain Power began replacing single-phase electro-mechanical meters with meters fitted with a radio frequency device. This device, TransPondIT, collects data through radio frequency from the meter and transmits it to a mobile or fixed data collection device. We are currently using both collection methods. The fixed system combines visual, touch, and radio reads on one route (this provides for immediate reading benefits before the route is entirely converted). The mobile system allows us to read a larger number of meters from a greater distance. We are using this mobile system in our Vergennes territory.

We have installed 35,000 residential meters with this capability. GMP and our customers benefit from improved accuracy, fewer estimated readings, set flags indicating possible meter tampering or theft of service, lower meter reading costs, faster meter reading, and increased customer care. Since the radio frequency device does not transmit a reading if there is no power to the meter, we have also been able to better manage outages.

In 2007, GMP will test an additional meter reading system, or Advanced Metering Infrastructure, to compliment our current radio frequency meter reading system. This two-way communication system will provide flexible billing dates, flexible rate options, energy usage analysis, and load profiling on any meter to support rate analysis and load forecasting. We also expect to improve outage and restoration processes, as well as virtual connects and disconnects.

This technology securely and reliably communicates between meters and collectors. Communication distances are increased because meters can become repeaters, increasing the reliability of the signal which dramatically reduces the number of actual repeaters in the system while increasing economic feasibility.

Information Technology

GMP's goal is to build information technology systems that fully support delivery service to our customers. These systems are flexible, can be scaled for future growth, reduce cost, create workforce efficiency, and increase customer satisfaction.

Our strategy is simple: obtain the greatest benefits as quickly and as cheaply as possible. We achieve this through a coding method of Rapid Application Development, a logical consequence of the 80/20 rule of software that states: 80% of use comes from just 20% of the features.

We identify the 20% of the features that get the most use and give the most value, build them first, and release them as soon as possible. We add more features in subsequent releases. This allows steady progress with tangible benefits realized throughout the project. Another important benefit: GMP can change work habits to make do with less. Sometimes we discover that additional planned features are not needed, so we don't produce them, saving more time and money.

Accessing Our Computer Systems Remotely

We have made significant strides towards remote workers. All of our linemen have laptops in their trucks. These laptops are loaded with their daily work orders, electronic versions of all of our circuit maps, and all of our equipment information. All laptops have embedded cell cards; when in coverage, linemen can see customer outages and other line trucks plotted on the map. Linemen can use this system to review, modify, and close outage tickets while in the field. This gets us restoration information as quickly as possible, and frees up radio traffic and manpower back in the storm center. The linemen also have electronic road maps (Mappoint-based) that allows them to locate any pole in our system, see a picture of the pole and retrieve its related equipment information, and get directions to that pole.

While we've focused heavily on linemen remote access, we continue to increase our remote access capabilities for all workers. Most of our systems are available to workers through use of VPN[4] and Citrix Metaframe. We only purchase new laptops rather than desktop computers. This allows the company much more flexibility in placing our workers. Whether the situation is an employee working remotely due to a major storm, a sick child, home-base work, or a pandemic, we create access so the company can be run remotely.

High-Availability

Most of our daily operations are run using highly integrated systems: Customer information system, work management system, Geographic Information System, Interactive Voice Response System, and Outage Management System. Losing access to those systems has a significant impact on our operations and our ability to quickly effect storm restoration.

Losing access to these systems rarely occurs, but we realize there are serious consequences if it occurred during a major storm. To address this issue, we are installing high-availability redundant Unix servers consisting of two parallel database servers and two parallel application servers. Each server is able to carry the full system load should the other fail. In additional, we are installing a third set of parallel database and application servers in our Montpelier disaster site. Application and database changes that occur in our Colchester office will be updated almost immediately in Montpelier. This allows us to switch operations to our disaster site in hours rather than days with little or no loss of data.

SCADA Redundancy

We are applying our high-availability model to our SCADA system. For our system operators, the SCADA system is their eyes and ears on the electric grid. Breakers that trip off, control of our generation plants, circuit switching is all done through SCADA. Currently our SCADA system sits in our Colchester control center. They are configured as set of two redundant fail-over boxes: should one box fail, control automatically falls over to the other box.

We are addressing a final security need. Our SCADA system is in one location. Should something happen to that machine, we lose all automatic control over our switches and breakers. All switching would have to take place manually by field personal. Should this occur during a major outage, our restoration time would be increased dramatically. Since SCADA boxes are highly specialized, it would take almost three months to replace them. We would be exposed to manual switching that entire time. To address this, we are installing a second, redundant SCADA system in our Montpelier disaster recovery site. This secondary site would give us a command post to restore our system and maintain automatic switching.

[4] VPN, a virtual private network, uses encryption to securely connect to GMP's internal network and servers using the Internet, an otherwise insecure network.

Managing Outages

We have a very well integrated outage management system. Data flows automatically from the Customer Service System and IVR[5], to the Work Management and GIS, out to the trucks, and back again. We need to improve how we incorporate handling device-driven outages. Our current system creates and tracks an outage ticket for each call entered, but it doesn't directly tie the outages to the failed device. This can leave the line crews handling multiple tickets for the same outage. Our goal is to establish a device-driven approach where all customer calls are rolled into a single ticket for the failed device. Linemen will have a single work order for each outage rather than multiple orders, reducing confusion and easing the administrative part of storms. It will also allow for more accurate and timely reports of customer outages, and automate Service Interruption Reports.

Replacing Our GIS System

Replacing our GIS system is a major initiative for 2008 and 2009. We have outgrown our current system: it is not as scalable, flexible, or easy to use as would be ideal. We have also found its database design and data integrity constraints to be lacking. We are looking for a new system with integrated maps, improved design software, and better integration with our existing systems — especially outage management and SCADA. We are currently meeting with vendors and will put this out for RFP in July of 2007.

Area Specific Collaboratives

GMP undertook a number of ASCs and other projects. The results for the completed ASCs were essentially all the same: these projects could not be deferred with energy efficiency or distributed generation. However, these projects did result in a more efficient and robust T&D system with less system loss. Although the loss achieved by these projects was generally significant for the specific study, the savings when compared to GMP's overall supply resource needs was very small and was not specifically accounted for when determining GMP's overall need for future generation resources.

The following area specific collaborative projects are more fully described in *Appendix F: Transmission and Distribution Planning* on 167.

Completed ASC projects in service

Docket No. 6797: Digital Injection Project (page 167)

Docket No. 6798: White River Junction Area Specific Collaborative (page 168)

Completed ASC projects not in service

Docket No. 6799: Lamoille County Loop Target Area (page 169)

Docket No. 6800: Mount Snow (page 169)

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[5] IVR, or Interactive Voice Response, uses prerecorded voice messages to allow callers to store, retrieve, and route messages, and to interact with our database to enable automated transactions.

On-going ASC projects

Docket No. 6801: Tafts Corners (page 170)

Burlington Waterfront Area (page 170), including:

- East Avenue Loop – Phase I (page 170)
- East Avenue Loop – Phase II (page 171)
- East Avenue Loop – Phase III (page 171)

Non-ASC transmission and distribution upgrade projects

Ethan Allen Conversion (page 172)

Gorge Substation Rebuild and Conversion (page 172)

Third Winooski 35.4 Kilovolt Feeder (page 173)

Vergennes Substation Upgrade (page 173)

Bellows Falls (page 173)

New Westminster 12 Kilovolt Substation (page 173)

Waterbury Center (page 174)

Waterbury (page 174)

Other planning efforts

Location-Specific Planning: Hinesburg Area (page 174)

4: Energy Resource Planning

Green Mountain Power uses the information and recommendations in this IRP to supply resources with the most value to us and our customers. We measure value from the following perspectives:

- Meeting the demands for electric power of our customers at the lowest cost.
- Striving for the mix of supply sources that have lowest practicable and effective environmental impact.
- Assuring that we are financially able to implement the resource plan with minimal risk.
- Providing a stable price environment for our customers.

We employ a multi-step process to create a recommended course of action for our resource portfolio strategy. It can be pictorially represented as shown below.

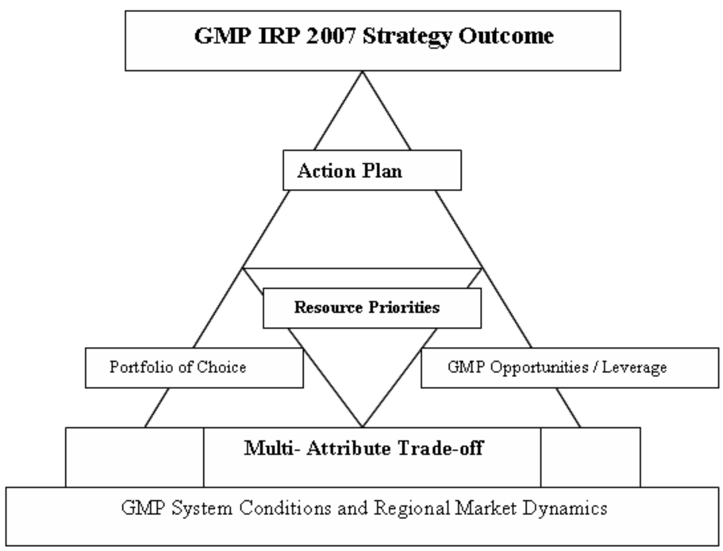

Figure 14: GMP's Multi-Step Resource Planning Strategy

We examine our power system, demand, generation, transmission and distribution, and their future outlook together with a thorough understanding of the regional marketplace and its outlook. The IRP planning centers on developing and modeling various resource portfolios that reflect potential thematic directions. We then evaluate these portfolios using several scenarios that illustrate future economic, political, and environmental variables for the local, regional, and global energy environments. In this analysis, we use a

Multi-Attribute Trade-off approach to choose the portfolio that is indicated as the most beneficial to pursue. This process helps to identify our best opportunities to develop additional resources to meet future needs, and the tradeoffs (based on current information) between them. From this combination, we establish a priority for developing resources for the next several years.

“Section 5: Action Plan” (on page 99) describes how we intend to implement the priorities identified in this plan.

Four Potential Scenarios

We developed energy efficiency forecasts based on four plausible set of future economic conditions, called scenarios. These scenarios are based on an outlook of the interacting events, forces, and changes that might exist together under a set of suggested conditions.

Many different organizations have used scenarios as a planning tool for at least two decades. Scenarios are useful in that they help determine a viewpoint on the best course of action to take from a classic economic analysis perspective of a particular investment and also provide insight regarding the flexibility, robustness, and value of different organizational strategies.

Factors Considered in Designing the Scenarios

In order to better plan resources and to maintain plausibility, the scenarios represent a significant variation in the key parameters that affect the demand for electricity and the cost to provide reliable electric service. We used a wide range of conditions to design a disparate set of scenarios (described in detail in “Appendix G: Scenario Descriptions” on page 175). These conditions are flexible and robust while being specific enough to clearly identify potential impacts.

We based these scenarios on original analysis performed by Platts Research and Consulting (used by permission), modified first for use in Vermont[6] (as described in the Vermont Integrated Resource Planning Scenario Development Document, dated February 20, 2003, Scenario Development Document), and updated by the GMP Integrated Resource Planning team during late 2006. For this IRP, we have adapted the scenarios to accommodate broader ranges of key components and to capture today’s starting point.

6 Among other things, the scenario names have been modified to focus the descriptions more directly on the Vermont IRP process. “Fortress America: Building the Barricades” was changed to Fortress America. “Eye of the Storm: Natural and Human Caused Disasters” was changed to Green Focus. “The Long Boom: Irrational Exuberance” was changed to Back to Business. “Emergence: Optimizing from the Bottom Up” was changed to Green Growth.

The major influences on the benefits of resource strategies to assure reliable electric supply are political and economic factors mapped against environmental factors:

- These parameters are evaluated for each scenario at the global, national, and local policy levels.
- An appropriate number of scenarios — four — against which to test portfolio alternatives.

Figure 15 portrays the combinations of geopolitical/economic and environmental factors that produce our four alternative scenarios. The relative emphasis of environmental considerations is plotted on the vertical axis, while the emphasis of economic growth is plotted along the horizontal axis.

- The Fortress America scenario (lower-left quadrant) focuses on the deterrence of terrorism and its concomitant, increased global polarization.
- The Green Focus scenario (upper-left quadrant) reflects an aggressive environmental protection agenda coupled with low economic growth and political disengagement.
- The Back to Business scenario (lower-right quadrant) focuses on aggressive economic growth unfettered by environmental or regulatory concerns.
- The Green Growth focus (upper-right quadrant) seeks to portray a balance between economic, social, and environmental objectives.

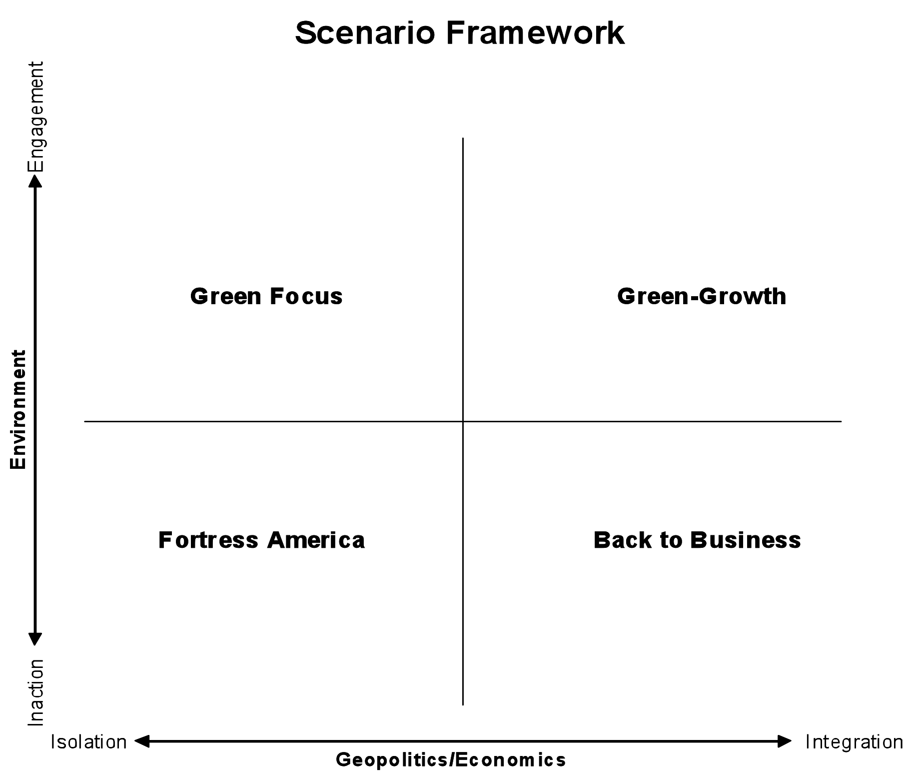

Figure 15: Framework for Future Condition Scenarios

Quantifying Key Components of the Scenarios

After establishing the scenarios in qualitative terms, we created future values for key components for each scenario to better evaluate alternative strategies through various resource portfolios on a quantitative basis.

The key inputs used to quantify the four scenarios (cross-referenced to the page where specifics and forecasts are discussed and graphically presented) are:

- Demand and Energy Outlook (page 56)
- Energy Efficiency Funding Levels and Impact (through Efficiency Vermont, page 57)
- Fossil Fuel Prices (specifically oil and natural gas, page 58)
- Renewable Portfolio Standards (page 60)
- Externality Values (such as the impact of pollutants, page 61)
- Emission Regulations (page 62)
- Electric Energy Wholesale Price Estimates (page 62)
- Electric Capacity Wholesale Price Estimates (page 66)

Summarizing the Scenario Inputs

We derived the scenario inputs from a number of sources. The U.S. Department of Energy publishes an Annual Energy Outlook (AEO) that includes alternative cases for projecting economic activity and, in particular, energy prices. Three cases were included in the 2006 AEO:

- Reference case (RF)
- High gas price case (HI)
- Low gas price case (LO)

In addition to scenarios directly reflecting the AEO cases, we included the Fortress America scenario outlook where prices for oil and gas are high in the near term and then transition to the reference trend. We derived externality values from those adopted by the Minnesota Public Utilities Commission. We based regional load growth on forecasts by ISO New England; and GMP-specific load growth on internal projections modified to match scenario conditions. Finally, we based spot electricity price forecasts on the La Capra Northeast Market Model.

Table 9 summarized the inputs for our four scenarios and (where applicable) their derivation from the AEO scenarios.

Input	**Fortress America**	**Green Focus**	**Back to Business**	**Green Growth**
Oil	HI, then RF	HI	LO	RF
Natural Gas	HI, then RF	HI	LO	RF
Coal	HI, then RF	HI	LO	RF
Externality values	Minnesota Suburban	Minnesota Suburban	Minnesota Suburban	Minnesota Suburban
Regional energy growth	1.17%	1.17%	1.65%	1.42%
GMP energy growth (pre-DSM)	0.91%	0.70%%	1.56%	1.34%

Table 9: Scenario Plan Inputs

Demand and Energy Outlook

We developed three alternatives for the economy and the resulting electricity demand growth for the GMP service territory. We determined a 1% per year reference level growth rate for energy consumption for GMP. We used historical cyclical periods of higher and lower growth of economic drivers to derive potential higher and lower demand growth outcomes. This resulted in a 1.6% per year high energy growth rate and a 0.6% low energy growth rate. Figure 16 depicts these forecasts.

We based these forecasts on econometric trends and statistical analyses where the electric energy consumption relationship changes if economic drivers were altered by the presence of efficiency programs intervention. This assumes that new energy efficiency program activities continue to reduce energy consumption levels. Implicitly, these econometric forecasts feature future energy efficiency programs similar to historical averages.

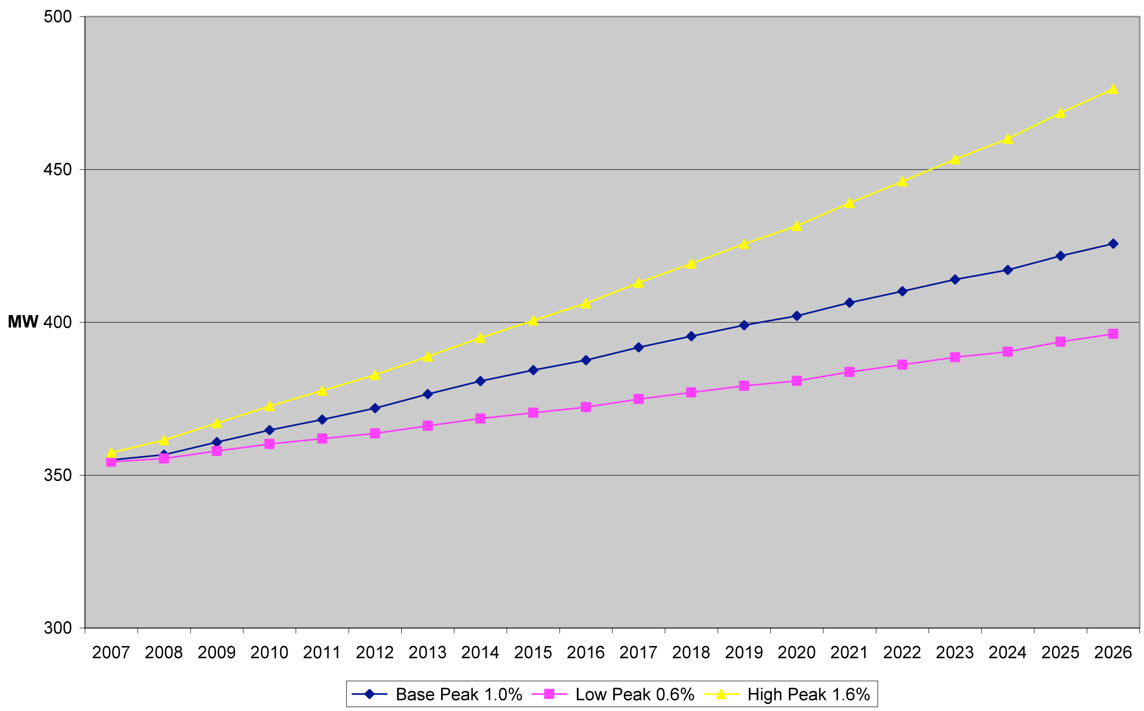

Figure 16: GMP's Annual Peak Demand Before Demand Side Management Program Influence

Energy Efficiency Funding Levels and Impact

In its 2003 IRP, GMP analyzed each portfolio and scenario combination to calculate the level of energy efficiency investment that would be economical. In this 2007 IRP, we have taken a different approach to integrating demand-side management (through Efficiency Vermont) with the supply resource options. This analysis ties different levels of efficiency program funding, associated peak demand, and energy savings to the four scenarios without referencing the numerous portfolio combinations. This reflects the fact that funding decisions on energy efficiency occur outside the utility IRP planning cycle, and that future efficiency funding can depend in part on factors (for example, consumer financial impacts, political consensus) other than its projected cost-effectiveness.

There are four basic levels of funding that are incorporated in the future scenarios. In each scenario, the statewide budgets through 2008 are assumed to remain at the recently approved level, which includes geotargeting of programs and funding approximately at the $28 million dollar annual level. In scenarios with the highest energy costs, we would expect Efficiency Vermont to identify and justify the greatest amount of energy efficiency opportunities. This likely would continue the most recently increased budget levels of nearly $30 million per year. Conversely, the lowest energy prices would tend to diminish the amount of economically justifiable program expenditures, perhaps to the early Efficiency Vermont annual funding levels of $10 million or less.

We have approximated four different program expenditure levels and their impact on peak demand and energy requirements. Each of these represents an approximate level of program expenditures: $10 million, $16 million, $24 million, and over $30 million per year. In Figure 17, we present the four scenarios with their varying levels of energy efficiency funding and their impact on peak demand and energy requirements.

The demand and energy forecasts (discussed on page 56) did not explicitly consider continued energy efficiency funding. We have estimated that the implicit level of efficiency program-driven load reductions in these demand and energy forecasts is equivalent to the $10 million budget level of energy efficiency program expenditure. Since we build this program funding level into the Back to Business scenario, no adjustment is necessary to the high demand growth forecast shown in the previous section. The Green Growth Scenario includes the reference demand growth forecast and assumes Efficiency Vermont is funding over the long-term at the $16 million level. Since the reference demand forecast had the $10 million level of funding built into its projections, we derive the demand forecast for the Green Growth scenario by taking the reference forecast and reducing it by the extra savings achieved at the $16 million funding level (versus the $10 million level). Similarly, the Fortress America scenario uses the low load forecast of the previous section and assumes the $24 million level of Efficiency Vermont funding. The Green Focus scenario combines the low demand forecast and the highest level of Efficiency Vermont funding due to its higher energy prices.

Figure 17 forecasts the summer peak megawatt energy efficiency savings for each scenario over the next 20 years.

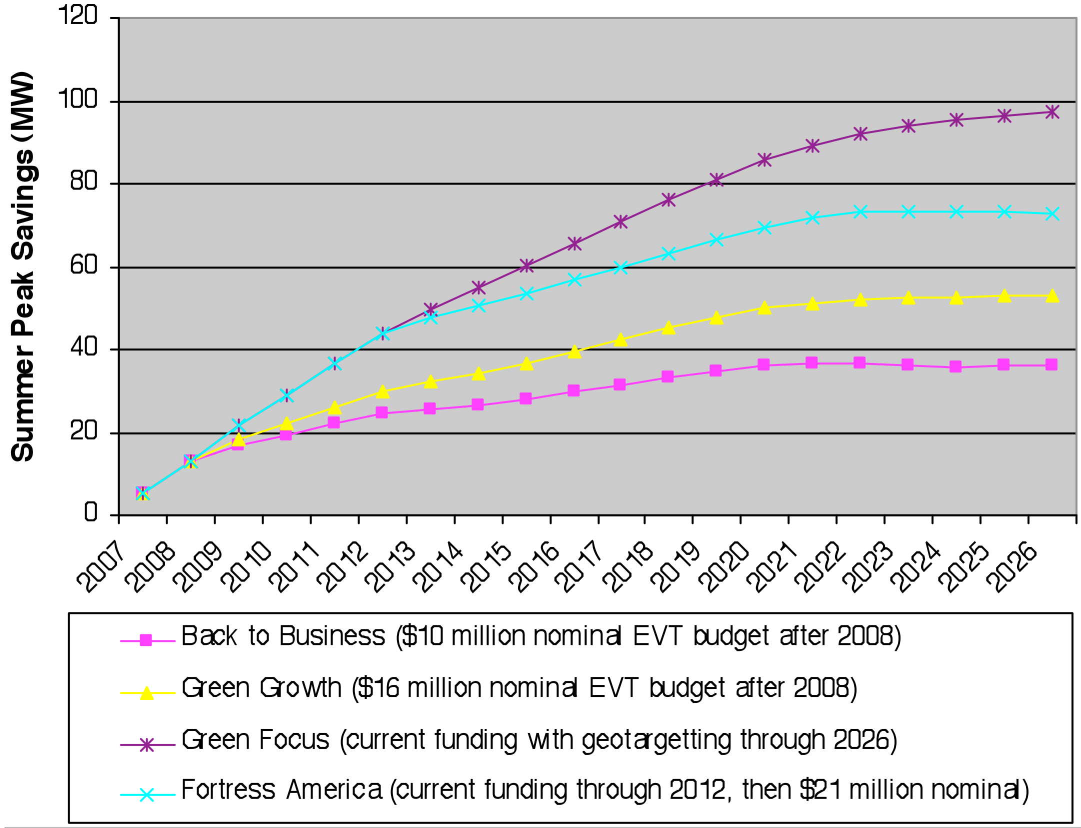

Figure 17: Efficiency Vermont Summer Peak Demand Reduction Forecasts

Fossil Fuel Prices

For each scenario, we developed an explicit price forecast for the major fuels that affect electric generator fuel costs, natural gas, crude oil, and coal. We derived the delivered fuel costs for regional power generators by applying estimated processing and transportation costs to the raw commodity price forecast.

Figure 18 and Figure 19 show the trend in natural gas and oil prices used in the scenarios. These forecasts were derived from the AEO 2006 fuel price forecasts. We note that in actual practice, short-term supply/demand events such as weather could cause annual prices to vary temporarily above or below the long-term trends shown here.

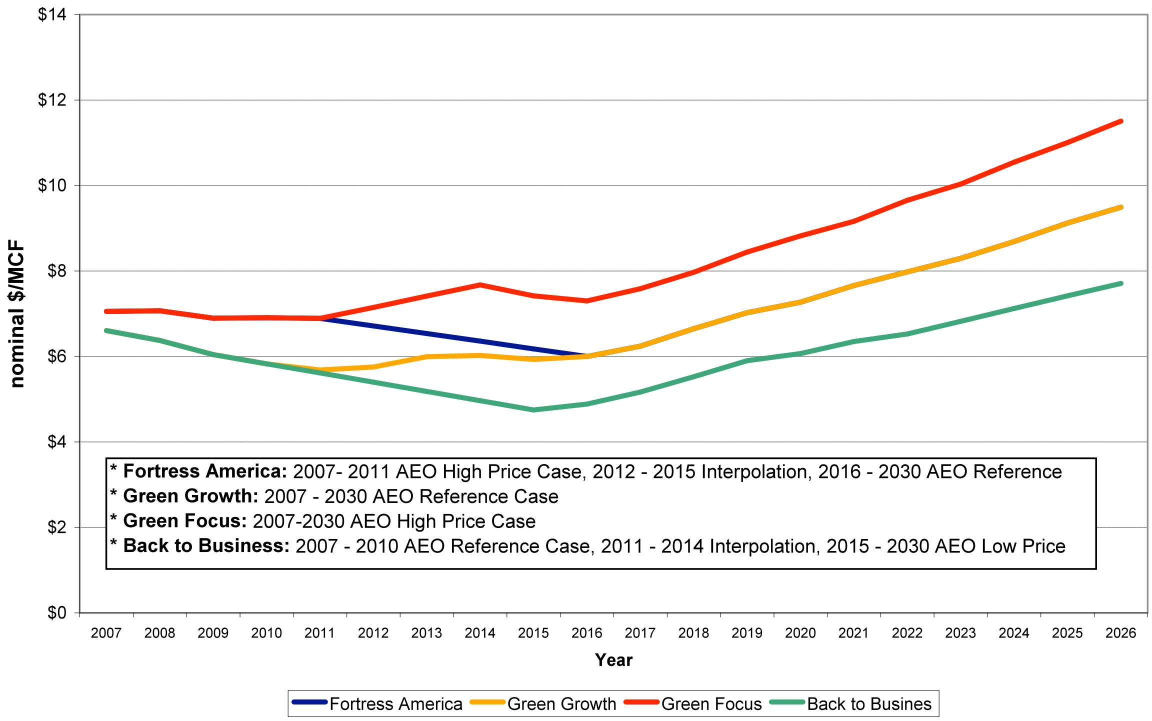

Figure 18: Comparison of Average Wellhead Natural Gas Price Forecasts

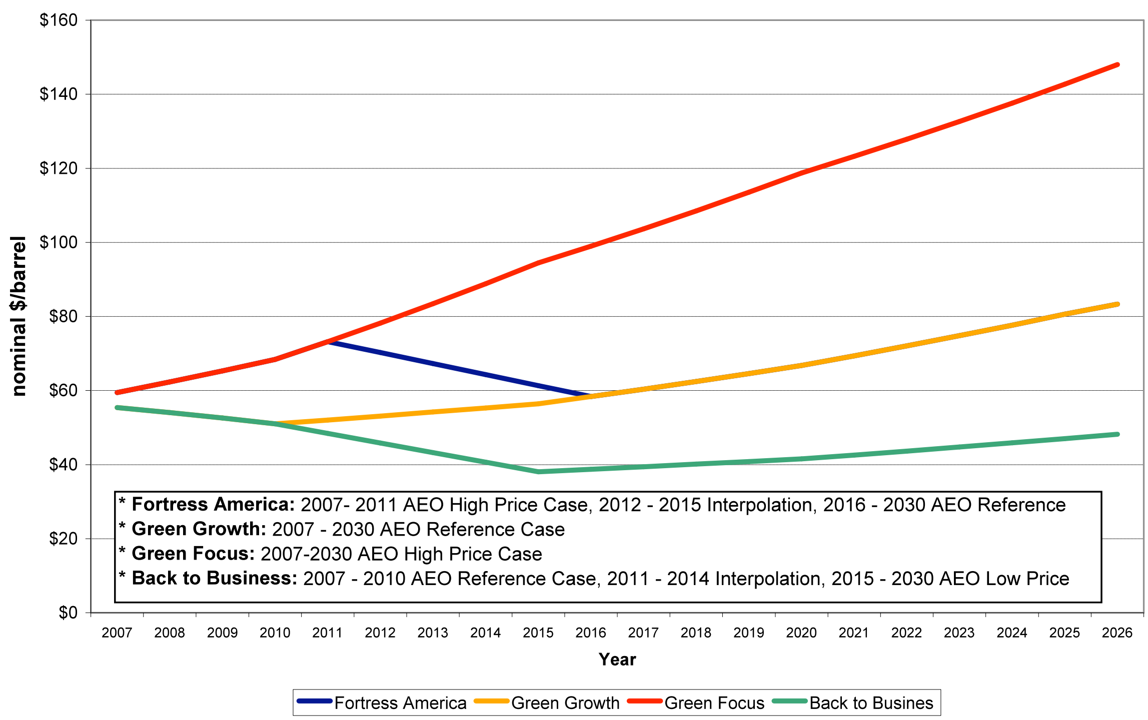

Figure 19: Comparison of Imported Crude Oil Price Forecasts

Renewable Portfolio Standards

This table summarizes the RPF requirements assumed for the New England states in each scenario.

<table>
<tr><th colspan="2"></th><th>Fortress America</th><th>Green Focus</th><th>Back to Business</th><th>Green Growth</th></tr>
<tr><td colspan="2">Load Forecast</td><td>CELT[7] 2006 low</td><td>CELT 2006 low</td><td>CELT 2006 high</td><td>CELT 2006 base</td></tr>
<tr><td rowspan="7">Renewables Future</td><td>Summary</td><td>All states achieve RPS, some increase their goal</td><td>All states achieve RPS, some increase goal</td><td>Reference</td><td>All states switch to meeting Federal RPS starting in 2011</td></tr>
<tr><td>MA</td><td>Increases to 10% after 2009</td><td>Increases to 10% after 2009</td><td>Increases to 7% after 2009</td><td rowspan="6">All states progress with their respective RPSs until the Federal RPS takes effect. The state RPS levels achieved by 2011 will be maintained until the Federal RPS surpasses the state level. Since we believe the earliest implementation of a Federal RPS will not be until 2011 (four years after the 110th Congress convenes), a 1% per year growth would be quite aggressive to attain 10% by 2020. So, we assume the Federal RPS is pushed out to 2025, with a growth trajectory of 0.5% in 2011 to 10% by 2025.</td></tr>
<tr><td>CT</td><td>Increases to 10%</td><td>Increases to 10%</td><td>Meets 7% RPS and maintains level</td></tr>
<tr><td>RI</td><td>Meets 16% RPS and maintains level</td><td>Meets 16% RPS and maintains level</td><td>Meets 16% RPS and maintains level</td></tr>
<tr><td>ME</td><td>RPS are considered mandatory and new generation appears as a result</td><td>RPS are considered mandatory and new generation appears as a result</td><td>No new generation in New England</td></tr>
<tr><td>VT</td><td>RPS are considered mandatory and new generation appears as a result. RPS is met with in-state renewables as a result of SPEED program</td><td>RPS are considered mandatory and new generation appears as a result. RPS is met with in-state renewables as a result of SPEED program</td><td>No new generation in New England</td></tr>
<tr><td>NH</td><td>RPS passes legislation and becomes mandatory</td><td>RPS passes legislation and becomes mandatory</td><td>No new generation in New England</td></tr>
</table>

Table 10: RPS Summary for Each New England State

[7] CELT = Capacity energy loads and transmission

Externality Values

GMP has evaluated resource options using a Multi-Attribute Trade-off analysis. In this analysis, the level of emissions is presented independent from the cost and associated benefits. That is, emissions and other environmental impacts are typically expressed in natural units (e.g., tons) rather than monetized. In this context, one might consider the monetization of the externality of emissions impacts unnecessary and possibly redundant. Nevertheless, GMP has also calculated monetized emission costs as described below.

Various states have approved externalities for the purpose of resource planning. In the context of the 2003 IRP, we considered values from California, Massachusetts, Minnesota, New York, Oregon, and Wisconsin for our IRP. We chose the Minnesota externalities values because they were based on an extensive analysis involving a two-year Minnesota Public Utilities Commission proceeding with 20 parties and over 50 witnesses.

The Minnesota externality values (except for CO_2) are based on a study by Triangle Economic Research that was sponsored by Northern States Power. Triangle Economic Research has extensive experience in conducting environmental damage assessments and used a damage cost approach in the analysis.

The Minnesota Pollution Control Agency proposed the approach of quantifying externalities for CO_2, based on the assumption that global warming will impact the economy. The high end of the CO_2 externality value that resulted from this approach is substantial, and reasonably close to the value of carbon in the current European market.

To reflect the geographic impact of siting generation resources, Triangle Economic Research developed Minnesota externalities for urban, suburban fringe, and rural locations; as well as values for generation resources greater than 200 miles from Minnesota. They also developed high and low ranges of estimated damage costs due to uncertainties in the analysis. The range approach to defining the damages was adopted in the approved Minnesota externalities values.

We mapped the four IRP scenarios to the Minnesota Externalities values according to the following table:

IRP Scenario	Minnesota Externalities Values
Fortress America	Suburban Fringe – High
Green Focus	Suburban Fringe – High
Back to Business	Suburban Fringe – High
Green Growth	Suburban Fringe – High

Table 11: Scenario Mapping to Minnesota Externalities

Minnesota externality costs in dollars per ton of emission were provided for the following: SO_2 (sulfur dioxide, set to zero after 2000 to reflect SO_2 emission trading), NOx (nitrogen oxide), PM10 (particular matter, less than 10 nanometers), CO (cobalt), Pb (lead), and CO_2 (carbon dioxide).

In April 2003, we updated the externalities values to 2002 dollars. Table 12 shows this. In the portfolio analysis, these values were inflated to the appropriate future years at the general inflation rate.

Emission	**Original ($1,995/ton)**		**Inflation Adjusted GDPI ($2,002/ton)**	
	Low	High	Low	High
SO_2	46	110	52	124
PM10	1,987	2,886	2,253	3,273
CO	0.76	1.34	0.86	1.52
NOx	140	266	159	302
Pb	1,652	1,995	1,873	2,262
CO_2	0.3	3.1	0.34	3.52

Table 12: 2003 Externality Values

Emission Regulations

Three future scenarios for the regulation of greenhouse gas emissions were used in the IRP scenario analysis – a base case, a moderate regulation case, and a case with aggressive regulation. Currently there is virtual consensus in the industry and in policy circles that carbon emissions will be regulated at the federal level, most likely using a cap-and-trade-type system. Only the details (such as when and how strictly) are considered uncertain. There is already some certainty about greenhouse gas regulation in New England with the cap-and-trade system of the RGGI slated to begin operation in 2009. Therefore each of the IRP scenarios assumes that generators in New York and all New England states (all RGGI signatory states) will have to pay for CO_2 allowances in 2010 and 2011. In 2012, federal legislation is assumed to kick in. This is where the greenhouse gas scenarios diverge into the base, moderate, and aggressive cases.

For the base case, we assumed that the federal legislation will result in a noticeable allowance price. We used an allowance price forecast for a regime that would aim to reduce greenhouse gas emission intensity by 2.6% during 2010–2019 and by 3.0% during 2020–2030 with a safety-valve cap set at $8.83 per ton in 2010 (2004 dollar allowance) escalating to $14.13 per ton in 2030 (2004 dollar allowance).[8] This is patterned after a program recommended by the National Commission on Energy Policy (NCEP), a nongovernmental, privately-funded entity, in its December 2004 report entitled *Ending the Energy Stalemate: A Bipartisan Strategy to Meet America's Energy Challenges* which has served as the foundation for many carbon legislation proposals introduced in Congress.

