# VERMONT UTILITIES

# TECHNICAL AND COST ISSUES

# OF GENERATION ALTERNATIVES

## PHASE ONE OF A TWO-PHASE REPORT

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# SECTION 1: EXECUTIVE SUMMARY

## 1.1 SCOPE / INTENT

A consortium of Vermont utilities ("Vermont Utilities"[1]) has launched a two-phase study to investigate issues related to building different types of generation technologies in Vermont within the next five to ten years ("the Study"). The Study is intended to help facilitate consideration by the various Vermont stakeholders of the potential alternatives for filling the approaching gap between consumer demand for electricity and the supply of electric generation that is either contracted or owned by the Vermont Utilities.

This report addresses Phase One of the Study – technical and cost considerations for generation technology alternatives, as well as ownership structure and financial considerations associated with the development of these technologies. Recommending a particular resource or set of resources is not within the scope of this Phase One report. Nor does the report try to explore all potential blends of ownership structure for potential resources.

While this Phase One report provides substantial information, the State's public outreach processes and other public inputs, including legislative and regulatory processes, are critical to addressing the spectrum of issues associated with developing new generation in Vermont. These issues include narrowing the field of potential generation sources and determining the values that Vermont places on the Phase One factors (technical, cost, ownership structure, financial), as well as environmental, aesthetic, reliability and other factors.

Phase Two of the Study is being worked on as a separate report and that work is currently underway. In this phase the study will focus on transmission issues[2] and the costs and challenges of completing the siting and permitting process of generation alternatives, but will leave which alternatives are most acceptable to customers, utilities and regulators alike to the public outreach, regulatory and legislative processes. However, we note that while this Phase 1 report indicates that certain new large scale facilities (coal and nuclear in particular) have the potential to generate power at an attractive cost per kWh, they seem to have little support among the general public, based on anecdotal information from public forums such as the Grafton conference and the recent statewide public outreach meetings conducted by the Department of Public Service.

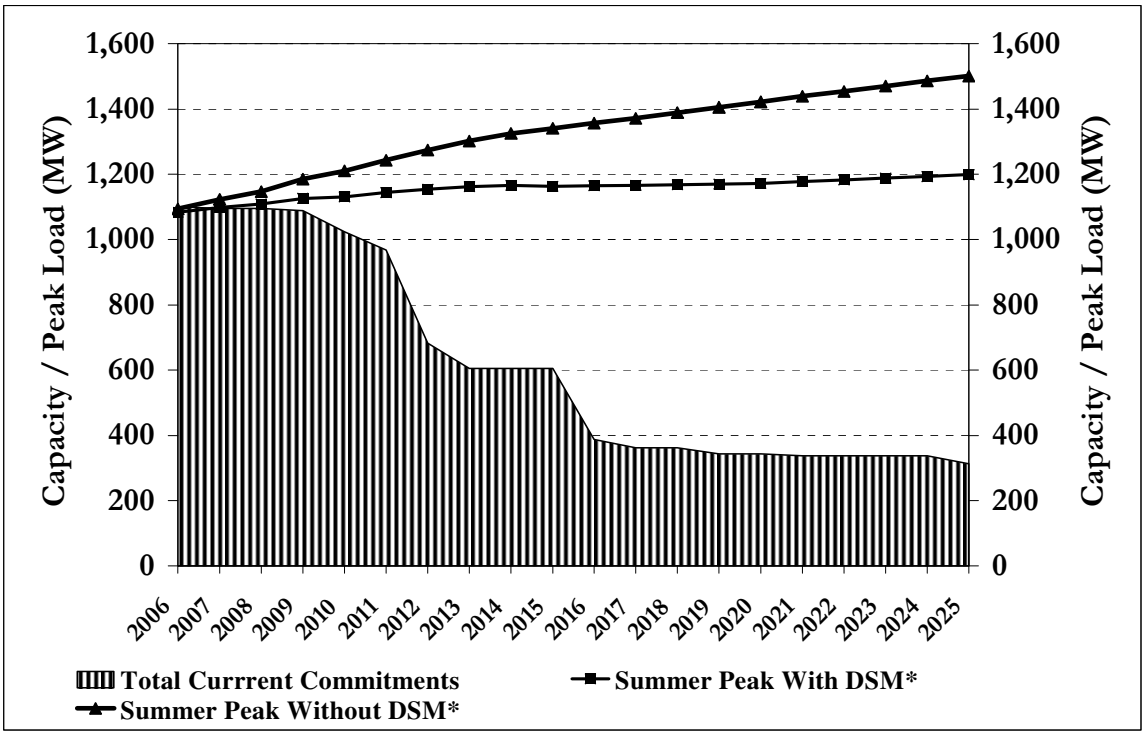
As noted above, this Study is an input in to the planning processes that will address the potential supply gap created by the expiration of the Vermont Yankee contract in 2012 and the HydroQuebec Vermont-Joint-Owners contracts in 2012 through 2020 (the "Supply Gap"). Currently, these power contracts account for nearly two thirds of the State's electricity requirements. Further, Vermont's electricity demand is projected to increase slightly or remain about as it is today despite significant

[1] The Vermont Utilities as a group is composed of Central Vermont Public Service Corporation, Green Mountain Power Corporation, Vermont Electric Cooperative, Washington Electric Cooperative, and the Vermont Public Power Supply Authority.

[2] New (particularly large or remotely sited) generation facilities would likely require significant expenditures for interconnection and to overcome transmission constraints the new generation would create or exacerbate. However, there are also locations in the state where the siting of correctly sized generation could actually help avoid new transmission expenditures.

energy efficiency and conservation efforts. As depicted in Figure 1, this divergence of supply and demand is expected to produce a Supply Gap of approximately 500 MW in late 2012, and approximately 1.0GW in 2020, unless additional capacity is procured.[3] This additional capacity could be procured either through purchases on the New England power market, through new long-term contracts, or by building new generation. It is important to note that this Figure depicts peak capacity needs, though a chart of Vermont's energy needs over the course of the year would paint a similar picture.

**Figure 1: The Potential "Supply Gap" in Vermont**




* Demand-Side Management.. This refers to the implementation of policies to reduce electricity demand.
Source: Vermont Department of Public Service.

In the time since Vermont's last commitments to major new power supplies, New England has instituted "locational" cost components in the structure of wholesale market prices for electric energy and electric capacity. Those components provide new economic incentives to Vermont to locate generation within the State. This report examines the potential financial contribution of these new locational aspects to overall power costs.

## 1.2 Technologies Considered

CEA, in conjunction with the Vermont Utilities, began with a broad universe of available technologies then narrowed that universe to eleven specific technologies to be studied in the course of developing this report. The technologies analyzed in this report are:

**The 11 Generation Technologies Considered in this Report**

1) Coal, Circulating Fluidized Bed ("Coal (CFB)")

[3] Source: Vermont Department of Public Service, "2005 Vermont Electric Plan," January 19, 2005.

2) Coal, Pulverized ("Coal (PV)")
3) Integrated Gasification Combined Cycle ("IGCC")
4) Hydrogen Fuel Cell ("Fuel Cell")
5) Gas, Combustion Turbine ("CT")
6) Gas, Combined Cycle ("CTCC")
7) Nuclear
8) Solar
9) Wind
10) Wood, Circulating Fluidized Bed ("Wood (CFB)")
11) Wood, Stoker

The following generation technologies were not analyzed in this report:

- *Small Hydro* – While CEA understands that there may be substantial potential for new small hydro generation in Vermont, the energy production from such facilities tends to be site-specific. This makes it difficult to broadly characterize the costs of this resource and to quantitatively compare them to other generating technologies. Further, the development potential of small hydro is likely to be constrained by environmental considerations and related costs. The Vermont Utilities will continue to investigate small hydro opportunities on a case-by-case basis.
- *Cogeneration* – Similarly, cogeneration (also known as "combined heat and power," or CHP), was not analyzed in this report since the thermal energy savings and the capital costs associated with cogeneration projects tend to be site-specific. As above, Vermont Utilities will continue to investigate cogeneration opportunities on a case-by-case basis.
- *Distantly Emerging Technologies* – Technologies that were not considered to be commercially feasible, such as utility-scale carbon sequestration, were not considered in this report. Costs associated with these technologies are still too high and/or too unclear to provide a reasonable comparison against other commercially available technologies.
- *Tidal* – Not considered in this study due to the lack of a significant source of tides proximate to Vermont.

Despite CEA's view that coal and nuclear technologies may be difficult to pursue in Vermont due to their environmental attributes and their large scale, these technologies were included in the study in order to provide a complete and objective comparison of all technologies for which a reasonable estimate can be made with regard to costs. Including coal and nuclear in the study also provides a comparison for purposes of understanding the generation sources with which generation in Vermont may compete regionally or nationally. Finally, we believe that this information will be a useful supplement to the public's understanding of these technologies as part of the public engagement process.

### 1.3 Technical and Cost Assessment of Technology Alternatives

Section 2 of the Study summarizes CEA's analysis and comparison of the group of eleven technologies considering size, technological maturity, and the ability to fulfill a spectrum of objectives with respect to power planning. In its review of the eleven technologies, CEA

considered construction and operating costs, operating characteristics, on-line time,[4] useful life, technological maturity, fuel availability, environmental characteristics, as well as the cost and feasibility of obtaining financing. These assumptions were entered into a revenue requirements financing model in order to estimate and compare their costs on a levelized basis in current dollars.[5]

Of note, all of these technologies considered – except nuclear, IGCC, Coal (CFB), Coal (PV), and Wind – are available to the Vermont Utilities to fill the supply/demand gap beginning in 2012, which is the nearest possible date to complete construction of the majority of the technologies studied. While CEA has found that each of these technologies is feasible in a basic sense, each will face hurdles that will greatly influence their overall desirability to Vermont. Our conclusions are presented in Section 1.5 "Key Findings" below. Three key drivers of these results – fuel prices, capital cost, and capacity factor – were tested through sensitivity analysis as further described in Section 2.6. The sensitivity analysis measures the extent to which variability in these inputs affects our results.

### 1.4 Ownership Structure and Financial Issues

Section 3 of this report summarizes the main considerations involved in raising capital to build new generation, both generically and in the context of the Vermont Utilities. While there are many ways that generation could be financed in Vermont, CEA has examined three potential ownership structures through which each of the above eleven technologies could potentially be owned and financed. Each of these three scenarios has a unique owner, structure, financing source and cost of capital. CEA uses these alternative capital costs as an input to the quantitative analysis performed in the comparative analysis of the technologies.

CEA provides an overview of current credit market conditions for financing the development and construction of power projects. This analysis focuses on the relationship between credit status and the cost of financing a new project. This includes:

- A review of the primary credit determinants used by the major rating agencies (i.e. Standard & Poor's, Moody's, Fitch Ratings) for both corporate and project debt; and
- A review of the credit implications of various financing alternatives.

Finally, the report includes an assessment of feasible ownership structures, specifically considering and evaluating public and private alternatives that may be available to the Vermont Utilities, taking into consideration:

- Capital structure and balance sheet impact;
- Financial community and rating agency views of additional debt;
- Different risks in each structure and their associated discount rates;

[4] "On-line" time refers to the time it would take to get the plant built and running, producing electricity.

[5] For each technology, the cost-of-service model sums the all the costs of generation in each year, including financing costs. These projected annual costs vary from year to year. The model converts these varying annual costs to a single "real levelized" cost that can be compared across technologies. The real levelized cost is the present-year dollar amount that, if paid in every year of the plant's life, after adjusting for inflation, would result in the same financial value as the actual annual projected costs.

- Viability of structures at different times of the Project (development, construction, operation);
- Expected returns and impact on the cost of the Project;
- Regulatory considerations; and
- Public policy considerations.

## 1.5 KEY FINDINGS

### 1.5.1 Feasible Technologies

CEA believes that the feasible technologies for the Vermont Utilities to pursue will be those with:

- A scale that best works to economically narrow or eliminate the coming Supply Gap;
- A record of reliability;
- An ability to provide portfolio diversity;
- The lowest reasonable expected cost given potential cost variability, as expressed on an all-in $/MWh basis (or a $/kW basis for peaking units);
- An environmental profile consistent with standards and sensitivities of the citizens of the State;
- A scale of fuel and waste transportation, storage and disposal requirements consistent with the facility's contribution to the State's power needs;
- The best ability to attract lenders to secure low-cost financing; and
- The most compatible with Vermont's utility ratemaking practices and the financial status of its utility providers.

Studying these characteristics for each technology produces important insights. For example, applying the perspective of matching each technology's scale to Vermont's total need and portfolio diversification objective reveals the following:

- The largest technologies, including, nuclear, pulverized and gasified coal (all larger than 500MW) are indeed very large, considering that, in the interest of portfolio diversity, no single generating plant should occupy a significant majority of the anticipated Supply Gap. The largest technologies also require capital investments larger than the likely feasible scale for financing by entities within Vermont alone. This suggests there would be a need for partnering with external parties in order to pursue such alternatives. This could bring additional risks and challenges in addition to possible benefits in today's competitive wholesale power business.
- Development of the smallest scale technologies, solar and wind, may imply a dedication of certain land resources that could conflict with Vermont's other land-use objectives.
- Significant expansion of Vermont's use of wood as a fuel at the scale of many tens of megawatts could stress the region's sustainable wood supply, putting upward pressure on the price of wood and potentially conflicting with Vermont land use, forestry and transportation

objectives. In addition, a new wood-fired power plant would compete for fuel with schools and other institutional buildings that use woodchips for space heat.

- Significant reliance on new natural gas based generation would require new gas pipeline capacity and or infrastructure both within and beyond Vermont.

All eleven technologies considered present potential challenges. Some technologies can be expected to provide significant production cost/ risk advantages compared to others, but those values may be offset or in some cases overcome by other external attributes and environmental concerns of customers and utilities, as well as permitting challenges. While several of these factors are beyond the scope of this study, CEA's analysis provides the following observations:

1) All-in Cost

Lowest cost on a $/MWh basis: The four least costly technologies on an all-in $/MWh levelized cost basis[6] are:

- Pulverized Coal ($53.69/MWh)
- CTCC ($54.38/MWh)
- Nuclear ($54.42/MWh)
- IGCC ($56.67/MWh)

These technologies provide the lowest projected cost of power, primarily as a result of their relatively low cost of fuel and the large number of MWh that they produce over their useful lives, thus reducing cost on a per-MWh basis.

Highest cost on a $/MWh basis: The four most costly technologies/configurations are:

- Fuel Cell ($351.23/MWh)
- Solar ($245.82/MWh)
- CT (25MW) ($176.18/MWh)
- CT (50MW) ($163.20/MWh)

These high all-in costs are generated primarily by the relatively high capital costs of these technologies relative to their size (MW) and the amount of energy that they are expected to produce (MWh).

We note that CT plants would be used for peaking operation; that is, they would be operated only during the hours of the highest electricity demand and market prices, or when the electricity system needs reserves. They would therefore represent a more cost-effective capacity option than would be suggested by the $/MWh cost alone.

2) Emissions

The all-in cost figures above include costs for operation of pollution abatement equipment and/or the purchase of emission allowances through programs such as the Regional Greenhouse Gas Initiative ("RGGI"). They do not, however, include other external costs or impacts of electrical generation. These non-quantifiable costs are described in Section 2. Also, the figures do not include the positive value of any environmental attributes, whether the value is captured through selling the

[6] Real $2007, as calculated in the Utility-Rate Base scenario.

attributes or avoiding the need to purchase those attributes on the open market. Traditionally, and through Vermont law and requirements of the Vermont Public Service Board, utilities in Vermont have evaluated options based on the Societal Test which includes a quantification and monetization of environmental effects.

Highest emissions: The three technologies with the highest emissions rates on a lbs/MWh basis are:

| | CO2 | SO2 | NOx |
|---|---|---|---|
| • Coal, PV | 1,825 | 1.00 | 0.90 |
| • Coal, CFB | 1,999 | 1.80 | 0.66 |
| • IGCC | 1,755 | 0.09 | 0.41 |

Lowest emissions: The three technologies with the lowest emissions rates on a lbs/MWh basis are Solar, Wind and Nuclear, all having no air emissions. Wood fired technologies have the most benign emissions profile of the plants that burn fossil fuel.

3) Stability of in All-in Cost

Changing fuel prices, capital cost over-runs and the possibility of outages (unexpected down time) are the three primary factors that contribute to price instability. The three technologies that are least affected by these factors are:

- Coal (PV)
- Wood (Stoker and CFB)
- Coal (CFB)

For many technologies, fuel prices are by far the greatest factor driving the variability of all-in costs. The three technologies with the greatest expected percentage change in their all-in cost resulting from a one standard deviation change[7] in their fuel costs are:

- CTCC – 22% expected change in all-in cost
- Fuel Cell – 12% expected change in all-in cost
- CT (50MW) – 11% expected change in all-in cost

4) Ability to Attract Financing

All eleven technologies represent feasible alternatives for the Vermont Utilities to pursue.[8] The most straightforward financings are those that are performed on the balance sheets of CVPS and/or GMP, especially those projects that will involve less than $300 million in total capital raised jointly by these utilities. Projects with greater reach to all citizens of the State could be feasible through a State Authority structure. Larger projects may require an outside source of equity, which is more complex, but still feasible. Finally, the Vermont electric cooperatives can feasibly build projects that

[7] A fuel price that is one standard deviation from the mean price is a price that is farther away from the mean price for a given time period than 68% of all prices for that period, assuming that fuel prices are normally distributed.