[8] Scenario "Cap-Trade 2" in EIA, "Energy Market Impacts of Alternative Greenhouse Gas Intensity Reduction Goals", March 2006, SR/OIAF/2006–01. Due to the lead time necessary to pass legislation and set up a program, our analysis assumes that a federal cap-and-trade system will not be implemented until 2012.

Greenhouse Gas Emissions Scenarios			
All prices are nominal $/allowance (1 allowance = 1 ton CO_2e)			
	2012	2015	2020
Base Case Carbon Regulation	$7.13	$9.81	$16.57
Moderate Carbon Regulation	$11.80	$16.24	$27.62
Aggressive Carbon Regulation	$19.68	$29.96	$50.41

Table 13: Greenhouse Gas Emission Scenarios

The base case is used in the Back to Business scenario because it currently seems to be a fairly likely case. It is also used in the Fortress America scenario due to the focus on domestic sources of fuel which will not make as much economic sense under more strict greenhouse gas regulation.

The forecast used for the moderate case is also based on the NCEP policy model with tighter restrictions. The greenhouse gas intensity reduction goal would be 2.8% during 2010–2019, 3.5% during 2020–2030, and a safety-valve allowance price cap set at $22.09 in 2010 (2004 dollar allowance) escalating to $35.34 in 2030 (2004 dollar allowance).[9] This case results in a middle of the road price for greenhouse gas emission allowances. The moderate case is therefore applied to the Green Growth scenario because it places a higher value on environmental regulation but maintains a safety-valve to ensure economic growth is the focus.

Finally, the aggressive case for greenhouse gas regulation is based on the McCain-Lieberman Climate Stewardship Act which has been a much discussed bill in the Senate for a number of years. The legislation caps greenhouse gas emissions at 2000 levels in 2010; there is no safety-valve on the price of allowances.[10] This case is used in the Green Focus scenario because the emissions reductions would be greater and it is less concerned with the potential of higher economic costs to comply.

[9] Scenario “Cap-Trade 3” in EIA, “Energy Market Impacts of Alternative Greenhouse Gas Intensity Reduction Goals”, March 2006, SR/OIAF/2006-01. Due to the lead time necessary to pass legislation and set up a program, our analysis assumes that a federal cap-and-trade system will not be implemented until 2012.

[10] EIA, “Analysis of Senate Amendment 2028, the Climate Stewardship Act of 2003”, May 2004, SR/OIAF/2004–06.

Electric Energy Wholesale Price Estimates

We began the process of forecasting electricity prices by using La Capra Associates Northeast Market Model. We based hourly demands on ISO New England's load forecast scenarios. ISO New England produces a reference high and low forecast for each of the New England states and in aggregate. We used these ISO New England forecasts for all states with the exception of Vermont, which we based on a combination of the DPS October 2006 demand forecasts and the growth rates for the GMP service territory demand used in a scenario. The Vermont forecasts assume statewide energy efficiency programs consistent with the GMP demand requirement levels. Table 14 depicts load growth forecasts.

IRP Scenario	Regional Average Energy Load Growth 2005 to 2015
Fortress America	0.31%
Green Focus	0.31%
Back to Business	2.14%
Green Growth	1.26%

Table 14: Regional Average Energy Load Growth

We then used these growth rates as a basis in the La Capra Northeast Market Model to develop market price forecasts for the four scenarios (see "Electric Capacity Wholesale Price Estimates" on page 66 for that discussion).

Figure 20 depicts long-term all-hours prices under the four scenarios. The growth trend within New England of market energy prices following natural gas prices continues; there is a similarity between these projections and the natural gas projections.

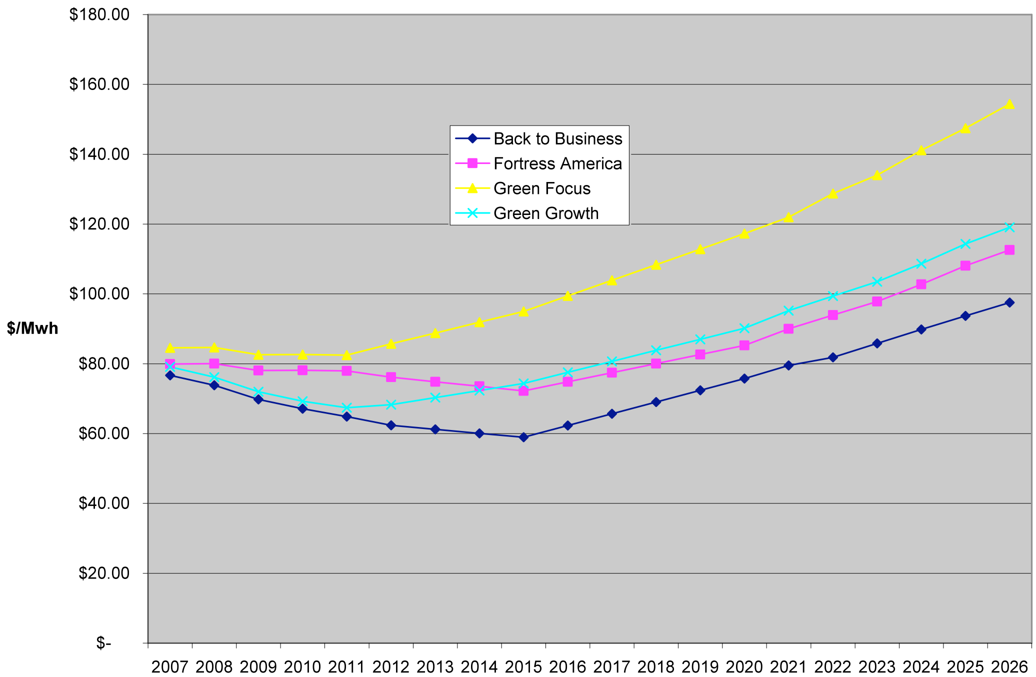

Figure 20: Scenario All-hours Market Energy Prices

Table 15 compares the current all-hours annual average prices in our scenarios to 2020 market energy prices. The lowest price of $75.77 per megawatt hour to the high of $117.26 represents over a 50% differential.

Historical Case	**Period**	**Range of Values**
May 1999 to February 2006	12 Month Rolling Average 12 Month Rolling On-Peak	$30.63 – $77.95 $36.92 – $87.80
Future Scenarios	Period	Scenario Value
Fortress America 2020	Annual Average Average On-Peak	$85.23 $97.26
Green Focus 2020	Annual Average Average On-Peak	$117.26 $133.46
Back to Business 2020	Annual Average Average On-Peak	$75.77 $86.99
Green Growth 2020	Annual Average Average On-Peak	$90.15 $101.81

Table 15: 2020 Market Energy Prices ($/MWh)

Electric Capacity Wholesale Price Estimates

The second major component of GMP's cost to serve the load in its service territory (after energy, the largest component) is that of maintaining adequate electric generation capacity. ISO New England determines the required amounts of capacity in the region and charges for GMP and other load serving entities. The capacity market is a new and developing market; ISO New England is responsible for acquiring sufficient regional resources and not the individual utilities or other load serving entities. The utilities participate in this marketplace by owning or contracting for electric generating capacity as a cost savings or hedge against future capacity prices.

On June 15, 2006, a Forward Capacity Market (FCM) was approved by FERC as a settlement agreement to resolve New England's capacity issues. To better estimate future capacity value, we based our estimates on these FCM rules as they exist in this settlement and any additional resolutions reached through ISO New England's Installed Capacity Working Groups.

Here is a brief summary of how the FCM was reached. Today's capacity market has been at surplus for the last few years. As such, New England's installed capacity (ICAP) market has not produced sufficient prices for new investments. The monthly market also did not provide any long-term price assurances for new capacity. Thus, the capacity market has not send a strong price signal to incent the development of new capacity or demand-side resources, especially in congested areas.

Instead, temporary measures were taken to ensure some units remain operational for reliability purposes; these units were given multi-year Reliability Must Run (RMR) contracts. These RMR contracts compensate units for their cost-of-service net of energy revenues. At present, 45 units in New England comprising over 6,200 megawatts are under Reliability Must Run (RMR) agreements — with potentially more to come. The total fixed cost (before netting energy revenues) of the RMR contracts in 2005[11] was $327 million for Massachusetts[12] and $329 million (plus $36 million for Southwest Connecticut GAP RFP Resources) for Connecticut. These costs were allocated to load in the respective states and not distributed among all load in ISO New England.

This temporary solution was to be replaced by a Locational Installed Capacity (LICAP) market as directed by FERC, but ISO New England's LICAP proposal was not well received by many stakeholders. The LICAP market was based on an administrative demand curve and produced price outcomes (depending on requirement assumptions) between $7 to $16 per kilowatt month by 2009 and 2010.

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[11] The 2005 RMR contract costs are ISO New England estimates, and do not include net energy revenue. Total cost to load should be considerably lower once energy revenue is netted out. For Connecticut, based on filed data from CL&P, La Capra estimated that the energy revenue reduced the RMR Fixed Cost by 40% in 2005.
http://www.iso-ne.com/genrtion_resrcs/reports/rmr/2005_monthly_cost_rel_agmts_workbook.xls

[12] The estimated 2006 RMR contract cost for Massachusetts increases to $484 million with the expected approval of additional RMR units.
http://www.iso-ne.com/genrtion_resrcs/reports/rmr/2006_monthly_cost_rel_agmts_workbook.xls

Subsequently, FERC encouraged a settlement agreement among the New England parties that would provide a satisfactory compromise. In March of 2006, the parties presented to FERC another settlement agreement containing an interim plan that would last from December 2006 to summer 2010 and an FCM auction mechanism that would take effect for capacity deliveries in 2010 forward.

The essence of the FCM is to procure needed "new" capacity through a descending clock auction three years prior to the commitment year in which the capacity would be needed. All generating capacity (including existing units) must bid into the auction but, with some exceptions, only "new" capacity can set the clearing price. In addition, a local requirement would still be needed in constrained zones for which separate auctions will be conducted. The auction process is intended to address the problems of insufficient price levels to support new capacity and long-term price uncertainty. Therefore, over time, it is reasonable to expect that the annual auctions will drive prices towards the Cost of New Entry (CONE).

The market prices assumed in this analysis are shown in Figure 21.

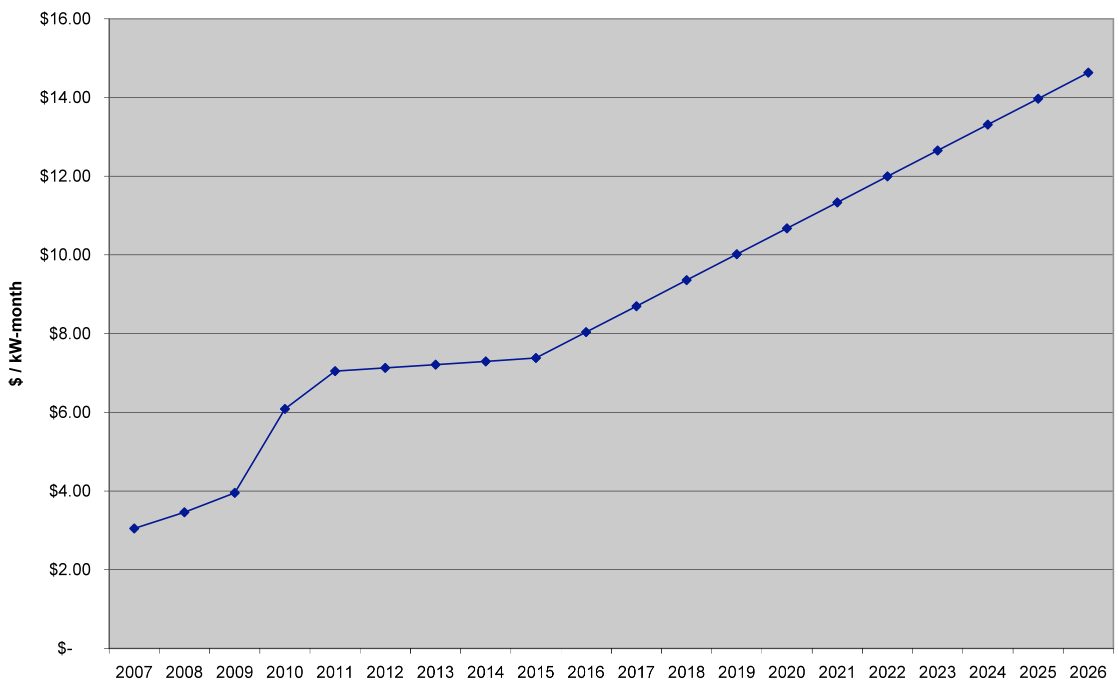

Figure 21: Capacity Price Outlook

A more thorough discussion of the FCM market is contained in "Appendix C: ISO New England's Forward Capacity Markets" on page 147.

Resource Portfolios

Introduction and Summary

The following discussion summarizes the analysis underlying GMP's evaluation of resource portfolios. Given the overall level of uncertainty in the New England electricity market and the diverse interests of stakeholders in GMP's service territory, the choice should be made based on a strategy that proves to be beneficial in cost reductions, low or relatively low on environmental impacts, feasible financially, and robust in its value across scenarios of the energy future.

Based on the portfolio selection process described below, this goal appears to be best achieved across all scenarios through two factors:

- A mix of key long-term supply contracts with regional base load generation, including continuing to import a significant amounts of economic firm energy.
- Capturing the benefits of significant purchasing from renewable energy based generation.

These portfolio elements offer a robust ability to lower and hedge GMP's cost to serve load, while continuing GMP's small carbon footprint. This portfolio strategy should result in relatively stable revenue requirements, while not creating unmanageable (that is, harmful to our credit rating) levels of imputed debt in bond rating agency analyses.

The goals of selecting a portfolio are to identify a mix of resources that performs best across all scenarios under criteria most important to GMP. This analysis includes the following steps:

1. **Identifying GMP's Resource Needs.** The analysis begins with an assessment of GMP's incremental resource needs over the planning period based on an analysis of expected loads and the characteristics of its existing supply and demand-side resources.

2. **Developing Alternative Portfolios.** The analysis next involves surveying generation technologies, efficiency and peak demand management programs, and contractual arrangements that are potentially available to meet incremental needs. We developed alternative resource portfolios that represent the range of resource strategies that GMP might reasonably pursue.

3. **Testing the Performance of the Alternative Portfolios.** We test each portfolio's performance based on the criteria most important to GMP. These include (1) revenue requirements and rates, (2) environmental impacts, (3) potential variability in revenue requirements over the long- and short-terms, and (4) the maintaining manageable levels of imputed debt by power contracting.

4. **Comparing of the Alternative Portfolios.** We then compared the results of each portfolio's performance across all scenarios using a Multi-Attribute Trade-off analysis; key observations are discussed below.

Identifying GMP's Resource Needs

We began the analysis by assessing GMP's incremental resource needs over the planning period, based on an analysis of expected loads and the characteristics of its existing supply and demand-side resources.

Load Forecast

The following table shows the net effect of the expected growth in peak demand within the scenarios given the underlying economy driven demand and energy forecast and the impact of the energy efficiency funding scenarios. This table illustrates that, in two of the scenarios, peak demand is actually declining slightly through 2020 and increasing modestly (about 74 megawatts) in the Back to Business scenario. As a result, the largest resource decisions that GMP will face over the next decade will likely not be driven by electricity demand growth, but by the attrition of existing resources (particularly expiration of the Vermont Yankee and Hydro-Québec contracts).

Net Demand Growth	Fortress America	Green Focus	Back to Business	Green Growth
Before New (2006 plus) EVT Program impacts	Low	Low	High	Reference
Demand Growth Rate	0.60%	0.60%	1.60%	1.00%
Energy Growth Rate	0.60%	0.60%	1.60%	1.00%
DSM Funding Scenario				
Budget Level: Dollars	mid-$20 millions	Current budget plan	$10 million	$16 million
Additional Peak Demand Reduction 2020	(34)	(50)	0	(14)
Net Peak Demand Growth (Reduction)				
Net Growth Rate through 2025: %	0.0%	–0.3%	1.4%	0.4%
Net Change in GMP Summer Peak by 2020: MW	(8)	(24)	74	33

Table 16: Net Demand Growth and Reduction

Committed Supply Forecast

Between 2012 and 2015, GMP will lose much of its existing supply portfolio.

- The Gorge gas turbine is scheduled to retire (from 2009 to 2011).
- The Vergennes diesels are scheduled to retire (from 2010 to 2012).
- The Berlin gas turbine is scheduled to retire (from 2011 to 2015).
- The Vermont Yankee contract expires in 2012.
- GMP's schedules of the Hydro-Québec Vermont Joint Owners (VJO) contract expire in 2015.

The Vermont Yankee and VJO expirations will expose most of GMP's base load and a large part of its intermediate load to the market.

The peaking resources that are scheduled to retire around the end of the decade have the potential to provide a valuable hedge against the volatility of peak prices and price spikes as well as our obligations to the Forward Capacity Market. This economic value depends greatly, however, on the extent to which the units can be relied upon to start and operate during key periods. As indicated by the tentative retirement dates above, it is not clear that these aging units can be relied upon over time; replacement with newer units could be a more reliable and cost-effective solution than continued incremental investments in these aging unit (along with the associated ongoing outage risk). The loss of these resources will leave the peak portion of the GMP's load curve more exposed to market price risks.

GMP plans to replace the Gorge unit with a larger, more efficient 25 megawatt unit if economics continue to be favorable. Our decision to replace the Berlin GT may depend on the joint needs of utilities connected to the adjoining segments of the VELCO system, and the extent to which capacity at that location would defer potential future bulk transmission investments.

The Resource Gap

Table 17 describes the portfolio decisions to come.

Retirement Resources	Fortress America	Green Focus	Back to Business	Green Growth
Vermont Yankee	106	106	106	106
Hydro-Québec VJO	114	114	114	114
Berlin CT	38	38	38	38
Vergennes	4	4	4	4
Gorge GT	14	14	14	14
Resource Gap 2020	283	265	375	329

Table 17: Retirement Resource Gap

Figure 22 summarizes GMP's long-term demand and capacity. It compares load growth in the four scenarios with the expirations of the Vermont Yankee and Hydro-Québec contracts.

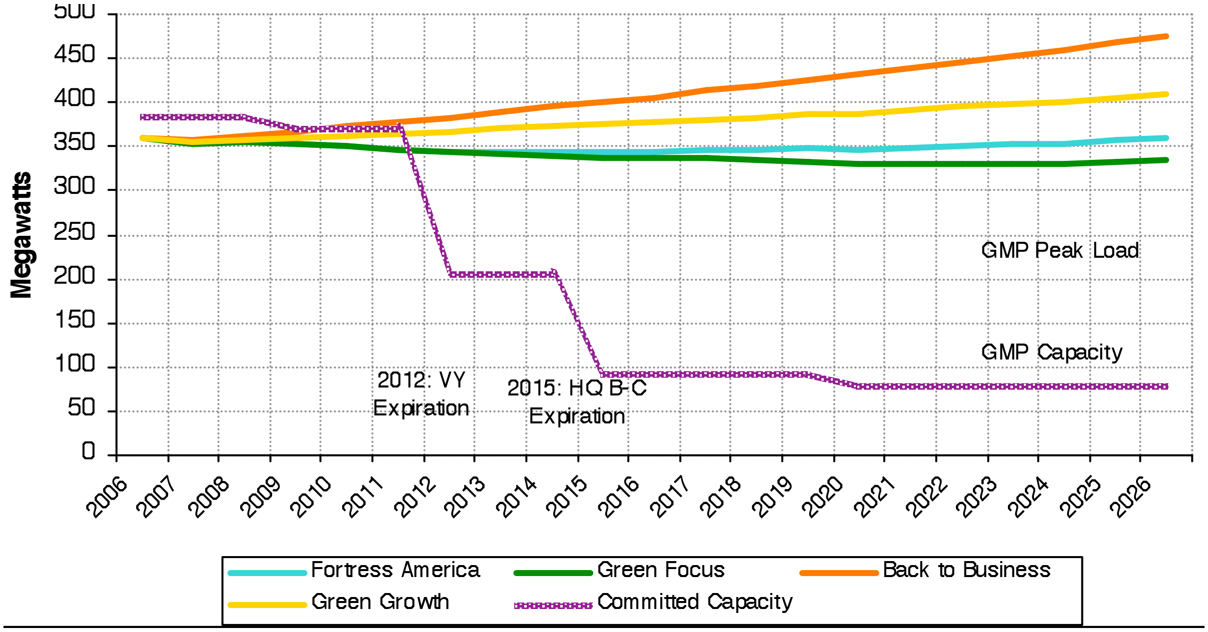

Figure 22: Comparing GMP's Future Demand and Capacity

Figure 23 compares GMP's current energy positions to its future obligations.

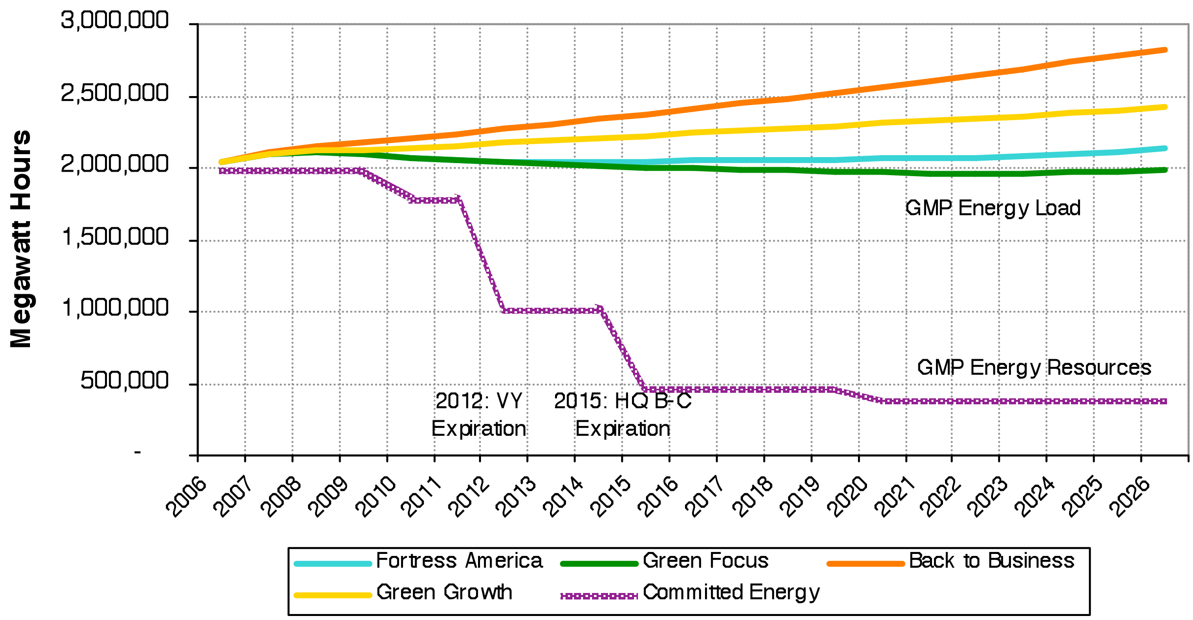

Figure 23: Comparing GMP's Energy Obligation to Resource Dispatch

Figure 22 and Figure 23 present the incremental resources needed to assure reliable supply over the next 20-odd years, based on each of the four scenarios. A detailed description of Green Mountain Power's incremental needs is contained in "Appendix A: 2007 Long-Term Energy and Peak Forecasts" on page 107.

GMP has already begun exploring ways to meeting as much of the energy shortfall as possible with renewable resources. GMP is currently before the Vermont Public Service Board to help the developer of GMP's Searsburg wind site expansion secure Section 248 approval. The project could add 33 megawatts of wind capacity. GMP would seek to purchase at least 10 megawatts under a long-term PPA (or obtain a comparable ownership share), assuming the price is consistent with least cost principles. If successful, the output of approximately 25,000 megawatt hours would supply roughly 1.25% of GMP's load.

The state's SPEED program provides incentives to jump-start such activity, although the volume of associated Act 61 requirements for new renewables are based on actual growth in Vermont electricity demand. As developers become more familiar with state and federal incentive programs, the rate of start-up investment in biomass and biogas may increase. GMP intends to remain flexible in structuring purchase arrangements with developers so that plants can go online with equitable sharing of risks and benefits.

Even though higher fossil prices and extension of the federal PTC have improved the economic outlook for new renewables, the construction of projects in the state has been slowed by very real environmental concerns. While the theoretical potential of Vermont renewable electricity projects (primarily wind and biomass) is probably several hundred MW, it is difficult to know the achievable scale and timing of such projects. We note that based on the electricity demand growth projections presented herein, GMP's renewable obligations under Act 61 could turn out to be quite limited. As explained below, we also examined a resource portfolio featuring much more substantial acquisition of new renewable energy sources.

Even an aggressive acquisition of new renewable resources (combined with ongoing energy efficiency investments through Efficiency Vermont) would leave a substantial supply shortfall after 2015 due to the Vermont Yankee and Hydro-Québec contract expirations. At present, our most promising replacement portfolio includes long-term favorable renegotiated contracts with one or both of those resources.

Other counterparties can provide long-term contracts with similar resource profiles. For Vermont Yankee, however, the requirements to obtain state regulatory and legislative approvals for license extension appears to provide a unique opportunity for a favorably priced contract. More generally, long-term fixed-price contracts (whether from renewables or conventional sources) would stabilize prices for customers, with the risk that the prices would be above-market under some future conditions.

Other potential resources that require construction do exist, in the form of in-state natural gas, regional coal, and natural gas fired generation. Some diesel or jet kerosene fired peaking capacity and dual fueled (distillate oil and natural gas) combined cycle capacity could also find their way into the regional supply mix.

Developing Alternative Portfolios

With GMP's incremental needs established, the next step in selecting a portfolio involves developing alternative resource portfolios designed to match our energy and capacity needs. GMP's portfolio choices will, due to their limited size, probably not have a meaningful effect on resource adequacy for New England as a whole. Rather, regional resource adequacy will depend primarily on the effectiveness of the new Forward Capacity Market (FCM) process at stimulating needed supply- and demand-side resources in sufficient quantities. Therefore, the primary effects of our supply resource commitments will be financial - serving as a financial hedge to stabilize GMP's net power supply costs.

The effect of GMP holding resources that are collectively either long or short relative to GMP's energy and capacity needs would be for GMP's net power supply costs to be exposed to movements in wholesale market prices. In this analysis, GMP has not designed portfolios intended to be either materially long or short of capacity and energy, in part because holding such a portfolio could be considered speculative. GMP's resource portfolios in this IRP analysis basically produce the same amounts of energy and capacity that GMP expects to be billed for by ISO New England to serve its load obligations.

We also included in our analysis a qualitative assessment of supply generation technologies, supply contractual arrangements, and efficiency and peak demand management programs. The goal of the analysis is to develop a portfolio strategy rather than to define the precise set of resources that GMP *will acquire* to meet future needs. Thus, the set of portfolios ultimately tested is designed to represent the range of resource strategies that GMP might reasonably pursue given the conditions arising under each scenario.

Survey of Supply-Side Resources

The survey generally focuses on commercially available generation technology options, and includes few alternatives that are in developmental stages. The technologies reviewed in current and past IRP processes — together with their typical fuel types, unit sizes, and modes of deployment — are summarized in the following table.

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

Table 18: Generation Technologies Options

Distributed Generation Technologies

The range of commercially available distributed generation (DG) technologies includes reciprocating engines, microturbines, industrial combustion turbines, and fuel cells. With the exception of fuel cells, each has an established track record in distributed generation applications and is commercially available. While their costs are generally comparable, preferring a given technology generally depends on the specific requirements of the desired application. Fuel cells are an emerging, very clean, distributed generation technology with considerable promise. Because there is no fuel combustion, some emissions by-products (for example, NOx) are avoided. However, at present, the equipment and installation costs are quite high and the technology is largely untested in large scale power generation applications.

Analysis performed on behalf of VELCO suggests that there is a potential for approximately 2 MW per year of Combined Heat and Power (CHP) applications in Northwest Vermont.[13] Based on this analysis, GMP estimates that approximately 1,000 kilowatts a year of CHP potential may exist on its system. GMP will continually evaluate CHP opportunities and will work with its customers to help install cost effective CHP schemes through continued efforts in standby rate design and programmatic support.

CHP options are so specialized and customer specific that benefits were not studied in the 2007 IRP

Renewable Energy Technologies

While recent economic trends for renewable generation have generally been favorable, and significant capacity development (particularly for wind projects) is underway in this country, the cost and practical availability of new renewable generation within New England are uncertain. Some of the development can be supported by long-term output contracts or local utility participation. The biggest impediment to renewable project development to date has been, and will almost certainly continue to be, local siting approval. This has resulted in a somewhat scarce market, where RPS-qualifying renewables can obtain high prices for their Renewable Energy Certificates (RECs).

Our scenario assumptions are based upon different implementations of Renewable Portfolio Standards (RPS) around New England. In our scenarios, we assume that the current siting log jam is overcome, and large amounts of new renewable generation facilities are built in New England or neighboring markets to meet those needs. With the softening of the prices being paid for RECs, we believe renewables developed beyond the RPS needs would be priced closer to their underlying costs (including return on investment). We will need to test the validity of this assumption from further real world project involvement and negotiations. GMP, in this study, believes the most insight on the potential for renewables to play a prominent position in its IRP or not comes with the assumption that projects are contracting with load serving entities like GMP at close to their underlying cost structure.

[13] Alternatives to the Northwest Vermont Reliability Project, La Capra Associates, May 2003.

The cost of renewables that were assumed in the portfolio comparisons are based on estimated installed costs of real projects being proposed in New England, along with future fuel and operating costs. The installed cost for a biomass plant (stoker or fluidized bed) of 25–50 megawatts in size is about $2,700 to $3,300 per kilowatt in 2006 dollars (averaging $3,000 per kilowatt). The installed costs for new wind plants has increased significantly in the last couple of years: a 25–75 megawatts wind farm now can cost between $1,800 to $2,200 per kilowatt in 2006 dollars. Under EPACT05 and an extension of the Production Tax Credit (PTC) last year, wind is eligible for a PTC of (approximately $0.02 per kilowatt hour in 2006) for ten years and biomass plants can now receive half of the PTC benefit (approximately $0.01 per kilowatt hour in 2006), also for ten years. This analysis assumes that PTC credits remain available throughout the study period; loss of PTC would adversely affect the cost-effectiveness of new renewables for GMP.

While the actual contract pricing can vary widely, we do estimate that under most scenarios, wind and biomass-fueled electric power will cost more than the prevailing market prices for capacity and energy combined, and thus cost higher than the market priced long-term contracts.

For the development of the renewables within the Renewable Emphasis portfolio (see page 82), we assumed that GMP meets 20% of the energy to serve load with new RPS-qualifying renewable generation, namely wind and biomass.[14] This supply could come from within Vermont or from outside, or a combination. In this portfolio, we assumed that the RECs are not sold on the market, thus assuring green power for GMP. Furthermore, we assumed the energy contribution to the renewables portfolio to be 50% from biomass and 50% from wind.

This resulting resource mixes of generation capacity are as follows:

Scenarios	Biomass (MW)	On-Shore Wind (MW)	Equivalent Capacity Contribution (MW)[15]
Fortress America	27	78	35
Green Focus	27	76	34
Back to Business	32	90	41
Green Growth	30	85	38

Table 19: Generation Capacity Resource Mix

Depending on the scenario, meeting 20% of energy needs with renewables would be equivalent to about 27 to 30 megawatts of a biomass facility plus 76 to 90 megawatts of a

[14] While landfill gas (LFG) can also be a very economic option, the opportunities for large facilities are likely to be limited so it was not modeled in the scenarios. If opportunities to sign contracts with new landfill gas projects do arise, the costs may fall within the range of the all-in-cost of wind and biomass, dependent on the size of the landfill gas project.

[15] Wind is assumed to contribute only 10% of installed capacity to the capacity market. New rules in measuring intermittent resources may allow wind to receive somewhat higher capacity value in the future.

wind facility. Given that almost every state in New England has a renewable portfolio standard (RPS) to meet, we expect that between 2007 and 2009, about 200 megawatts of additional biomass or 500 megawatts of wind would be needed in the region to meet these near-term RPS requirements. The new renewables to meet GMP's 20% goal would be in addition to these RPS-related developments. We can potentially expand existing renewable generation facilities in Vermont to help achieve a 20% renewables goal. The two main facilities are Searsburg with a proposed expansion of 40 megawatts to 50 megawatts, and McNeil which could conceivably be expanded. We will need to fully explore the opportunities and issues related to these potential expansions.

One big question is related to how RECs will be priced by merchant renewable projects. Currently RPS-qualifying RECs trade at over $50 per megawatt hour from eligible renewable resources and will continue at these levels as long as there is a supply shortage relative to RPS requirements. As a buyer of a bundled product (energy, capacity, and RECs), this IRP analysis assumes the purchase price reflects the revenue requirement of a project to achieve appropriate returns on investment. However, it does not factor in the market value of the RECs and energy as part of the contract. In particular, the price of new renewables to GMP will depend, in part, on whether the regional RPS market achieves equilibrium or, alternatively, if GMP must compete aggressively for scarce renewable project output in a short market.

As an alternative to purchasing renewable output, GMP can explore owning and operating these facilities to better retain the total benefit associated with ownership including PTC. Considerations associated with ownership include the organizational capabilities associated with owning and operating such plants, and the scale of capital outlay required and associated financial risk.[16]

A discussion of renewable resource characteristics is provided in "Appendix H: Renewable Resources and Environmental Assumptions" on page 183.

Bulk Fossil-Fired Technologies

Commercially-available bulk generation technologies include combustion turbine, combined cycle, coal, nuclear, oil-and natural gas-fired steam turbines, municipal solid waste, internal combustion engines, and hydropower facilities. With the exception of peaking resources (such as gas turbines or large internal combustion engines), most bulk generation technologies achieve economies of scale at unit sizes greatly exceeding GMP's anticipated base load or intermediate needs. Over the last decade, the broader power market has turned to natural gas fired combined cycle and simple cycle combustion turbines as the preferred source of incremental capacity. However, if natural gas commodity prices remain above $6/MMBtu over the long-term, the market may choose alternative technologies (such as coal and nuclear power). In any event, GMP's construction of a large scale generation facility would be inconsistent with its goal of minimizing risk.

[16] For example, a single 20 MW biomass plant at $3,000/kW would represent an initial capital investment of $60 million. This is a very substantial investment relative to GMP's existing capital structure.

The focus in the 2007 IRP update is on contracts for capacity and energy from four fossil fueled generation plant types: Aero-derivative smaller Combustion Turbines, Larger Frame Peaking Combustion Turbines, Natural Gas-fired Combined Cycles, and Base Load Clean Coal facilities. For these options, we assumed that GMP would be negotiating a 15-year power contract (PPA) with either developers of new capacity or owners of existing facilities. We have assumed that these PPAs are executed with a structure that allows them to mirror their fixed costs, with return of and on capital, and the variable costs of fuel, variable O&M, and emission allowance costs. This will enable GMP to determine which technologies should have the best underlying cost structure and therefore appear worthy of further exploration by GMP.

Long-term Contractual Options

Extending GMP's contract with Vermont Yankee would likely be at a discount to market prices, because the owner needs to obtain Vermont regulatory and legislative approvals in order to continue operation after expiration of the plant's current operating license in 2012. In addition, unit-contingent contracts tend to feature some price discount relative to firm all-hours power that is not contingent on the performance of a single unit. For purposes of this study, we modeled the price of a future Vermont Yankee contract at 10 percent below the scenario-specific projections of future all-hours prices. We do not intend this discount to represent the actual renegotiated price obtained along with other interested parties; this price, of course, is unknown. We assume a placeholder price discount in order to highlight the unique leverage that Vermont has with respect to this resource, and to promote realistic outcomes in modeling portfolio alternatives. GMP seeks to maintain as diverse a resource base as possible. Therefore relying on a large unit contingent contract would need to demonstrate an appropriate level of savings for our customers. We note that Entergy also operates the Pilgrim Nuclear Station in Massachusetts, and there are other nuclear facility owners and operators that might find value in a long-term contractual arrangement with GMP.

We also have the potential to pursue a long-term contract with imported power. The current contract with Hydro-Québec ends in 2015. The Highgate Converter and Phase 2 of the Quebec/New England Interconnection will likely be in service far beyond that date. The current contract with Hydro-Québec is structured with a target energy delivery equivalent to a 75% annual capacity factor. GMP has some options to take additional energy, and Hydro-Québec has some options to deliver less energy. The pricing structure saw a large fixed charge and a very low energy delivery charge. There are other import power opportunities to explore instead of or in conjunction with Hydro-Québec: Ontario, New Brunswick, and New York. While Hydro-Québec does figure prominently in most of the portfolios, its role is as a proxy of imported power options since we do not see a continued Hydro-Québec contract as a forgone conclusion. For purposes of this analysis, we have modeled the Hydro-Québec power as a fixed price contract which begins in 2015 at a price equal to the then-current market price with a moderate escalation thereafter.

Shorter Term Contractual Options

Acquiring supply through purchase contracts is an alternative to owning generation facilities that, as noted above, GMP currently employs for some of its needs. Due to their flexibility, shorter term purchase contracts present an attractive alternative to ownership.