[8] The ownership and financing alternatives explored in this report assume that one or more of the Vermont Utilities or the State of Vermont would effectively be the sponsor(s) of any of the feasible technologies selected. We note that new generation supply could alternatively be provided by one or more independent developers. In this case, the Vermont Utilities could issue a Request for Proposals (RFP) for competitive supply bids, and only the developer would be responsible for arranging financing. The Vermont Utilities would then enter into an agreement to purchase power from the new resource at a market-based rate.

generally fit the needs of their membership – generally smaller than $60 million in capital cost. A summary of these limitations is shown in Figure 11 in Section 3.

#### 1.5.2 Viable Ownership and Financing Scenarios

The most feasible ownership options are those that rely upon financing structures already in place in the State. These include:

- CVPS and/or GMP utility rate base financing
- Co-op financing through U.S. Department of Agriculture ("USDA") or other Federally-sponsored programs

### 1.6 CONCLUSIONS

Based on the preceding information, CEA concludes:

1) Given the future expiration of significant power contracts, along with the new economic incentives within the region's wholesale power market structure to build capacity, the Vermont Utilities should focus their continuing examination on generation sources that are reliable, that can be built at a reasonable cost, that are attractive to the capital markets, and that otherwise fit with the long-term goals of the State and the Vermont Utilities.
2) The generation sources with the lowest expected economic costs, Pulverized Coal, CTCC, and Nuclear, present difficult scale and financing issues and may present equally difficult public acceptance and environmental issues.
3) Determining which of the options will best serve Vermont will require substantial public input and consideration of the weight Vermonters place on fuel diversity, environmental, aesthetic, and other considerations. This report provides substantial insights on the costs and attributes of various generation sources and should dovetail with that public input.[9]

#### 1.6.1 What Should Not be Concluded from this Phase One Study

Recommending a particular resource or set of resources is not within the scope of this Phase One report. Such a recommendation can only be made through a detailed analysis of factors that are typically analyzed through a comprehensive integrated resource plan. Instead, the intent of the study is to provide information in order to facilitate additional power planning. The conclusions above are intended to focus further study on those technologies that appear to be most feasible within Vermont.[10]

[9] Even if none of the technologies considered in this Phase One report are ultimately built in Vermont, this report contains substantial information regarding generation that could be developed in the region by others. In this case the Vermont Utilities may benefit by using this information to evaluate partnering or power contracting opportunities.

[10] This analysis assesses the feasibility of generation alternatives to be located within the State. However, the cost characteristics used in this report are generally relevant for locations in neighboring states as well. Indeed, lower cost resources located in neighboring states could, over time, establish the benchmark resources with which a Vermont utility project would compete.

Similarly, the possible methods of financing presented in Section 3 do not represent definitive terms. They are intended to convey the broad array of financing options available to the Vermont Utilities, as well as some of the limitations of those financing possibilities.

Finally, this study does not address the feasibility of siting generation within specific areas of the State, but does consider on a technology-by-technology basis certain locations that may have siting advantages by virtue of their existing infrastructure or geographic location relative to load. The Vermont Utilities intend to distribute this study to stakeholders to raise awareness of the considerations involved in the cost and financing of a broad universe of power supply options.

## 1.7 DATA SOURCES

### 1.7.1 Technology Cost and Operating Assumptions

The technology cost and operating assumptions made in this report were developed by CEA using several sources of information, including:

- Internal CEA knowledge and proprietary research
- 2007 Annual Energy Outlook (developed by the U.S. Energy Information Administration)
- DOE/NETL-2007/1281 – "Cost and Performance Baseline for Fossil Energy Plants" May, 2007
- Data from the Nuclear Energy Institute
- Data from the American Wind Energy Association
- Cost escalation data from the Handy-Whitman index of producer costs
- Data from existing Vermont generating facilities

The analysis also considers technology-specific data provided by the Electric Power Research Institute ("EPRI"). CEA also obtained information from telephone interviews with various Vermont sources familiar with the attributes of various technologies in Vermont. Finally, CEA reviewed industry publications and credit ratings reports to obtain information on recent project financings.

### 1.7.2 Financing Assumptions

Financing assumptions were primarily obtained through CEA's ongoing exposure to the generation financing marketplace, supplemented with additional research. Specific financing rates and terms were also obtained from:

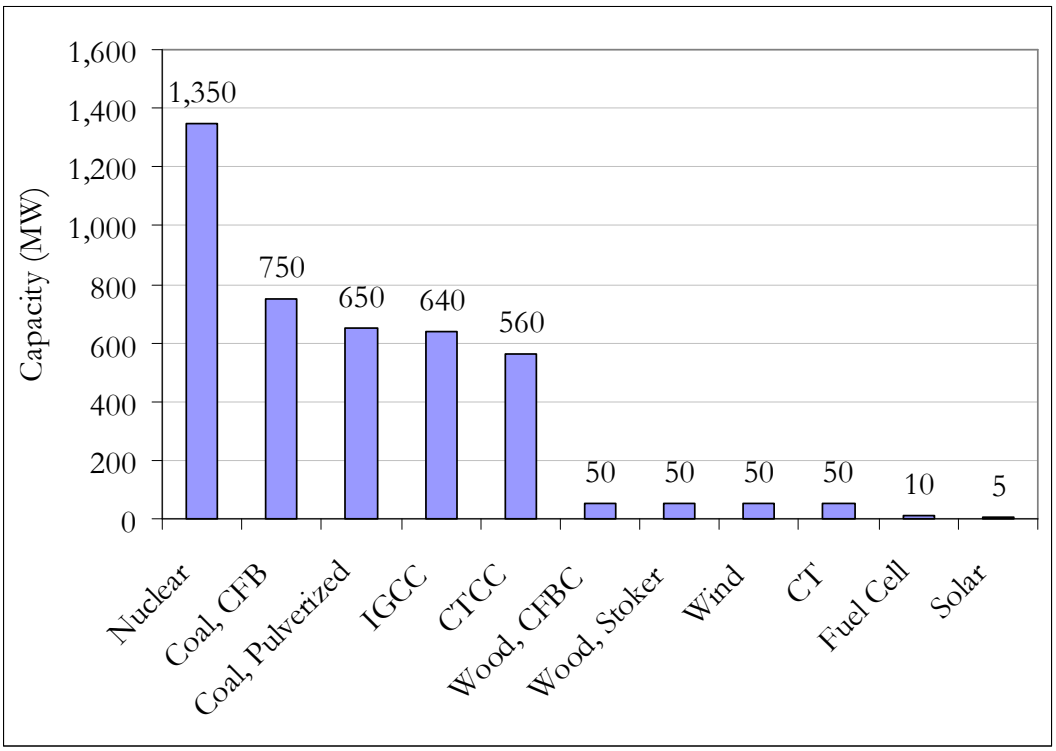
- Conversations with Vermont Utilities personnel and the Vermont State Treasurer's office
- Recent rate cases of CVPS and GMP
- The U.S. Federal Reserve
- The U.S. Department of Agriculture
- Other internet research

# SECTION 2: BASE CASE TECHNOLOGY FINDINGS

## 2.1 Assumptions Regarding Size of Each Technology

While many of the 11 technologies are available in multiple plant sizes, each of the technologies has a size expressed in megawatts of generating capacity (MW), where economies of scale coupled with related performance characteristics produce the most economical unit. The Vermont Utilities have the opportunity to build one or more of these technologies as one potential source of supply toward eliminating the Supply Gap. Figure 2 illustrates the eleven technologies, ranked by capacity.

**Figure 2: The Eleven Feasible Technologies, Ranked by Capacity**




It is evident from this Figure that if the Vermont Utilities were to rely on new generation construction in order to close the Supply Gap, larger scale technologies such as Nuclear, Coal, IGCC, or CTCC technologies would provide the greatest headway toward achieving this goal through a single project. However, addressing the gap with one large plant could increase the risk of the state's portfolio by relying heavily on one resource. Building a series of smaller technologies, although potentially more costly under normal operating conditions, may be preferred since this strategy may enhance the diversity of Vermont's generation portfolio. Portfolio decisions such as these will be made by each utility as part of its individual integrated resource planning process.

## 2.2 Technology-by-Technology Findings

The following pages contain a technology-by-technology overview. Each technology segment provides a description of the technology, along with its costs and potential financing methodologies.

The "Utility", "State Authority" and "Cooperative" scenarios under "All-in Levelized Cost" reflect financing scenarios that are described in detail in Section 3.

The descriptions below also provide indicative siting locations within the State that may make sense with respect to technical feasibility. Consistent with the requested scope of this study, these suggestions regarding site location do not consider a detailed review of permitting requirements, specific environmental concerns, or political or local views on development, but do present an overview of these issues for further analysis.

A "CEA Overnight Capital Cost" and an "All-in Real Levelized Cost ($/MWh)" are provided for each technology description below.