In the current energy market, contractual options and potential counterparties are limited. The typical products being traded are flat blocks of power, on-peak, off-peak, or all-hours with short to medium term (for example, terms ranging from one day to a year). The market for long-term contracts (that is, contracts exceeding one year) is very thin. Very few parties deal in more sophisticated contracts (such as options) and the premiums demanded for such contracts are often high. At present, there is no standardized, exchange-traded power contract for New England (such as the PJM futures contract that trades on the New York Mercantile Exchange). Much of the market illiquidity and the lack of product choice for long-term transactions are due to the poor credit standing and weak balance sheets of many of the sellers in the market. Buyers are unwilling to sign long-term contracts with companies that are financially risky and sellers are unwilling to take on volume and price risk. Another factor limiting the prevalence of long-term contracts is that New England's largest utilities (in Massachusetts, Connecticut and Maine) procure standard service for their non-shopping customers with relatively short contracts (i.e., a few months to two years).

In light of the attractiveness of purchase contracts, we assume that over the planning period the wholesale energy market will improve in liquidity and product customization and that a significant market in bilateral contracts will return.

In addition to the bilateral energy market, this analysis establishes the FCM to allow, promote, and facilitate more bilateral capacity-only contracting to occur.

This analysis uses as options the availability of 1-, 3-, and 5-year bilateral contracts for energy or capacity. This allows GMP to obtain a portfolio that is balanced to load and capacity requirements it has with the ISO New England, without relying on spot markets for capacity and energy to any significant degree. Such purchases are represented using a fixed price structure, based on market price expectations for the applicable scenario.

Some other pricing structures – such as options or collars – could also be available. Because such alternative pricing structures are not traded on a standard basis today, and it is not clear whether the market for them will be as competitive as for energy, we have not explicitly analyzed them in this portfolio analysis. We note, however, that they could potentially be effective tools to help GMP manage price uncertainty.

Peak Demand Management

As discussed in Chapter 3, GMP currently works with its customers to manage our exposure to peak demand, which can reduce capacity obligations, transmission costs, and the need for peaking power. GMP's efforts are complemented by region-wide demand response programs designed to allow large customers to reduce consumption in response to market prices. The regional demand response programs should temper the volatility of market prices, thereby reducing fixed price contract premiums. To the extent this occurs, GMP will benefit from lower contract prices.

Energy Efficiency

Please refer to "Appendix B: Energy Efficiency Forecasts" on page 143 for a complete discussion of Energy Efficiency's role in the GMP IRP 2007 analysis.

Alternative Portfolios Chosen for Study

Our portfolio testing in the 2007 IRP provides a unique opportunity to consider how the position and strengths of GMP and it service territory can capitalize on the business environment surrounding it.

The wholesale marketplace in New England is now characterized as mostly short-term energy buyers and developers playing in a new Forward Capacity Market where new capacity resources can obtain up to a five-year contract. Developers throughout New England, however, tend to desire longer term contracts for most conventional and renewable generation projects. In general, the primary way a long-term commitment can be made is when the buyer is a load serving entity in New England with some long-term surety of an obligation to serve load. In New England, these buyers only exist among Vermont utilities, municipal/cooperative electric systems in other states, and a limited number of retail customers in other states that have signed long-term purchase commitments with retail suppliers. While all sellers tend to base their price requirements on opportunity costs (for example, near-term forward contracts, long-term market price forecasts), GMP's unique position as a potential long-term buyer could offer an opportunity to acquire resources at relatively favorable prices. With that in mind we modeled six portfolios, some of which include substantial amounts of newly constructed capacity, with the price to GMP based on the estimated all-in cost of construction and operation.

We developed these portfolios by first looking at the resource options available based on the specific description of each portfolio. We focused first on the year 2020 to estimate appropriate amounts of each resource to meet GMP's needs, and chose amounts and timing for acquiring resources to reflect GMP's needs, the sizes of the specific resource option available for development or purchase, and the availability of these resources. For example, follow-up or replacement long-term, base load and import contracts with Vermont Yankee and Hydro-Québec or other counterparties should take effect immediately following the expiration of the current contracts. Negotiations are expected to precede these contract expirations by several years.

1. Reference – Current Portfolio Energy Plan (applied to GMP with low fossil fuel exposure)

This portfolio implements the preferences expressed in state energy policy and consumers in Vermont for price stability, non-emitting supply sources, and limited local generation that has the potential to defer transmission investment.

- New long-term energy and capacity via long-term base load contracting and significant imported power (such as those currently provided by Vermont Yankee and Hydro-Québec).
- Short-term[17] purchase for additional energy[18] and FCM for peak capacity requirements.
- Renewables, DSM, and local generation generally only as prescribed by SPEED, Efficiency Vermont, and replacement of retiring GMP capacity.

2. Renewable Emphasis

This portfolio is a major expansion of GMP's renewable energy-based supply mix well beyond RPS standards. Major emphasis on base and intermediate energy comes from regional renewable resources (specifically wind and advanced low-emission biomass, which qualify as new renewable resources in other New England states) and a renegotiation of Hydro-Québec's imports. The major variable present here is the price at which the renewables and imports may be obtained.

- Strong commitment to in-region renewables (20% of GMP energy requirements from a mix of unit ownership/entitlement and PPAs for renewables)
- New long-term contracting for imported power
- Short-term market purchases for additional energy, and FCM price for peak capacity requirements.

3. Unit Contracting – Combined Cycle and Market

The fundamental building block of this portfolio is the natural gas combined cycle. This is obtained through PPA unit entitlements in existing or new combined cycles throughout New England. The ability to offer combined cycle owners and developers 15-year contracts rather than have them rely on the shorter term FCM market for their capacity revenues is posited to give GMP negotiating leverage.

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[17] Short-term market purchases are defined as the on-going energy management or trading activities to either firm up the next few months or up to two years. Limited amounts of energy may be bought and sold in the daily and real-time markets to balance GMP's needs and adjust to fluctuations in GMP's load (for example, due to weather) and market prices.

[18] Under the current ISO-NE market design, GMP actually purchases its entire load obligation at Vermont-specific LMPs and sells all output from its resources at node-specific LMPs. That is, GMP's current and future resources will typically act as a financial hedge against its load purchase obligation, rather than reducing that obligation. Unless noted otherwise, the IRP will generally ignore this distinction, referring to GMP's purchase needs as the difference between its load obligation and committed resources.

- Natural gas fueled combined cycles (existing and new) for capacity and energy, short-term market purchases for additional energy, and FCM price for peak capacity requirements.
- Renewables, DSM, and local generation only as prescribed by SPEED, Efficiency Vermont, and replacement of retiring GMP capacity.

4. Unit Contracting – Peaking Capacity and Market Energy

The fundamental building block of this portfolio is natural gas or diesel peaking capacity. This is obtained by GMP owning or building peaking capacity in Vermont and some through PPA unit entitlements in existing and new peaking capacity within New England. The ability to offer capacity owners and developers 15-year contracts rather than have them rely on the shorter term FCM market for their capacity revenues could provide significant negotiating leverage.

- Peaking for capacity and short-term contracting for energy.
- Renewables, DSM, and local generation prescribed by SPEED, Efficiency Vermont, and replacement of retiring GMP capacity.

5. Unit Contracting – Base Load and Market

The fundamental building block of this portfolio is the addition of new regional base load capacity entitlement, using the proposed clean coal IGCC facilities in New England and New York as proxies. This is obtained through PPA unit entitlement. The ability to offer developers 15-year contracts rather than have them rely on the shorter term FCM market for their capacity revenues could give GMP significant negotiating leverage.

- Base load unit for capacity and energy, peaking unit contracts for additional capacity, short-term energy purchasing for intermediate power needs, and spot market for peaking energy.
- Renewables, DSM, and local generation prescribed by SPEED, Efficiency Vermont, and replacement of retiring GMP capacity.

6. Market Contracting

In contrast to unit ownership strategies, this portfolio uses combinations of 1-, 3-, and 5-year bilateral contracts for energy and capacity to stabilize costs and provide energy at regional emissions levels beyond RPS requirements. This portfolio would be consistent with the ability of the ISO New England FCM and LFRM to bring sufficient capacity into the market and opportunities for GMP to have multiple sellers with whom to negotiate.

- Market contracts 1-, 3-, and 5-years for capacity and energy, and spot market for swing peaking energy.
- Renewables, DSM, and local generation only as prescribed by SPEED, Efficiency Vermont, and replacement of retiring GMP capacity.

In addition to the reference portfolios summarized above, two alternatives for each portfolio were studied. These variations, along with the reference configuration, are shown together as a test of the flexibility and robustness of the individual strategies. Thus, a second set of portfolios was studied where, in each case, the Vermont Yankee purchase is set to the amount of capacity that produces 20% of the GMP energy requirements in the year 2020. This value varies among the scenarios between 50 megawatts and 65 megawatts, based on projected GMP load growth. A third set of portfolios fixes the amount of Hydro-Québec energy purchased by GMP to also provide 20% of the 2020 energy requirements (along with the same amount of Vermont Yankee energy).

#	Portfolio	Resource Additions Providing Operating Duty		
		Base Load	**Intermediate Load**	**Peaking Load**
1	Current Portfolio Energy Path	Long-term contract extensions with Vermont Yankee and Hydro-Québec or replacements with alternative counterparties	Short-term Market Energy	FCM Capacity, Short-term Market Energy
2	Renewable Emphasis	Renewables, New Hydro-Québec	Bilateral Contract	FCM Capacity, Short-term Market Energy
3	Combined Cycle Unit Contract	Combined Cycle	Combined Cycle	FCM Capacity, Short-term Market Energy
4	Peaking Capacity Unit Contract	Peaking Capacity, Bilateral Energy Contract	Peaking Capacity, Bilateral Energy Contract	Peaking Capacity, Short-term Market Energy
5	Base Load Capacity Unit Contract	New Base Load (IGCC)	FCM Capacity, Bilateral Energy Contract	FCM Capacity, Short-term Market Energy
6	Market Contracting	Bilateral Contracts — Capacity and Energy	Bilateral Contracts — Capacity and Energy	FCM Capacity, Short-term Market Energy

Table 20: Portfolios Studied in the 2007 IRP

Comparing the Alternative Portfolios

Reference Portfolios

Figure 24 is an example of how the various portfolio strategies would vary the mix of generating resources in place in 2026, the end of this study period. There are two additional variations of each of these portfolios (not illustrated below) reflecting specific amounts of Vermont Yankee and Hydro-Québec purchases. As discussed in the prior section, these resources are used as proxies for either regional nuclear/baseload suppliers or power imports under long-term contracts.

In Figure 24 and Table 21, as applicable, all nuclear, hydroelectric, VEPPI thermal, and IGCC capacity are depicted as baseload. These sources deliver essentially whenever they are available to do so, with output not varying significantly in response to spot market prices. New renewable resources are depicted separately. GMP's owned and purchased shares in McNeil, Stony Brook, Wyman, and Hydro-Quebec, along with new combined cycle, are depicted as intermediate sources. These resources are not always called upon to operate when available, but do operate fairly regularly. Peaking sources, which operate infrequently due to their relatively high variable costs, include GMP-owned internal combustion and combustion turbine units, along with future combustion turbine units where applicable.

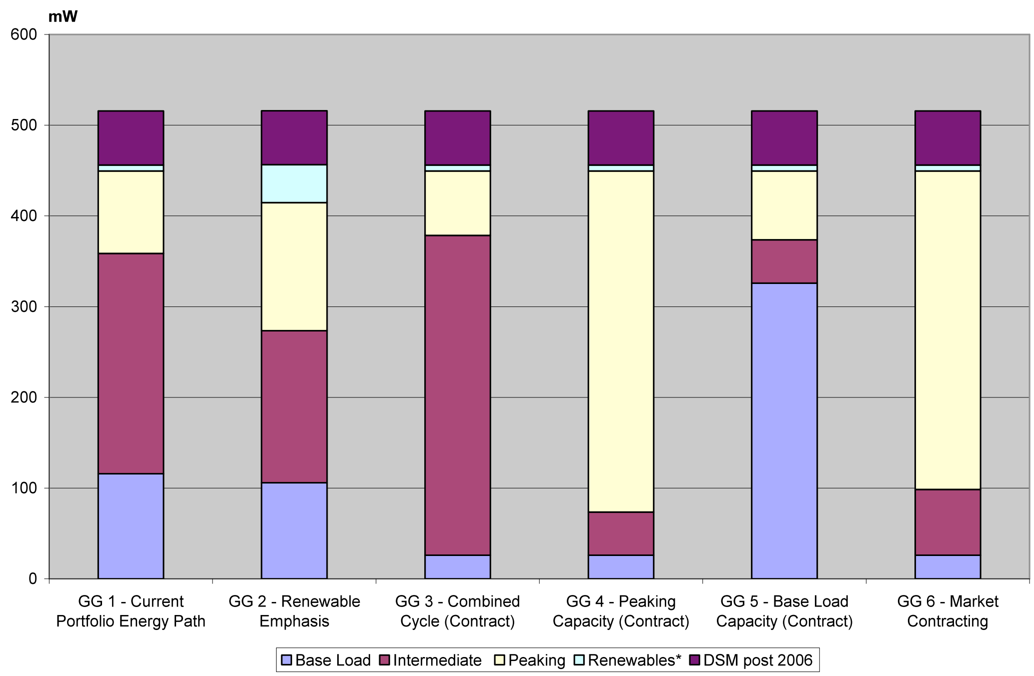

Figure 24: Resulting Resources by Portfolio 2026: Green Growth

Resource Portfolios Additions Summary through 2026

Table 21 summarizes the projected additions (GMP's committees sources are not included) to each of the six reference portfolios, for each of the four scenarios through the year 2026.

Reference Portfolio Additions (each emphasis varies with strategy) in the year 2026	1. Current Portfolio Energy Path	2. Renewable Emphasis[19]	3. Combined Cycle Unit Contracts	4. Peaking Capacity Unit Contracts	5. Base Load Unit Contracting	6. Market Contracting
Fortress America						
Base Load	80.0	50.0	0.0	0.0	240.0	0.0
Intermediate	140.0	140.0	240.0	0.0	0.0	0.0
Peaking	100.0	95.0	80.0	320.0	80.0	320.0
Renewables[20]	1.1	36.8	1.1	1.1	1.1	1.1
DSM post 2006	81.4	81.4	81.4	81.4	81.4	81.4
Total	402.5	403.1	402.5	402.5	402.5	402.5
Green Focus						
Base Load	80.0	35.0	0.0	0.0	175.0	0.0
Intermediate	140.0	90.0	225.0	0.0	50.0	0.0
Peaking	75.0	135.0	70.0	295.0	70.0	295.0
Renewables[20]	1.1	34.2	1.1	1.1	1.1	1.1
DSM post 2006	109.2	109.2	109.2	109.2	109.2	109.2
Total	405.3	403.4	405.3	405.3	405.3	405.3
Back to Business						
Base Load	40.0	50.0	0.0	0.0	295.0	0.0
Intermediate	200.0	210.0	340.0	0.0	0.0	0.0
Peaking	190.0	135.0	90.0	430.0	135.0	430.0
Renewables[20]	13.7	48.7	13.7	13.7	13.7	13.7
DSM post 2006	40.2	40.2	40.2	40.2	40.2	40.2
Total	483.9	484.0	483.9	483.9	483.9	483.9
Green Growth						
Base Load	90.0	80.0	0.0	0.0	300.0	0.0
Intermediate	195.0	120.0	305.0	0.0	0.0	25.0
Peaking	85.0	135.0	65.0	370.0	70.0	345.0
Renewables[20]	6.5	41.8	6.5	6.5	6.5	6.5
DSM post 2006	59.5	59.5	59.5	59.5	59.5	59.5
Total	436.0	436.3	436.0	436.0	436.0	436.0

Table 21: Reference Resource Portfolios Additions Summary through 2026

[19] The total capacities of the renewable emphasis portfolios are slightly different from the other portfolios because of small incremental purchases of renewables needed to match the 20% target for renewable energy.

[20] Wind is shown here as the Effective Capacity of FCM eligibility which is assumed at 10% of nameplate.

Multi-Attribute Trade-off Analysis Results

In this analysis, we developed six attributes across the six portfolios, then applied three variations of each portfolio. We performed all this analysis for each of the four scenarios. The results of the portfolio analysis therefore provide a substantial amount of information.

The six attributes capture important facets of the outcome of a strategy over time: revenue requirement minimization, environmental impact, price stability, and a strategy's ability to be financed. We refer to these as the Impact Attributes. The six impact attributes that GMP felt were the most important with respect to evaluating the strategy that provided the most benefit to our customers are:

- Net present value revenue requirement: 20 years, relative to projected market prices over the same period (negative values reduce revenue requirements and are thus beneficial to GMP customers).
- Societal net present value (revenue requirements plus externalities costs): 20 years.
- Short-term market and fuel price exposure: the percent of energy exposed to natural gas prices (average over 20 years).
- Long-term hedged percentage: the percent of energy with fixed costs or prices fixed for terms greater than five years (average over 20 years).
- Imputed debt: the amount of debt that is implied to be addressed in a utility's financial statements due to its power contracting activities (maximum single year value).
- Emissions: tons of CO_2, NOx, and SO_2 (total over 20 years).

In addition to these 20-year attributes, the portfolio analysis measured a similar set of statistics at the year 2020. This helped us determine if the portfolio characteristics at the end of the study could be as or more influential in making decisions as the portfolio characteristics over the study period. We also stress tested the better portfolios for short term shocks to the system (such as market and fuel price variations, and losing a large resource for a year). For details, see "Stress Testing" on page 93.

As discussed by GMP and others at the Board's February 2007 workshop, a useful way to evaluate a portfolio is to plot pairs of attributes against each other for all the strategies and all the scenarios. Shown below are five of these plots. Each plot includes 12 cases with the same portfolio strategy symbol. This represents the three variations within the strategy for each of the four scenarios. We examined each plot for clustering of points, which demonstrates a robustness of that portfolio strategy performance for that attribute across the four scenarios. Of course, the trends and clustering depicted in this analysis reflect, among other things, on the price assumptions used to derive them. While the shape of these results (and the relative attractiveness of the underlying portfolios) will probably evolve in the future as GMP obtains specific proposals from potential suppliers, the multi-attribute approach presented here can be adapted relatively easily to help GMP evaluate its options as conditions change.

Figure 25 suggests that there may not be a large trade-off between the expected revenue requirements of a portfolio strategy and the amount of long-term hedge against market or fuel price fluctuations that the portfolio strategy provides over the study period. That is, the portfolios that produce the most benefit to reduce revenue requirements can also produce the highest degree of long-term fuel and market price hedge, combined with low emissions. Portfolio 1, the Current Portfolio Energy Path strategy has high hedging capability and generally equal-to-or-better revenue requirement impact than the other portfolios.

Similar to the previous plot, Figure 26 shows that the relatively low-cost portfolios (toward the left hand side) can still have limited price volatility exposure.

Figure 27 shows that the portfolio strategies based on either market- or coal-based resources have the highest CO_2 emissions and do not perform particularly well on the cost attributes.

Figure 28 demonstrates the small relationship between cost benefits and the amount of imputed debt created by the portfolios. There is, however, a direct trade-off between the amount of imputed debt and long-term hedging of the portfolio.

Figure 29 shows that nearly $50 million dollars of imputed debt is created by trying to raise the hedge level within a portfolio by ten percent.

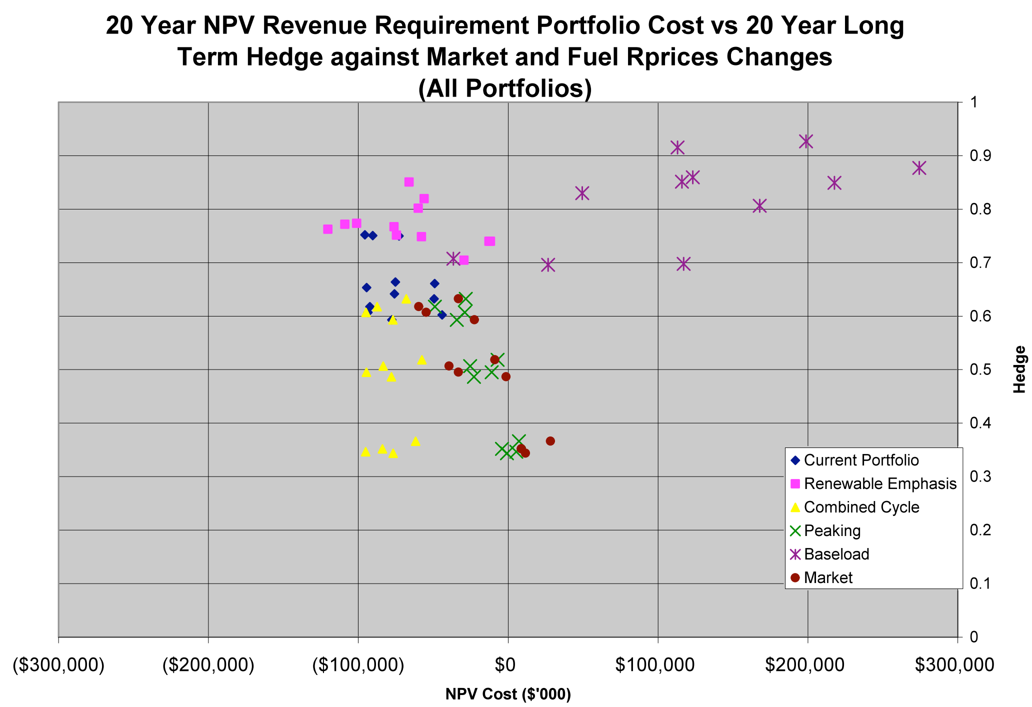

Figure 25: Plotting 20-Year Net Present Value Requirement Portfolio Cost versus 20-Year Term Hedge against Market and Fuel Price Changes

20 Year NPV Revenue Requirement Portfolio Cost vs 20 Year Average Short Term Volatility (All Portfolios)

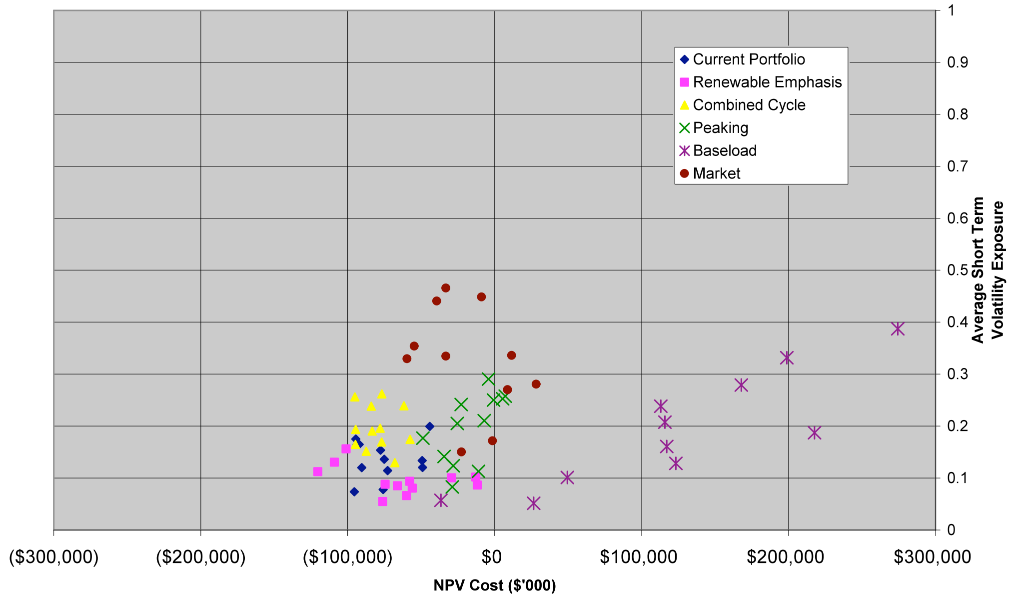

Figure 26: Plotting 20-Year Net Present Value Requirement Portfolio Cost versus 20-Year Average Short-term Volatility

20-Year NPV Revenue Requirement Portfolio Cost vs CO_2 Emissions from New Resources

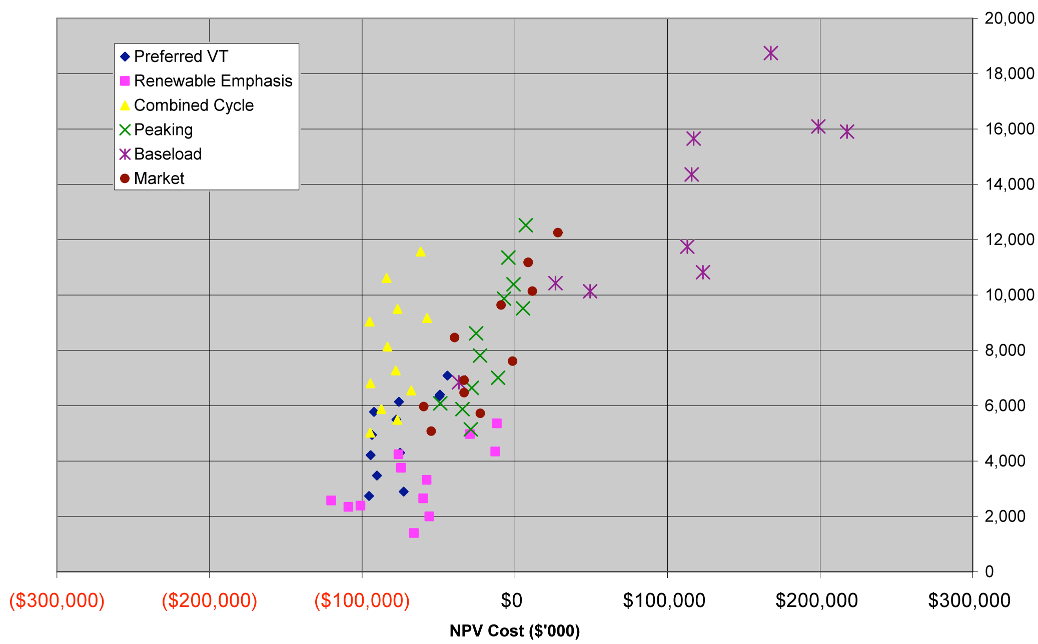

Figure 27: Plotting 20-Year Net Present Value Requirement Portfolio Cost versus Carbon Dioxide Emissions from New Resources

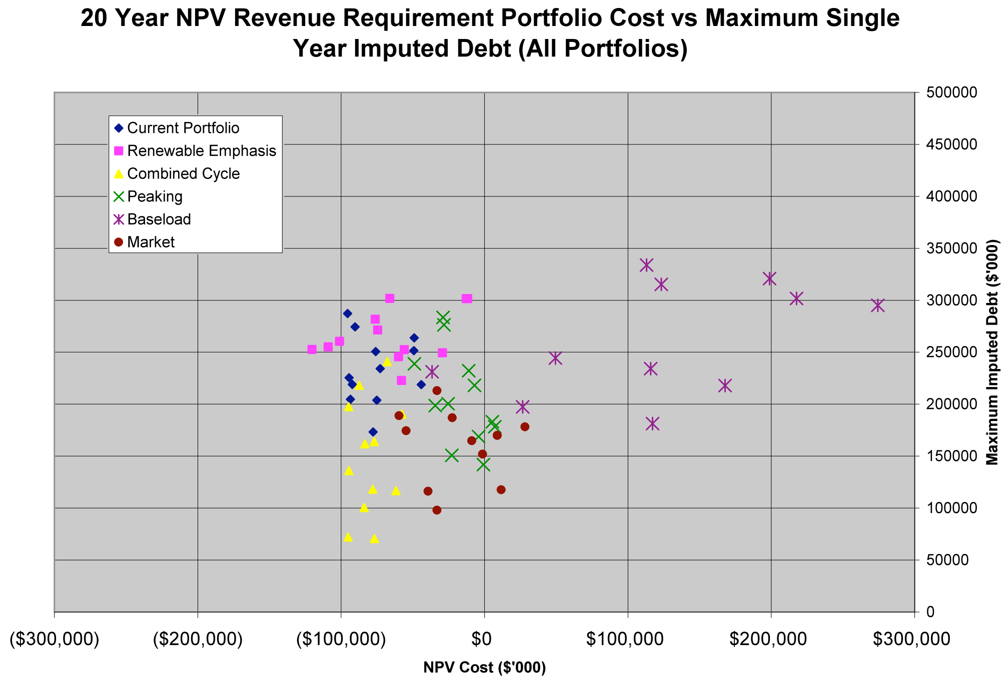

Figure 28: Plotting 20-Year Net Present Value Requirement Portfolio Cost versus Maximum Single Year Imputed Debt

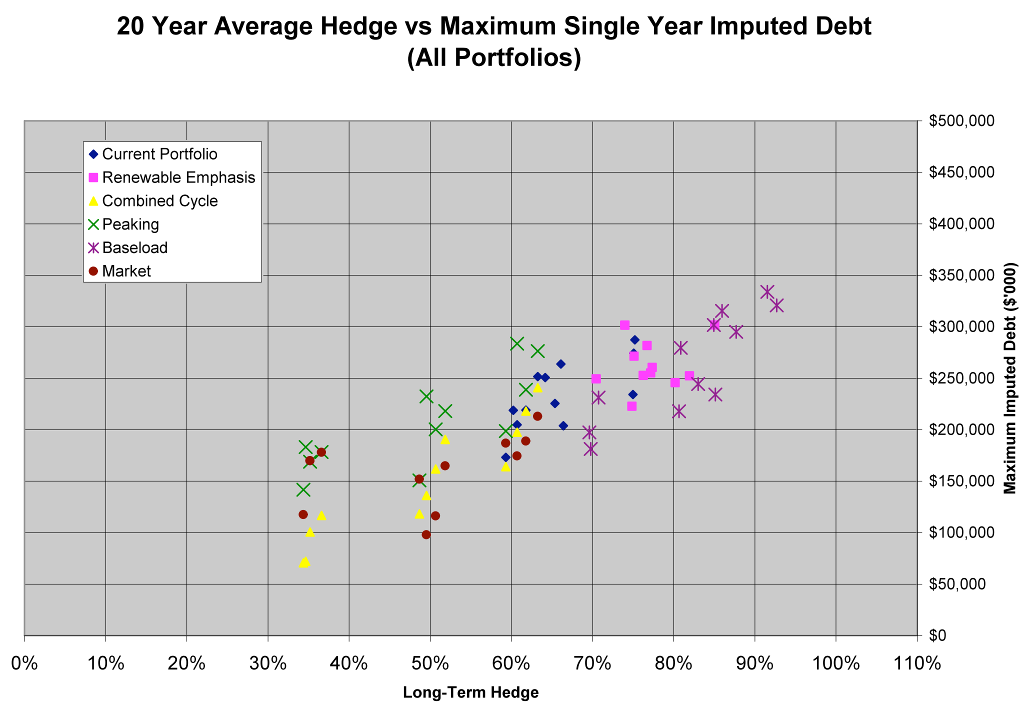

Figure 29: Plotting 20-Year Average Hedge versus Maximum Single Year Imputed Debt

Observations. GMP has drawn the following observations from these five plots:

- The clustering in these plots shows three robust portfolios when considering the net present value of the revenue requirement benefits across all the scenarios and attributes: the Current Portfolio Energy Path, Renewable Emphasis and Combined Cycle.
- The portfolios with the better cost or economics tend to perform reasonably or well with respect to the other attribute. They reduce exposure to market and fuel volatility in the short term and provide a stronger long-term hedge against fuel prices.
- The best carbon mitigation portfolios are the Current Portfolio Energy Path and Renewable Emphasis.
- A small carbon footprint can be obtained (probably without sacrificing economics) by optimizing regional base load (nuclear) long-term contracts (similar to Vermont Yankee); adding cost-effective, renewable-based generation; or replacing the Hydro-Québec contract with one or more significant imported long-term power contracts, or both.
- A goal of having new renewables supplying significant amounts of the energy consumed by GMP's customers provides strong hedge benefits and may also yield lower revenue requirements, depending upon actual costs and contract pricing for New England renewable projects.
- The least favorable portfolio based on financial and environmental considerations is the Base Load and Market, which contains substantial amounts of IGCC coal capacity (without sequestration). The unfavorable cost results are due primarily to the capital intensity of coal plants, the significant coal transportation costs to New England, and the fact that each scenario studied assumes at least some level of future carbon emission regulation (i.e., emission allowance costs).
- The scenarios analyzed in this IRP assume at least some level of future carbon emission regulation. This tends to advantage portfolios with relatively low emissions (i.e., Current Portfolio Energy Path, Renewable Emphasis, and Combined Cycle) relative to those (i.e., Baseload, Peaking) with higher emissions. Therefore, if no greenhouse gas emission limits (or only very modest reduction targets) are ultimately established, these latter portfolios could turn out to be more attractive than shown here.
- The portfolios that offer the greatest degree of price stability over time tend to feature the largest potential exposure to debt imputation, and similarly the largest exposure to above-market costs in the event that future electricity market prices decline. This relationship will require vigilance and planning in designing resource contracts.
- In addition to debt imputation, counterparty performance issues (which are not explicitly evaluated here) will bear on the feasibility of GMP's resource choices. In evaluating long-term resource options, GMP will need to consider the relative financial stability of its suppliers (that is, their ability to deliver on a below-market contract) and the performance assurance terms (e.g., collateral) that suppliers will require of GMP. Depending on future market conditions and on negotiations with

potential sellers, this factor could potentially constrain the amounts and duration of long-term power purchase contracts that are financially feasible for GMP.

- Similar trends are shown for the carbon, hedging, and volatility exposure of the portfolios, whether using an average over the 20-year study period or single year 2020 values when considering trade-offs.
- The more favorable portfolios with respect to cost - particularly the Current Portfolio Energy Path, Renewable Emphasis, and Combined Cycle - feature fairly similar projected costs.[21] The relative rankings for these resources (and the appropriate amounts to include in GMP's portfolio) could therefore evolve as GMP obtains specific proposals from potential suppliers and as future market conditions change. As a result, this IRP's action plan should emphasize steps to identify and evaluate potential resource options, as opposed to prescribing specific volumes and timing for targeted resources.

- Based on these observations, we chose three portfolios to stress test for potential further differentiation:
- Current Portfolio Energy Path
- Renewable Emphasis
- Combined Cycle and (with Vermont Yankee and Hydro-Québec as long-term market proxies)

[21] For context, we estimate that a $50 million change in net present value cost represents roughly a 2.5 percent change in GMP revenue requirements over the period.

Stress Testing

As a final step in the analysis, we stress tested the better scenarios on the basis of a 2020 snapshot. The stress tests included a:

- 10% increase in electric market energy prices (due to factors other than fossil fuel prices).
- 25% increase and decrease in market energy and fuel prices.
- One-year temporary loss of the Vermont Yankee resource.
- The stress tests produce three additional attributes in the trade-offs discussed above. We refer to these attributes as the Resiliency Attributes since they test the beneficial nature of the portfolios in a more dynamic environment. These attributes are:
- 2020 revenue requirements portfolio value impact.
- 2020 total retail price volatility: percent and cents per kilowatt hour.
- Stressed fuel price volatility exposure: percent of energy exposed to the short-term market.

Figure 30 and Figure 31 compare the change in the portfolio value in 2020 to the original scenario value (that is, without the stress test change).

In Figure 30, the pure value of the portfolio fluctuates most for the Renewable Emphasis portfolio, primarily due to the assumption that renewable energy contract pricing is a function of renewable projects' underlying cost structures rather than prevailing market pricing. By itself, this would mean that this portfolio has the largest risk of above-market exposure in the event of low market prices. However, since these portfolios are designed to either reduce revenue requirements in absolute terms or hedge against increases in market prices or fuel prices, it is best to observe these portfolio cost changes when combined with the retail price impact the stress produces. Figure 31 depicts this scenario.

- The least net change in average retail price of electricity occurs in the Renewable Emphasis portfolio; this means that the portfolio value increases the most as market fuel price increase, putting pressure on retail electric rates through the load serving charges from ISO New England. This helps us demonstrate the potential benefits of longer term fixed pricing in PPAs and renewable generation contracted at the right price might be beneficial to minimize costs, reduce environmental impact, and maximize hedge. Our general observations from the stress testing process are:
- These portfolios, with strong elements of Vermont Yankee, Hydro-Québec, and renewable energy generation, can continue to dramatically reduce fuel price exposures. They do, however, expose GMP to power costs above the regional market should future market prices turn out relatively low.
- A 25% increase in fuel prices would only result in about a 5% or less change in retail rates, with the Renewable Emphasis portfolio being close to 100% hedged. Prices of standard service from utilities in neighboring states are more exposed to market price movements that play out over a few years – so that customers in those states would

tend to pay much more in high market price events, and to benefit more in low-price events.

- The Combined Cycle portfolio costs move more in response to fuel and market changes. This portfolio is a less effective hedge, and therefore is less exposed to temporary above- or below-market outcomes.
- A loss of the largest resource, Vermont Yankee, has some impact on the annual portfolio economics in the future. Because we did not test the unfavorable outcomes in combination (i.e., an extended Vermont Yankee outage, under unusually high market price conditions), the indicated change was modest. In the recent past, GMP has obtained outage insurance to protect against potential unfavorable combinations of this type. GMP expects that if Vermont Yankee or another single unit represents a large exposure in the future, we will explore such insurance. Diversification of baseload purchases across multiple units is also a potential way to limit the financial exposure associated with outages.

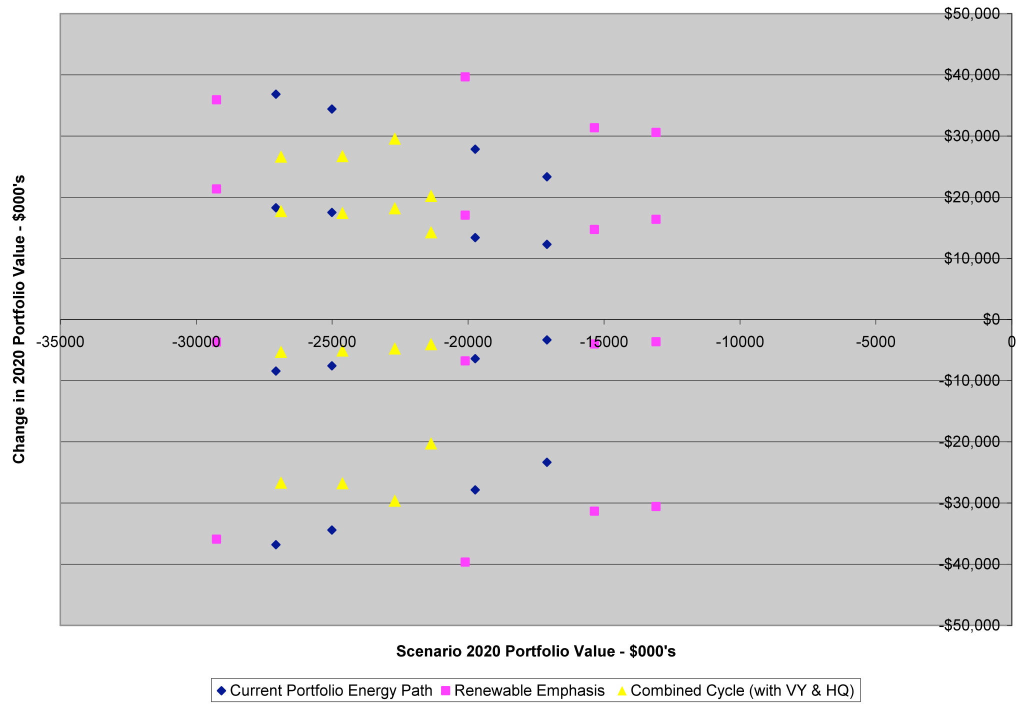

Figure 30: 2020 Portfolio Value versus Change from Stress Tests

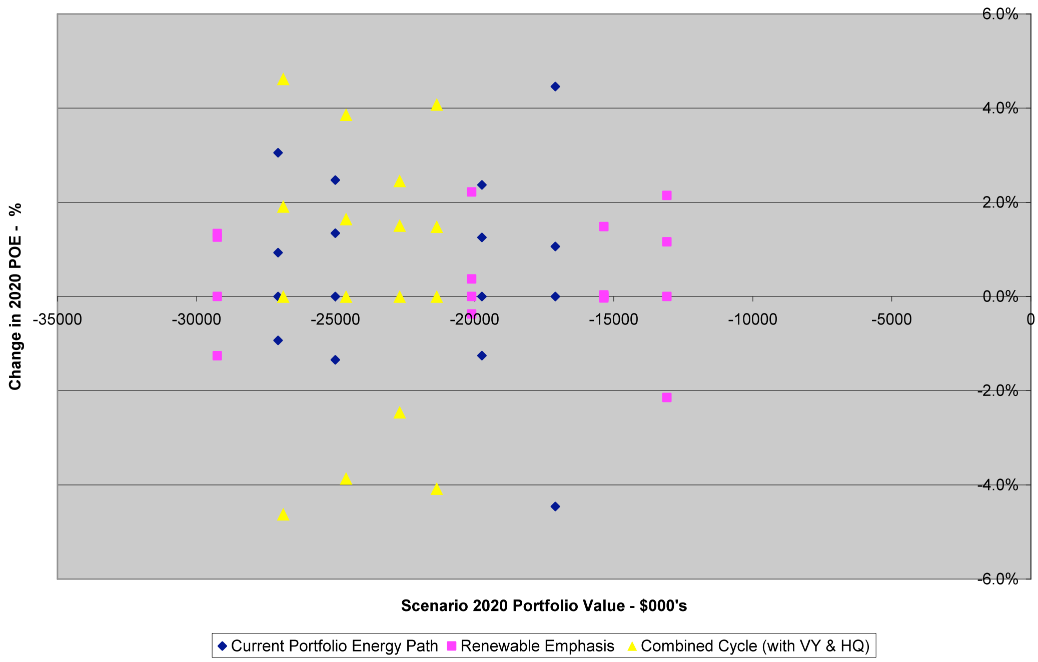

Figure 31: 2020 Portfolio Value versus Percent Change in the Retail Price of Electricity

Portfolio of Choice. This analysis creates insight into the resources that would compose the portfolio of choice. Portfolio 1: the Current Portfolio Energy Plan and portfolio 2: the Renewable Emphasis show slightly more favorable trade-offs among the attributes across the scenarios. These portfolios produce strong carbon and hedging benefits and likely the most favorable economics. Therefore, GMP's portfolio of choice should include significant elements of Vermont Yankee, Hydro-Québec, and renewable energy generation. It is important to note that the actual amounts of these and other resource within the portfolio depend on price negotiations as well as other contract terms, and on renewable project costs.

Leverage Advantages and Opportunities

There are several areas where GMP has leverage in the marketplace to potentially provide resources at below market cost when actually purchased. The need for Vermont approval of a Vermont Yankee license extension, and possible value sharing with its owner could provide GMP with an early opportunity for beneficial power supply. In addition of the long-term capital recovery perspective of a cost-of-service regulated utility on behalf of its customers may compare favorably to a market based on merchant financing costs and risk perspectives. As an integrated utility, GMP should have the ability to capture all the economic advantages of generation that location, reliability, and T&D savings might create. GMP's ability and willingness to enter into long-term supply contracts with existing or new generation facilities could potentially provide leverage in negotiating with project developers.

This can lead to several opportunities for GMP. One is developing utility-owned local peaking generation with 'wires' benefits, in coordination with VELCO analysis and planning. GMP also has the ability, albeit difficult, to join or form a consortium of vertically integrated utilities within New England to jointly develop resources and purchase from large resources in order to capture economies of scale or buying power advantages.

The results of this analysis establish several resources as having priority in the GMP planning over the next few years. These resources are:

Vermont Yankee and Other Nuclear Owners. Negotiations to yield most favorable contract balancing size of purchase, price, degree of fixed versus indexed pricing, and management of large single resource vulnerability.

Hydro-Québec and/or Other Import Opportunities. Determine the potential price and energy attributes of a post-2015 purchase of a renewed Hydro-Québec contract, other import contracts, or a combination of both.

Renewable Generation. Project development or long-term contracting, including Vermont based resources.

Natural Gas Combined Cycle Participation. Determine the project participation potential in Vermont and in New England, and the potential for small unit or tolling long-term contracting inventory, terms, and conditions.

In-State Peaking or Combined Cycle Capacity.[22] Identify site specific generation options that provide T&D project deferral benefits, creating a key leverage opportunity to enhance the value of GMP's portfolio.

Transmission and Distribution Scenario Analysis

Thus far, this portfolio analysis integrated generation supply and demand-side alternatives. Now, we consider transmission and distribution resources. In particular, we evaluate GMP's existing T&D under each of the four scenarios. While not resulting in any quantitative conclusions, the qualitative discussion enable future planning efforts.

The Fortress America scenario focuses on defending itself against terrorism and therefore becomes isolated from world markets. This would significantly impact T&D planning in several ways. For example, terrorism and related security concerns would justify establishing a centrally-controlled national grid. This would directly impact GMP's business of providing T&D delivery services to our customers. With a national grid, GMP would likely operate and maintain the T&D facilities on contract with the national grid, with the national grid planning T&D. Small scale distributed generation and on-site power facilities would become more attractive due to concerns regarding the security of central station generation facilities. Costs increase when operating these micro-grids, and from the

[22] The primary value of in-state peaking or combined cycle capacity would probably not derive from the energy-based stress testing discussed in this plan. Rather, the primary value of in-state capacity of this type would more likely be as a hedge against future capacity and reserve market prices, for local area reliability, and for deferring potential bulk transmission investments.

inspections and customer support required to interconnect distributed generation facilities to the grid. In the short term, distributed generation installed at customer sites should result in lower T&D demand peaks, but the long-term effect would simply defer investments by a few years. Fortress America load growth is the lowest of all four scenarios, and this would likely delay the need for installation of new T&D facilities. Lower load growth results in lower revenues and therefore adversely affects the ability to replace aging facilities.

In the Green Focus scenario, global warming would affect the climate. Storm activity would increase, causing flooding of low-elevation substation and generation plants within 20–25 feet of sea level. This should not affect any Vermont facilities, all of which are located at higher levels. As with Fortress America, Green Focus would make small-scale renewable distributed generation and on-site power facilities attractive due to reliability concerns and the desire to install renewable generation. This would result in establishing micro-grids needed to interface with existing T&D facilities. Load growth in the Green Focus scenario is expected to be slightly lower than the base load forecast. This would likely cause the installation of new T&D facilities to take longer. In 2010, the Green Focus scenario summer peak demand is 5 megawatts lower than the base load forecast. This difference increases to about 10 megawatts by 2015. Decreased revenues in this scenario due to low load growth reduce the availability of operating and maintenance dollars to replace aging facilities.

The Back to Business scenario includes aggressive economic growth with limited concern about the environment. Least-cost resources are implemented without emphasis on distributed generation or green resources. Demand-side management programs are not promoted aggressively, and T&D expansion involves adding new facilities as needed to serve new load. GMP’s T&D focus would be to serve customers at the lowest cost while maintaining or improving reliability and safety. Load growth is expected to be the highest of all scenarios, resulting in accelerated timelines for installing new T&D facilities. Increased revenues in this scenario allow for additional funds to replace aging facilities.

In the Green Growth scenario, there is a balance between environmental awareness and maintaining economic growth. Grass-roots efforts to install renewable generation and increased demand-side management programs are likely in this scenario. DSM programs partially offset the increased demand and energy requirements caused by economic growth. As with the two previous scenarios, small scale renewable distributed generation and on-site power facilities would become attractive options, resulting in establishing micro-grids needed to interface with existing T&D facilities. Load growth in the Green Growth scenario is expected to be slightly higher than the base load forecast, which would probably accelerate timelines for installing new T&D facilities. Higher energy sales provide additional funds to replace aging facilities.

5: Action Plan

This Action Plan explains how the conclusions identified through our analysis can be implemented. We base our conclusions on GMP's internal analyses at a specific point in time. Future critical inputs might ultimately impact the present conclusions. These inputs include commentary from public engagements that the DPS is coordinating and the results of a generation feasibility study that various Vermont utilities are managing.

The IRP will consider these projects as well as other future changes in regulation and legislation as they unfold.

Supply

The scenario analysis identifies two fundamental conclusions. First, the multiple objectives of minimizing cost, environmental stewardship, financial health, and stable prices can potentially be met without trading away one objective in favor of the others. Second, continuing the current portfolio of resources enhanced with additional cost effective renewable generation can be the best solution to meeting those objectives.

General Concepts

Based upon the resource portfolio of choice, the possible leverage advantages and opportunities, and the resource priority, we state the following set of actions to confirm and implement the 2007 Integrated Resource Plan:

- Incorporate these IRP conclusions and insights into the public outreach process of the Department of Public Service in order to inform stakeholders on the relative trade-offs and obtain useful feedback about the priority among attributes.
- Establish a comprehensive program to determine the potential participation costs in specific renewable energy generation projects and assess the probability of these projects actually getting completed and put in service. Potentially issue an RFP for some renewable energy, a critical step for validating the preferential pricing of a renewable portfolio.
- Together with other Vermont utilities and government officials, discuss negotiating long-term PPAs with Vermont Yankee (and perhaps other nuclear facilities) and the major players who can export firm energy into New England for a long-term PPA (such as Hydro-Québec, Ontario Hydro, and New Brunswick).
- Guide and participate in the Vermont generation facility siting study.
- Work closely with Vermont Transmission stakeholders to determine where, and at what size, 'in-Vermont wires' cost has offset benefits and how these benefits flow to GMP consumers.
- Establish an inventory of the potential New England combined cycle owners that would sell unit entitlement or similar contracts. Develop representative contract terms based on that information to determine market pricing and alternative pricing to long-term PPAs.
- Monitor the bidding behavior and results of the ISO New England FCM market auctions to better leverage favorable contracts and GMP project development.
- Monitor and participate in the public policy evolution regarding renewables and environmental regulations.

Implementation Timeline for Major Resource Procurement Activities

Table 22 presents the timeline for implementing these activities.

Date	Activity
2007	Prepare IRP. Monitor and participate in the Vermont DPS public outreach process.
2007 to 2008	Explore opportunities for renewable energy resource PPAs, to assess their potential role in the resource portfolio. Begin soliciting or negotiating for renewables.
2007 to 2008	Conduct discussions for replacing our nuclear contract after its expiration in 2012. Also discuss potential future contract opportunities with Hydro-Québec. Review the long-term market alternatives to both of these resources.
2007 to 2008	Test the potential for cost-effective long-term contracts with existing and new natural gas combined cycle capacity. Inventory the potential for contracting with these resources for discrete entitlements (less than 50 megawatts).
2007	Guide and participate in the joint utility Vermont generation siting study.
2007 to 2009	Review FCM auction results to determine if GMP has a financial advantage or can leverage its vertical integration when facilitating the development of in-state capacity.
2009 to 2011	Gorge gas turbine is retired and replaced with a newer 25 megawatt unit.
2010 to 2012	Vergennes diesel retirement is reviewed: evaluate life extension and replacement with a newer unit.
2011 to 2015	Berlin is retired. Its replacement may be evaluated in the context of participation in a statewide process.
2012	Vermont Yankee contract expires.
2013 to 2015	Potentially take positions in short- and medium-term base/intermediate load contracts up to the expected net short in 2015/2016. Hydro-Québec VJO Schedule B contract expires.
Post 2015	Replace and add contracts as needed, consistent with GMP's Risk Management Policy.

Table 22: Implementation Timeline

Demand and Power Delivery Systems

Demand

Green Mountain Power will use the distributed utility framework to ensure that DSM spending is directed towards projects where they represent the least-cost solution for the areas in ASCs. Working in concert with the ISO, we will increase the amount of demand under control and improve GMP's customer load response program. GMP will continue to work with local planning organizations to encourage cooperative planning and efficient resource use.

The design of rate tariffs affects the customer's ability to make resource use choices and GMP's ability to effectively hedge against certain risks. GMP plans to make new tariffs available that mirror market opportunities to mitigate risks and differentiate pricing, promote efficiency, and achieve public policy goals. Expanding GMP's rate offerings will provide customers with the ability to choose green energy resource alternatives and take advantage of price differentials available in the market. Customers might also be able to reduce costs by committing to buy firm blocks of energy and load-following services separately to suit their needs and ability to plan for use.

GMP's single greatest load risk remains a possible dramatic reduction in energy use by its largest customer, IBM.

GMP will continue to advance its service quality program to maintain high standards of customer service, including rapid response times, money-backed guarantees, and performance monitoring.

Transmission and Distribution Planning

GMP has embarked on a comprehensive multi-year study of the efficiencies of our transmission and distribution system. We will continue to monitor the reliability indices for the power delivery system. We will undertake periodic reviews and focus our limited resources on improving the reliability of service provided to our customers

Based on historical analysis, GMP plans to annually fund right-of-way clearing and vegetative management at approximately $2.7 million annually. We will focus what is learned from measuring our reliability to achieve the most benefit from our resources. We will continue to employ line patrols and infrared scans to find and correct problems before they cause outages to customers.

Improvements to the Planning Process

Green Mountain Power intends to continually refine its IRP process, analysis, and plan to accommodate emerging information on the cost and benefits of supply and demand management options in a number of ways.

First, the GMP IRP process and analytical approach is now a living effort; we continually assess it.

Second, GMP will more directly incorporate the decision viewpoints as the criteria of the multiple stakeholders in the Vermont Energy community. This can most easily be accommodated given the trade-off approach that has been incorporated.

Third, as the overall costs of providing of electric utility service rise, it is critical for GMP to better integrate DSM and transmission and distribution planning into selecting the most appropriate portfolio, to better capitalize on the unique advantages of the integrated utility in today's merchant generation and unbundled utility dominated landscape within ISO New England.

Finally, the IRP will accommodate additional stress tests as activities and stakeholders warrant further testing of the robustness of our resource conclusions.

In sum, this Integrated Resource Plan reflects yet another large step in establishing a comprehensive, open, and informative planning process to create a more practical tool for procuring necessary resources.

Appendices

A: 2007 Long-Term Energy and Peak Forecasts

Customer Class Sales Forecast

The long-term energy and demand forecast is based on the current class sales forecasts. The sales forecast is based on separate econometric customer class models. Forecast models are estimated for the residential, small commercial, large commercial and industrial customers. The primary economic drivers include household income, number of households, employment, regional output and price. Other drivers include forecasted weather conditions and end-use saturation and efficiency trends.

Residential Sector

Residential sales are estimated using a Statistically Adjusted End-Use (SAE) model specification. An SAE modeling approach entails constructing end-use variables that include end-use saturation and efficiency trends as well as economic, price, and weather impacts. The SAE specification allows us to directly capture the impact of improving end-use efficiency and end-use saturation trends on class sales. The process entails constructing end-use variables (that is, XHeat, XCool, and XOther) and using these variables in estimated average use regression models as shown below:

$$AvgUse_m = a + b_1 \times XHeat_m + b_2 \times XCool_m + b_3 \times XOther_m + \varepsilon_m$$

The objective is to construct an end-use variable that approximates the major end-uses. XHeat is thus calculated as:

$$XHeat_{y,m} = HeatIndex_y \times HeatUse_{y,m}$$

where:

$$HeatUse_{y,m} = \left(\frac{HDD_{y,m}}{HDD_{01}}\right) \times \left(\frac{HHSize_y}{HHSize_{01}}\right)^{0.20} \times \left(\frac{Income_y}{Income_{01}}\right)^{0.20} \times \left(\frac{Price_{y,m}}{Price_{01}}\right)^{-0.15}$$

The economic and price drivers are incorporated into the HeatUse variable. By construction, the $HeatUse_{y,m}$ variable sums close to one in the base year (2001). This index value changes through time and across months in response to changes in weather conditions, prices, household size, and household income. The heat index (HeatIndex) is a variable that captures heating end-use efficiency and saturation trends, thermal shell improvement trends, and housing square footage trends. The index is constructed from the EIA annual end-use residential forecast for the Northeast Census Region.

The heat index (HeatIndex) and heat use variable (HeatUse) are combined to generate the monthly heating variable XHeat. Figure 32 shows the calculated XHeat variable for the residential heating customer class.

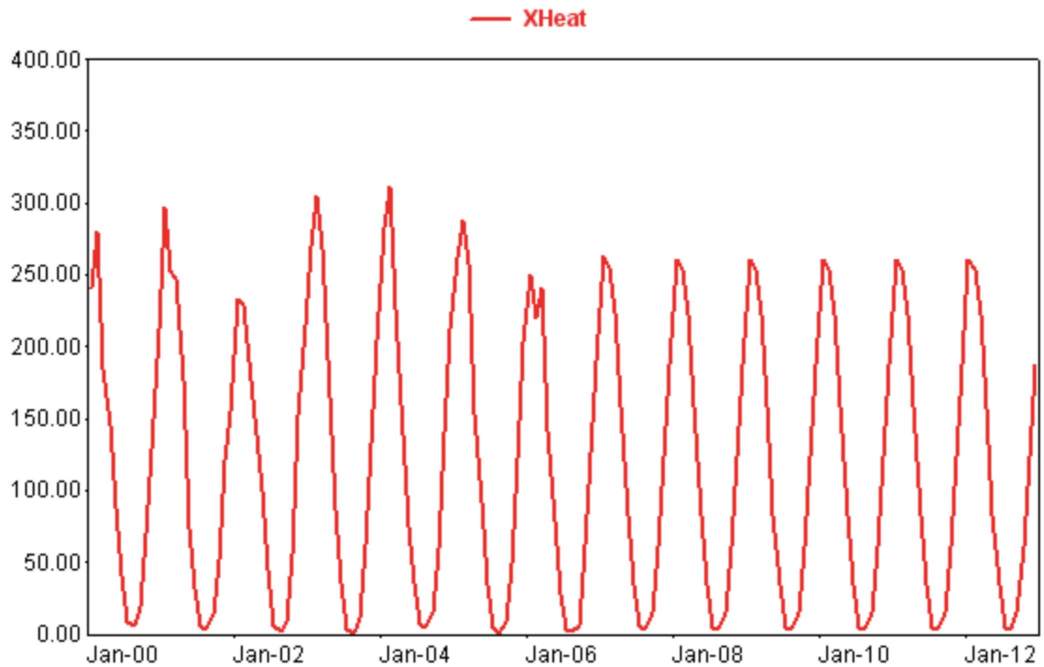

Figure 32: XHeat Variables for Residential Heating

The constructed XHeat variable is an estimate of monthly heating requirement (kWh). Similar variables are constructed for cooling (XCool) and other end-uses (XOther).

Figure 33 and Figure 34 show XCool and XOther.

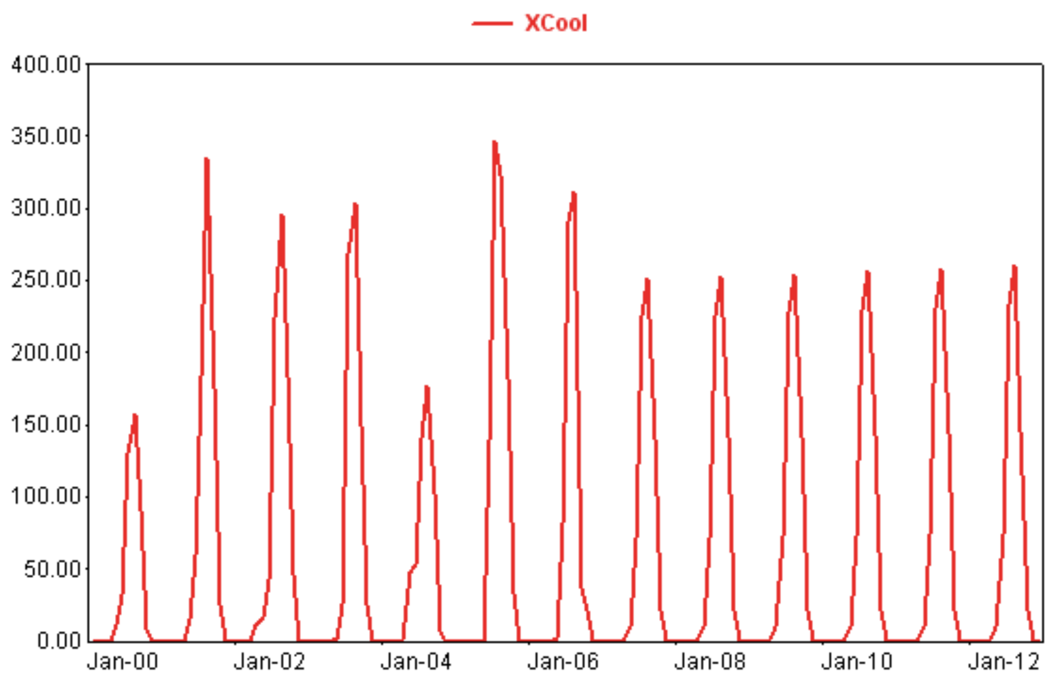

Figure 33: XCool Variables for Residential Heating

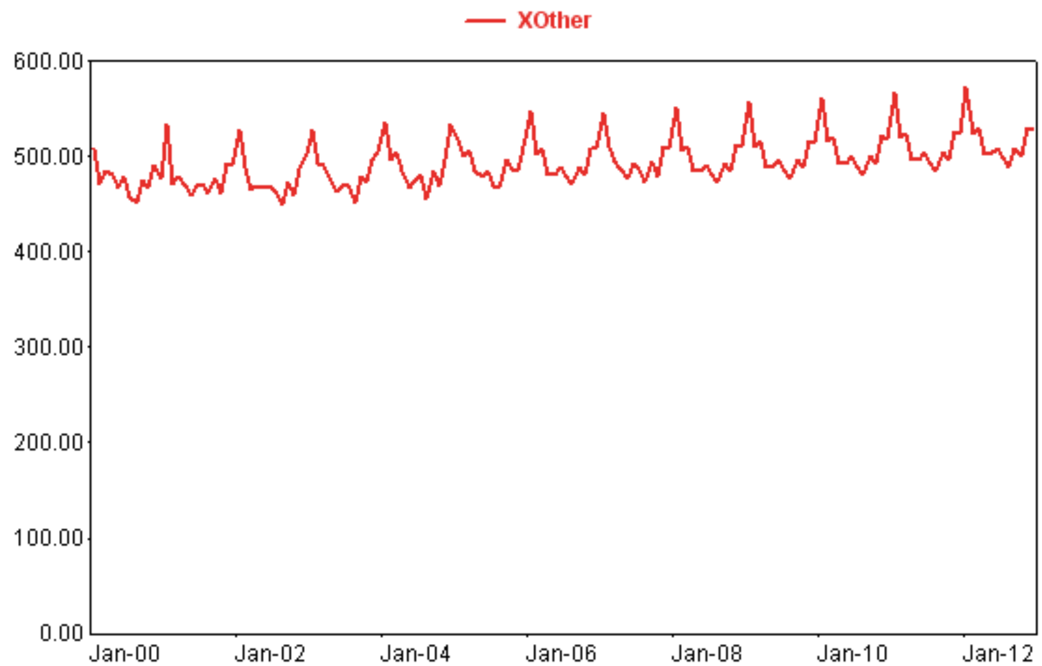

Figure 34: XOther Variables for Residential Heating

The monthly variation in the XOther variable is driven by variation in the number of billing days, lighting requirements, and electricity usage for water heating.

The end-use variables are used to estimate an average use model for each residential class.

Figure 35 shows actual and predicted average use for the NEH revenue class.

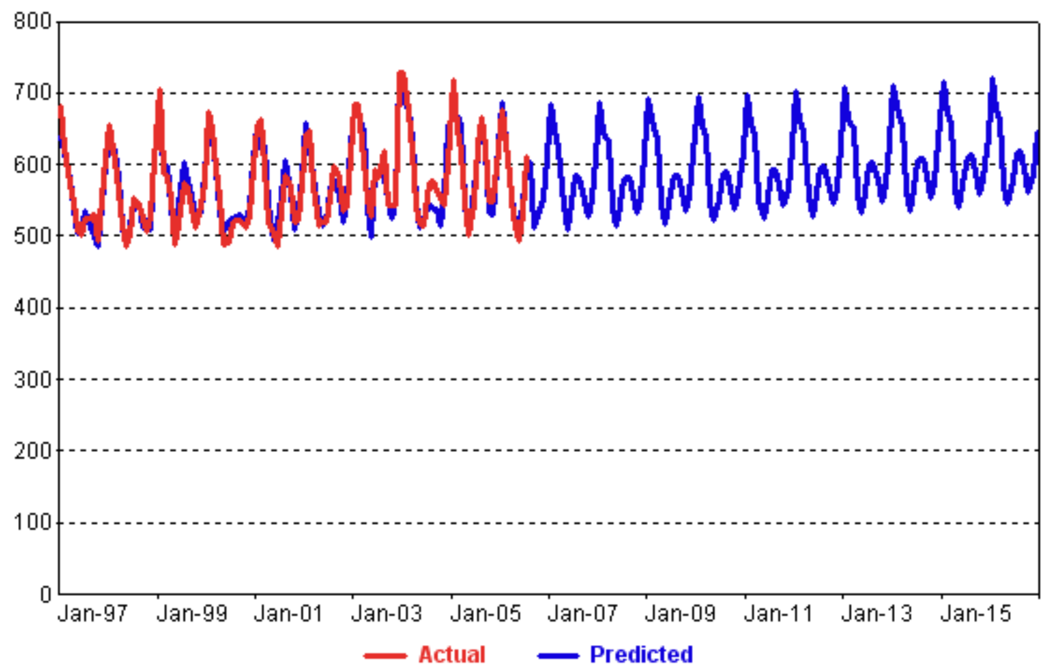

Figure 35: NEH Average Use Model (Kilowatt Hour)

The model explains historical data well. The adjusted R-squared is 0.90 with a MAPE of 2.5%. A similar specification is used for the combined space and electric water heating revenue class. The adjusted R-squared for this model is 0.95 with a MAPE of 4.5%.

The customer forecast is derived from a regression model that relates customers to historical and projected households.

Figure 36 shows actual and predicted customer forecast. The number of residential customers is projected to average 2.2% growth through the forecast period.

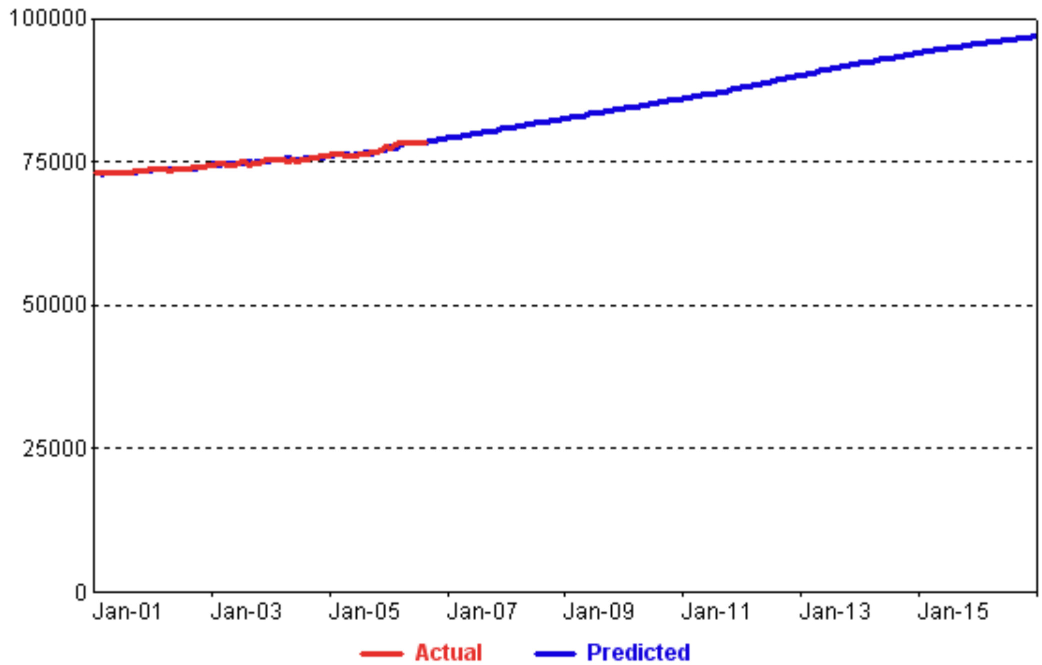

Figure 36: Residential Customer Forecast

The number of electric and water heat customers are based on a separate regression model that relates the number of customers to household projections. The share of homes with electric heat has been declining throughout the historical period. This is expected to continue, but at a slower rate. The number of homes with electric heat is expected to decline by 0.7% per year over the forecast period.

Figure 37 shows the projected number of customers with electric heat.

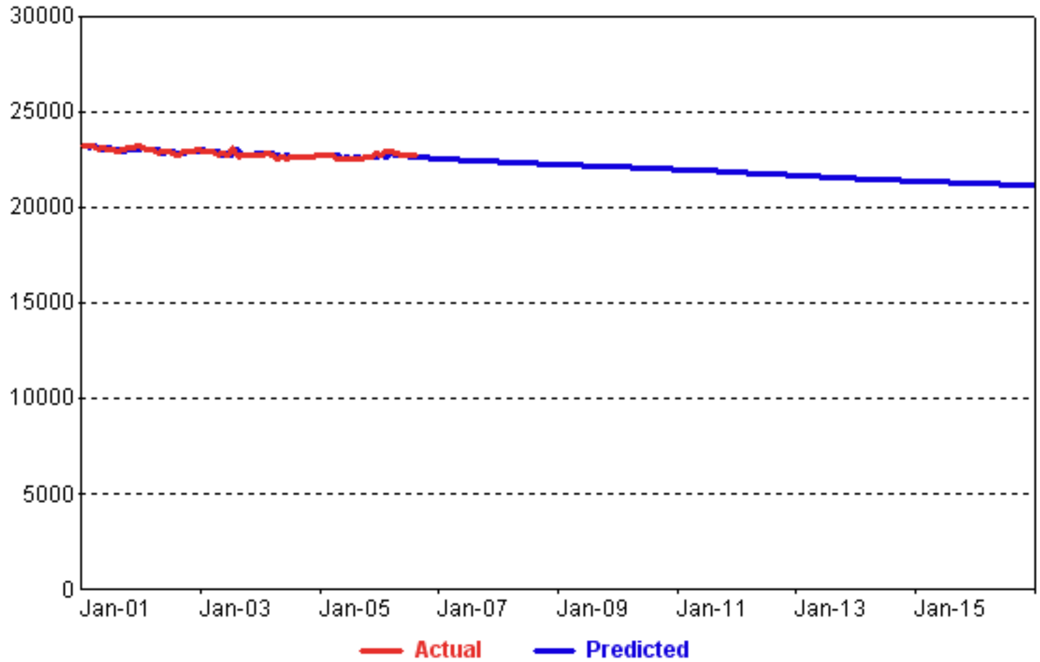

Figure 37: Residential Electric and Water Heat Customer Forecast

Customer and average use forecasts are combined to generate monthly billed sales forecast (Sales = Average Use x Customers).

Figure 38 shows monthly sales forecast.

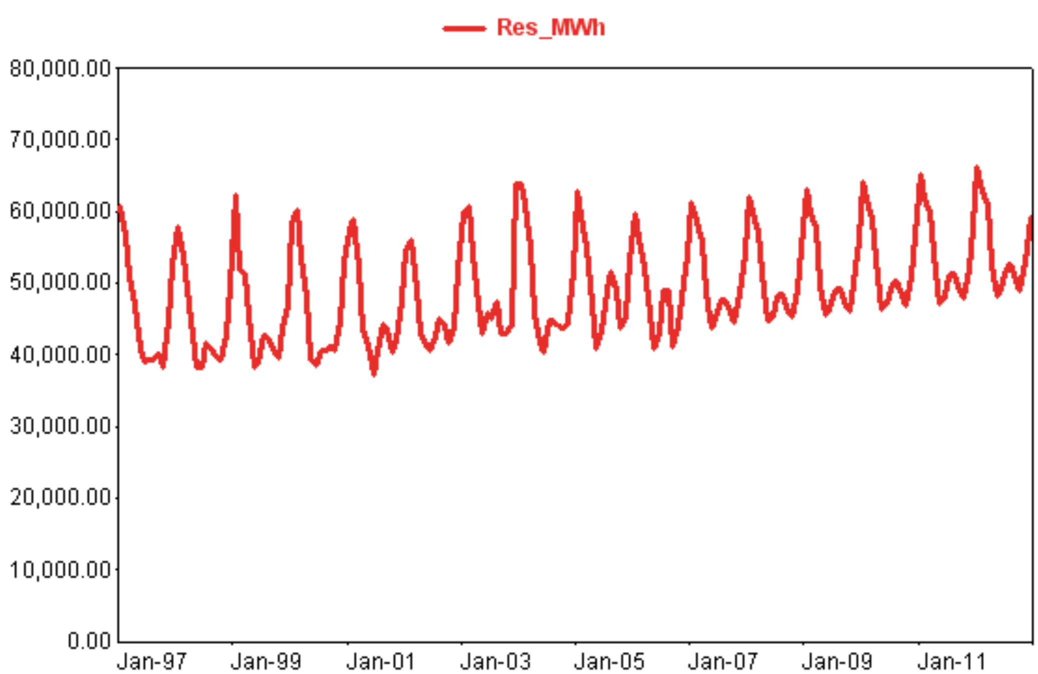

Figure 38: Monthly Residential Sales Forecast (MWh)

Figure 39 shows the forecasts on an annual basis.

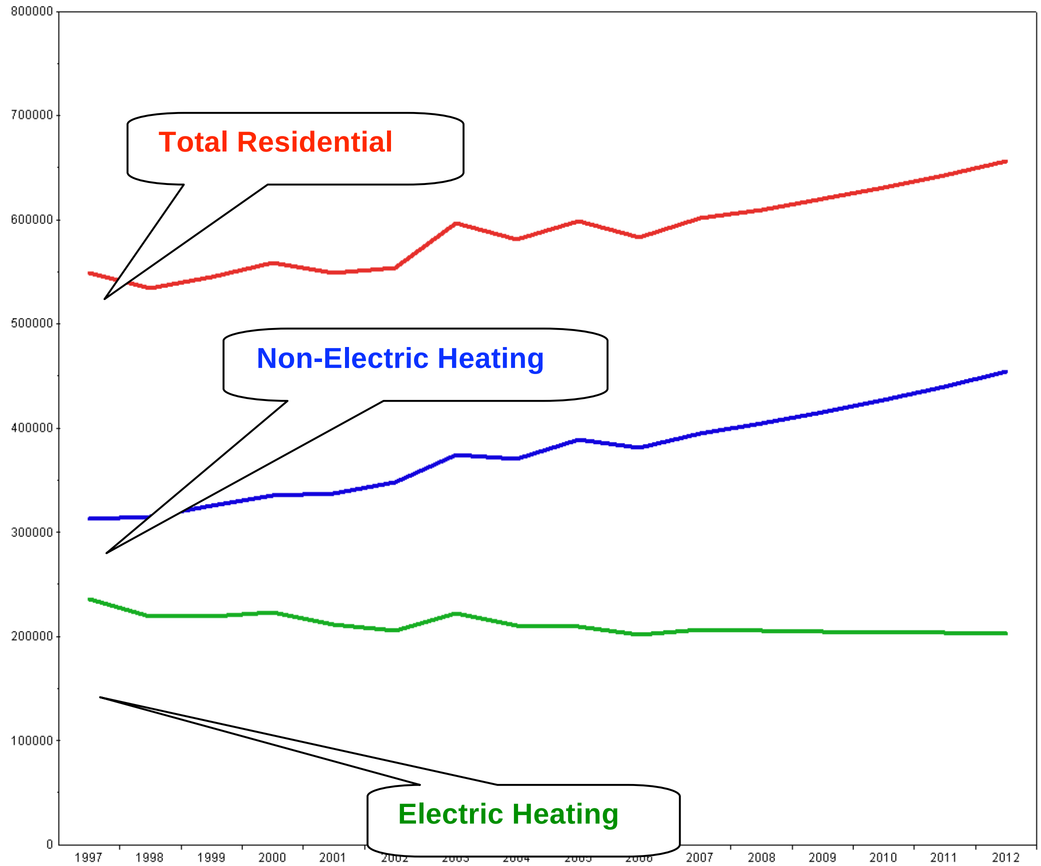

Figure 39: Annual Sales Forecast by Revenue Class (MWh)

Commercial

The commercial sector includes three classifications:

- General Service Customers (GS)
- Time-of –Use Customers (TOU)
- Commercial and Industrial Large (CIL)

Separate monthly sales and customer forecast models are estimated for each class.