- "CEA Overnight Capital Cost" is the cost of building a given plant, as if the plant could be built instantaneously, without accumulating any interest cost or plant cost inflation during development and construction. This figure is expressed in $2006, and includes land acquisition, equipment, installation, and the cost of interconnecting with the electricity grid. It does not include pre-construction, permitting and design costs.
- "All-in Real Levelized Cost ($/MWh)" is the annual payment that would have to be made over the life of a given plant, after adjusting for inflation, in order to pay for all of the plant's capital and operating costs, including emissions costs. This payment is expressed on a per-MWh basis in $2008.

### 2.2.1 Coal (CFB)

Description and Cost

This technology uses bituminous coal, in conjunction with upward blowing jets of air to create a combustion process that heats water, creating steam, causing a turbine to rotate, thereby generating electricity. The CFB technology is designed specifically to control emissions of sulfur dioxide ('$SO_2$"), but has a higher capital cost than the pulverized coal technology described below. Because coal is a relatively inexpensive fuel source, the marginal cost of operating a Coal (CFB) plant is low, so it is generally used as a baseload source of electricity. Coal is an abundant domestic resource and remains a stable and relatively inexpensive source of fuel for electric power despite recent price increases. Coal (CFB) plants emit carbon dioxide ("$CO_2$"), $SO_2$, nitrogen oxides ("NOx"), and mercury emissions.

| | |
|---|---|
| Assumed most efficient size for technology: | 750 MW |
| CEA Overnight Capital Cost ($/kW): | $2,355/kW |
| CEA Overnight Capital Cost ($): | $1.8 billion |

Possible Ownership Structures

Development of this technology would likely require partnership among the regulated utilities, or a new State-sponsored power authority given the size of the investment. Either of these options would likely require partnership with outside investors.

All-in Real Levelized Cost ($2008/MWh)

| Utility | State Authority | Cooperative |
|---|---|---|
| $63.83 | $59.95 | $59.31 |

Emissions Control Technologies Assumed

- *NOx Reduction* - Less NOx is created because combustion takes place at a lower temperature than pulverized coal units (e.g., 800-900 degrees Celsius for CFB vs. 1,300-1,400 degrees Celsius in the case of pulverized coal technology).
- *$SO_2$ Reduction* – Limestone is injected into the bed to remove $SO_2$. Limestone is also used to remove ash byproduct.
- *Particulate Matter Reduction* – Particulate matter is contained in the fuel gas. After passing through the combustion chamber, the fuel gas enters a cyclone where larger particulate matter is recycled back through the combustion chamber and smaller particulate matter is removed with a fabric filter.

Possible Locations

Locations are possible along the Connecticut River in southeast and central-east Vermont, and along the Lake Champlain shoreline in the northwest corner of the State. Considerations for siting a Coal (CFB) plant in Vermont include:

- *Fuel Delivery* – Coal is typically delivered to power plants by rail, barge and truck. Therefore, proximity to existing or potential rail and truck-accessible highways are critical siting considerations. Significant trucking of coal may not comport with Vermont's environmental and transportation infrastructure goals. For context, a 750MW CFB would require approximately 178,000 tons of coal delivered every month, which would require more than 4,000 deliveries per month by a 40-ton truck or eighteen full rail deliveries per month from a 10,000-ton train. CEA does not consider barge delivery to Vermont to be feasible.
- *Cooling Water Source* - Coal (CFB) plants require a large source of cooling water. Therefore, proximity to a lake or river with significant reserves is a critical siting consideration.
- *Land* – A 750MW coal plant would require approximately 50-100 acres of land. For example, the 745MW pulverized coal plant at Salem Harbor, MA occupies 65 acres. The CFB configuration would have similar requirements.
- *Proximity to Transmission* – As with all other technologies, proximity to existing transmission infrastructure makes siting a Coal (CFB) plant more feasible and cost-effective.

Environmental Considerations

- Coal (CFB) plants emit $CO_2$, $SO_2$, NOx, and Mercury. All of these emissions are reduced by the fluidized bed combustion process. However, more stringent emissions caps than expected may make coal-fired plants uneconomic.
- Fuel delivery via truck causes roadway erosion and congestion; rail access appears to be fairly limited in Vermont.
- As with any technology that requires cooling water, increases in source cooling water temperatures may occur, with potential damage to underwater ecosystems.

Key Risks

- Future environmental mandates may increase capital or emissions allowance costs.
- Efficient unit size is relatively large, potentially creating portfolio diversification concerns.

### 2.2.2 Coal (Pulverized)

Description

Pulverized coal plants, which are baseload units, are among the most mature and tested technologies in use today. These plants are technologically the same as Coal (CFB) plants, but lack the SO2 controls that CFB units provide. As noted above, coal is a relatively inexpensive fuel, but does produce $CO_2$, $SO_2$, NOx, and mercury emissions.

| | |
|---|---|
| Assumed most efficient size for technology: | 650 MW |
| CEA Overnight Capital Cost: | $1,879/kW |
| CEA Overnight Capital Cost: | $1.2 billion |

Possible Ownership Structures

Development of this technology would likely require partnership of the regulated utilities, or through a new State-sponsored power authority given the size of the investment. Either of these options would likely require partnership with outside investors.

All-in Real Levelized Cost ($2008/MWh)

| Utility | State Authority | Cooperative |
|---|---|---|
| $53.69 | $50.60 | $50.09 |

Emissions Control Technologies Assumed

- NOx Reduction
  - Low-NOx burners
  - Staged Over-fire Air
  - Selective Catalytic Reduction (SCR) technology
- $SO_2$ Reduction – Flue Gas Desulphurization ("scrubber")
- Particulate Matter Reduction – Fabric Filter

Possible Locations

Locations are possible along the Connecticut River in southeast and central-east Vermont, and along the Lake Champlain shoreline in the northwest part of the State. High-level considerations for siting a Coal (Pulverized) plant include:

- *Fuel Delivery* – Coal is typically delivered to power plants by rail, barge and truck. Therefore, proximity to existing or potential rail and truck-accessible highway are critical siting considerations. Significant trucking of coal may not comport with Vermont's environmental and transportation infrastructure goals. A 650MW pulverized coal plant would require approximately 140,000 tons of coal delivered every month, which would require more than 3,500 deliveries per month by a 40-ton truck, or fourteen rail deliveries per month from a 10,000-ton train. CEA does not consider barge delivery to Vermont to be feasible.

- *Cooling Water Source* - Coal (Pulverized) plants require a large source of cooling water. Therefore, proximity to a lake or river with significant reserves is a critical siting consideration.
- *Land* – A 650MW coal plant would require approximately 50-100 acres of land. For example, the 745MW pulverized coal plant at Salem Harbor, MA occupies 65 acres.
- *Proximity to Transmission* – As with all other technologies, proximity to existing transmission infrastructure makes siting a Coal (Pulverized) plant more feasible and cost-effective.

Environmental Considerations

- As with any technology that requires cooling water, increases in source cooling water temperatures may occur.
- Coal plants emit $CO_2$, $SO_2$, NOx, and Mercury. Most of these emissions are reduced through the emissions technologies noted above. However, more stringent emissions caps than expected may make coal-fired plants economic.
- Fuel delivery via truck causes roadway erosion and congestion; rail access appears to be fairly limited in Vermont.
- If NOx, $SO_2$, Mercury and/or $CO_2$ emissions rates are capped, operation of the plant may become uneconomic.

Key Risks

- Future environmental mandates may increase capital or emissions allowance costs.
- Efficient unit size is relatively large, potentially creating portfolio diversification concerns.

### 2.2.3 Combustion Turbine (CT)

Description

CTs are a popular peaking resource due to their mature technology, low capital costs and variety of sizes and configurations. Similar to an aircraft jet engine, a CT uses natural gas or oil in a combustion chamber to rotate the turbine to generate electricity. The relatively low capital investment is offset in part by the CT's relatively poor efficiency, meaning that owners of CTs usually run their units only when the price of power is high or when the power system requires operating reserves. CTs emit $CO_2$ and NOx, but do not emit $SO_2$ or mercury.

Primarily for environmental reasons, the general preference is to run on natural gas at sites where it is available, although oil is sometimes burned during periods of high natural gas prices. Most of Vermont's CT's are currently oil-fired.

| | |
|---|---|
| Assumed most efficient size for technology: | 50 MW |
| CEA Overnight Capital Cost ($/kW): | $950/kW |
| CEA Overnight Capital Cost ($): | $48 Million |

Possible Ownership Structures

The development of gas CTs could possibly be backed by three different entities: Investor-owned utilities, State Authority, or Cooperative electric utilities.