General Service

An SAE approach is used for GS and TOU revenue classes. The GS sales are modeled by combining an average use forecast with a customer forecast. As in the residential model, end-use variables XHeat, XCool, and XOther are constructed from end-use saturation and efficiency trends, regional output, price, and weather conditions. XHeat is defined as:

$$XHeat_{y,m} = HeatIndex_y \times HeatUse_{y,m}$$

where

$$HeatUse_{y,m} = \left(\frac{HDD_{y,m}}{HDD_{01}}\right) \times \left(\frac{Output_y}{Output_{01}}\right)^{0.20} \times \left(\frac{Price_{y,m}}{Price_{01}}\right)^{-0.15}$$

The HeatIndex is a variable that reflects commercial end-use saturation and efficiency trends as projected by the EIA for the Northeast Census Region. Real non-manufacturing output is the primary economic driver in the average use model. Similar variables are constructed for XCool and XOther. The constructed variables are then used to drive the average use forecast model.

Figure 40 shows the resulting GS model results.

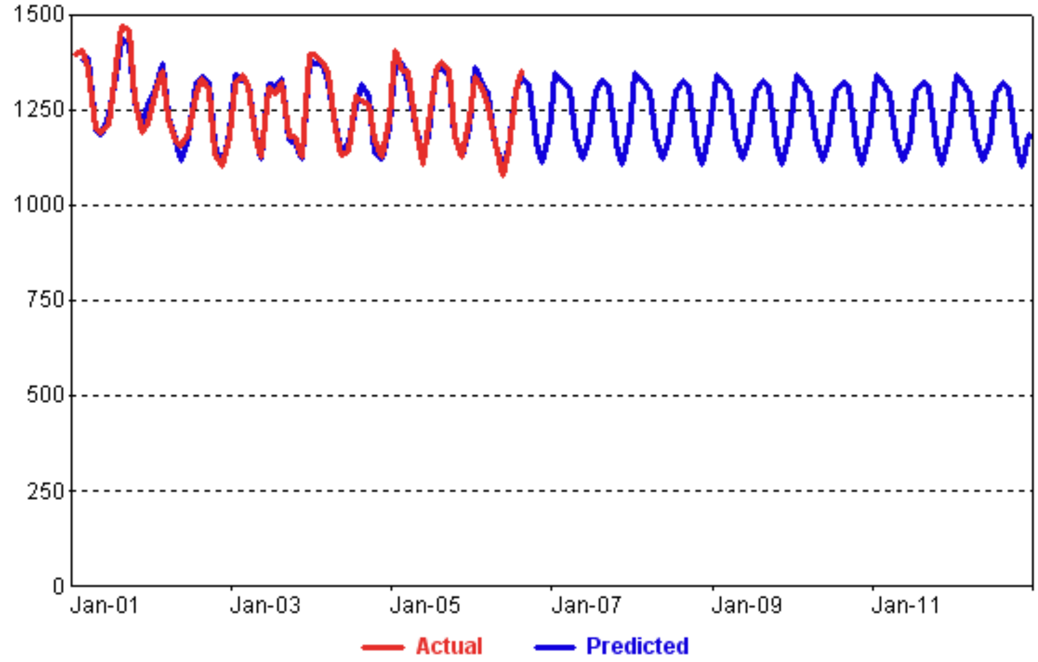

Figure 40: Actual and Predicted General Service Average Use (kWh)

The GS average use model performs well with an adjusted R-squared of 0.94 and a MAPE of 1.6%. The customer model is driven by non-manufacturing employment projections.

Figure 41 shows actual and predicted GS customers.

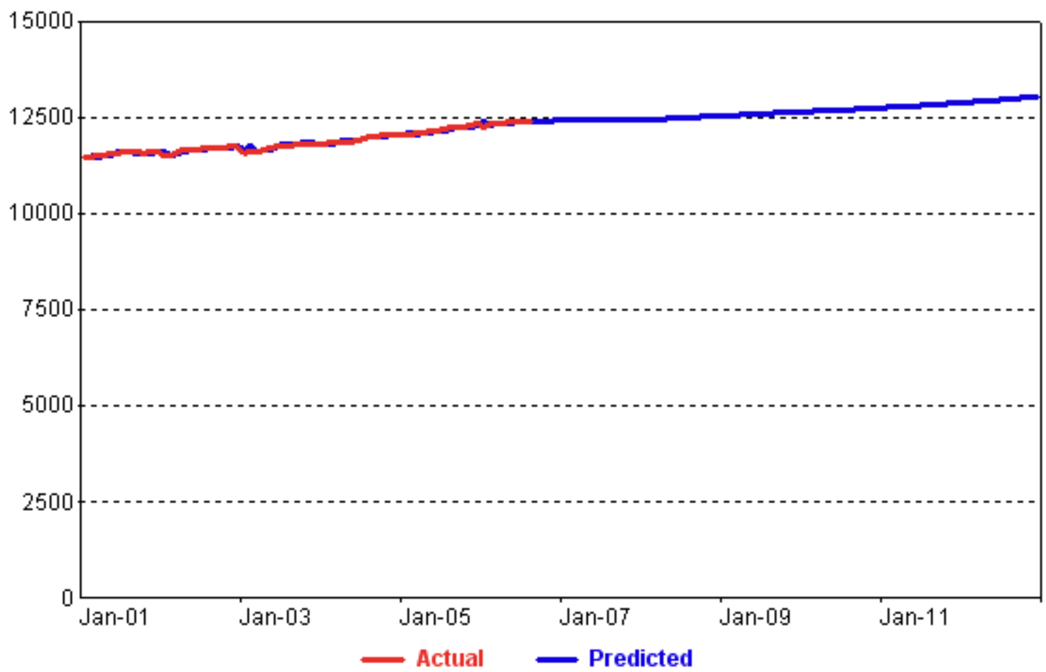

Figure 41: General Service Customer Forecast

The average use forecast is combined with the customer forecast to generate a monthly sales forecast. Figure 42 shows resulting sales forecast.

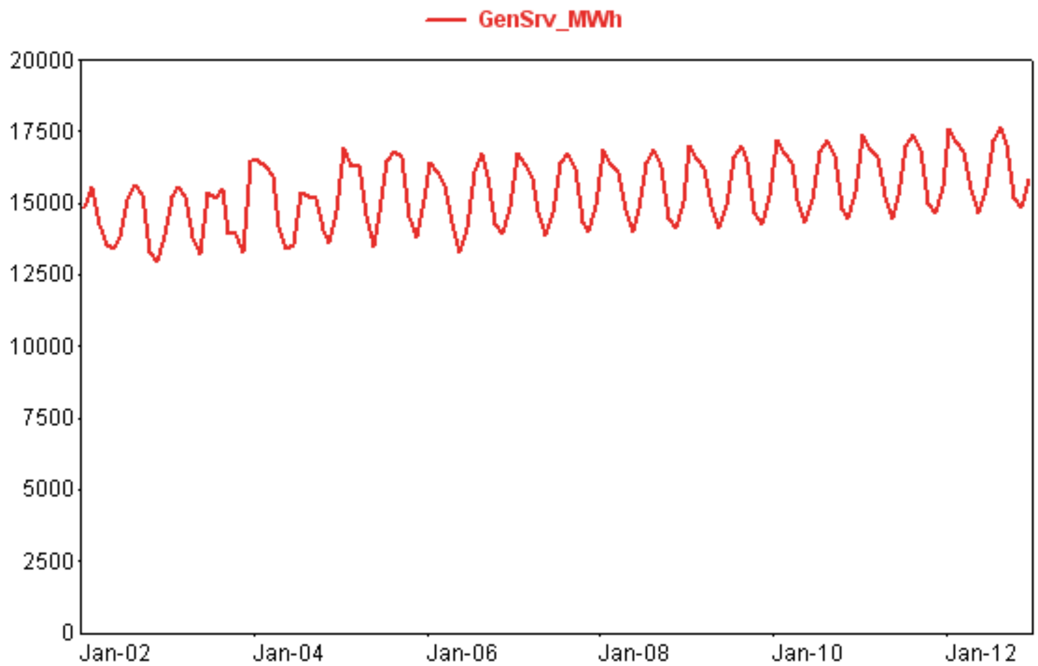

Figure 42: General Service Sales Forecast (MWh)

Time of Use

The TOU model is structured is similar to the GS model, with two key differences. First, the TOU model is constructed using total sales, rather than average use. Second, the primary economic driver is total regional output, rather than non-manufacturing output. Price is also specific to the TOU revenue class. Heating (XHeat), cooling (XCool), and other use (XOther) variables are constructed from end-use saturation and efficiency trends, weather conditions, regional output, and price. The constructed end-use variables are then used in a monthly sales regression model. Figure 43 shows the model results.

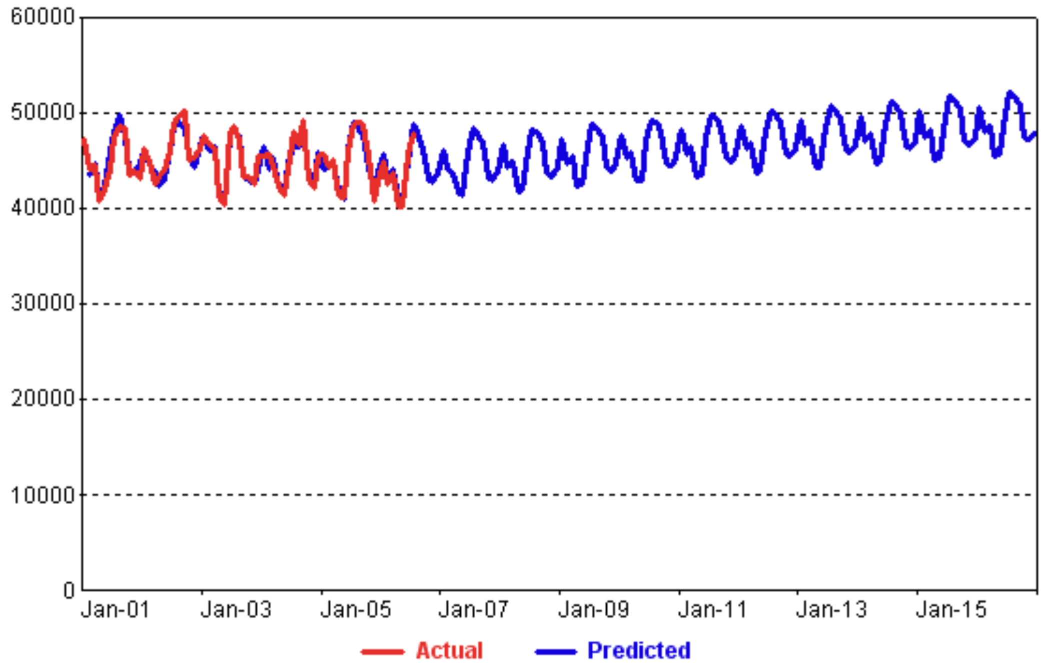

Figure 43: TOU Sales Forecast (MWh)

The TOU model performs well, with an adjusted R-squared of 0.93 and MAPE of 1.4 %. Customers are forecasted separately using a regression that relates TOU customers to total employment.

Commercial and Industrial Large

CIL includes GMP's 24 largest customers. CIL sales forecast is derived from an econometric model that relates monthly sales to GDP and monthly binary variables designed to capture seasonality in sales. Heating degree-days (HDD) and cooling degree-days (CDD) were either insignificant or had the wrong sign (that is, negative signs on the coefficients) and were therefore omitted from the model. Several binary variables were also used to capture shifts in the data reflecting changes in the CIL customer mix. CIL sales forecast is shown in Figure 44.

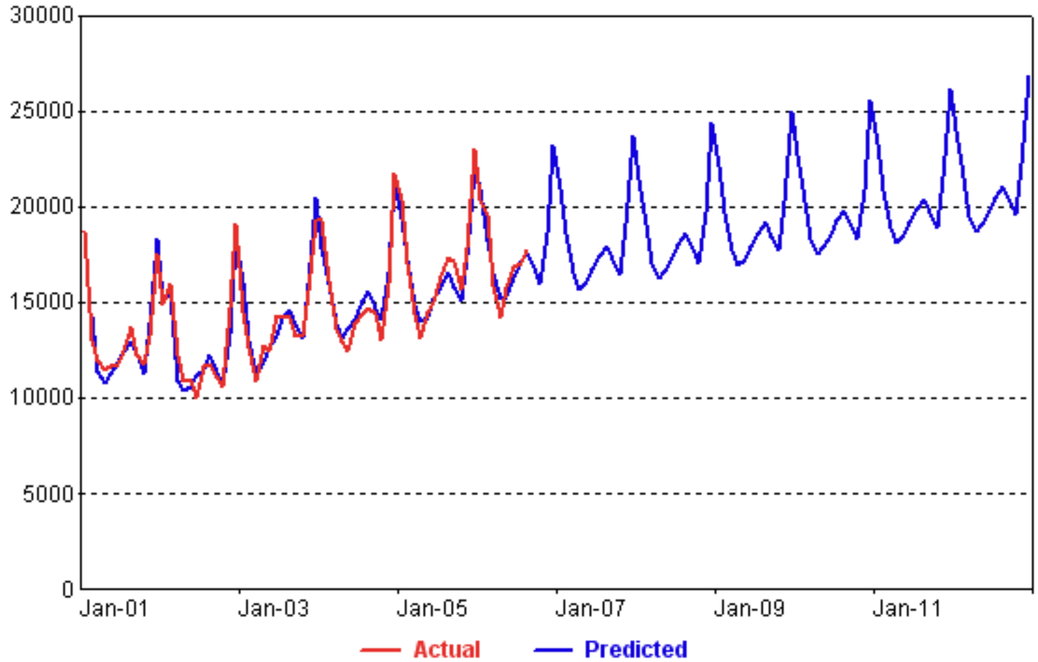

Figure 44: Commercial and Industrial Large Sales Forecast (MWh)

This model adjusted R-squared is 0.91 and the MAPE is 4.2%.

Other Classes

Separate regression models are estimated for station power and street lighting/public authority. Forecasts are based on simple trend variables with binaries added to capture large outliers. Sales for both station power and street lighting have been flat over the last five years and are expected to show little growth over the forecast period.

Forecast Results

Table 23: shows the annual sales forecast through 2026.

Year	Residential	Commercial	IBM	StL & PA	Total
2001	549.2	883.5	518.9	5.0	1,956.6
2006	585.2	926.2	458.7	4.4	1,974.4
2011	642.6	971.1	464.6	4.4	2,082.7
2016	707.7	1,018.0	464.6	4.4	2,194.7
2021	766.6	1,064.8	464.6	4.4	2,300.4
2026	825.4	1,117.0	464.6	4.4	2,411.5
Chg					
2001–2006	1.3%	1.0%	–2.4%	–2.8%	0.5%
2006–2011	1.9%	1.0%	0.3%	0.1%	1.1%
2006–2026	1.7%	0.9%	0.1%	0.1%	1.0%

Table 23: Sales Forecast Fall 2006

Over the long-term, sales are projected to increase 1.0% per year. Residential sales are expected to increase at a relatively healthy 1.7% with 0.9% growth in the commercial sector. IBM sales are expected to be flat through the forecast period.

Base Case Economic Assumptions

Residential. The primary economic drivers in the residential models are the number of households and real household income. The number of households drives the residential customer forecasts and real household income is a primary economic variable in the residential average use model. The number of households is expected to grow about 0.7% over the forecast horizon. This is somewhat stronger than the 0.6% growth over the last five years. The number of customers in the service area increase at a somewhat faster rate than household projections reflecting the relatively stronger residential customer growth in the GMP service area.

Table 24 shows Economy.com's regional household projections and GMP's residential customer forecast.

Year	Households	Customers
2001	74,940	73,249
2006	77,180	78,289
2011	80,880	83,643
2016	84,820	90,088
2021	87,410	94,343
2026	89,260	97,370
Chg		
2001–2006	0.6%	1.3%
2006–2011	0.9%	1.3%
2006–2026	0.7%	1.1%

Table 24: Regional Household and Customer Projections

Household income captures the impact of economic growth in the residential average use model. Economy.com projects relatively strong income growth for the region, with real personal income increasing 1.9% over the forecast period. Real income per household is projected to increase at a healthy 1.1% per year. This compares with real income growth over the last five years of 1.6% and per household income growth of 1.0%. Table 25 shows Economy.com's income projections.

Year	Real Personal Income ($ millions)	Real Household Income ($ thousands)
2001	5,774.3	77.1
2006	6,248.4	81.0
2011	6,956.8	86.0
2016	7,642.3	90.1
2021	8,326.6	95.3
2026	9,023.4	101.1
Chg		
2001–2006	1.6%	1.0%
2006–2011	2.2%	1.2%
2006–2026	1.9%	1.1%

Table 25: Real Personal Income

Another driver in the forecast model is the price projection. Price is calculated as a 12-month rolling average of the monthly average rate. We assume that households do not respond immediately to a rate increase, but rather respond over the year as costs change. The price series is then translated to constant or real dollars using the CPI (Consumer Price Index).

Figure 45 shows the residential non-electric heat price series.

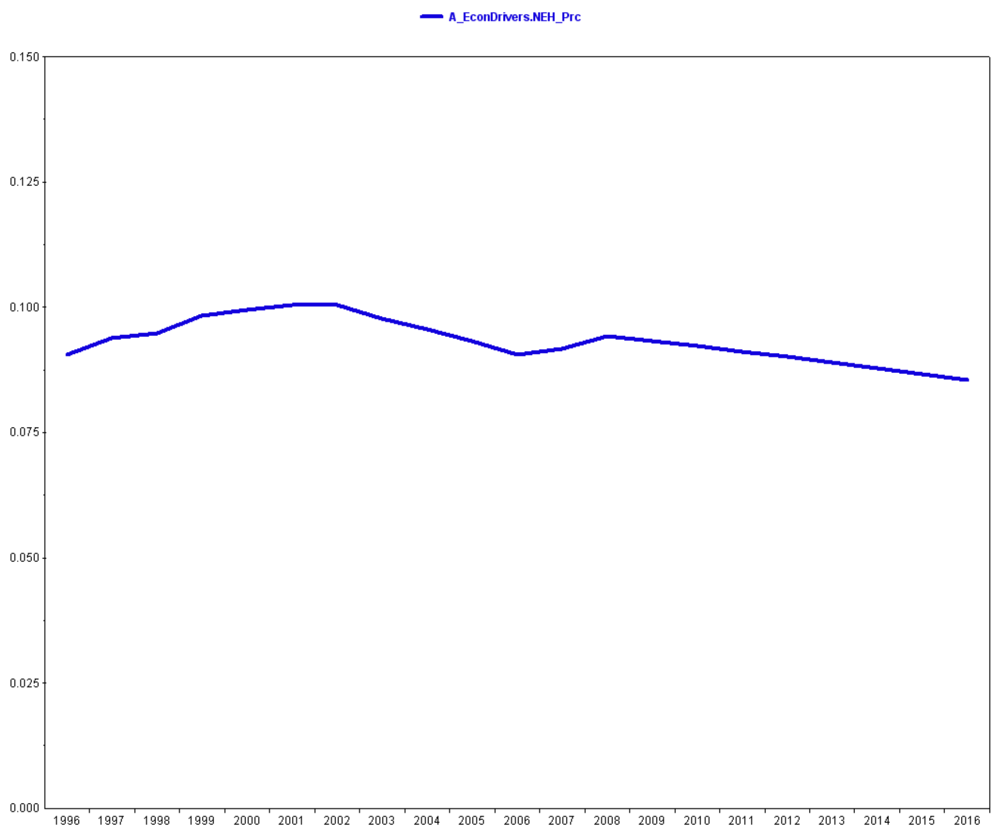

Figure 45: Non-Electric Heating Price Forecast ($/kWh)

On a real basis, the 12-month moving price has been declining since 2002. Real prices begin to drift up beginning in 2006 and are expected to increase through 2008, as a result of the expected rate increase in 2007. Prices after 2007 are assumed to decline roughly 1.2% over the forecast horizon. We assume that electric rates increase no more than half the rate of inflation. Price impacts the sales forecast through an imposed price elasticity estimate. We assume an electric price elasticity estimate of –0.15.

Commercial. Regional output and employment are used to drive the commercial customer and sales forecast. Economy.com expects real long-term growth in the region to be relatively healthy with long-term output growth of 2.2%. The non-manufacturing sector will grow slightly faster than the economy as a whole, with non-manufacturing output growing at 2.3%. Output growth is somewhat slower than that expected for the nation. Since 2001, output growth has been stronger than projected growth, largely as an outcome of exceptionally strong economic gains in 2003 and 2004. Table 26 summarizes regional output projections.

Year	Total Output	Non-Manufacturing Output
2001	6,679	5,581
2006	7,773	6,799
2011	8,689	7,652
2016	9,707	8,605
2021	10,734	9,586
2026	11,916	10,727
Chg		
2001–2006	3.1%	4.0%
2006–2011	2.3%	2.4%
2006–2026	2.2%	2.3%

Table 26: Regional Output Projections (million $)

While regional output has been strong over the last five years, net employment gains have been relatively weak, with total employment growth averaging 0.2%. Economy.com assumes that the worst is over with the manufacturing sector. As a result, regional employment is expected to increase at a somewhat faster level of 0.9%. The non-manufacturing sector has been the primary economic driver, with historical employment growth of 1.1%. Non-manufacturing employment is forecasted to grow 1.1% through 2026. Table 27 summarizes employment projections.

Year	Total Employment	Non-Manufacturing Employment
2001	105	87
2006	105	92
2011	109	96
2016	115	102
2021	120	107
2026	126	114
Chg		
2001–2006	0.2%	1.1%
2006–2011	0.7%	0.9%
2006–2026	0.9%	1.1%

Table 27: Employment Projections (thousands)

Price is also incorporated into the commercial sales forecast models. The price variable is again calculated as a 12-month moving average of revenue per kilowatt hour, which is then converted to a real dollar basis. The commercial price series are similar to that of the residential price series. Real prices fall between 2002 and 2006, and increase in 2007 as a result of the expected rate increase. We then assume that real prices increase at a rate no more than half that of inflation through the forecast period. Price impacts are modeled using a –0.15 price elasticity. The time-of-use price series is depicted in Figure 46.

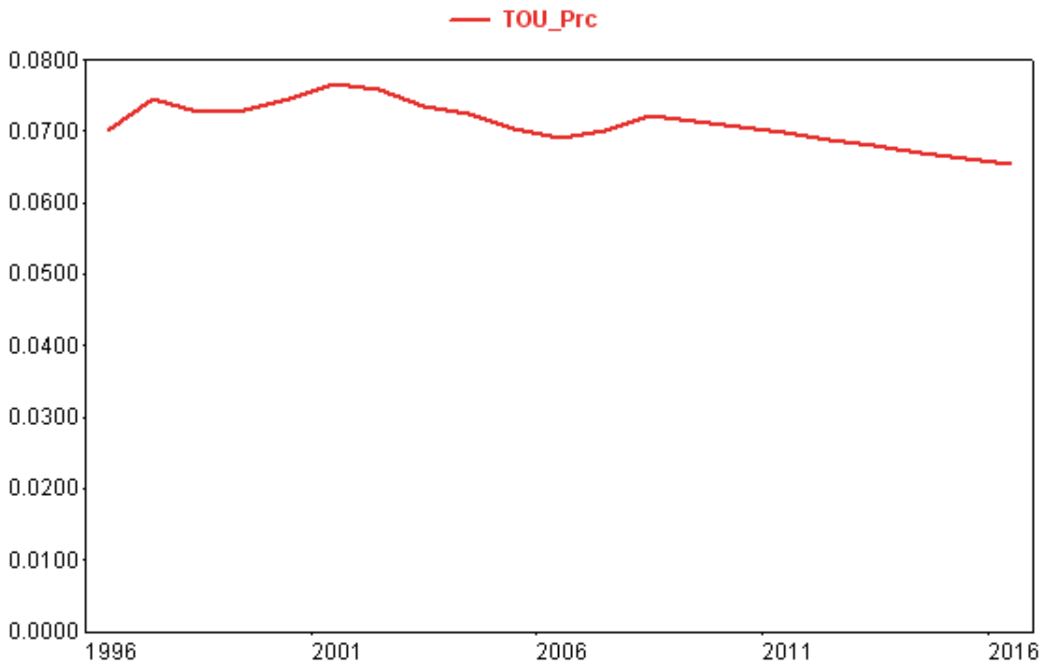

Figure 46: TOU Real Price Projection ($/kWh)

Energy and Demand Forecast

Energy Forecast

The sales models are estimated using billed class sales and customer data. Billed sales generally do not line up with the calendar month, but rather reflect the meter read schedule. While it will vary from month to month, roughly half the billed sales occur in the prior calendar month. A large share of July billed sales, for example, actually occurs in June.

To translate the sales forecast to an energy forecast, we first estimate calendar-month (versus billing-month) sales. Using the estimated class regression model, we substitute calendar-month HDD and CDD for billing-month HDD and CDD and the number of calendar days for the number of billing days. Figure 47 shows the average use simulations for residential non-electric heat.

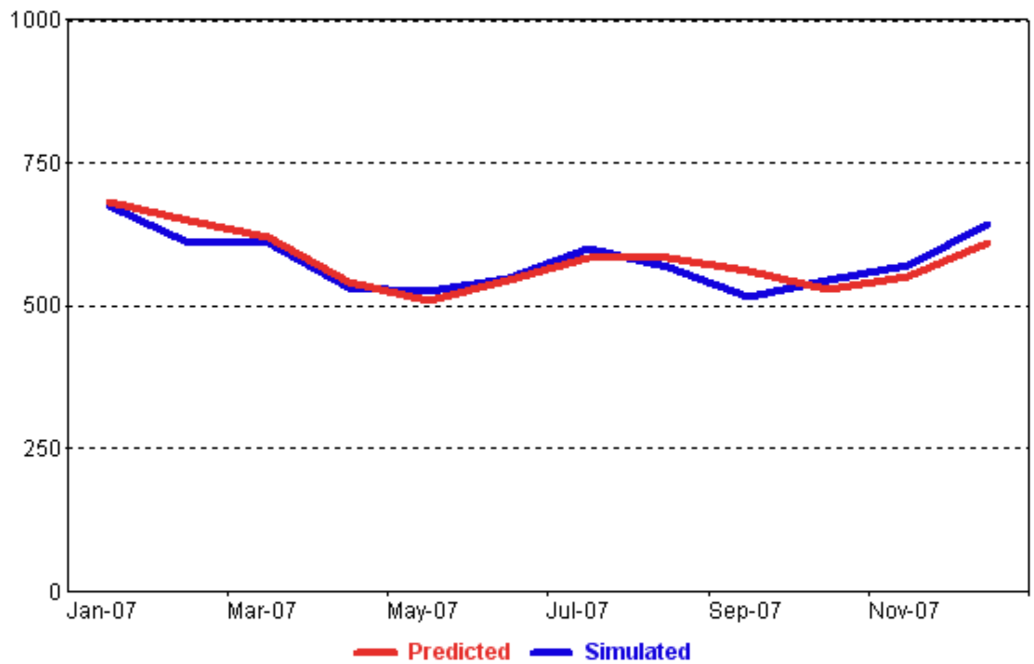

Figure 47: NEH Calendar-Month Simulation (kWh per customer) 2007

Figure 48 shows the simulation results for the CIS TOU revenue class.

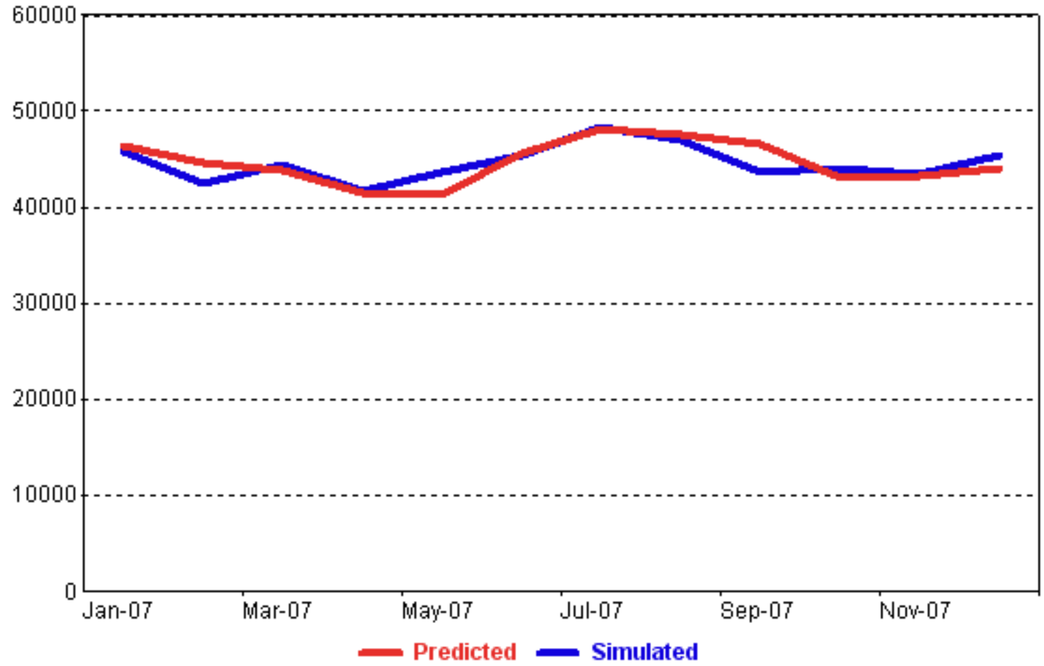

Figure 48: CIS TOU Calendar-Month Simulation (MWh) 2007

The predicted value shows forecasted 2007 billed sales and the simulated value shows forecasted 2007 calendar month sales. Note that the differences in the monthly estimates. Calendar-month sales are lower than billed sales in February as there are fewer calendar days than billing days. Calendar-month sales are also lower in September than billed sales as more than half the billed sales occur in August reflecting the warmer weather conditions. These variances reflect differences in calendar versus revenue-month weather conditions and calendar days versus billing days. Calendar-month sales are somewhat higher than billed-sales in May and July again reflecting differences in the number days and weather conditions.

Calendar-month class sales forecasts are aggregated to a total annual sales forecast and then adjusted for line losses to derive an annual energy forecast. Line loss estimate is derived by comparing the historical annualized sales estimate against system net energy delivery for 2003 to 2005. The estimated loss factor is 5.0%. When adjusted for 5.0% losses, monthly sales are extremely close to actual net system energy as shown in Table 28.

Year	Loss Adjusted Sales	Net System Energy
2003	2,039.1	2,039.6
2004	2,059.1	2,055.2
2005	2,110.2	2,081.7

Table 28: Annualized Sales (Loss Adjusted) Versus Net Energy (GWh)

Table 29 shows resulting long-term energy forecast by customer class.

Year	Residential	Small C&I	Large C&I	IBM & Other	Total
2006	617,051	748,976	221,818	488,164	2,076,009
2011	671,339	786,757	227,327	494,912	2,180,334
2016	740,889	830,021	236,913	496,443	2,304,266
2021	801,368	867,943	246,595	494,952	2,410,858
2026	863,035	911,491	257,729	494,973	2,527,228
Chg					
2006–2011	1.7%	1.0%	0.5%	0.3%	1.0%
2006–2026	1.7%	1.0%	0.8%	0.1%	1.0%

Table 29: Customer Class Energy Forecast (MWh)

Demand Forecast

Demand forecast is derived by combining system energy forecast with system hourly load profile for normal daily weather conditions. An hourly profile model is estimated using four years of system hourly load data. A regression model is estimated for each hour where model variables include:

- HDD
- CDD
- Day of the week
- Month
- Holidays
- Hours of Light

Hourly models explain hourly use reasonably well with Adjusted R^2 that very from 0.82 in the early morning hours to 0.93 in the afternoon hours. Model results are summarized in section 4: Model Statistics and Coefficients.

Figure 49 compares actual and predicted system hourly load shape for August 2005.

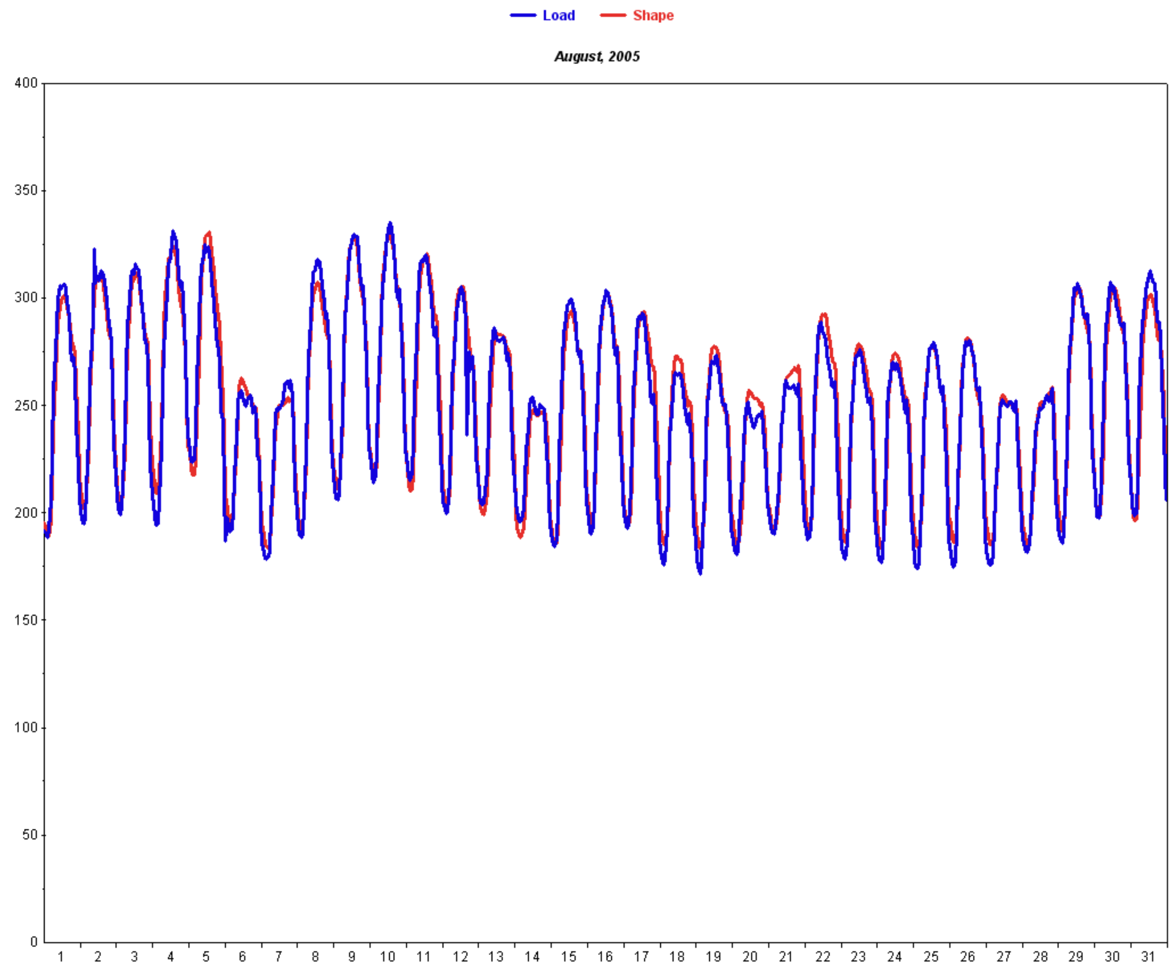

Figure 49: Actual (Blue) and Predicted (Red) System Hourly Load (MW)

The hourly load profile for normal daily weather conditions is combined with the energy forecast to derive the system hourly load forecast. Using MetrixLT, the sales forecast is allocated to each hour based on that hour's percent of total system hourly load. The result is an 8760 hourly load forecast for forecast year.

Figure 50 shows the forecasted hourly profile for 2011.