All-in Real Levelized Cost ($2008/MWh)

| Utility | State Authority | Cooperative |
|---|---|---|
| $163.20 | $149.29 | $146.98 |

CEA also studied a 25 MW capacity CT. Units of this size will tend to be more costly per kW than a 50MW unit, but may be preferred in some circumstances. For example, a smaller unit may be better able to fit an existing generation site, or may face lower required costs for generation upgrades. Combinations of smaller units may also make it possible to defer transmission investments more effectively than a smaller number of larger units. The results of the smaller capacity CT are as follows:

| | |
|---|---|
| Assumed Size | 25MW |
| CEA Capital Cost ($/kW): | $1,100/kW |
| CEA Capital Cost ($): | $28 million |

All-in Real Levelized Cost ($/MWh)

| Utility | State Authority | Cooperative |
|---|---|---|
| $176.18 | $160.07 | $157.39 |

Emissions Technologies Assumed

- NOx Reduction - Low-NOx burners

Possible Locations

Gas infrastructure requirements limit potential sites to the gas pipeline-served portion of northwestern Vermont and near Massachusetts pipeline infrastructure in southern Vermont. High-level Considerations for siting a CT include:

- *Fuel Delivery* – Natural Gas is delivered to power plants through gas pipelines. Therefore, proximity to existing or potential gas infrastructure is a critical siting consideration.

  A 50MW CT, operating at a 10% capacity factor (876 hours per year) is expected to consume approximately 451,000 mcf per year. For comparison, Vermont Gas Systems, Inc. ("VGS") has peak demand of approximately 65,000 mcf per day. Therefore it is not expected that either a new 50MW CT or a new 25MW CT would place inordinate demands on the VGS system.

Environmental Considerations

- Gas-fired plants emit $CO_2$ and NOx, albeit in significantly smaller quantities than other types of fossil fuel-fired plants.
- In addition to natural gas, CTs can burn diesel fuel. While these units are expected to burn diesel only as a backup fuel source, oil is a more polluting fuel than natural gas.

Key Risks

- Price competitiveness of natural gas as a fuel source.
- Natural gas prices are volatile and comprise a large percentage of all-in costs. In the CEA Base Case, a one standard deviation change in the price of fuel causes an 11.4% change in all-in power costs from the 50MW CT and a 10.5% change in the case of the 25MW CT.
- CTs have high heat rates (low efficiency) at full load and are therefore only useful during periods of peak power prices.
- CTs can have high levels of de-rating in summer months causing a reduction in output capacity.

### 2.2.4 Combustion Turbine Combined Cycle (CTCC)

Description

Combustion turbine combined cycle units use natural gas in a combustion process similar to the CT, but then utilize the waste heat to create steam to rotate a turbine generating additional electricity. It is an efficient process that often allows the CTCC to operate as an intermediate or baseload resource. The short-run economics of a CTCC are similar to purchasing electricity on the New England market because the economics of both alternatives are driven primarily by the prevailing price of natural gas. Like the CT, the CTCC emits $CO_2$ and NOx (albeit at lower rates than the CT), but does not emit $SO_2$ or mercury.

| | |
|---|---|
| Assumed most efficient size for technology: | 560 MW |
| CEA Overnight Capital Cost ($/kW): | $709/kW[11] |
| CEA Overnight Capital Cost ($): | $396.9 million |

Possible Ownership Structures

Development of this technology would likely require partnership of the regulated utilities, possibly with outside investors. Alternatively, a CTCC project could possibly be backed by State Authority.

All-in Real Levelized Cost ($2008/MWh)

| Utility | State Authority | Cooperative |
|---|---|---|
| $54.38 | $53.16 | $52.95 |

Emissions Technologies Assumed

- NOx Reduction - Low-NOx burners

Possible Locations

Gas infrastructure requirements limit potential sites to the gas pipeline-served portion of northwestern Vermont and near Massachusetts pipeline infrastructure in southern Vermont. High-level Considerations for siting a CTCC include:

[11] A smaller-sized CTCC would have a lower absolute capital cost, but a higher capital cost on a $/kW basis. For example, the equipment-only price of a 560MW CTCC is approximately $400/kW, while the equipment-only price for a 250MW CTCC is approximately $500/kW (Source: "Gas Turbine World, 2006 Handbook")

- *Fuel Delivery* – Natural Gas delivered to a CTCC through gas pipelines. Therefore, proximity to existing or potential gas infrastructure is a critical siting consideration.

  A 560MW CTCC, operating at an 85% capacity factor (7,500 hours per year) is expected to consume approximately 28 bcf of natural gas per year. According to VGS, this quantity is not currently feasible due to the size of TransCanada's delivery pipeline on the Canadian side of the border. However, it is possible that TransCanada would be amenable to increasing their delivery capability to provide sufficient gas pressure to Vermont for this purpose. This may require TransCanada to loop approximately 15 miles of their lateral. On the Vermont side, VGS may also need to add a compressor. These combined costs likely represent less than 10% of the CEA Overnight Capital Costs for the CTCC, and are not included in the calculation of either the CEA Overnight Capital Cost or the All-in Real Levelized Cost.

- *Land* – A 560MW CTCC would likely require 20–50 acres of land, a relatively small footprint among baseload facilities. For example, two different 525MW facilities in Newington, NH and Westbrook, ME occupy 24 and 47 acres, respectively.

Environmental Considerations

- Gas-fired plants emit $CO_2$ and NOx, albeit at significantly lower rates than other types of fossil fuel-fired plants. CTCCs emit $CO_2$ and NOx at a lower rate that conventional CTs.

Key Risks

- Natural gas prices are volatile and comprise a large percentage of overall operating costs. In the CEA Base Case, a one standard deviation change in the price of fuel causes a 22.2% change in all-in power costs.
- Efficient unit size is relatively large, potentially creating portfolio diversification concerns.
- Price competitiveness of natural gas as a fuel source.

### 2.2.5 Fuel Cells

Description

Like a battery, a fuel cell consists of an electrolyte between two electrodes. Oxygen passes over one electrode and hydrogen over the other, generating electricity, water and heat. Hydrogen fuel is expensive and, like natural gas from which it is derived, it has a volatile price history. Because of its high marginal cost, a fuel cell would most likely be used in periods of peak electricity demand. Fuel cell sizes can vary. For this study we have analyzed a 10MW solid oxide fuel cell. Fuel cells emit a very small amount of $CO_2$. They produce no NOx, $SO_2$ or mercury.

| | |
|---|---|
| Assumed most efficient size for technology: | 10 MW |
| CEA Overnight Capital Cost ($/kW): | $5,651/kW |
| CEA Overnight Capital Cost ($): | $56.5 million |

Possible Ownership Structures

The development of fuel cells could possibly be backed by three different entities: Investor-owned utilities, State Authority, or Cooperative electric utilities.

All-in Real Levelized Cost ($2008/MWh)

| Utility | State Authority | Cooperative |
|---|---|---|
| $351.23 | $323.73 | $319.17 |

Emissions Technology Assumption

None are assumed. Fuel cells have very limited emissions.

Possible Locations

Because it is possible to store large amounts of hydrogen on site (reducing or eliminating any gas infrastructure siting requirement) and because the efficient size is so small (10 MW) there are few, if any siting limitations for fuel cells. Perhaps the only siting limitation is the ability to deliver hydrogen and the ability to store it on-site.

Environmental Considerations

Fuel cell emissions are essentially zero. Small amounts of $CO_2$ are emitted, but the $CO_2$ emission rate is small when compared to other fossil fuel technologies.

Key Risks

Hydrogen fuel cells are an emerging and unproven technology. Risks include:

- Construction and operating cost risk – As an emerging technology, fuel cells all-in power cost is estimated to change 11.6% in the event of a possible 25% deviation from CEA's capital cost estimate.
- Technical uncertainty/unit life – The technology has little operating history.

### 2.2.6 Integrated Gasification Combined Cycle (IGCC)

Description

IGCCs are baseload, coal-fired units. An IGCC unit heats coal in a "gasifier" to turn the coal into gas, which is then combusted to rotate the combustion turbine in order to generate electricity. The waste heat from the combustion process heats water into steam and turns a turbine to generate additional electricity. While an IGCC unit emits $CO_2$, $SO_2$, NOx and mercury like the other coal technologies, the $SO_2$, NOx and mercury emissions are significantly lower (on a per-megawatt-hour basis) because of the efficiency of the unit design and the use of the waste heat from the initial combustion process. The capture and sequestration of $CO_2$ is an emerging technology that is not expected to reach commercial feasibility during the study period, and is therefore not assumed. However, it will be possible to add this technology to an existing IGCC if it becomes feasible at a future date.

| | |
|---|---|
| Assumed most efficient size for technology: | 640 MW |
| CEA Overnight Capital Cost ($/kW): | $1,998 /kW |
| CEA Overnight Capital Cost ($): | $1.3 billion |

Possible Ownership Structures

Development of this technology would likely require partnership of the regulated utilities, or through a new State-sponsored power authority given the size of the investment. Either of these options would likely require partnership with outside investors.