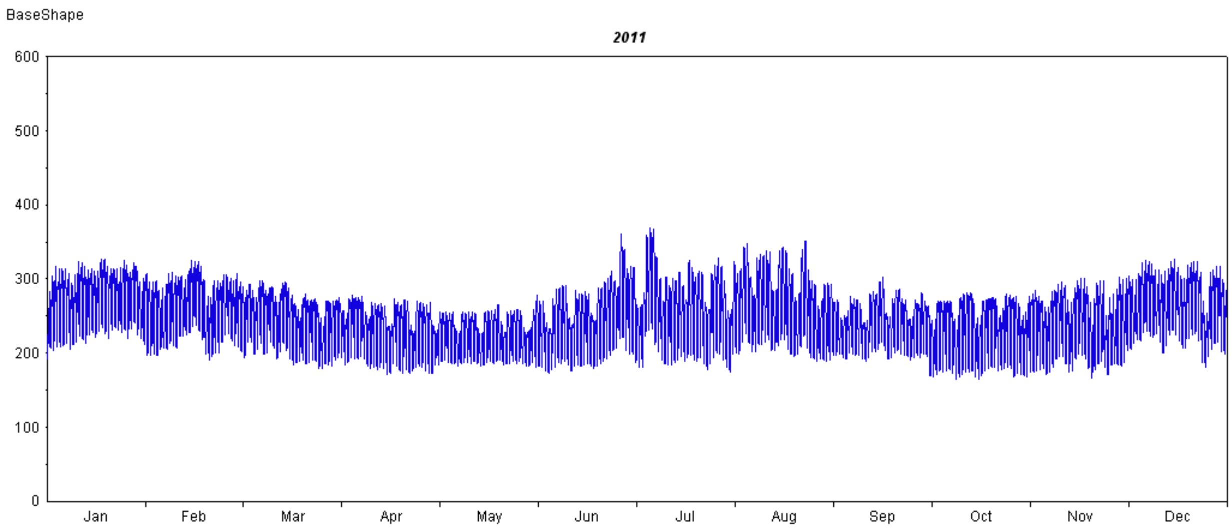

Figure 50: System Hourly Load Forecast 2011 (MW)

Calibration to Actual Peak Demands

The last step is to calibrate model results to actual monthly peak demands. To calibrate peaks, we execute *MetrixLT* over the historical period using actual daily weather conditions and calendar file. The monthly peaks from the models are then calibrated to actual monthly peaks by calculating the average error in each month. In most months, the model tends to under forecast the monthly peak. July required the largest upward adjustment; on average, the model under forecasted July peak by 2.5%. In May and September, the model tended to over forecast the peak; model peaks were calibrated down in these months by 2.0% and 3.0% respectively.

The specific monthly adjustment factors are summarized in Table 30.

Month	Adjustment Factors	Adjustment (%)
January	1.003	0.3%
February	1.016	1.6%
March	1.000	0.0%
April	1.002	0.2%
May	0.978	–2.2%
June	1.005	0.5%
July	1.025	2.5%
August	1.010	1.0%
September	0.970	–3.0%
October	1.015	1.5%
November	1.010	1.0%
December	1.010	1.0%

Table 30: Monthly Peak Adjustment Factors

The monthly adjustment factors are applied to the monthly peak forecast resulting from the initial hourly load models. A final system hourly load forecast is generated by combining the energy forecast, system hourly load profile, and calibrated peaks. Table 31 shows the base-case energy and summer and winter demand forecast.

Year	Energy (GWh)	Winter Peak (MW)	Summer Peak (MW)
2006	2,076	321.5	366.7
2011	2,180	327.3	368.2
2016	2,304	344.5	387.6
2021	2,411	361.1	406.5
2026	2,527	378.1	425.8
Chg 2006–2026	1.0%	0.8%	0.7%

Table 31: Base-Case Energy and Demand Forecast

Forecast Scenarios

Both a high and a low forecast scenarios were ran as part of the analysis. The high forecast assumes stronger economic growth and decline in real prices, while the low forecast is based on slower economic activity and increase in real price. Table 32 through Table 36 compare the primary economic assumptions for the three forecasts – high, base, and low case.

Year	High	Base	Low
2006	77.18	77.18	77.18
2011	82.78	80.88	79.02
2016	88.78	84.82	80.89
2021	95.22	87.41	82.81
2026	102.13	89.26	84.77
Chg 2006–2026	1.4%	0.7%	0.5%

Table 32: Number of Households (thousands)

Year	High	Base	Low
2006	80.95	80.95	80.95
2011	87.60	86.01	83.12
2016	94.79	90.10	85.35
2021	102.57	95.25	87.63
2026	110.98	101.09	89.98
Chg 2006–2026	1.6%	1.1%	0.5%

Table 33: Real Household Income (thousands $/household)

Year	High	Base	Low
2006	7,773	7,773	7,773
2011	9,161	8,689	8,214
2016	10,796	9,707	8,680
2021	12,723	10,734	9,173
2026	14,995	11,916	9,693
Chg			
2006–2026	3.3%	2.2%	1.1%

Table 34: Regional Output (millions $)

Year	High	Base	Low
2006	105	105	105
2011	112	109	108
2016	120	115	110
2021	127	120	112
2026	136	126	114
Chg			
2006–2026	1.3%	0.9%	0.4%

Table 35: Employment (thousands)

Year	High	Base	Low
2006	0.091	0.091	0.091
2011	0.086	0.091	0.089
2016	0.081	0.086	0.087
2021	0.077	0.080	0.086
2026	0.073	0.075	0.084
Chg			
2006–2026	–1.1%	–0.9%	–0.4%

Table 36: Real Electric Price ($/kWh)

The economic scenarios were developed by evaluating historical periods of high and low economic growth. Late 1990s to recent years saw some of the strongest economic growth experienced in Vermont. Similarly, some of the slowest economic growth was experienced between 1990 and 1995. We assume that these periods of strong and weak growth could potentially occur in the future and use economic growth rates from these periods to construct our high and low economic scenarios. Table 37 compares the energy forecast for the three scenarios and Table 38 shows the resulting peak demands for the three scenarios.

Year	High Case	Base Case	Low Case
2006	2,076	2,076	2,076
2011	2,237	2,180	2,144
2016	2,415	2,304	2,213
2021	2,604	2,411	2,276
2026	2,828	2,527	2,352
Chg			
2006–2026	1.6%	1.0%	0.6%

Table 37: Energy Forecast (GWh)

Year	High Case	Base Case	Low Case
2006	366.68	366.68	366.68
2011	377.69	368.16	361.96
2016	406.21	387.64	372.21
2021	439.06	406.46	383.77
2026	476.37	425.75	396.24
Chg			
2006–2026	1.3%	0.7%	0.4%

Table 38: Demand Forecast Comparison (MW)

Figure 51 shows the demand trend for the three scenarios.

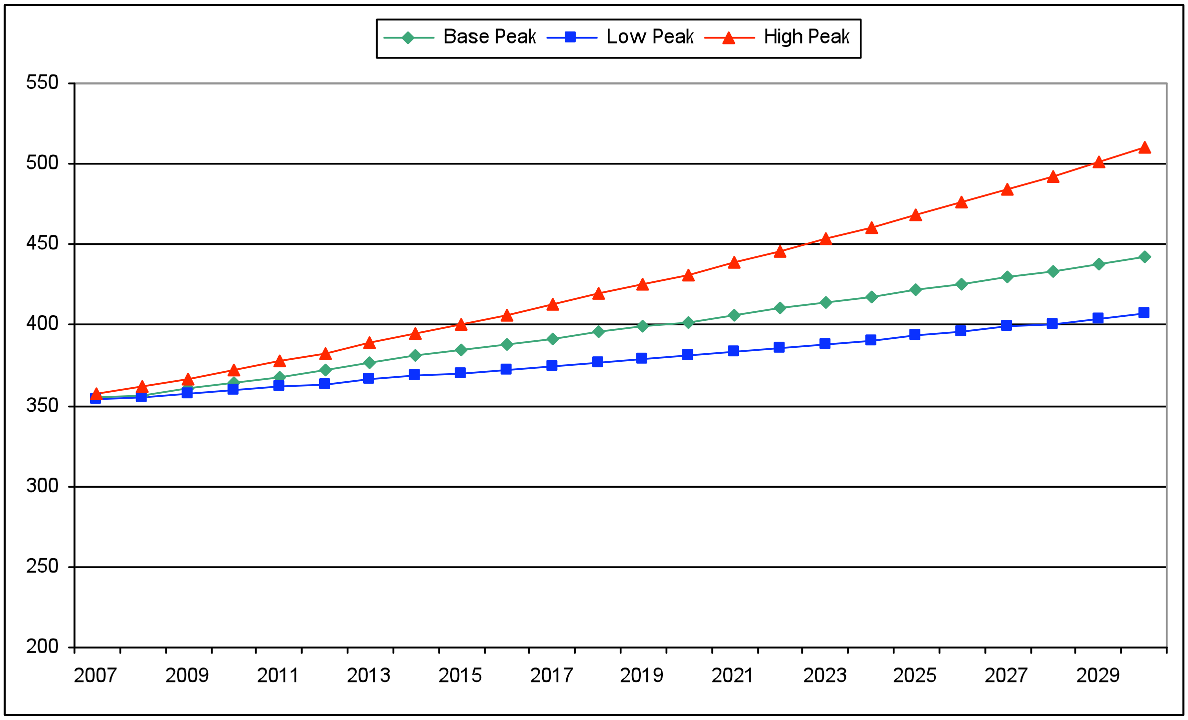

Figure 51: Demand Forecast Scenarios (MW)

Model Statistics and Coefficients

Statistic	Value
Iterations	1.00
Adjusted Observations	115.00
Deg. of Freedom for Error	102.00
R-Squared	0.901
Adjusted R-Squared	0.889
Durbin-Watson Statistic	1.938
AIC	6.063
BIC	6.373
F-Statistic	77.301
Prob (F-Statistic)	0.00
Log-Likelihood	–494.47
Model Sum of Squares	358485.00
Sum of Squared Errors	39419.00
Mean Squared Error	386.46
Std. Error of Regression	19.66
Mean Abs. Dev. (MAD)	14.51
Mean Abs. % Err. (MAPE)	2.52%
Ljung-Box Statistic	59.12
Prob (Ljung-Box)	0.0001

Variable	Coefficient	StdErr	T-Stat	P-Value
CONST	87.625	55.445	1.58	11.72%
NEH_RevVars.XHeat	0.569	0.033	17.011	0.00%
NEH_RevVars.XCool	0.396	0.032	12.407	0.00%
NEH_RevVars.XOther	0.831	0.119	6.981	0.00%
BinT.Jan01	–47.994	20.534	–2.337	2.14%
BinT.Jun03	85.869	20.145	4.263	0.00%
BinT.Dec03	105.459	19.941	5.288	0.00%
BinT.Aug05	62.294	20.62	3.021	0.32%
BinT.Sep05	48.033	20.303	2.366	1.99%
BinT.Mar06	–63.194	19.997	–3.16	0.21%
BinT.Nov	–28.037	7.306	–3.837	0.02%
BinT.Apr	–34.825	6.89	–5.055	0.00%
BinT.May	–24.806	7.265	–3.414	0.09%

Table 39: NEH Average Use Model Statistics and Coefficients

Statistic	Value
Iterations	7.00
Adjusted Observations	114.00
Deg. of Freedom for Error	106.00
R-Squared	0.953
Adjusted R-Squared	0.95
Durbin-Watson Statistic	2.106
AIC	7.7
BIC	7.892
F-Statistic	304.831
Prob (F-Statistic)	0.00
Log-Likelihood	–592.67
Model Sum of Squares	4405030.00
Sum of Squared Errors	218826.00
Mean Squared Error	2064.39
Std. Error of Regression	45.44
Mean Abs. Dev. (MAD)	31.64
Mean Abs. % Err. (MAPE)	4.45%
Ljung-Box Statistic	30.8
Prob (Ljung-Box)	0.1597

Variable	Coefficient	StdErr	T-Stat	P-Value
CONST	262.57	143.883	1.825	7.09%
WtHt_RevVars.XOther	0.548	0.308	1.781	7.79%
WtHt_RevVars.XHeat	1.806	0.093	19.408	0.00%
WtHt_RevVars.XCool	0.501	0.07	7.112	0.00%
BinT.Feb01	140.275	41.893	3.348	0.11%
BinT.Dec03	217.914	40.909	5.327	0.00%
BinT.Y2000	–348.097	24.21	–14.378	0.00%
AR(1)	0.514	0.085	6.028	0.00%

Table 40: EH – H_20 Average Use Model Statistics and Coefficients

Statistic	**Value**
Iterations	5.00
Adjusted Observations	115.00
Deg. of Freedom for Error	111.00
R-Squared	0.998
Adjusted R-Squared	0.998
Durbin-Watson Statistic	2.823
AIC	11.244
BIC	11.339
F-Statistic	23606.042
Prob (F-Statistic)	0.00
Log-Likelihood	–798.68
Model Sum of Squares	5228513141.00
Sum of Squared Errors	8195147.00
Mean Squared Error	73830.16
Std. Error of Regression	271.72
Mean Abs. Dev. (MAD)	180.78
Mean Abs. % Err. (MAPE)	0.23%
Ljung-Box Statistic	80.19
Prob (Ljung-Box)	0.00

Variable	**Coefficient**	**StdErr**	**T-Stat**	**P-Value**
CONST	–49251.989	33665.99	–1.463	14.64%
Economics.Households	1642.704	442.939	3.709	0.03%
BinT.Y2000	21714.883	195.988	110.797	0.00%
AR(1)	0.945	0.032	29.9	0.00%

Table 41: Residential Customer Model Statistics and Coefficients

Statistic	Value
Iterations	5.00
Adjusted Observations	115.00
Deg. of Freedom for Error	111.00
R-Squared	1.00
Adjusted R-Squared	1.00
Durbin-Watson Statistic	2.417
AIC	9.24
BIC	9.335
F-Statistic	161859.5
Prob (F-Statistic)	0.00
Log-Likelihood	–684.46
Model Sum of Squares	4.83E+09
Sum of Squared Errors	1104758.00
Mean Squared Error	9952.78
Std. Error of Regression	99.76
Mean Abs. Dev. (MAD)	68.58
Mean Abs. % Err. (MAPE)	0.28%
Ljung-Box Statistic	77.9
Prob (Ljung-Box)	0.00

Variable	Coefficient	StdErr	T-Stat	P-Value
CONST	37693.82	953.216	39.544	0.00%
Economics.Households	–196.109	12.753	–15.377	0.00%
BinT.Y2000	21096.02	57.554	366.545	0.00%
AR(1)	0.586	0.078	7.537	0.00%

Table 42: EH – H_20 Customer Model Statistics and Coefficients

Statistic	Value
Iterations	9.00
Adjusted Observations	115.00
Deg. of Freedom for Error	93.00
R-Squared	0.947
Adjusted R-Squared	0.935
Durbin-Watson Statistic	2.01
AIC	6.93
BIC	7.455
F-Statistic	79.506
Prob (F-Statistic)	0.00
Log-Likelihood	–534.95
Model Sum of Squares	1439708.00
Sum of Squared Errors	80194.00
Mean Squared Error	862.3
Std. Error of Regression	29.36
Mean Abs. Dev. (MAD)	21.08
Mean Abs. % Err. (MAPE)	1.63%
Ljung-Box Statistic	38.49
Prob (Ljung-Box)	0.0309

Variable	Coefficient	StdErr	T-Stat	P-Value
CONST	830.834	120.039	6.921	0.00%
RevVars.GenServ_XHeat	0.782	0.127	6.145	0.00%
RevVars.GenServ_XCool	0.189	0.042	4.49	0.00%
RevVars.GenServ_XOther	0.256	0.106	2.428	1.72%
Bin.BefApr02	98.73	15.312	6.448	0.00%
Bin.Jan00	–697.648	26.55	–26.277	0.00%
Bin.Mar00	59.583	26.653	2.236	2.78%
Bin.Apr01	–70.976	25.897	–2.741	0.74%
Bin.Jan02	–88.93	26.59	–3.344	0.12%
Bin.Mar02	–96.753	27.522	–3.516	0.07%
Bin.Jun03	164.107	26.117	6.284	0.00%
Bin.Sep03	–112.198	26.42	–4.247	0.01%
Bin.Dec03	167.701	25.889	6.478	0.00%
Bin.Jan	103.675	13.387	7.744	0.00%
Bin.Feb	88.581	13.704	6.464	0.00%
Bin.Mar	70.317	12.134	5.795	0.00%
Bin.May	–43.644	8.761	–4.982	0.00%
Bin.Jul	81.189	18.51	4.386	0.00%
Bin.Aug	109.581	21.84	5.017	0.00%
Bin.Sep	99.541	14.492	6.868	0.00%
Bin.Nov	–55.187	8.65	–6.38	0.00%
AR(1)	0.637	0.082	7.775	0.00%

Table 43: GS Average Use Model Statistics and Coefficients

Statistic	Value
Iterations	7.00
Adjusted Observations	115.00
Deg. of Freedom for Error	108.00
R-Squared	0.997
Adjusted R-Squared	0.997
Durbin-Watson Statistic	1.42
AIC	8.297
BIC	8.464
F-Statistic	5234.812
Prob (F-Statistic)	0.00
Log-Likelihood	–627.73
Model Sum of Squares	1.39E+08
Sum of Squared Errors	408314.00
Mean Squared Error	3780.69
Std. Error of Regression	61.49
Mean Abs. Dev. (MAD)	38.89
Mean Abs. % Err. (MAPE)	0.34%
Ljung-Box Statistic	19.57
Prob (Ljung-Box)	0.7207

Variable	Coefficient	StdErr	T-Stat	P-Value
EconT.NonMan_Empl	132.873	1.032	128.713	0.00%
Bin.Nov98	–167.775	44.962	–3.731	0.03%
Bin.Jan99	196.98	44.935	4.384	0.00%
Bin.Jan00	10688.62	44.896	238.074	0.00%
Bin.Jan01	–250.509	45.147	–5.549	0.00%
Bin.Jan03	–111.344	44.897	–2.48	1.47%
AR(1)	0.937	0.032	29.064	0.00%

Table 44: General Service Customers Statistics and Coefficients

Statistic	Value
Iterations	15.00
Adjusted Observations	114.00
Deg. of Freedom for Error	95.00
R-Squared	0.94
Adjusted R-Squared	0.928
Durbin-Watson Statistic	2.185
AIC	13.579
BIC	14.035
F-Statistic	82.325
Prob (F-Statistic)	0.00
Log-Likelihood	–916.75
Model Sum of Squares	1005510271.00
Sum of Squared Errors	64462665.00
Mean Squared Error	678554.37
Std. Error of Regression	823.74
Mean Abs. Dev. (MAD)	601.49
Mean Abs. % Err. (MAPE)	1.38%
Ljung-Box Statistic	32.13
Prob (Ljung-Box)	0.1238

Variable	Coefficient	StdErr	T-Stat	P-Value
CONST	12404.062	2609.776	4.753	0.00%
RevVars.TOU_XHeat	0.432	0.08	5.431	0.00%
RevVars.TOU_XCool	0.205	0.018	11.522	0.00%
RevVars.TOU_XOther	0.775	0.065	11.873	0.00%
Bin.Bef00	–2544.245	406.287	–6.262	0.00%
Bin.BefApr03	1797.944	436.265	4.121	0.01%
Bin.Apr	–1998.699	278.558	–7.175	0.00%
Bin.May	–1882.277	284.18	–6.624	0.00%
Bin.Nov	–1174.875	255.668	–4.595	0.00%
Bin.Jun98	3208.655	826.184	3.884	0.02%
Bin.Jul98	–4918.228	813.376	–6.047	0.00%
Bin.Sep98	3770.47	816.442	4.618	0.00%
Bin.Oct98	–3161.707	826.908	–3.824	0.02%
Bin.Apr01	–1907.901	773.248	–2.467	1.54%
Bin.Jun03	4214.206	769.929	5.473	0.00%
Bin.Sep03	–2805.488	741.178	–3.785	0.03%
Bin.Sep04	2806.304	748.085	3.751	0.03%
Bin.YrAfter2004	–779.158	487.799	–1.597	11.36%
AR(1)	0.52	0.092	5.67	0.00%

Table 45: Time-of-Use Sales Model Statistics and Coefficients

Statistic	Value
Iterations	9.00
Adjusted Observations	91.00
Deg. of Freedom for Error	81.00
R-Squared	0.991
Adjusted R-Squared	0.99
Durbin-Watson Statistic	1.59
AIC	5.294
BIC	5.57
F-Statistic	962.825
Prob (F-Statistic)	0.00
Log-Likelihood	–356.05
Model Sum of Squares	1556295.00
Sum of Squared Errors	14547.00
Mean Squared Error	179.6
Std. Error of Regression	13.4
Mean Abs. Dev. (MAD)	9.53
Mean Abs. % Err. (MAPE)	0.62%
Ljung-Box Statistic	29.69
Prob (Ljung-Box)	0.1952

Variable	Coefficient	StdErr	T-Stat	P-Value
CONST	–1156.46	356.568	–3.243	0.17%
EconT.Ttl_Empl	24.723	3.465	7.135	0.00%
Bin.Jul_Dec02Trend	104.351	6.392	16.324	0.00%
Bin.Nov01_Feb01_Trend	54.944	7.469	7.357	0.00%
Bin.AftYr03	–79.904	11.411	–7.002	0.00%
Bin.AftFeb02	230.985	11.397	20.268	0.00%
Bin.July02	–41.854	11.491	–3.642	0.05%
Bin.Dec03	–81.452	12.475	–6.529	0.00%
Bin.Jan06	–39.157	11.168	–3.506	0.08%
AR(1)	0.687	0.085	8.088	0.00%

Table 46: Time-of-Use Customers Model Statistics and Coefficients

Statistic	Value
Iterations	6.00
Adjusted Observations	115.00
Deg. of Freedom for Error	94.00
R-Squared	0.923
Adjusted R-Squared	0.907
Durbin-Watson Statistic	2.061
AIC	13.709
BIC	14.21
F-Statistic	56.689
Prob (F-Statistic)	0.00
Log-Likelihood	–922.34
Model Sum of Squares	865191871.00
Sum of Squared Errors	71731735.00
Mean Squared Error	763103.56
Std. Error of Regression	873.56
Mean Abs. Dev. (MAD)	597.4
Mean Abs. % Err. (MAPE)	4.19%
Ljung-Box Statistic	33.9
Prob (Ljung-Box)	0.0865

Variable	Coefficient	StdErr	T-Stat	P-Value
CONST	14389.467	2496.949	5.763	0.00%
Bin.AftApr03	2815.756	527.562	5.337	0.00%
Bin.Yr06Plus	1363.443	582.983	2.339	2.15%
Bin.Jan	–2092.068	366.56	–5.707	0.00%
Bin.Feb	–4732.331	431.542	–10.966	0.00%
Bin.Mar	–6801.251	457.459	–14.867	0.00%
Bin.Apr	–7985.627	459.713	–17.371	0.00%
Bin.May	–7839.02	463.416	–16.916	0.00%
Bin.Jun	–7059.545	463.738	–15.223	0.00%
Bin.Jul	–6644.836	461.628	–14.394	0.00%
Bin.Aug	–6183.693	456.321	–13.551	0.00%
Bin.Sep	–6855.219	450.219	–15.226	0.00%
Bin.Oct	–7521.705	423.173	–17.775	0.00%
Bin.Nov	–4704.146	367.814	–12.789	0.00%
Bin.KimberlyLoss	–1323.068	537.496	–2.462	1.57%
Bin.Nov97	2942.738	847.539	3.472	0.08%
Bin.Dec98	–2567.806	852.507	–3.012	0.34%
Bin.Mar00	2609.819	846.138	3.084	0.27%
Bin.Feb02	2658.578	849.201	3.131	0.23%
Economics.GRP	747.795	402.729	1.857	6.65%
AR(1)	0.455	0.087	5.228	0.00%

Table 47: Commercial and Industrial Large Sales Model Statistics

Appendices
A: 2007 Long-Term Energy and Peak Forecasts

B: Energy Efficiency Forecasts

How Energy Efficiency Savings Were Forecast

To develop the energy savings forecasts, we at Green Mountain Power began by examining Efficiency Vermont's original budget and goals for 2006 to 2008. From this information, we correlated a connection between spending and savings. We then used this correlation as a reference to determine the effects that increasing or decreasing the budget would have on energy savings. Over a wide range, the correlation between spending and savings is not linear. Because of this, we also examined the information Efficiency Vermont presented at the PSB workshops concerning the savings that could achieve under various funding levels. With this information as well as the current budget and savings information, we devised savings forecasts for each scenario.

This table depicts the correlations between budget and savings for the energy efficiency savings forecasts in each scenario; and, with the exception of the Green Focus scenario (which assumes geotargeting funding never decreases), the table also depicts the correlation between funding and savings absent the effects of geotargeting. (We discuss the effects of geotargeting later in the report.)

Scenario	Budget as a Percentage of Current EVT Budget	Savings as a Percentage of Current Savings Goals
Fortress America	130%	133%
Green Focus	179%	178%
Back to Business	66%	66%
Green Growth	100%	100%

Table 48: Correlations of Budgets to Energy Efficiency Savings

Estimating GMP's Share of the Energy Efficiency Savings

We began by developing all the energy efficiency savings forecasts at a statewide[23] level.

Each of the past Efficiency Vermont annual reports contained summer peak, winter peak, and annual energy savings totals. Each report also breaks down the savings achieved in each utility's service area. From this formation, we calculated the percentage of statewide savings attributed to GMP's service area. We then applied these percentages to the statewide savings forecasts to forecast GMP's energy efficiency savings.

The table below shows the percentage of statewide savings achieved in GMP service area (using the method discussed above). We used these percentages to determine GMP's energy efficiency forecasts.

Savings Metric	GMP's Percentage of Statewide Savings
Summer Peak	35%
Winter Peak	31%
Annual Energy	31%

Table 49: GMP's Percentage of Statewide Savings

Geotargeting Funding and its Impacts on the Energy Efficiency Forecasts

On 2 August 2006, the Public Service Board ordered increased funding for the EEU from 2006 through 2008. Subsequently, results from PSB workshops concluded that this increased funding would be targeted at specific geographic areas where reductions in load could have the added benefit of deferring or eliminating the need for transmission or distribution upgrades that serve the targeted areas. This strategy for deploying energy efficiency funds in this manner is called "geotargeting".

Not all utility service areas will be geotargeted with the additional funding, however, an area within GMP's service area was selected for geotargeting. Therefore, we estimated the impacts geotargeting would have on GMP's energy savings forecasts.

Since the beginning of 2007, Efficiency Vermont was still developing specific savings goals for geotargeting. Most likely, savings achieved from geotargeting would not begin until mid-2007. Thus, it became necessary for us to develop an estimate of geotargeting based on the information Efficiency Vermont presented at the PSB's workshops, then incorporate those estimates into our forecasts. We also had to account for the delay in geotargeting savings. To account for this delay, we made two assumptions: first, that some of the savings from the three year geotargeting budget would not be realized until 2009; and second, that a focused effort is required to apply all three years' of the increased funding

[23] Statewide savings refers to savings achieved by Efficiency Vermont and does not include Burlington Electric Department savings.

by the end 2008 or early 2009, thus resulting in a spike in savings in 2008 and to a lesser savings in 2009.

Decay of Energy Efficiency Savings and Its Effect on the Forecast

When forecasting energy efficiency savings, we must account for a decay in energy savings as energy efficiency measures mature (reach the end of their lives). We considered this decaying effect in all energy efficiency forecasts in this Integrated Resource Plan[24]. As can be inferred, the effect of decay on the forecasts causes the cumulative annual savings rate in future years to taper off.

The amount of decay increases each year as more of each past year's savings decay and is applied to the current year's incremental savings. The compound effect of multiple years of decay diminishes the impact that the current year's savings has on the cumulative savings. Thus, decay can be overstated from years 10 to 20. Although the funding levels remain the same and the current year incremental savings is constant, the net effect of that year's savings on the cumulative forecast diminishes.

Although not explicitly implied, the compounding effect of decay could also represent the impact that energy efficiency programs have at transforming the market at a pace greater than advancements in energy efficiency technology. As a result, smaller annual incremental gains in energy efficiency savings are realized in future years.

Regardless of how the diminishing impact of future savings is determined, decay must be somehow accounted for in forecasts.

[24] Efficiency Vermont provide the decay rates used in forecasts.

Seasonal On and Off Peak Breakdown of Annual Energy Savings Forecast

We incorporated an aggregate energy efficiency savings load shape to develop a seasonal on- and off-peak breakdown of the annual energy savings forecast. To develop this load shape, we used the energy savings by end-use information contained in Efficiency Vermont annual reports and the specific load shapes found in the Technical Resource Manual maintained by Efficiency Vermont.

This table depicts how seasonal on- and off-energy savings are distributed as a percentage of annual energy savings for both business and residential customers.

	Winter On-Peak	Winter Off-Peak	Summer On-Peak	Summer Off-Peak
Business	25.4%	8.2%	43.1%	23.2%
Residential	28.2%	9.0%	34.4%	28.3%

Table 50: Seasonal Breakdown of Annual Energy Savings

We applied these percentages to the business and residential total annual energy savings forecasts to determine the seasonal on- and off-peak values. We then added together both these values to determine the total value for each seasonal on- and off-forecast.

C: ISO New England's Forward Capacity Markets

Overview

As a load serving entity, GMP will face obligations associated with ISO-NE's Forward Capacity Market (FCM). This appendix is intended to summarize key features of the FCM.

The essence of the FCM is for ISO-NE to procure needed capacity through a descending clock auction, three years prior to the Commitment year in which the capacity would be needed. All capacity must bid into the auction but only "new" capacity, with some exceptions, can set the clearing price. Additionally, a local requirement will be implemented in constrained zones, for which a separate auction will be conducted. This auction process is intended to address the problems of insufficient price levels to support new capacity and long-term price uncertainty. Therefore, the annual auction should typically drive prices towards the Cost of New Entry (CONE).

The FCM structure was designed to achieve two objectives: (1) to provide a market structure that will encourage needed capacity to be built and (2) to allow new capacity to set the clearing price, thus providing a market-based measure of the need for new investment. There will be an initial transition period, during which all capacity is paid a set price and RMR units continue to be paid supplemental revenues.. The first auction for FCM will take place in 2008 for the Commitment Year 2010/2011. The details of the transition period and the FCM auction are described in the next two sections.

Transition Period

The transition period will last from December 2006 to June 1, 2010, during which, all capacity would receive payment according to the schedule in the table below. Market rules for the existing installed capacity market will apply and the capacity that is paid is based on unforced capacity (UCAP) on a seasonal basis with weighted EFORd.

Transition Period	**Capacity Payment $/kW-month**
December 2006–May 2008	$3.05
June 2008–May 2009	$3.75
June 2009–May 2010	$4.10

Table 51: Transition Period Capacity Payment Schedule

Forward Capacity Market

The Forward Capacity Market will procure capacity 3-years prior to a "Commitment Year" in order to provide adequate time and incentive for new capacity to be built. The capacity product may be supplied by many types of resources including New Capacity, Existing Capacity, Intermittent Resources, and Demand Side Resources.

The FCM is a central procurement of capacity where ISO New England procures on behalf of all load in the region. The costs of the procurement are then charged to load serving entities.. Load serving entities that own capacity will be able to self supply their capacity under limited conditions. Load serving entities will also be able to buy capacity bilaterally. The details of how bilateral transactions will be handled is also under development.

The FCM is based on a declining clock auction. The way a descending clock auction works is that if more resources are bid than are needed to meet Installed Capacity Requirement (ICR), the price is lowered and bidding begins again. The auction continues by lowering prices and bidding of capacity until the Qualified Capacity of Resources bid equals ICR. The theory is that multiple bidders would be able to drive prices to an economically efficient level. This, of course, assumes there is an excess of existing and new capacity under development to meet the ICR prior to the auction period.

The basic details of the FCM are described below.

Auction Parameters

- The first auction is slated to take place at the end of February 1, 2008 for the "Commitment Period" beginning June 2010 and another for June 2011 shortly thereafter.
- The duration of the supply commitment period coincides with the June-to-May Power Year and is one year for all existing capacity, while new capacity may choose a Commitment period of up to five years.

Capacity Requirements

- Annual auction to procure 100% of forecasted ICR.
- There local source requirements (LSR) for transmission constrained areas. LSR and Capacity Transfer Limits will be calculated using a reliability model, like the GE Maps, and will be published prior to the auction. As in the Transition period, the level of capacity payment paid to a qualified resource will be directly tied to the performance of the resource, not the capacity that is bid. The assessment will continue to emphasize availability during periods when capacity resources are determined to be most needed due to conditions on the system.

Cost of New Energy (CONE)

- Cost of New Entry (CONE) is set at $7.50/kilowatt-month for the first auction. CONE is the estimated installation cost of a new frame type combustion turbine. Future CONE would be based on a formula using clearing prices of previous auctions.
- Descending clock auction used to set the Capacity Clearing Price beginning at 2 x CONE ($15/kilowatt-month).
- Price collar in first three auctions will be 1.4x to 0.6 x CONE ($4.50 to $10.50 in first year)

Capacity Clearing Price

- Only "new" capacity will be allowed to set the Clearing Price of the auction, with a few exceptions.
- Existing Capacity's De-list Bids[25], Export Bids[26], and Permanent De-list Bids[27], and Imports[28] are eligible to set the Capacity Clearing Price only within specified limits (see Market Mitigation section below)

[25] De-list units are existing capacity wishing to opt out of the capacity market who submit a De-list Bid. Such resources can offer capacity in reconfiguration auctions. If a capacity resource's De-list Bid is accepted, that resource may still participate in all other markets. During any round of the descending clock auction, any existing resource can offer to delist all or a portion of its capacity (including a partial De-list bid) if the De-list Bid is offered at or below 0.8 times CONE. Such an offer is eligible to set the Capacity Clearing Price.

[26] Export bids offered into the auction will be treated the same as De-list Bids except that they must also indicate the interface over which the capacity will be exported, and the interface is binding.

[27] Permanent De-list units can set the price of the auction up to 1.25xCONE without triggering a review. However, once accepted the units can not participate in future auctions unless it qualifies as a "New" unit.

[28] Capacity that a party wishes to import that may or may not be under a multi-year contract entered into prior to the auction date. If entered prior, the resource is considered Existing Capacity and if there is not a contract yet, the capacity would be considered New Capacity.

- If the Capacity Clearing Price falls below the level of a de-list bid, the existing capacity submitting that bid will be allowed to de-list all or a portion of a Resource unless the absence of the resource would produce reliability problems, in which case the Resource will be entitled to just and reasonable compensation but will *not* set the Capacity Clearing Price.

"New" Capacity

- To be considered "New", the unit must never have been listed as a capacity resource prior to the auction.
- Once the new capacity clears the market, it may choose a "Commitment Period" of up to five years. New capacity suppliers that win the auction are entitled to a one-time option to lock-in capacity prices for up to five years. New suppliers are given this option because it gives investors predictable revenues streams during the project's early years and should facilitate project financing.
- Multiple financial assurances[29] have been put in place to ensure new capacity is built and available during critical periods.
- Existing resources can qualify as New Capacity if they undertake specified types of major investments to upgrade.

Peak Energy Rent

- A hypothetical unit's Peak Energy Rent will be used to offset cleared capacity prices. It provides a hedge for load against price spikes in the energy market and acts as a disincentive for suppliers to exercise market power.[30]

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[29] In order to submit a bid, New Capacity must provide a deposit equal to $2/kW times the amount of its bid which would count toward it financial assurance if accepted. Upon receiving an award from the auction, the New Capacity must then provide additional financial assurances equal to CONE*Capacity at three separate times (for a total of three times CONE*Capacity): (1) within 5 business days following announcement of winners (2) at least 15 days prior to next annual auction after the initial auction, and (3) at least 15 days prior to the second annual auction following the initial auction. For example, the total payment for a 100 MW unit at $7.50/kW-month CONE, would be $2,250,000 (3x100x$7.50).

[30] The PER deduction is determined by calculating the difference between the real time energy price and a strike price derived from the incremental hypothetical cost of a proxy unit. In addition, the PER is converted to a 12-month rolling average and is subtracted from monthly capacity payments.

Reconfiguration Auction

- Reconfiguration auctions will be held after an initial auction for each Commitment Period so planners may reassess changes in requirements due to unexpected retirements or transmission changes. Suppliers and traders can buy, sell, and exchange capacity obligations.

  "The FCM provides for an annual reconfiguration auction two years, one year, and just prior to the Commitment Periods and twice-yearly seasonal auctions and monthly auctions just prior to and during each Commitment Period."

Market Mitigation

- The Insufficient Competition rule sets prices for capacity resources if the system is short of capacity, the total amount of new capacity bid is small, and any of the new capacity bid is needed to meet ICR (or local sourcing requirement, if applicable). If the Insufficient Competition rule is triggered, then new capacity resources are paid the Capacity Clearing Price and existing capacity resources are paid the lower of the Capacity Clearing Price or 1.1xCONE.
- The internal Market Monitor will review bids when they exceed certain thresholds. For example, if a De-list bid is higher than 0.8xCONE, a review of the resource's going-forward costs will be triggered. Likewise, if new capacity bids below 0.75xCONE, it will also trigger a review.
- Permanent De-list units that bid below 1.25xCONE will be eligible to set the price of the auction. However, once accepted the units can not participate in future auctions unless it qualifies as a "New" unit.

Issues Under Development

Following on the FERC order issued in April there are a number of details within the FCM implementation that need further refinement. Specifically, the FERC required:

Interconnection Queue Process and FCM. The make a filing with the FERC by or before September 1, 2007, after consultation with NEPOOL and NECPUC, setting forth the order of priority in which it will consider important FCM issues. The FERC noted that while it would not itself prioritize issues for the region, "we believe the interconnection queue issue is of sufficient importance to merit, at the very least, a position near the top of any list of priority." *PP 68-70.*

De-List Bids Rejected for Reliability Reasons / Reliability Agreements. The FERC supported a proposal for a future stakeholder process to determine the method of compensation for units seeking to de-list for reliability reasons.

Market Monitor Review of De-List Bids. FERC required ISO in its September 1 filing to modify the FCM rules to increase the role of the Market Monitoring function in the FCM process.

Seasonal Demand Resources. FERC upheld the ISO's use of composite bids but directed ISO to file a report by July 15, 2007 on the status of the composite bid process. The FERC also directed ISO to initiate a stakeholder process on this issue to insure the best use of these resources in the FCM.

HQ Interconnection. FERC required ISO in its September 1 filing to modify the FCM rules so that the maximum amount of import capacity contracts accepted in the auction over the HQ interconnection should be limited to the total available capacity of the line minus the value of extant HQICCs.

In addition to these required changes, as the ISO implements software and operational procedures to support the FCM design additional changes will need to occur in many other areas of the rule. However, to the extent that these changes materially affect the stakeholders it is envisioned that they will be fully vetted in the committee process.

D: Impact of Expenditures on Cost and Availability of Capital

The goals of this financial analysis are to:

- Determine the effects of various supply resources and alternative financing structures on GMP's creditworthiness.
- Find the best way to assure that resource portfolios are financially feasible.

Financial Issues requiring consideration

The following factors limit access to investment capital, including collateral costs and limits for purchased power:

- Capital investments: our needs over planning horizon
- Purchase power and fuel costs as a percentage of all costs
- Ownership versus unit entitlements versus long-term PPAs versus short-term market purchases
- Renewable energy-based generation
- Capital intensity: utility capital as a percentage of net present value costs
- Credit exposure as a percent of capitalization
- Use of project specific versus general financing
- Effect of pledging assets or cash flows (revenues)

Here is some specific data about GMP's financial situation:

Description	**Position**
GMP cost of debt	7.0%
GMP cost of equity	10.25%
GMP bond rating	bbb
Relationship between bond rating and non-recourse debt capacity ("elasticity")	.006 * change in category * total capital
Relationship between bond rating and ROE and rate on debt	60 basis points per category
Relationship between allowed ROE or coverage ratios and bond rating	-.011 * dividend ratio + 1.43 * ebit to interest coverage ratio -.018 * debt to capital ratio (based on a linear relationship)

Table 52: Specifics on GMP's Financial Situation

There is a time lag in the above relationships (for example, it takes three months for bond ratings to respond to changes).

Current Topics in Bond Ratings and Finance

Imputed Debt

Rating agencies treat PPAs as "imputed debt". They assign to the balance sheet a proxy debt number that represents an approximation of the liability GMP would take on if rather than entering into a long-term supply contract it had built generation. This has the very pragmatic effect of permitting those companies financial ratios to be compared directly against companies that actually do incur debt and own generation. Rating agencies admit it's not a perfect system but maintain that some adjustment is needed for their purpose. They hint at improvements being made to the method.

The problem for utilities is that while a PPA appears like a way to stay unencumbered by ownership issues, in fact one of the greatest potential benefits – freeing up capital – is seriously eroded by this rating treatment.

Trigger Misfires

Contracts often contain "triggers" that require specific actions when conditions indicating potential financial problems occur with one of the parties. Trigger clauses are intended to be a defense mechanism to keep the parties on equal footing regarding liquidity to preserve the contract and protect the other party. The problem is that the actions required by a trigger can cause a cascade of events that result in financial collapse. This is particularly problematic if a timeout and renegotiation could have averted business failure.

Imputed Debt Due to Power Obtained through PPA Rather than Ownership

Standard & Poors uses a formula to make default risk adjustments to the balance sheets of utilities that purchase more than 10% of their power through PPAs rather than owning generators. The rationale is to make inter-company comparisons of financial position more equitable. The NPV of the risk factor portion of fixed payments is added to the balance sheet in both numerator and denominator to calculate certain ratios. Companies with fuel adjustment clauses and annual true-ups fare better than those with simple base rate treatment. The formulas presented below, including revisions, have been in effect since 1991.

PPA Fixed Cost Recovery Mechanism	Risk Factor
Base rates	50%
Fuel Adjustment Clause	25%
Regulatory True-Up	25–50%: 37.5%
Legislative True-Up	0%

Table 53: PPA Fixed Cost Risk Factors

- The imputed debt is added to both debt and asset sides of the balance sheet when making ratio analysis. The NPV is calculated at GMP's average cost of debt.

- Interest expense on the imputed debt is calculated at GMP's average cost of debt for use in ratio analysis
- Depreciation expense on the imputed asset is calculated per tax tables for use in ratio analysis
- When the PPA uses a single "all-in" energy rate, the fixed portion is calculated as the construction cost of a combined cycle peaking unit in $/megawatts.

For example, Company A has revenues of $1.0 billion consisting of 12% of funds from operations (FFO)[31]; capital of $1.0 billion consisting of 50% debt and equity with interest payments of $50 million; the average cost of debt is 10%; a 20 year PPA for $40 per megawatt hour and $58.7 million in fixed costs ($14.83 per kilowatt month) has been signed. The present value (PA) of the fixed costs is $500 million. The construction cost of an equivalently single cycle turbine is $198 million or 40% of the PPA fixed cost present value. Company A has a fuel adjustment charge. Before taxes.

Ratio	Unadjusted PPA	Risk Adjustment	Risk Adjusted
Debt and capital	$500 million /$1000 million	.25 x 500 million = $125 million	625 / 1125
Annual interest	$50 million	.1 x $125 million = $12.5 million	62.5
Annual Depreciation	$50	.05 x $125 million = $6.25 million	56.25
FFO	120	(6.25+12.5) = 18.75	138.75
FFO/Interest	120/50 = 2.4		138.75/62.5 = 2.22
FFO/Total Debt	120/500 = 24%		138.75/625 = 22%
Debt to Capitalization	50%		625/1125 = 56%

Table 54: Risk Adjustments for Financial Ratios

The 12% change in debt to capital ratio is accompanied by a 7.5% change in ratios using income. Regulatory treatment — whether FAC, true-up or base rates — has a major role in "engaging" debt imputation and reducing the value of the PPA.

As an indication of the effect of incremental change in financial ratios the tables below show typical S&P bond ratings for utilities arranged by average FFO to Total Debt and Total Debt to Capitalization ratios.

[31] Funds from operations is defined as net income plus depreciation & amortization, deferred income taxes and other deferred items. It is essentially an estimate of cash flow.

Typical Ratings for Utilities by FFO / Total Debt[32]

Firm Risk Profile	Rank	AAA	AA	A	BBB	BB	B
Well above average	1	23	18	15	10	5	—
	2	29	23	19	14	9	—
Above average	3	35	29	23	17	12	7
	4	40	34	28	21	15	9
Average	5	46	37	30	24	18	11
	6	53	43	35	27	19	13
Below average	7	63	52	42	31	21	14
	8	75	61	49	35	23	15
Well below average	9	—	—	57	41	27	17
	10	—	—	69	50	34	22

Table 55: Typical Bond Ratings for Utilities by FFO and Total Debt

Typical Ratings for Utilities by Total Debt / Capitalization[32]

Firm Risk Profile	Rank	AAA	AA	A	BBB	BB	B
Well above average	1	47	53	58	64	70	—
	2	43	49	54	60	66	—
Above average	3	39	45	50	57	64	70
	4	35	41	46	53	61	68
Average	5	33	39	44	51	59	67
	6	30	36	43	50	57	65
Below average	7	27	34	41	49	56	64
	8	23	31	39	47	55	62
Well below average	9	—	—	35	43	51	58
	10	—	—	29	37	43	50

Table 56: Typical Bond Ratings for Utilities by FFO Total Debt and Capitalization

[32] Source: Standard and Poors Corporate Ratings Criteria 2002

Reuters Corporate Spreads for Industrials[33]

Rating	1 yr	2 yr	3 yr	5 yr	7 yr	10 yr	30 yr
Aaa/AAA	5	10	15	22	27	30	55
Aa1/AA+	10	15	20	32	37	40	60
Aa2/AA	15	25	30	37	44	50	65
Aa3/AA-	20	30	35	45	53	55	70
A1/A+	30	40	45	58	62	65	79
A2/A	40	50	57	65	71	75	90
A3/A-	50	65	79	85	82	88	108
Baa1/BBB+	60	75	90	97	100	107	127
Baa2/BBB	65	80	88	95	126	149	175
Baa3/BBB-	75	90	105	112	116	121	146
Ba1/BB+	85	100	115	124	130	133	168
Ba2/BB	290	290	265	240	265	210	235
Ba3/BB-	320	395	420	370	320	290	300
B1/B+	500	525	600	425	425	375	450
B2/B	525	550	600	500	450	450	725
B3/B-	725	800	775	800	750	775	850
Caa/CCC	1500	1600	1550	1400	1300	1375	1500

Table 57: Reuters Corporate Spreads for Industrials

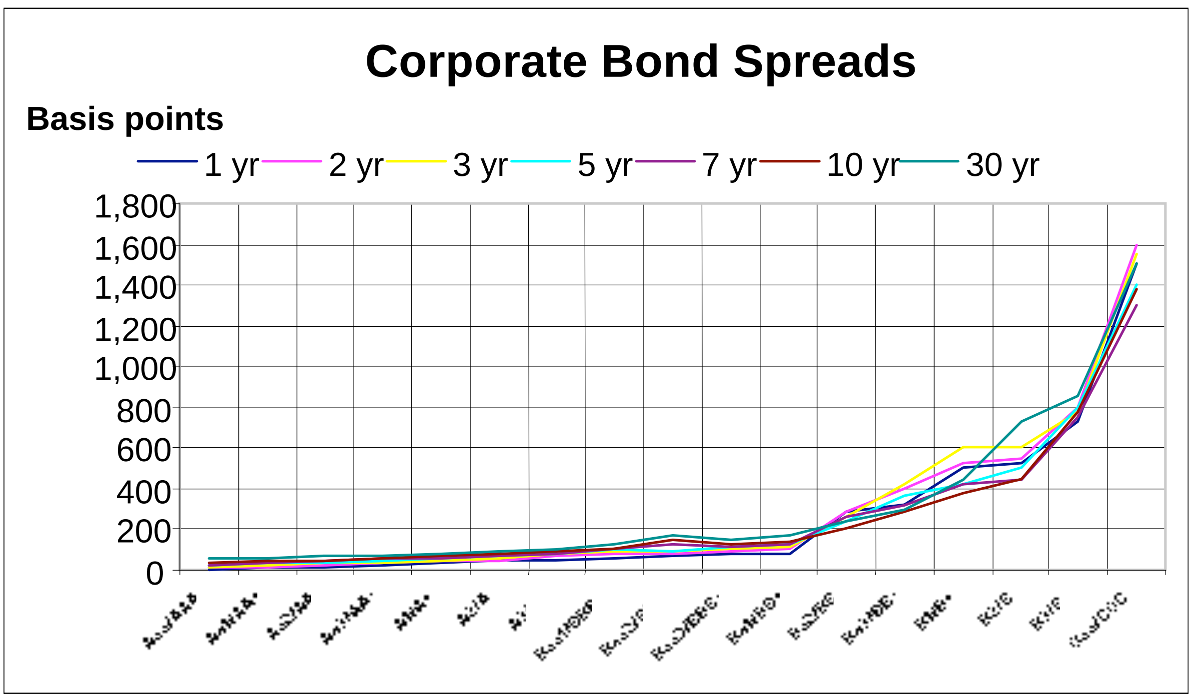

Figure 52: Corporate Bond Spreads (30 Years)

33 As of 30 June 2004

The table below shows spread versus treasuries over time from work by Damodaran at NYU that shows the indicated probability of default (rate). Our calculation of summary data to the right shows a strong non-linear pattern with higher penalties for high risk levels.

Yield Spread over Treasuries

Bond rating	Probability of default within 10 years	Yield spread versus Treasuries	Expected recovery
AAA	0.01%	0.20%	100.20%
AA	0.28%	0.50%	100.50%
A+	0.40%	0.80%	100.80%
A	0.53%	1.00%	101.01%
A-	1.41%	1.25%	101.27%
BBB	2.30%	1.50%	101.54%
BB	12.20%	2.00%	102.28%
B+	19.28%	2.50%	103.11%
B	26.36%	3.25%	104.44%
B-	32.50%	4.25%	106.36%
CCC	50.00%	5.00%	110.25%
CC	65.00%	6.00%	118.11%
C	80.00%	7.50%	143.56%
D	100.00%	10.00%	259.37%

Summary 10-year spreads; incremental spreads	
AAA–AA	30.0
AA–A	50.0
A–BBB	50.0
BBB–BB	50.0
BB–B	125.0
Total	305.0

Source: www.stern.nyu.edu/~adamodar/spreadsheets used in Damodaran's text "Applied Corporate Finance" published by Wiley Some of the numbers are also from Altman and Kishore, "The Default Experience of US Bonds", 1996 NYU working paper.

Table 58: Yield Spread over Treasuries

The graph below compares the probability of default and yield spread on Treasury curves.

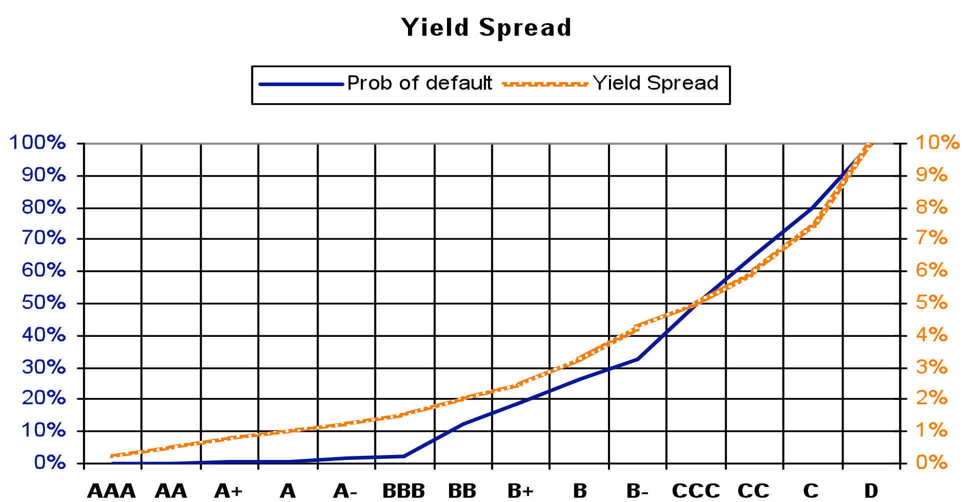

Figure 53: Probability of Default and Yield Spreads for Bond Ratings

The following data set was put together by Standard and Poor's to illustrate the rationale for their imputed debt calculations that result in a proxy debt service burden being placed on most utilities with PPAs.

Key Utility Financial Ratios		**U.S. Utility Long-Term debt for 12 months ended September 2001 (Ratio or %)**			
Financial Statistic		**AA**	**A**	**BBB**	**BB**
	Rank	4	3	2	1
EBIT Interest Coverage	EIC	4.2	3.4	2.8	1.9
Preferred dividend coverage	PDC	4.1	3.3	2.7	1.8
Return on Equity	ROE	12.3	12.5	10.9	11.4
Common dividend payout	CDP	92.3	81.7	81.6	33.9
short-term debt to capital	STDC	8.2	10.4	11.2	6.2
Total debt to capital	TDC	51.7	55.9	58.8	73.3
Preferred stock to capital	PSC	2.3	3.0	2.7	4.5
Common stock to capital	CSC	50.9	43.2	39.6	26.1
Funds from operations interest coverage	FOIC	5.1	4.0	3.5	2.4
Funds from operations to total debt	FOTD	35.5	23.8	20.4	12.5
Net cash flow to capital expenditures	CFCE	97.5	74.8	80.6	65.2

Table 59: Key Utility Financial Ratios

In an analysis of the data we show that there is a distinguishable relationship of two types of financial ratios to bond ratings. The two significant correlations are to the “cash flow to debt coverage ratio” offset by the “dividend payout ratio” and the “debt to total capital ratio”.

Best fit model by multivariate linear least squares

	VAR	COEFF *	T-SCORE	R^2
Common dividend payout	CDP	(0.01107)	0.21884	0.999
EBIT Interest Coverage	EIC	1.42717	0.04591	Const=0
Total debt to capital	TDC	(0.01814)	0.05996	
Example: If TDC increase from 50% to 55%, the change in bond rating is calculated as:	(55–50) *	(0.01814)	=	–0.09072
So that the bond rating would drop 1/11 of a “notch”, excluding effects of parallel changes in the other two variables.				
The first table on the “bond ratings” page indicates a move of 1/5 “notch”, as a comparison.				

Table 60: Best Fit Model by Multivariate Linear Least Squares

Long-term Bond Ratings Defined

Moody's	S&P	Fitch	Risk
Aaa	AAA	AAA	Prime. Maximum Safety
Aa1	AA+	AA+	
Aa2	AA	AA	High Grade High Quality
Aa3	AA-	AA-	
A1	A+	A+	
A2	A	A	Upper Medium Grade
A3	A-	A-	
Baa1	BBB+	BBB+	
Baa2	BBB	BBB	Lower Medium Grade
Baa3	BBB-	BBB-	
Ba1	BB+	BB+	
Ba2	BB	BB	Non Investment Grade Speculative
Ba3	BB-	BB-	
B1	B+	B+	
B2	B	B	Highly Speculative
B3	B-	B-	
Caa1	CCC+	CCC	
Caa2	CCC	–	Substantial Risk In Poor Standing
Caa3	CCC-	–	
Ca	–	–	Extremely Speculative May be in Default
C	–	–	
–	–	DDD	
–	–	DD	Default
–	D	D	

Table 61: Long-term Bond Rating Definitions

E: Generation Improvement Opportunities

Item	Project Title	Project Type	Location: Plant, Sub, or Line	Project Description
	Production blanket: hydro			
1	New requirements		Various	
2	Upgrade rack raker	III Replacement	Plant 1	Spec and purchase replacement rake raker
3	Sound enclosure	I Mandatory: safety	Plant 1	Purchase and install sound proof enclosure for plant personnel
4	Waste gate monitoring and control	III Replacement	Plant 2	SCADA control of each waste gate
5	Marshfield penstock relocation (AOT)	I Mandatory: AOT required	Plant 6	Engineering service for penstock replacement for AOT road relocation and rebuild in Cabot
6	Peacham valve control	II Least Cost	Plant 6	Install motor and controls to remotely control flow valve at Peacham Pond
7	Unit 2 governor and protection upgrade	III Replacement	Plant 9	Install PLC and 300G relay for hydro unit #2
8	Replace trash rack	III Replacement	Plant 15	Replace deteriorated trash racks at W. Danville plant
9	Upgrade air compressor	III Replacement	Plant 19	Replace 5 hp air compressor with 10 hp air compressor
10	Tent heater	IV Reliability	Plant 9	Purchase 80,000 BTU tent heater
11	Replace voltage regulator	III Replacement	Plant 2	Replace voltage regulator
12	**Production blanket: other**			
13	New requirements		Various	

Item	Project Title	Project Type	Location: Plant, Sub, or Line	Project Description
14	Diesel #5 ring gear	III Replacement	Plant 9	Replace worn out ring gear on diesel #5
15	Wind site communication	III Replacement	Plant 92	Replace SCADA communication system to wind towers
16	Operating permit renewal	III Replacement	Plant 5	Renewal of operating permit for Berlin #5
17	Searsburg modems	III Replacement	Plant 92	Replacement modems for wind towers
18	Production blanket: safety			
19	Plant security	I Mandatory: regulatory	Various	Various security enhancements at power plants
20	Remote annunciation upgrades	IV Reliability	Various	Provide remote monitoring of generating unit operations and alarms
21	Safety equip	I Mandatory: safety	Various	Employee safety equipment
22	**Major Generation**			
23	Wicket gate bushings	III Replacement	Plant 1	Replace worn out wicket gate bushings on unit #2
24	Spillway concrete repairs	III Replacement	Plant 2	Replace spilled concrete on spillway face
25	Rubber dam	II Least Cost	Plant 2	Install rubber dam section on Middlesex dam
26	Rewind #1 generator	IV Reliability	Plant 2	Rewind generator, failure predicted
27	Rewind #2 generator (carryover)	IV Reliability	Plant 2	Rewind generator from failure and fire
28	Rack raker	I Mandatory: safety	Plant 2	Purchase and install trash rack raker versus manual process

Item	Project Title	Project Type	Location: Plant, Sub, or Line	Project Description
29	Engine repair contingency		Plant 5	
30	Replacement transition ducts	III Replacement	Plant 5	Replace deteriorated transition ducts on gas turbine
31	Replace penstock	III Replacement	Plant 6	Replace deteriorated penstock section near surge tower
32	Rehab unit 1 (carryover)	II Least Cost	Plant 9	Rehab of Vergennes hydroelectric unit #1 for greater reliability and efficiency
33	Plant automation (remote start, monitoring)	II Least Cost	Plant 15	Automate West Danville hydroelectric unit for remote operation
34	Replace GT (Engineering only)	II Least Cost	Plant 16	Engineering services for unit replacement study
35	Unit upgrade (Engineering only)		Plant 18	Project postponed, funding Searsburg generators
36	Replace hydro control system		Plant 19	
37	Minimum flow unit (carryover)	II Least Cost	Plant 19	Install hydroelectric generator purchased in 2006
38	Replace diesels 4 MW get (Carryover)	II Least Cost	Plant 19	Install four 2.0 MW generators purchased in 2006
39	Plant drain system	I Mandatory: regulatory	Plant 19	Replace plant drainage system with oil containment
40	Runner repair/ replacement	III Replacement	Plant 22	Replace water wheel (runner) deteriorated beyond repair

Item	Project Title	Project Type	Location: Plant, Sub, or Line	Project Description
41	Waterbury relicensing (Eng)	I Mandatory: regulatory	Plant 22	Engineering services for post-licensing requirements for hydroelectric project
42	Searsburg expansion and land purchase		Plant. 92	
43	Searsburg generator conversions	IV Reliability	Plant. 92	Convert generator from random wound to form wound coils plus rewind
44	**Total**			

Table 62: Production Plant Capital Improvements

F: Transmission and Distribution Planning

Described in this section are completed, open, and on-going area specific collaboratives (ASCs); upgrade projects; and other planning initiatives surrounding Green Mountain Power's transmission and distribution planning.

The results for the ASCs listed here (docket numbers 6797: Digital Injection Project; 6798: White River Junction; 6799: Lamoille County Loop; 6800: Mount Snow; 6801: Tafts Corner, and the Burlington Waterfront Area: Phase I) were essentially all the same.

These projects could not be deferred by reducing loads with energy efficiency or serving local loads with distributed generation; therefore the five projects had no energy supply impact on GMP's IRP. The projects — whether completed, not yet in service, or on-going — did result in a more efficient and robust T&D system with less system loss. While the loss achieved by these projects was generally significant for the specific study, the savings when compared to GMP's overall supply resource needs was very small and was not specifically accounted for when determining GMP's overall need for future generation resources.

These projects also resulted in a more robust T&D system, making the system more capable of accepting and transmitting generation at more locations. This increased capability was somewhat mitigated in dockets 6798 (White River Junction), 6800 (Mount Snow), and 6801 (Tafts Corner) since these three projects only affected the distribution system.

Completed ASC Projects In Service

The following is a description of ASC's involving GMP that have been terminated, including a summary of the resolution reached and how the resolution is reflected in the IRP.

Docket No. 6797: Digital Injection Project

The ASC. Could the proposed substation to be located in Williston at Tafts Corners be avoided or deferred through DSM or distributed generation options?

Participants. Green Mountain Power, Vermont Electric Cooperative, Department of Public Service

Board Status Report. A March 28, 2003 report concluded that the project could not be cost effectively avoided or deferred.

Board Action. The Board terminated the ASC on April 4 2003.

About the Project. This project provided electric support to the sub transmission line that serves the area. Constructing a new 115 kilovolt/34.4 substation at Tafts Corners and a sub-transmission line from the new substation to the existing GMP Digital Substation #43 (located near Technology Park just west of Tafts Corners) proved to cost the least. The project was completed in 2004 and is now operational.

Docket No. 6798: White River Junction Area Specific Collaborative

The ASC. Addressed load growth in the White River Junction area

Participants. Green Mountain Power, Department of Public Service

Board Status Report. An April 7, 2004 report supported a project consisting of two general components:

- The first component, to be completed in 2004, involved conversion of a portion of GMP's 70J2 circuit from 4.16 kilovolts to 12.47 kilovolt, to enable a rebalancing of the summer load among GMP's White River and Wilder Substations, and an upgrade of the existing transformer at GMP's Wilder substation from 7.5/10.5 kilovolt-amps to 10/14 kilovolt-amps.
- The second component, to be completed in 2005, involved conversion of the remainder of the 70J2 circuit and a partial conversion of the 70J1 circuit to further reduce load on the White River Substation.

Both projects were anticipated to avoid the need for further upgrades in the area served by the White River Substation until 2012 (based on projected load growth). The participants also agreed that GMP would monitor load growth in the White River Junction DUP area. GMP can reopen the ASC if and when the area faces capacity constraints sufficient to require DUP analysis.

Board Action. The Board closed this docket on April 4, 2004. The project was completed within the time frame identified in the ASC.

Completed ASC Projects Not In Service

Docket No. 6799: Lamoille County Loop Target Area

The ASC. Addressed potential solutions for serving load in the Lamoille County area.

Participants. Green Mountain Power, Department of Public Service. The Vermont Electric Power Corporation (VELCO) and Vermont Electric Cooperative, although both were never formal parties to the ASC, attended many of the meetings and contributed technically to the process.

Board Status Report. An August 13, 2004 report indicated (among other things) that various T&D, DSM, and distributed generation options for addressing capacity constraints had been identified, and that it was appropriate to conclude the ASC.

Board Action. On September 8, 2004 the Board closed the docket.

About the Project. After Docket 6977 was closed, VELCO, the Stowe Electric Department, and GMP applied for a certificate of public good to construct a 115 kilovolt line and related facilities to serve the area. As part of the resulting proceeding (Docket No. 7032), the petitioners updated the ASC analysis of the distributed generation and DSM alternatives. The analysis demonstrated that neither DSM nor distributed generation, individually or in combination, could defer need for the project.

On March 16, 2006, the Board issued a certificate of public good for the transmission project.

Docket No. 6800: Mount Snow

The ASC. Addressed potential solutions for serving load growth in the Mount Snow area.

Participants. Green Mountain Power, the Department of Public Service, and Mount Snow Ltd. (Mount Snow).

Board Status Report. A March 18, 2005 report stated, in part, that based on the information presented and discussed in the ASC, the need for additional T&D resources could not be cost-effectively avoided or deferred by DSM or distributed generation. The report indicated that the DPS did not necessarily agree with all assumptions and methodologies used in the DSM and distributed generation analysis, but agreed that the results of the analysis were reasonable.

Board Action. The Board terminated the ASC on April 5, 2005.

About the Project. The recommended T&D project be completed in two stages and be supplied with an additional 5.5 megawatts for Mount Snow's ski area planned expansion of snowmaking and lift facilities as well as an additional 2.5 megawatts for future growth at the Haystack resort area. The first stage includes replacing an existing 14 MVA transformer at GMP's Dover Substation #90 with a 22 MVA transformer and building a 12.5 kilovolt dedicated express circuit to Mount Snow. The second stage includes two components:

- A 14 MVA substation at the Haystack area to serve additional Mount Snow and Haystack loads and provide feeder backup for loads in the Wilmington area.
- A 12.5 kilovolt distribution tie line along Coldbrook Road to enhance feeder backup.

On-Going ASC Projects

Docket No. 6801: Tafts Corners

The ASC. Examines energy efficiency and distributed generation as alternatives to a new 115 kilovolt to 12.5 kilovolt substation and new distribution circuits in the Williston, Tafts Corners area.

Participants. Green Mountain Power, Vermont Electric Cooperative, and the Department of Public Service.

Board Status Report. None yet.

Board Action. None yet.

Burlington Waterfront Area

The ASC. Examines solutions to reliability issues in the Burlington area.

Participants. Green Mountain Power, Burlington Electric Department, and the Vermont Electric Power Corporation.

Board Status Report. None yet. The participants never opened a docket for the Burlington Waterfront ASC; nonetheless, the project has proceeded in much the same manner as a formal ASC. The participants developed a preliminary solution for this area; the project team expects to complete its analysis and file for a Certificate of Public Good by mid-2007 for Phase I.

Board Action. None yet.

About the Project. The preliminary proposal, known as the East Avenue Loop Project, consists of three phases and reflects a twenty-year plan for the area. The ASC participants expect Phase I to be needed by 2009, Phase II in 2010, and Phase III in 2016. The exact dates depend on how the area load develops relative to the forecasted load used for the study. Participants will perform additional analysis with updated forecasts and review non-transmission alternatives before they request Certificates of Public Good for Phase II and Phase III of the project.

East Avenue Loop – Phase I

Phase I involves three components:

- Upgrading the existing 115 kilovolt transmission line between the Essex substation and the East Avenue substation, constructing a new 115 kilovolt line between East Avenue and Essex substation, and opening the exiting tie between Tafts Corner and Essex. The upgrade will insert an East Avenue substation into the Vermont bulk power system loop so that it can be served from either the Tafts Corner substation or the

Essex substation, thus eliminating East Avenue outages for any single contingence line failure.

- Constructing a 34.5 kilovolt subtransmission line from East Avenue Substation to McNeil substation, upgrading the McNeil Substation to accept the new line, and upgrading the East Avenue substation by installing a 115 – 34.5 kilovolt transformer. These components are needed to provide another source for the 34.5 sub transmission system at the McNeil Substation. The new source is needed to feed Burlington Electric Department's load relocated from Lake Street and to maintain an N-1 criterion for the area 34.5 kilovolt system. For a loss of one of the Essex 115-34.5 kilovolt transformers, the remaining transformer needs to remain within rated capacity.
- Relocating the Lake Street Substation. The relocation of Burlington Electric Department 's Lake Street substation is an integral part of the 34.5 kilovolt circuit (described above). It allows any two substations to back feed the third substation in case of an outage, failure, or regular maintenance.

East Avenue Loop – Phase II

The East Avenue Loop – Phase II project is a component of the twenty-year plan for the area discussed in the Burlington Water Front ASC. Phase II will be required when reliability criteria dictate, currently projected for 2010. Phase II is made up of four components:

- Constructing a new 115 – 34.5 kilovolt substation on the west side of Airport Parkway in the existing VELCO K-25 and GMP 3307 – 3308 line corridor (Gorge VELCO substation).
- Reconstructing approximately 2,500 feet of the existing 3307 and 3308 34.5 kilovolt line between the new Gorge VELCO substation and the existing Gorge GMP substation.
- Upgrading the Gorge GMP substation.
- Reconstructing the existing 3307 34.5 kilovolt line between Gorge GMP and McNeil Substation.
- Removing GMP's 3323 and 3328 lines (Waterfront Lines).

GMP has targeted the area served by this project with additional EEU funds. The Board has approved the use of a portion of those funds.

East Avenue Loop – Phase III

The East Avenue Loop – Phase III project is a component of the twenty-year plan for the area discussed in the Burlington Waterfront ASC

Phase III will be required when reliability criteria dictate, currently projected for 2016. Phase III is made up of three components:

- Replacing the two existing 115 – 34.5 kilovolt 50 MVA transformers at the Essex VELCO substation with 75 MVA transformers.

- Reconductoring the two 34.5 kilovolt (3350 – 3351) lines between Essex VELCO and Essex GMP to accommodate the new transformers.
- Upgrading the Essex GMP substation.

GMP has targeted the area served by this project with additional EEU funds. The Board approved this proposal in a recent order.

It is premature to speculate on the outcome of the DUP analysis for Phases II & III at this point and their impact on the IRP's resource needs.

Non-ASC Transmission and Distribution Upgrade Projects

We did not identify the following projects when the MOU in Docket 6290 was signed, or they were identified as not requiring formal DUP analysis. Some of these projects are still in the early planning stages, so we cannot determine if they will evolve into formal ASCs. Even if these projects do not evolve into an ASC, GMP is still required to demonstrate whether the projects could be deferred with DSM or distributed generation.

For some of these projects still in the early planning stages, GMP has recommended — and the Board has approved — that the EEU can target some of its increase funding in those areas that will be served by these projects. The IRP's load forecast does not specifically account of the impact each of these areas targeted by the additional EEU funding. However, the IRP accounts for increased EEU funding through 2008 and analyzes a scenario where this increased funding continues beyond 2008 to 2026.

Ethan Allen Conversion

The Ethan Allen 4 kilovolt feeder is being converted to 12 kilovolt to address concerns about drops in voltage. Once converted, the new 12 kilovolt circuit can convert pieces of the Gorge circuit16J1, thereby deferring the Gorge conversion project discussed below. This project has not undergone a formal DUP analysis, but GMP has recommended — and the Board has approved — that the EEU increase funding in the area served by this project.

Gorge Substation Rebuild and Conversion

This project converts distribution feeders served by the Gorge Substation from 4 kilovolt to 12 kilovolt. The timing of this project will depend on load growth, rather than the 34.5 kilovolt system's capacity and is therefore independent of the East Avenue Loop project. This project also involves a major Gorge GMP substation renovation that is required to interconnect with the proposed Gorge VELCO substation (part of the East Avenue Loop Phase II). GMP has not determined if this project will be subject to a formal DUP analysis and be the subject of an ASC.

GMP had recommended —and the Board has approved — targeting EEU funds for this area.

Third Winooski 35.4 Kilovolt Feeder

Future load growth in the City of Winooski and the surrounding area (served by two 34.5 kilovolt feeders) will create the need for a third feeder so that outages can be avoided when a contingency occurs on an existing feeder. This third feeder will be sourced from the Gorge GMP substation. GMP cannot begin this project until we renovate the Gorge substation. We have not determined if this project will be subject to a formal DUP analysis and an ASC. GMP has recommended — and the Board has approved — using targeted EEU funds.

Vergennes Substation Upgrade

This project involves replacing two existing transformers with a single transformer. This would accommodate a new 34.5 line connecting the Vergennes substation with a new 115 kilovolt/34.5 kilovolt substation to be built as part of the Northwest Reliability Project. Because this project was required at part of the Northwest Reliability Project, it was never subject to DUP analysis.

Bellows Falls

In 2007, GMP will request Board Section 248 approval to construct a new 46 kilovolt/12.5 kilovolt, 14 MVA Bellows Falls Substation in a new location in downtown Bellows Falls. The current 8.3 kilovolt/4 kilovolt substation, located in an extremely undesirable location, operates at voltages that can't provide feeder backup or be served by GMP's mobile substation. The higher voltage and capacity of the new substation will allow the Bellows Falls service area to not only operate at 12.5 kilovolt, but also back up feeders from the Westminster Substation.

GMP is presently preparing the Bellows Falls distribution feeders to operate at 12.5 kilovolt. The issues addressed by the project could not be satisfied by DUP, so DUP analysis is not required.

New Westminster 12 Kilovolt Substation

Following the construction of the new Bellows Falls Substation and the 12.5 kilovolt voltage conversion of the Bellows Falls service territory, GMP will convert the Westminster 8.3 kilovolt distribution circuits to 12.5 kilovolt distribution voltage and install step-down transformers on lateral feeds off the main distribution line. At present, we do not know when we will complete this work.

Once the circuits are converted, we will replace the Westminster Substation transformer with a 14 MVA transformer, and will operate the service area at 12.5 kilovolt and be capable of feeder back-up with Bellows Falls. Just like the Bellows Falls project, the issues addressed by the project could not be satisfied by DUP, so DUP analysis is not required.

Waterbury Center

On January 12, 2007, GMP requested Board Section 248 approval to renovate the Waterbury Center Substation by expanding the substation fence and installing a new 14MVA transformer. We will divide the existing single distribution circuit into two separate circuits, improving reliability in the area. The project will also provide future benefits for voltage conversion and feeder back-up to the Waterbury service area.

Although this project was never subject to an ASC, it did undergo DUP analysis which demonstrated that neither energy efficiency nor distributed generation would defer the need for this project.

Waterbury

Once the Waterbury Center Substation is rebuilt, we will convert the Waterbury 4 kilovolt circuits to 12.5 kilovolt distribution voltage so that they are electrically compatible with Waterbury Center Substation. Once this work is complete, GMP will seek Section 248 approval to construct a new Waterbury Substation (directly adjacent to the existing substation) to provide full feeder back-up capability in the Waterbury and Waterbury Center service areas. Because the primary reason for this project is to increase reliability rather than load growth, this project will not be subject to DUP analysis.

Other Planning Efforts

Location-Specific Planning: Hinesburg Area

We find that a new substation in the Hinesburg area will likely be needed because, eventually, area load will no longer be reliably served by the 28G2 circuit from Charlotte. GMP is currently examining whether DUP analysis will be required to identify the optimum solution.

G: Scenario Descriptions

Four scenarios formed the basis of much of the portfolio analysis and energy efficiency savings forecasts in this Integrated Resource Plan. Here, we characterize each scenario from three different viewpoints: global, national, and local (Vermont).

Fortress America

Global View

- War on terrorism is the central U.S. focus leading to prolonged U.S. presence in Iraq with limited international support.
- World oil supplies are substantially compromised driving world energy prices rapidly higher.
- Oil and liquid natural gas flows to the West are restricted, as energy producing countries hoard resources.
- Downward spiral of world economy deepens despair of developing nations as foreign aid is radically reduced.
- Depressed economic conditions of developing nations spawn more terrorism attacks.
- Mideast world unites, polarizing the rest of the world.
- U.S. is considered a “rogue” superpower by many other nations.
- U.S. and European relations are severely strained.
- International trade is dramatically reduced.
- Mixed environmental regulation changes, no clear direction.

National View

- North American natural gas supply is tight during the next decade with delayed new supply development, few liquid natural gas re-gas terminals built in U.S. High prices crest in 2011.
- Energy efficiency programs expanded to the highest levels in the short term.
- U.S. resources focused on homeland security and the war on terrorism.
- Global climate change and other environmental issues are a low priority on the national agenda.
- U.S. misses opportunities for lowest cost carbon off-sets.
- Mideast imposes an oil and liquid natural gas squeeze on shipments to the U.S.
- Heavy emphasis placed on U.S. gas and oil development to achieve energy independence.

- New coal generation slow to develop providing no significant relief to natural gas demand until 2016.
- U.S. economy stagnates due to a number of factors including an uncertainty in equity markets, increased energy prices, decreased international trade, and investment directed toward war and security rather than productivity enhancement.
- Central station power plants and transmission grid are vulnerable to terrorism.
- High efficiency and cleaner central-station generation technologies are not actively pursued.
- Utilities have limited access to capital and interest rates increase rapidly (a vulnerability premium).
- Limited utility capital investments are made to replace aging equipment and systems.
- Distributed generation and dual fuel resources are increasingly attractive due to central station and transmission vulnerability.
- Costs of protecting central station power plants and substations increase due to terrorist activity.
- Stagnant economy results in flat electricity demand and energy growth.
- Electricity becomes relatively expensive due to vulnerability and increased fuel costs.
- Electric grid is nationalized and emergency response crews are established to repair downed power lines and ruptured pipelines when terrorism occurs.