All-in Real Levelized Cost ($2008/MWh)

| Utility | State Authority | Cooperative |
|---|---|---|
| $56.67 | $53.21 | $52.64 |

Emissions Technology Assumptions

- *NOx Reduction* – Low NOx burners
- *$SO_2$ Reduction* – Solvent used at the end of the gasification cooling process

Possible Locations

Locations are possible along the Connecticut River in southeast and central-east Vermont, and along the Lake Champlain shoreline in the northwest part of the State.
High-level Considerations for siting an IGCC plant include:

- *Fuel Delivery* – Coal is typically delivered to power plants by rail, barge or truck. Therefore, proximity to existing or potential rail and truck-accessible highway are critical siting considerations. A 640MW IGCC plant would require approximately 130,000 tons of coal delivered every month, which would require more than 3,000 deliveries per month by a 40-ton truck or thirteen rail deliveries per month from a 10,000-ton train. CEA does not consider barge delivery to Vermont to be feasible.
- *Cooling Water Source* - IGCC plants require a large source of cooling water. Therefore, proximity to a lake or river with significant reserves is a critical siting consideration.
- *Proximity to Transmission* – As with all other technologies, proximity to existing transmission infrastructure makes siting an IGCC plant more feasible and cost-effective.
- *Land* – Land requirements for a IGCC would be similar for those of a pulverized or CFB coal-fired facility

Environmental Considerations

- As with any technology that requires cooling water, increases in source cooling water temperatures may occur, with potential damage to underwater ecosystems.
- IGCC plants emit $CO_2$, $SO_2$, NOx, and Mercury. $SO_2$, NOx, and Mercury are reduced by the gasification process. However, more stringent emissions caps than expected may make coal-fired plants uneconomic.

Key Risks

- Price competitiveness of coal as a fuel source.
- Future environmental mandates requiring reduced $CO_2$, NOx, and/or Mercury emissions may be costly.
- Efficient unit size is relatively large, potentially creating portfolio diversification concerns.
- IGCC technology is still in its commercial infancy in the US, creating uncertainty around durability, capital and operating cost predictability, and unit life.

### 2.2.7 Nuclear Generation

Description

Nuclear plants use uranium-filled rods in a controlled radioactive process to convert water into steam which rotates a turbine, generating electricity. Nuclear plants are capital intensive and are typically built (economically) in sizes 1,000 MW and larger. Given their large capital costs, the relatively low (albeit rising) cost of nuclear fuel, and operational characteristics, a nuclear plant will always serve as a baseload resource. Nuclear plants do not emit $CO_2$, NOx, $SO_2$ or mercury.

| | |
|---|---|
| Assumed most efficient size for technology: | 1,350 MW |
| CEA Overnight Capital Cost ($/kW): | $2,556 /kW |
| CEA Overnight Capital Cost ($): | $3.5 billion |

Possible Ownership Structures

Development of this technology would likely require partnership of the regulated utilities, or through a new State-sponsored power authority given the size of the investment. Either of these options would likely require partnership with outside investors.

All-in Real Levelized Cost ($2008/MWh)

| Utility | State Authority | Cooperative |
|---|---|---|
| $54.42 | $50.48 | $49.82 |

Possible Locations

Given the extensive environmental and geographical characteristics required to site a new nuclear unit, the most likely feasible site would be at or adjacent to the Vermont Yankee Nuclear plant. This location would likely provide the necessary infrastructure (with upgrades) at the lowest cost.

However, a significant potential binding constraint is the use of cooling water. VT Yankee is currently restricted from using the Connecticut River as a source of cooling water during the summer months due to the potential negative effect on native fish stocks and the resultant increase in river water temperature around the discharge point. The current NPDES permit, which governs Vermont Yankee's use of Connecticut River for cooling water is being appealed in VT Environmental Court by the Connecticut River Watershed Council. An additional 1,350 MW proposed plant would almost certainly face similar or more severe restrictions, and raise significant concerns from stakeholders interested in limiting the effects that a plant would have on the Connecticut River temperature and fish population. While a new plant could use cooling towers to avoid using the Connecticut River, this would reduce the thermal efficiency of the plant, may be constrained by well water restrictions, and may be opposed due to the visual aesthetics of the towers.

Environmental Considerations

- There is currently no long-term solution in the US for the disposal and storage of spent nuclear fuel and high-level nuclear waste. The interim solution is on-site storage, which poses additional safety and environmental risks.
- As with any technology that requires cooling water, increases in source cooling water temperatures may occur, with potential damage to underwater ecosystems as noted above.

- Nuclear plants do not emit $CO_2$, NOx, $SO_2$ or Mercury (if NOx, Mercury and/or $CO_2$ emissions are further restricted, operation of the plant will become more economic).
- It is not uncommon for environmental studies to reveal the seepage of radioactive material (tritium etc.) in to the ground, and eventually the groundwater of the site and the land directly around the site.
- The repercussions of an accident at a nuclear plant could have far more negative consequences than a similar accident at a non-nuclear facility.
- Closed-loop water circulation technology, which cools through evaporation, would eliminate the return of warmer water into the natural water supply. While the closed loop system addresses the environmental concerns about heating natural water sources, it can place significant demand on the local water supply.

Key Risks

- There is at least a 10-year lead time required to site and build a nuclear power plant. This extends well beyond the initial years of the Supply Gap, and increases the risk that the plant's capital cost and other financial considerations will vary during that time period.
- A costly issue discovered at one nuclear plant would have the potential to spur NRC mandates requiring significant capital spending at all other nuclear plants.
- Nuclear plants are subject to homeland security risk due to on-site storage of nuclear materials.
- Efficient unit size is relatively large, potentially creating portfolio diversification concerns.
- A new nuclear plant has not been built in the U.S. for decades. Current technology is therefore still in its commercial infancy, creating uncertainty around durability, capital and operating cost predictability, and unit life.
- Price competitiveness of uranium as a fuel source.

### 2.2.8 Solar Generation (Photovoltaic)

Description

Photovoltaic solar power units use photovoltaic cells to convert sunlight directly into electricity. They are typically small (1-10MW capacity) and are expensive on a $/kW basis. Once built, the variable operating costs are relatively low, given that there is no fuel cost. Because the strength of the sunlight on a given day is unpredictable, these units typically operate only 20% (approximately) of the time. Solar units are not "dispatchable", meaning the operator can not ramp up or ramp down the unit's output on demand. These units do not emit $CO_2$, NOx, $SO_2$ or mercury.

| | |
|---|---|
| Assumed most efficient size for technology: | 5 MW |
| CEA Overnight Capital Cost ($/kW): | $5,864/kW |
| CEA Overnight Capital Cost ($): | $29 million |

Possible ownership structures

Investor-owned utilities, a State Authority, or Cooperative electric utilities are all potential owners of this technology.

All-in Real Levelized Cost ($2008/MWh):

| Utility | State Authority | Cooperative |
|---|---|---|
| $245.82 | $205.16 | $198.41 |

Possible Locations

Solar technology is not highly dependant upon infrastructure, so it can be located anywhere in Vermont with open land and reasonable transmission access.

Environmental Considerations

Land use is intensive. A 5 MW photovoltaic installation would require 30 – 35 acres of cleared land, with good southern-facing sun exposure.[12]

Key Risks

Photovoltaic solar power is an emerging and unproven technology. Risks include:

- Construction and operating cost risk.
- As an emerging technology, solar generation has technical and unit life uncertainties.
- Lack of adequate solar exposure/weather reliability, causing degradation in capacity factor. The amount of sola radiation reaching the ground in Vermont is significantly less than in some other parts of the country.

### 2.2.9 Wind Turbines

Description

Wind turbines rely on the wind to rotate a turbine to generate electricity. Because a wind farm is typically comprised of several small (1-2 MW) wind turbines, the size of the farm is usually flexible. Some Midwest wind farms exceed 300MW, although Vermont's terrain and siting will permit capacity sizes in the range of perhaps 50MW. A 16-turbine, 40MW Sheffield wind farm was recently approved by the Vermont Public Service Board after three years of consideration. Wind turbines must be sited in areas that meet specific meteorological requirements in order to operate economically. Capacity factor for wind technologies varies considerably with the wind regime at the site. Wind units are not dispatchable. These units do not emit $CO_2$, NOx, $SO_2$ or mercury.

| | |
|---|---|
| Assumed most efficient size for technology: | 50 MW |
| CEA Overnight Capital Cost ($/kW): | $1,999/kW |
| CEA Overnight Capital Cost ($): | $100 million |

Possible Ownership Structures

The development of wind turbines could possibly be backed by investor-owned utilities or by a State Authority.

All-in Real Levelized Cost ($2008/MWh)

| Utility | State Authority | Cooperative |
|---|---|---|
| $77.61 | $68.86 | $67.41 |

[12] Source: U.S. Department of Energy, National Renewable Energy Lab.