Vermont View

- Vermonters renew their sense of self-reliance and independence to protect and secure their way of life from increasingly hostile outside forces.
- Modest influx of people to the area to “escape” the metropolitan areas, the rising urban “fortress”, and the increasing military state.
- Energy conservation and renewable programs are promoted as a means of increasing self reliance.
- Efficiency Vermont budget remains at high levels for the next four to five years. Building standards tighten for new construction.
- The Canadian border tightens further due to increased national security.
- The Canadian neighbors try to support Vermont’s energy independence by making exported power available.
- Vermont and the communities within the state seek secure energy sources and supplies less dependent upon international and regional arrangements.
- Community and home-based energy solutions with multiple fuel sources evolve in response to higher energy prices and the desire for self-reliance.
- Local air quality standards, stream protection, and land use restrictions all “bend” to accommodate local and home-based energy systems that favor self-reliance.

Green Focus

Global View

- Debate on global warming has ended with a need to act but with no consensus on the degree of global actions. Nations scramble to recover from hurricane and storm damage related to global warming.
- Significant numbers of substation facilities are forced out of service due to flooding and storm damage.
- Drought and extreme heat plague multiple regions of the globe resulting in human suffering and stresses on many national electrical systems.
- Kyoto succeeds and moves forward implementing carbon regulations, establishing an active international CO_2 market.
- European Union commits to portfolio standards of 20% of electricity from renewables.
- Mideast world unites, polarizing the rest of the world.
- World oil supplies are substantially compromised driving world energy prices rapidly and continually higher.
- Higher oil and natural gas prices become a fixture in the world over the next two decades.
- War on terrorism is a central U.S. focus; prolonged U.S. presence in Iraq with limited international support.
- U.S. is considered a “rogue” superpower by other nations.
- Downward trend of the world economy as investments remain high with false expectations of moderating energy prices.

National View

- Insurance companies refuse to insure facilities within 25 feet of sea level.
- U.S. sees energy independence and environmental agenda as synergistic.
- Resurgence in nuclear industry where new plants are being ordered.
- U.S. sees reliability and security of electric supply as critical, which also supports distributed renewable resources.
- U.S. ratifies Kyoto protocol and commits to reductions of 10% from 1990 levels by 2020.
- Incentives are introduced for renewable resources, advanced generation systems, and distributed generation to reduce greenhouse emissions.
- Wind resources supplemented with storage technologies are preferred over coal generation.
- U.S. establishes carbon cap and trade regulations.

- U.S. economy stagnates due to a number of factors including increased energy prices, decreased international trade, and investment directed toward war and security.
- High natural gas prices in a long-term trend.
- Clean coal with carbon capture dominates new fossil fueled generation across much of the U.S.
- Stagnant economy results in flat electricity demand and energy growth.
- Renewable energy based generation development reaches new heights in annual capacity builds.
- States rejuvenate Energy Efficiency program in all U.S. markets. A DSM-first mentality develops.
- U.S. still spending considerable resources on homeland security.

Vermont View

- Energy efficiency standards increased.
- Efficiency Vermont budget remains at high and aggressive level over the next two decades.
- Environmental impact costs are used to make resource decisions and higher costs are included in the revenue requirements for setting of electric rates.
- Renewable resource portfolio standard is established.
- State energy economy is characterized by an increased percentage of renewable generation and a model of "green economy" leadership.
- Public subsidies become common to support environmental alternatives.
- Security issues are addressed as a secondary benefit of renewable energy and demand management resources.

Back to Business

Global View

- U.S. pullout from Iraq by the end of 2008 results in minor residual global polarization.
- New Iraqi leader friendly to Western interests.
- Moderate leaders control all key oil producing states.
- World community succeeds in reducing the terrorism threat.
- World oil price stabilizes at $40 per barrel over the next decade.
- NATO expands to include Russia and all of Europe.
- U.S. focuses on economic growth.
- Global corporations reach into new markets.
- Japan and China lead an economic recovery in the Far East.
- North Korea aggressive military and weapons export tensions lessen.
- Kyoto protocol softens as Europe brings U.S. position into alignment with the world view.

National View

- With the terrorist agenda dampened, national politics focus on economic growth.
- U.S. economic growth rates return to levels experienced throughout the 1990s.
- Energy prices are much lower than in the Fortress America and Green Focus scenarios due to stable world oil prices.
- U.S. promotes coal and new domestic gas and oil only when it can compete with imports.
- Renewable technologies are free to compete but face stiff competition from abundant fossil fuels.
- Nuclear plants attract new interest and regulatory constraints are relaxed to allow more competitive costs.
- Coal plants and combined cycle gas central station plants form the competitive nexus for new base load generation to accommodate rapid economic expansion.
- Environmental regulations are loosened and new exploration for domestic gas and oil is encouraged when economical, although not to the extent that occurred when energy independence was the motivator.
- Policies on renewable resource portfolios and environmental externalities are left to the states. Low-end externality values, if any, are applied to fossil fuel resources.
- Business is driven by efficiency gains as international competition is strong.
- Federal energy policy is focused on the transportation sector.

- ISO markets mesh with utility and merchant construction of transmission and generation, resulting in less congestion.

Vermont View

- Vermont economy surges with the growth in commercial and industrial sectors, reducing unemployment.
- The economic boom from the New York and Boston metropolitan areas stretches into Vermont aided by advances in telecommuting, flexible work schedules, and virtual companies without headquarters.
- Retirees discover northern rural living and developers follow suit with large developments centered on mountains, lakes, streams, and new golf courses.
- Vermont utilities rally interest in citing generation in Vermont in order to reduce transmission congestion costs.
- Transportation and energy corridors connect Vermont with its southern and northern neighbors, removing the sense of isolation or separateness.
- Local air quality standards, stream protection, and land use restrictions all “bend” to accommodate industrial growth in the state.
- Security issues are ignored in terms of influencing and consuming investment decisions.
- Demand Response (capacity) Programs are extended to the economic maximum in efforts to shield Vermont from regional capacity costs.

Green Growth

Global View

- Dominant economies of the world adopt a common view of the relative values of economic growth and environmental protection.
- The consensus views center on positions between current U.S. and European energy policies.
- Greenhouse gas emission markets flourish.
- Sustainable development and poverty reduction are recognized as prerequisites to long-term economic vitality for all.
- Major debt forgiveness programs are established but are tied to strong commitments to improved health and education programs in the beneficiary countries.
- Major new markets emerge as downtrodden economies begin to prosper.
- Carbon markets flourish and the Kyoto protocol is expanded to include third world countries. Carbon payments help to fuel investments in third world countries.
- . U.S. pullout from Iraq by the end of 2008 results in minor residual global polarization.
- New Iraqi leader friendly to Western interests.
- NATO expands to include Russia and all of Europe.

National View

- All states recognize “middle of the road” externality values for power planning and pricing.
- U. S. economy grows at a moderate rate. Energy intensity declines as a “green growth” philosophy becomes the brand of choice for aging baby-boom investors.
- Fuels compete openly but externalities favor cleaner fuels.
- High efficiency and cleaner generation technologies are developed to reduce emissions and fossil fuel consumption.
- Mass production of distributed generation plants reduces costs and promotes wide-scale customer-owned installations.
- Federal Renewable Portfolio Standards are established.
- U.S. ratifies Kyoto and vigorously enters the carbon trading market to minimize the costs of adjustment.

Vermont View

- New energy technologies develop that provide electricity needs at moderate costs and environmental impact.

- The power delivery “grid” and “micro-grids” fully accommodate central and distributed generation.
- Customer-owned and demand-side sources provide an increased share of the supply, control, and use system.
- Communications systems link all elements of the energy system so real-time multi-source control facilities demand response programs.
- Vermont electric growth is moderate to low despite strong economy as electricity grows at half the normal proportion to economic growth due to efficiency gains.
- Security issues are ignored in terms of influencing and consuming investment decisions.
- State Renewable Portfolio Standards are developed.

H: Renewable Resources and Environmental Assumptions

Green Mountain Power based this Integrated Resource Plan on a number of factors: scenarios regarding current renewable resources; assumptions about the financial factors on GMP's renewable resources; assumptions about emissions; and environmental externalities regarding renewable resources.

Renewable Resources Build-out By Scenarios

Reference case (business as usual):

- Massachusetts increases to 7% after 2009.
- Connecticut meets 7% RPS and maintains level.
- Rhode Island meets 16% RPS and maintains level.
- Maine and Vermont RPS are considered optional, so no new generation in New England as a result.
- New Hampshire RPS is still under consideration and has not passed legislation, so no demand from NH.

Green Growth (all states achieve RPS, some increase goal):

- Massachusetts increases to 10% after 2009.
- Connecticut increases to 10%.
- Rhode Island meets 16% RPS and maintains level.
- Maine and Vermont RPS are considered mandatory and new generation appears as a result. Also, Vermont RPS is met with in-state renewables as a result of SPEED program.
- New Hampshire RPS passes legislation and becomes mandatory.

Green Focus (all states switch to meeting Federal RPS starting in 2011):

- All states progress with there respective RPS until the Federal RPS takes effect. The state RPS levels achieved by 2011 will be maintained until the Federal RPS surpasses the state level.
- 2005 Proposed RPS in Senate: Mandates that retail electric suppliers obtain 10% of their power production in 2020 from "select" renewable energy resources.
- Since we believe the earliest implementation of a Federal RPS will not be until 2011 (four years after the 110th Congress convenes), a 1% per year growth would be quite aggressive to get to 10% by 2020. So, we assume the Federal RPS is pushed out to 2025, with a growth of trajectory of 0.5% in 2011 to 10% by 2025.
- We assume that RECs to meet the Federal RPS are still obtained from within the region and not from non-connected regions of the country.

New Renewable Resources Build

The graphs below show new additional renewable resources that would be built into the PROSYM simulation. We already assume that there are some existing resources and imports that can also meet the states' RPS demand.

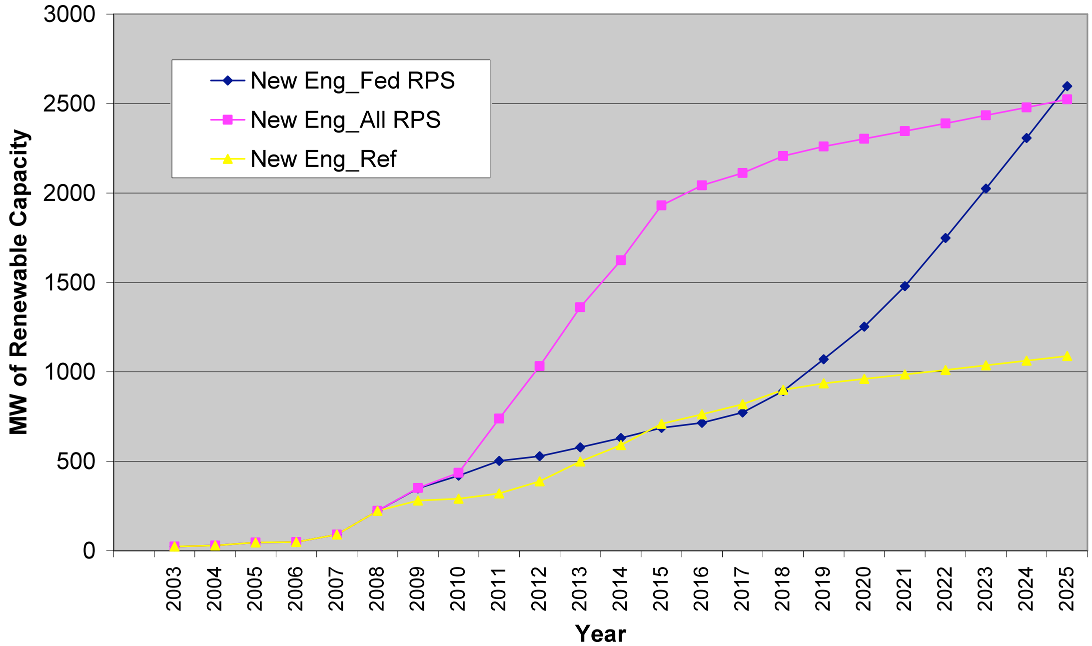

Figure 54: Renewables by Scenarios

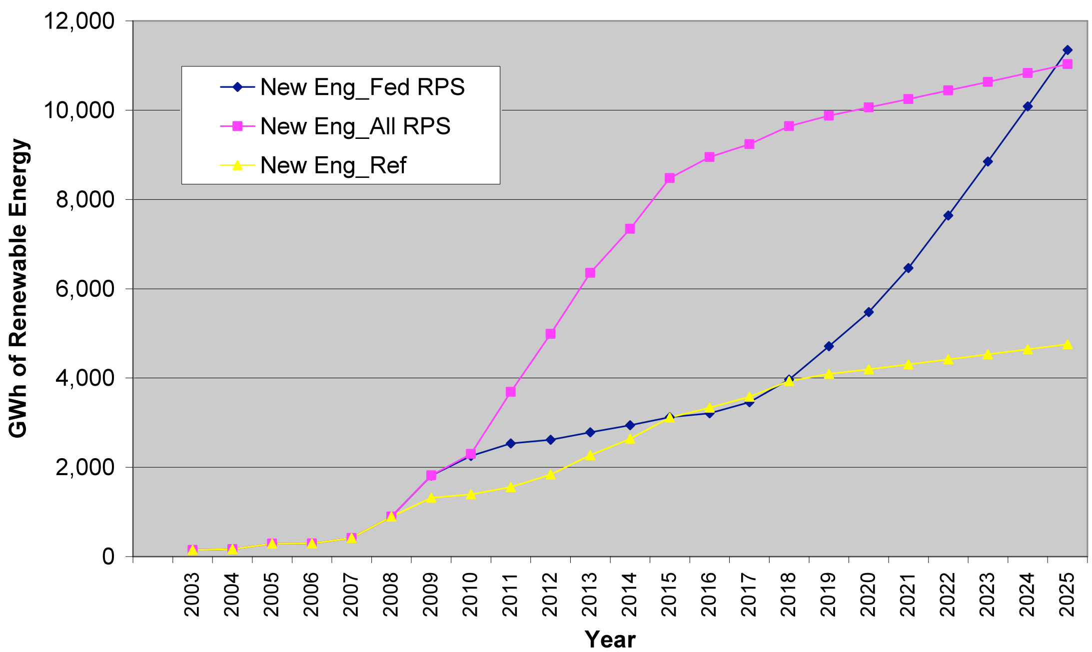

Figure 55: Renewables Build by Scenarios

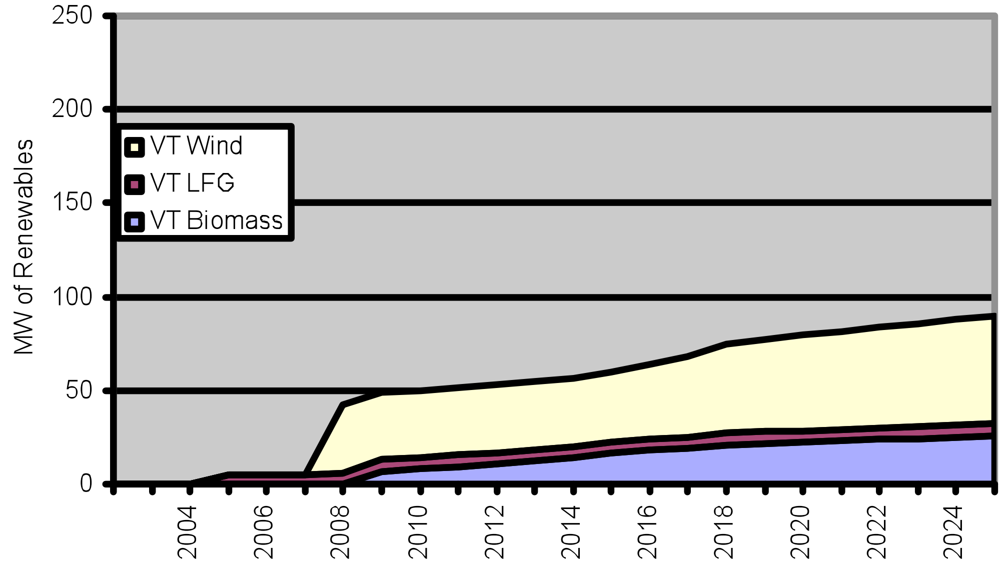

Figure 56: New Renewables by Resource in Vermont (Reference)

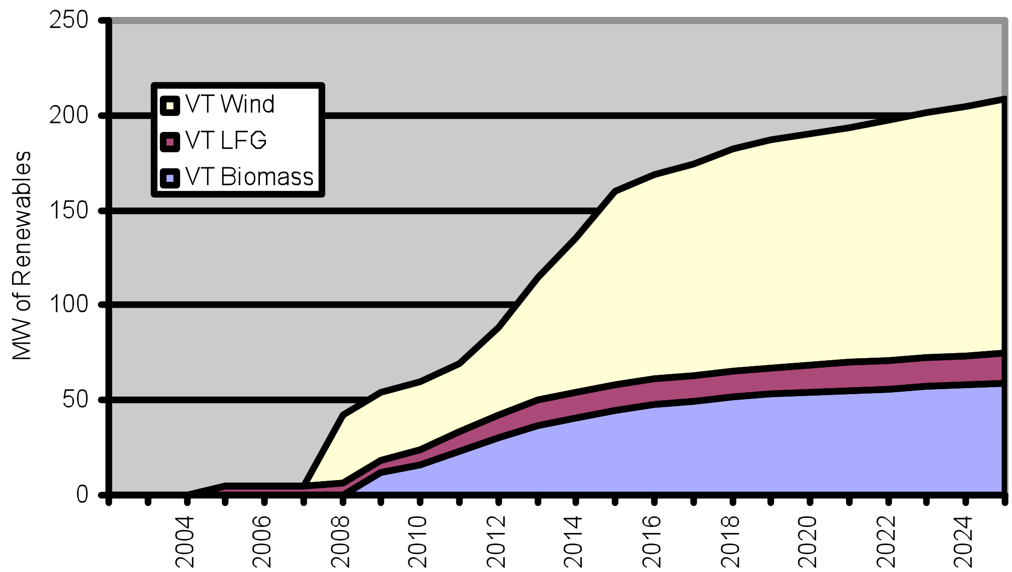

Figure 57: New Renewables by Resource in Vermont (All RPS)

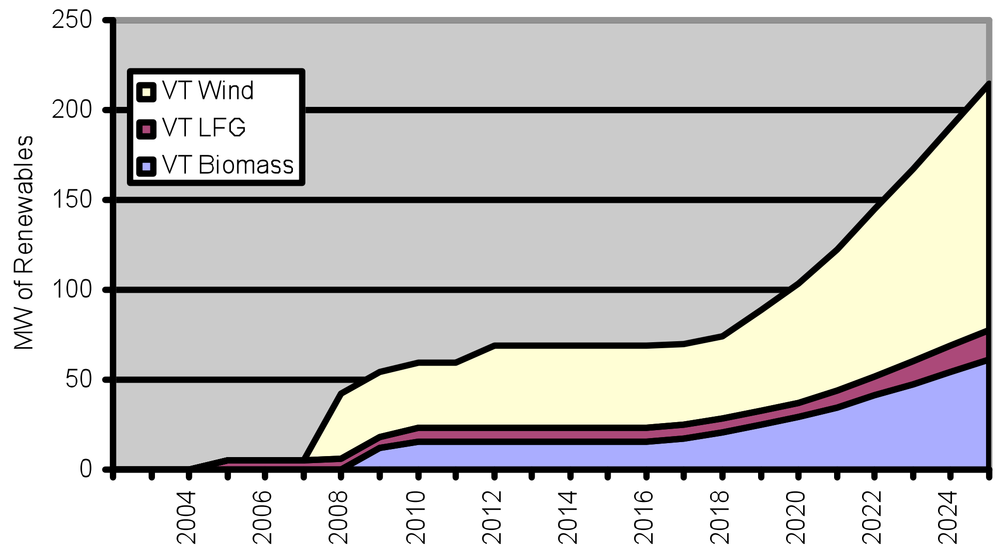

Figure 58: New Renewables by Resource in Vermont (Federal RPS)

Renewable Resources Assumptions For GMP Portfolios

Technology	**Biomass**	**Landfill Methane**	**Onshore Wind**
Levelized Carrying Charge Rate	13.8%	12.2%	11.0%
Economic Life	20	20	20
Debt %	70.0%	70.0%	60.0%
Equity %	30.0%	30.0%	40.0%
Cost of debt	8.0%	8.0%	8.0%
Cost of equity	14.0%	14.0%	14.0%
Debt term, years	15	10	15
Depreciation Life, years	20	7	5
Depreciation Schedule	1.5	2	2
Tax Rate	40.0%	40.0%	40.0%
PTC (2005$)	$9.5/MWh	$9.5/MWh	$19/MWh

Table 63: Financing and Tax Assumptions for IPP

Note. Financing assumptions in Table 63 would be different for utility-owned generation.

Achieving 20% renewables for GMP load can be calculated using the assumptions in Table 64 and Table 65.

Technology Type	Resource Type	Capacity Factor	Modeled Project Size (MW)	Levelized Cost per MWh 2008	Levelized Cost per MWh 2017	Total Installed Cost (nominal$/kW of rated max output) 2008	Total Installed Cost (nominal$/kW of rated max output) 2017	Total Installed Cost (2006$/kW of rated max output) 2008	Total Installed Cost (2006$/kW of rated max output) 2017	Technology Cost Decline Rate (% in real $)
Wind Farms (10–50 MW)	Class III	29%	30	$72.29	$74.14	$1,786	$1,860	$1,700	$1,417	2.0%
Wind Farms (10–50 MW)	Class IV	32%	30	$62.99	$64.04	$1,786	$1,860	$1,700	$1,417	2.0%
Wind Clusters (2–10 MW)	Class III	29%	5	$90.79	$94.39	$2,101	$2,188	$2,000	$1,667	2.0%
Wind Clusters (2–10 MW)	Class IV	32%	5	$79.75	$82.39	$2,101	$2,188	$2,000	$1,667	2.0%
New Biomass (gasification)	Wood Block 1 plus C&D	90%	25	$112.37	$123.01	$3,887	$3,866	$3,700	$2,946	2.5%
New Biomass (fluidized bed)	Wood Block 1 plus C&D	90%	25	$98.89	$114.72	$3,152	$3,436	$3,000	$2,618	1.5%
New Biomass (stoker)	Wood Block 1 plus C&D	90%	25	$91.38	$114.10	$2,837	$3,543	$2,700	$2,700	0.0%
Biomass Repower (gasification)	Wood Block 1 plus C&D	90%	25	$75.62	$86.46	$1,786	$1,776	$1,700	$1,354	2.5%
Biomass Repower (fluidized bed)	Wood Block 1 plus C&D	90%	25	$62.13	$74.65	$1,051	$1,145	$1,000	$873	1.5%
Biomass Repower (stoker)	Wood Block 1 plus C&D	90%	25	$54.63	$68.20	$735	$918	$700	$700	0.0%
Landfill Gas w/ collection	Landfill Gas	80%	5.0	$46.99	$58.67	$1,523	$1,903	$1,450	$1,450	0.0%

Table 64: Renewables Modeled Using Levelized Cost (part one)

Technology Type	Resource Type	Fixed O&M (2006$/kw-yr)	Variable O&M Costs (2006$/MWh)	Fuel Heat Rate (btu/kWh)	Fuel Costs (2006$/mmBtu)
Wind Farms (10–50 MW)	Class III	$45.00	$2.00	$0	$0.00
Wind Farms (10–50 MW)	Class IV	$45.00	$2.00	$0	$0.00
Wind Clusters (2–10 MW)	Class III	$55.00	$2.00	$0	$0.00
Wind Clusters (2–10 MW)	Class IV	$55.00	$2.00	$0	$0.00
New Biomass (gasification)	Wood Block 1 plus C&D	$100.00	$10.00	$12,500	$2.05
New Biomass (fluidized bed)	Wood Block 1 plus C&D	$75.00	$10.00	$13,800	$2.05
New Biomass (stoker)	Wood Block 1 plus C&D	$75.00	$10.00	$13,000	$2.05
Biomass Repower (gasification)	Wood Block 1 plus C&D	$100.00	$10.00	$12,500	$2.05
Biomass Repower (fluidized bed)	Wood Block 1 plus C&D	$75.00	$10.00	$13,800	$2.05
Biomass Repower (stoker)	Wood Block 1 plus C&D	$75.00	$10.00	$13,000	$2.05
Landfill Gas w/ collection	Landfill Gas	$200.00			

Table 65: Renewables Modeled Using Levelized Cost (part two)

Assumptions about Emissions

Emissions	AESC (VT DSM)Assumptions	LCA Assumptions
SO_2 Regulations	Existing Phase II Acid Rain Policy and Clean Air Interstate Rule (CAIR) policies.	Updated CAIR with CAMR standards included (EPA Forecast)
	Allowance prices commence with national prices close to $600/ton rising in real terms	$800/ton (2010) rising to $1270/ton (2020) in 2005$
NOx Regulations	NOx SIP Call; NOx Clean Air Interstate Rule (CAIR) policy.	Updated CAIR with CAMR standards included (EPA Forecast)
	National allowance prices are in the $700 to $3,000/ton range	$1380/ton (2010) rising to $1500/ton (2020) in 2005$
Mercury Regulations	Clean Air Mercury Rule cap-and-trade program beginning in 2010.	CAMR implemented but no cap-and-trade allowance prices affecting marginal energy pricing. Many states are opting out of cap-and-trade and choosing mandatory reductions. CAMR alters SO_2 and NOx forecasts.
CO_2 Regulations	Expected Federal Program beginning at mild levels in 2010; Regional Greenhouse Gas Initiative (RGGI) Policy affecting Northeast states assumed enacted in 2006 as a predecessor to the Federal Program.	RGGI is delayed with Federal Program implemented by 2012: $4–$5/ton

Table 66: Current PROSYM Emissions (Reference Case)

Valuing Externalities for Renewables (and CHP)

Excerpts from Southern Loop Phase II notes:

System-wide T&D: $110/kilowatt-yer (2002$) (MOU of Docket No. 6290)

Line Losses: (DPS Sept 2006 proposal)

Environmental externalities:

- Option 1: Assign externality value to emissions based on “Power to Save” report. Estimate emissions profile for representative generation types. Develop weighted average of emissions profile based on types of generation are on the margin to represent “market emissions”. Compare with emissions (or zero emissions) of renewables. Multiply by externality value of emissions.
- Option 2: Compare ISO New England calculated marginal emissions. Use assigned externality value from “Power to Save”. Compare with emissions of renewables. Multiply by externality value of emissions.
- Option 3: Comparison of externality costs among portfolios (GIS Method) where externality costs are assigned to each type of generation contracted and/or market purchases. Externality costs are added to the NPV of each portfolio. In the case of non-emitting renewables, the externality cost would be close to zero.

Other avoided costs to be included:

- Avoided energy and capacity costs for electricity generated.
- Avoided energy and capacity costs for heat and hot water, if electric heated.
- Avoided fuel for heat and hot water, if gas heated.

I: 2003 IRP Stipulation Items

IRP Stip #	Requirement	GMP Actions / Response
	General	
17	GMP shall include an updated action plan.	The updated action plan is contained in Section 5 of the IRP.
17	GMP shall describe the status of each step in the 2003 IRP action plan and identify the actions taken to further each such step. See below, Sections A, B1, C.	
	Assess opportunities for contract block purchases to manage intermediate load price exposure post 2006.	During 2006 GMP conducted a request for proposals for potential replacements for its expiring Morgan Stanley contract. GMP implemented a contract with JP Morgan for deliveries in 2007 through 2010. This contract provides a shaped energy profile that follows GMP's estimated hourly demands on a monthly basis, reducing the potential for significant surplus. The fixed price substantially reduces GMP's market price exposure, particularly during peak hours.
	Promote price responsive demand management programs that shift load from on-peak to off-peak periods. Increase the amount of peak demand under control, improve customer load response program working in concert with ISO-NE.	GMP promotes participation in ISO-NE voluntary price response and mandatory demand response programs. GMP also implements peak pricing programs and is exploring a "virtual choice" program for its largest customer. Refer to Chapter 3 (Rate Design section).

IRP Stip #	Requirement	GMP Actions / Response
	Evaluate investment in maintenance/upgrade of existing renewable resources, including hydro units.	Since the 2003 IRP, we have completed (and planned for) a number of projects for maintenance and upgrade of existing and new renewable resources. Projects completed and planned include: Replacement of the hydro turbine at GMP's Marshfield Plant #6 hydroelectric plant in 2004 for greater reliability and increased performance. Replacement of the #2 hydro turbine at the Vergennes #9 hydroelectric plant in 2005 for increased reliability and performance. Replacement of the #1 hydro turbine and rewinding of the generator for greater reliability and increased capacity from 650 kW to 850 kW. Installation of a new nominal 850 kW hydroelectric turbine and generator at the Essex plant #19 that is scheduled for commissioning in June of 2007. Collaboration and support of the proposed 34 MW expansion of the Searsburg wind plant including execution of a letter of intent with the developer for a purchase power agreement.
	Retire Essex Diesels (2004 - 2009), consider replacement with 8 MW GT. Retire Gorge GT (2009 to 2014), consider replacement with newer 25 MW unit. Retire Vergennes diesels (2010 – 2015), consider replacement with new unit.	Essex diesels are being retired in 2007; 7.2 MW of replacement diesels will be installed at the site. Gorge is slated for retirement within several years. The company plans to evaluate peaking opportunities at the Gorge site as access to the bulk transmission system is improved. Berlin and Vergennes are tentatively slated for retirement within 5 to 8 years. Vergennes faces emissions restrictions which could accelerate its retirement.

IRP Stip #	Requirement	GMP Actions / Response
	Begin plans in the 2005-2006 timeframe to acquire replacement capacity for expiring power purchases in 2012 and 2015… Evaluate the merits of obtaining a long position for some portion of its expected base load needs prior to the 2012 expiration of the Vermont Yankee contract.	GMP has begun exploring long-term power supply options. GMP has conducted initial discussions with Vermont Yankee, Hydro-Quebec, Vermont generators, and other potential suppliers. GMP and other utilities have initiated a Vermont generation siting study in 2007. The IRP action plan includes exploration of the potential for contracts with renewables and a range of other potential suppliers. The portfolio analysis in this IRP evaluates the tradeoffs, across several attributes, associated with a range of potential long-term portfolio designs. Refer to Chapter 4.
	Power Supply	
8	GMP shall include an evaluation of a diverse mix of resources to replace VY and HQ contracts when they terminate… and, based on that evaluation, shall identify what it believes is the appropriate course of action with respect to such replacement	The portfolio analysis presented in Chapter 4 identifies and evaluates potential portfolio strategies. The strategies range from continuation of the current portfolio structure to a substantial emphasis on renewables to significant reliance on new or existing combined cycle capacity. GMP believes that the most appropriate course of action is to refine the options presented in this IRP, and evaluate them based on the most current information. Refer to Chapters 4 and 5.
9	GMP shall include a description of the efforts and actions taken to date, and that it plans to undertake, to comply with the requirement to continue its efforts and explore new opportunities to increase the value of and manage its resource portfolio through purchases and sales with credit worthy market participants or other appropriate hedging or risk-mitigating strategies or mechanisms.	GMP's risk management policy provides for the use of multiple potential tools to enhance the price stability of its portfolio. For significant transactions, the policy includes specific requirements (e.g., counterparty approval, investment grade rating) with respect to counterparty creditworthiness.

IRP Stip #	Requirement	GMP Actions / Response
10	GMP will describe its plan for replacing its current VY and/or HQ contracts if they are terminated before expiration or otherwise become unavailable, due to unexpected contingencies or otherwise	GMP believes that the bulk transmission system is presently adequate to deliver replacement supplies from New England or neighboring markets if one of these sources becomes unavailable before expiration. At the end of 2006 the company has begun evaluating the potential, working with other VT companies, to uprate the Derby line interconnection with Quebec to 100 MW using GE's Variable Frequency Transformer technology (VFT). GMP does not have a specific plan for replacing the HQ/VJO contract, primarily because it is a system power contract with access to several potential delivery points. In the recent past GMP has purchased insurance that provides financial compensation in the event of an extended Vermont Yankee outage. GMP has also initiated a customer-funded reserve to help manage the costs associated with potential unit outages in the future.
11	GMP will examine portfolio alternatives to address the need to replace contracts terminating within the planning horizon, including VY and HQ/VJO contracts… and will examine the mechanisms to build and implement the new portfolio over time, including ownership, contracts, and mechanisms for managing financial risk.	The portfolio analysis in this IRP evaluates the tradeoffs, across several attributes, associated with a range of potential long-term portfolio designs. Refer to Chapter 4. GMP and other utilities have initiated a Vermont generation siting study to be conducted in 2007. The IRP action plan includes exploration during 2007 and 2008 of the potential for contracts with renewables and other potential suppliers. While the portfolio analysis focuses primarily on fixed-price options, GMP also expects to consider more creative price structures, along with ownership. Refer to Chapters 5 and 4.

IRP Stip #	Requirement	GMP Actions / Response
11	GMP will evaluate the effect, if any, of current ratemaking policy or methodology on portfolio selection	The Alternative Regulation Plan, which was implemented in 2007, is expected to enhance GMP's financial strength. This, in turn, may enhance GMP's flexibility and negotiating position with respect to new long-term contracts. The Plan also gives GMP the flexibility to pursue resources (e.g., unit-contingent contracts) that it believes to be least cost. The rate treatment associated with establishing a customer-funded Vermont Yankee outage reserve has the potential to reduce total power costs over time.
11	…and will include cost of service and rate estimates likely to result from the selected portfolio.	The portfolio analysis in Section 4 illustrates the results of the leading portfolios in terms of their impact on average retail rates in a snapshot year of 2020. As indicated in the portfolio analysis, GMP is not recommending a specific set of resources at this time; we therefore have not developed a projection of annual rates. As a practical matter, since our current portfolio is priced well below market and since we project increases in emission costs and construction costs, we expect power supply costs for our customers to increase over the next decade. The greatest increases are expected to occur when existing favorably priced entitlements expire in 2012 and 2015.
	T & D	
14	GMP will describe, based on information from it, the PSB and other ASC parties, the status of each ongoing ASC including the progress made to date and planned future activities. GMP also will describe, to the extent feasible, how potential transmission and non-transmission solutions to the constraints being addressed in the ASCs may affect other portions of the IRP.	Appendix F (Transmission and Distribution Planning) summarizes each completed and ongoing ASC. Also refer to Chapter 3 (Transmission and Distribution Studies and Improvements).
14	For ASC's with a termination date that is prior to the next IRP, GMP will state why the ASC terminated, summarize any resolution and state how it is reflected in the IRP.	Appendix F (Transmission and Distribution Planning) summarizes each completed and ongoing ASC. Also refer to Chapter 3 (Transmission and Distribution Studies and Improvements).

IRP Stip #	Requirement	GMP Actions / Response
15	GMP shall describe its process for monitoring its T&D system and identifying areas potentially subject to DUP, including a statement of the monitoring, the results, and an evaluation of each area identified as potentially subject to DUP.	Refer to Chapter 3 (Transmission and Distribution Studies and Improvements).
16a	GMP will review the projects identified in the ES for cost-effectiveness, based on current information and using the methodology employed in the ES. GMP proposes to do this review during 2005-2006. GMP shall provide a report to the Department no later than January 9, 2006 describing the results of this review as of that date, which shall include no less than 105 projects. It shall complete its review and provide additional reports to the Department as follows: (1) No later than April 21, 2006; (2) No later than July 25, 2006: (3) No later than October 30, 2006:	Refer to Chapter #3 (Transmission and Distribution Studies and Improvements).
16a	In connection with its capital planning process for purposes of scheduling ES projects, the Company will identify any synergies among projects confirmed as cost-effective and synergies between those projects and non-efficiency-driven projects.	Refer to Chapter #3 (GMP Transmission and Distribution Efficiency Study).
16a	Implementation of projects confirmed to be cost-effective under the ES will be subject to GMP's project approval process, budgetary constraints and schedules; …. GMP will make every attempt to include high priority projects in the 2006 capital plan. GMP shall create a multi-year plan to implement all cost-effective ES projects and shall provide plans to the Department on the dates of the reports identified in section 16(a). Semi-annually, GMP will update the DPS on the progress of its implementation of projects identified as cost-effective under the ES.	Refer to Chapter #3 (GMP Transmission and Distribution Efficiency Study).

IRP Stip #	**Requirement**	**GMP Actions / Response**
20	GMP will identify any increased need for VELCO bulk transmission services to transport to its service area incremental power resources that are remote from its load and, in consultation with VELCO, determine the appropriate method by which to evaluate in its planning studies internal resources, making clear what incremental local resources it plans to rely on thereby potentially limiting the need for VELCO bulk transmission services.	Refer to Chapter #3 (Planning Coordination with VELCO and Other Utilities).
	DSM/Efficiency	
12	GMP will identify the level of efficiency resources expected to be available from Efficiency Vermont during the planning period.	Refer to Chapter 4 (Four Potential Scenarios) and Appendix B (Energy Efficiency Forecasts).
21	GMP will describe how its resource portfolio decision-making process identifies, evaluates and incorporates opportunities for strategic peak load management, demand response programs, direct load control programs, rate designs based on marginal cost, and other non-energy efficiency resources besides supply.	Refer to Appendix F (Transmission and Distribution Planning), Chapter 3 (Transmission and Distribution Studies and Improvements, and Rate Design).