Possible Locations

The prime locations are on the Green Mountain spine, and along the high ridges in the eastern and northeastern parts of the State. These prime locations are few in number, and at least two of which are already dedicated to existing projects. High-level considerations for siting a wind farm include:

- *Proximity to Transmission* – As with all other technologies, proximity to existing transmission infrastructure makes siting wind turbines more feasible and cost-effective.
- *Meteorological Characteristics* – A feasible site requires attractive seasonal, directional and time-of-day wind characteristics that can be ascertained through a meteorological study.
- *Viewshed* – A history of failed wind projects in Vermont can most commonly be traced to political opposition to disturbing the views of a ridgeline. Preferred locations are away from population centers.
- *Land Use* – The Sheffield project required dedicating approximately 3,000 acres to the project, 2,700 of which is to be conserved for bear habitat.

Environmental Considerations

- The best wind regimes in Vermont occur on ridgelines. These locations also have the greatest effect on the viewshed.
- Potential to disturb local bird and bat populations.

Key Risks

- *Capacity factor* – Capacity factors for wind technologies varies considerably with the wind regime at the site. Based on Vermont sources, we have estimated a 33% capacity factor for Vermont-based wind. However, there is a limited supply of these favorable sites, and capacity factors can fluctuate by as much as 10% downward over the course of a given year, regardless of the site selected. Further, wind generation is difficult to forecast on an hour-to-hour basis, and therefore cannot be relied upon as a significant capacity resource.
- *Construction Cost Escalation* – Costs to develop wind farms have been increasing at a faster pace than costs associated with any of the other technologies included in this study.

### 2.2.10 Wood-Fired Generation, Circulating Fluidized Bed (CFB)

Description

Wood (CFB) units utilize the same technology as the coal (CFB) units except that they burn wood biomass instead of coal. Like coal, the cost of wood biomass fuel is relatively low allowing wood (CFB) units to serve as an intermediate or baseload resource. Wood (CFB) units reduce NOx emissions and have no emissions of $CO_2$, $SO_2$ or mercury. While carbon monoxide is produced, wood biomass generation is neutral with respect to $CO_2$ emissions since the wood fuel emits the same amount of $CO_2$ regardless of whether it decays on the ground or is burned at the plant. This technology is more expensive but less reliable than the Stoker technology described below.

| | |
|---|---|
| Assumed most efficient size for technology: | 50 MW |
| CEA Overnight Capital Cost ($/kW): | $2,445/kW |
| CEA Overnight Capital Cost ($): | $122 million |

Possible Ownership Structures

The development of wood (CFB) units could possibly be backed by one or more investor owned utilities or by a newly formed State Power Authority.

All-in Real Levelized Cost ($2008/MWh)

| Utility | State Authority | Cooperative |
|---|---|---|
| $70.37 | $66.03 | $65.32 |

Possible Locations

To keep costs low, wood biomass technology should be sited to accommodate fuel transportation by truck. At the McNeil plant in Burlington, approximately 75% of the fuel is shipped by train from points throughout Northern New England, which means that transportation is responsible for nearly 50% of the plant's total fuel cost. McNeil plant manager John Irving indicates that preferred sites such as Franklin County, or Bennington, would reduce this transportation cost. These locations have the best wood lots, and may therefore obviate the need for bimodal transportation (train and truck). It should be noted, however, that trucking in 100% of fuel requirements would increase highway traffic and truck emissions.

Environmental Considerations

- While wood-fired (CFB) plants emit carbon monoxide and NOx, they emit no $CO_2$, $SO_2$ or mercury.
- Contributes to degradation of New England/New York forests in the event of over-cutting.
- Fuel transportation via train and/or truck is an additional source of air pollution and highway congestion.

Key Risks

- Unpredictable capital costs and fuel costs. According to the VT ANR, a 50 MW wood-fired facility would likely increase regional wood prices slightly and temporarily. This price increase has been reflected in the financial model.
- Limited efficiency.
- Wood-fired plants require more personnel than fossil fuel plants.

### 2.2.11 Wood-Fired Generation, Stoker Technology

Description

Wood (stoker) units burn wood chips in a boiler to create steam to rotate the turbine to generate electricity. Wood is a relatively cheap and abundant resource, giving these units a low marginal cost, and allowing them to serve as intermediate or baseload resources. Wood (Stoker) units emit NOx but do not emit $CO_2$, $SO_2$ or mercury. While carbon monoxide is produced, wood biomass generation is neutral with respect to $CO_2$ emissions since the wood fuel emits the same amount of $CO_2$ regardless of whether it decays on the ground or is burned at the plant.

| | |
|---|---|
| Assumed most efficient size for technology: | 50 MW |
| CEA Overnight Capital Cost ($/kW): | $2,315/kW |
| CEA Overnight Capital Cost ($): | $116 million |

Possible Ownership Structures

The development of wood (stoker) units could possibly be backed by one or more investor-owned utilities or by a newly-formed State Power Authority.

All-in Real Levelized Cost ($2008/MWh)

| Utility | State Authority | Cooperative |
|---|---|---|
| $75.03 | $70.92 | $70.24 |

Possible Locations

As with the Wood CFB technology, the Stoker technology should be sited to accommodate fuel transportation by truck in order to keep costs low. At the McNeil plant in Burlington, approximately 75% of the fuel is shipped by train from points throughout Northern New England, which means that transportation is responsible for nearly 50% of the plant's total fuel cost. McNeil plant manager John Irving indicates that preferred sites such as Franklin County, or Bennington, would reduce this transportation cost. These locations have the best wood lots, and may therefore obviate the need for bimodal transportation (train and truck). It should be noted, however, that trucking in all fuel would increase highway traffic and truck emissions.

Environmental Considerations

- Wood-fired stoker plants emit carbon monoxide and NOx. They emit no $SO_2$ or mercury, and are $CO_2$ –neutral as noted above.
- Contributes to degradation of New England/New York forests in the event of over-cutting.
- Fuel transportation via train and/or truck is an additional source of air pollution and highway congestion.

Key Risks

- Unpredictable capital costs and fuel costs.
- Limited efficiency.
- Wood-fired plants require more personnel than fossil fuel plants.

### 2.3 Cost of Service Model Overview

CEA used a revenue requirements model to determine the cost to customers of building and operating each technology. The main output of the model is a real levelized cost of electricity for each technology on a 2008$/MWh basis. The real levelized cost of electricity was calculated using the following formula:

All-in Real Levelized Cost ($/MWh) = A / B

Where;

$A = NPV (WACC, COP_1, COP_2, COP_3, \ldots COP_N)$

And

B = PMT (REAL_WACC, N, A)

NPV = Net Present Value
WACC = Discount rate of 8.72%
COP = Total Costs of Production (including AFUDC, fixed and variable O&M, maintenance capital, fuel expenses, depreciation, return on rate base, property taxes and insurance)
N = Number of years in the unit's expected useful life
REAL_WACC = Real discount rate of 5.66%

## 2.4 RESULTS OF THE COST OF SERVICE MODEL

The following tables summarize the base-case results of CEA's real levelized cost analysis for three different ownership structures. The financing and ownership scenarios are described further in Section 3.

Column 5 represents the all-in real levelized cost expressed in $/MWh. This figure is comparable across all technologies, but superior or inferior technologies can not be inferred from this figure alone. Columns 7-9 represent potential revenue streams (negative costs) available to the project once built. Column 7 may or may not be a credit to the project depending on the owner's obligation to own capacity in order to comply with ISO-New England reliability requirements. Columns 10-12 are potential additional revenue streams for renewable technologies. These revenues are not included in column 5 due to their uncertain nature of these programs. Items 13-15 provide additional risk parameters with respect to each technology.

### 2.4.1 The Utility-Led Financing Option

This scenario considers the financing of different generation projects by GMP and/or CVPS through a traditional rate-base approach.

| Utility-Led Financing Alternative | | | | | Included in Levelized Energy [3] | Base Load Technologies Only | | | Not Included in Levelized Energy [3] | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| (1) Generation Type/Size | (2) Real Levelized Capacity $/Kw-yr | (3) Real Levelized Energy $/Mwh | (4) CF | (5) Real Levelized All-in $/Mwh | (6) Real Levelized Emissions $/Mwh | (7) Real Levelized FCM Credits $/Mwh | (8) Real Levelized Energy Credits $/Mwh | (9) All-in Costs Less All-in Credits $/Mwh | (10) Real Levelized PTCs $/Mwh | [11] Real Levelized RECs $/Mwh | [12] Real Levelized IGCC Credits $/Mwh | [13] Capacity Cost Risk factor Level | [14] Energy Cost Risk Factor Level | [15] Lead Time Years |
| Coal (CFB) | $198.70 | $36.83 | 84% | $63.83 | $5.20 | ($6.80) | ($84.15) | ($27.12) | $0.00 | $0.00 | $0.00 | Medium | Low | 6 |
| Coal (Pulverized) | $164.59 | $31.33 | 84% | $53.69 | $4.85 | ($6.80) | ($84.15) | ($37.25) | $0.00 | $0.00 | $0.00 | Low | Low | 4 |
| CT (50MW) | $81.34 | $70.35 | 10% | $163.20 | $3.52 | | | | $0.00 | $0.00 | $0.00 | Low | High | 2 |
| CT (25MW) | $92.71 | $70.35 | 10% | $176.18 | $3.52 | | | | $0.00 | $0.00 | $0.00 | Low | High | 2 |
| CTCC | $62.98 | $45.93 | 85% | $54.38 | $2.12 | ($8.34) | ($84.07) | ($38.02) | $0.00 | $0.00 | $0.00 | Low | High | 4 |
| Fuel Cell | $431.90 | $186.89 | 30% | $351.23 | $1.89 | | | | $0.00 | ($26.09) | $0.00 | High | High | 3 |
| IGCC | $188.73 | $29.74 | 80% | $56.67 | $4.12 | ($7.14) | ($84.15) | ($34.62) | $0.00 | $0.00 | ($0.21) | High | Low | 6 |
| Nuclear | $212.58 | $27.15 | 89% | $54.42 | $0.00 | ($5.72) | ($84.56) | ($35.87) | $0.00 | $0.00 | $0.00 | High | Medium | 10 |
| Solar | $452.20 | $0.00 | 21% | $245.82 | $0.00 | | | | ($6.70) | ($26.09) | $0.00 | High | None | 2 |
| Wind | $211.32 | $4.51 | 33% | $77.61 | $0.00 | | | | ($7.50) | ($25.09) | $0.00 | Medium | None | 5 |
| Wood (CFB) | $224.12 | $39.55 | 83% | $70.37 | $0.37 | ($8.83) | ($84.07) | ($22.53) | ($6.70) | ($26.09) | $0.00 | Medium | Medium | 4 |
| Wood (Stoker) | $223.70 | $44.26 | 83% | $75.03 | $0.74 | ($8.83) | ($84.07) | ($17.88) | ($6.70) | ($26.09) | $0.00 | Low | Medium | 4 |

(1) - Type and scale of technology
(2) - (3) Real levelizeded capacity and energy costs
[4] - Projected capacity factor
(5) - Real levelized all-in cost at representative capacity factor for technology
(6) - Real levelized emissions cost $/Mwh
[7-9] - Projected real levelized capacity and energy market receipts
[10-12] - Other incentives/credits not included in the "All-in" cost in column 5. Note that PTC and EPAct2005 credits only apply to Utility and Coop sponsored scenarios
(13-14) - Relative score reflecting volatility of capacity and energy cost
(15) - Required lead time

### 2.4.2 The State Authority Financing Option

This scenario involves the formation of a new State-sponsored power authority that would borrow based on the credit of its project or projects, but may involve some backing by the State in order to lower borrowing costs.

| State Authority Financing Alternative | | | | | Included in Levelized Energy [3] | Base Load Technologies Only | | | Not Included in Levelized Energy [3] | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| (1) Generation Type/Size | (2) Real Levelized Capacity $/Kw-yr | (3) Real Levelized Energy $/Mwh | (4) CF | (5) Real Levelized All-in $/Mwh | (6) Real Levelized Emissions $/Mwh | (7) Real Levelized FCM Credits $/Mwh | (8) Real Levelized Energy Credits $/Mwh | (9) All-in Costs Less All-in Credits $/Mwh | (10) Real Levelized PTCs $/Mwh | [11] Real Levelized RECs $/Mwh | [12] Real Levelized IGCC Credits $/Mwh | [13] Capacity Cost Risk factor Level | [14] Energy Cost Risk Factor Level | [15] Lead Time Years |
| Coal (CFB) | $170.16 | $36.83 | 84% | $59.95 | $5.20 | ($6.80) | ($84.15) | ($31.00) | $0.00 | $0.00 | $0.00 | Medium | Low | 6 |
| Coal (Pulverized) | $141.81 | $31.33 | 84% | $50.60 | $4.85 | ($6.80) | ($84.15) | ($40.35) | $0.00 | $0.00 | $0.00 | Low | Low | 4 |
| CT (50MW) | $69.15 | $70.35 | 10% | $149.29 | $3.52 | | | | $0.00 | $0.00 | $0.00 | Low | High | 2 |
| CT (25MW) | $78.59 | $70.35 | 10% | $160.07 | $3.52 | | | | $0.00 | $0.00 | $0.00 | Low | High | 2 |
| CTCC | $53.83 | $45.93 | 85% | $53.16 | $2.12 | ($8.34) | ($84.07) | ($39.25) | $0.00 | $0.00 | $0.00 | Low | High | 4 |
| Fuel Cell | $359.62 | $186.89 | 30% | $323.73 | $1.89 | | | | $0.00 | ($26.09) | $0.00 | High | High | 3 |
| IGCC | $164.51 | $29.74 | 80% | $53.21 | $4.12 | ($7.14) | ($84.15) | ($38.08) | $0.00 | $0.00 | $0.00 | High | Low | 6 |
| Nuclear | $181.86 | $27.15 | 89% | $50.48 | $0.00 | ($5.72) | ($84.56) | ($39.81) | $0.00 | $0.00 | $0.00 | High | Medium | 10 |
| Solar | $377.40 | $0.00 | 21% | $205.16 | $0.00 | | | | $0.00 | ($26.09) | $0.00 | High | None | 2 |
| Wind | $186.03 | $4.51 | 33% | $68.86 | $0.00 | | | | $0.00 | ($25.09) | $0.00 | Medium | None | 5 |
| Wood (CFB) | $192.59 | $39.55 | 83% | $66.03 | $0.37 | ($8.83) | ($84.07) | ($26.87) | $0.00 | ($26.09) | $0.00 | Medium | Medium | 4 |
| Wood (Stoker) | $193.85 | $44.26 | 83% | $70.92 | $0.74 | ($8.83) | ($84.07) | ($21.98) | $0.00 | ($26.09) | $0.00 | Low | Medium | 4 |

(1) - Type and scale of technology
(2) - (3) Real levelizeded capacity and energy costs
[4] - Projected capacity factor
(5) - Real levelized all-in cost at representative capacity factor for technology
(6) - Real levelized emissions cost $/Mwh
[7-9] - Projected real levelized capacity and energy market receipts
[10-12] - Other incentives/credits not included in the "All-in" cost in column 5. Note that PTC and EPAct2005 credits only apply to Utility and Coop sponsored scenarios
(13-14) - Relative score reflecting volatility of capacity and energy cost
(15] - Required lead time

### 2.4.3 The Coop Financing Option

This scenario involves a financing at one or more of the Vermont electric cooperatives, using a blend of project-backed financing and Federally-sponsored loans. This scenario has the lowest cost of financing, but many of the larger projects would not be feasible as they would not be in keeping with the corporate mandate of the cooperatives and may also disqualify the cooperatives from borrowing at the lower Federally-sponsored rates.

| Coop Financing Alternative | | | | | Included in Levelized Energy [3] | Base Load Technologies Only | | | Not Included in Levelized Energy [3] | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| (1) Generation Type/Size | (2) Real Levelized Capacity $/Kw-yr | (3) Real Levelized Energy $/Mwh | (4) CF | (5) Real Levelized All-in $/Mwh | (6) Real Levelized Emissions $/Mwh | (7) Real Levelized FCM Credits $/Mwh | (8) Real Levelized Energy Credits $/Mwh | (9) All-in Costs Less All-in Credits $/Mwh | (10) Real Levelized PTCs $/Mwh | [11] Real Levelized RECs $/Mwh | [12] Real Levelized IGCC Credits $/Mwh | [13] Capacity Cost Risk factor Level | [14] Energy Cost Risk Factor Level | [15] Lead Time Years |
| Coal (CFB) | $165.43 | $36.83 | 84% | $59.31 | $5.20 | ($6.80) | ($84.15) | ($31.64) | $0.00 | $0.00 | $0.00 | Medium | Low | 6 |
| Coal (Pulverized) | $138.03 | $31.33 | 84% | $50.09 | $4.85 | ($6.80) | ($84.15) | ($40.86) | $0.00 | $0.00 | $0.00 | Low | Low | 4 |
| CT (50MW) | $67.13 | $70.35 | 10% | $146.98 | $3.52 | | | | $0.00 | $0.00 | $0.00 | Low | High | 2 |
| CT (25MW) | $76.25 | $70.35 | 10% | $157.39 | $3.52 | | | | $0.00 | $0.00 | $0.00 | Low | High | 2 |
| CTCC | $52.31 | $45.93 | 85% | $52.95 | $2.12 | ($8.34) | ($84.07) | ($39.46) | $0.00 | $0.00 | $0.00 | Low | High | 4 |
| Fuel Cell | $347.63 | $186.89 | 30% | $319.17 | $1.89 | | | | $0.00 | ($26.09) | $0.00 | High | High | 3 |
| IGCC | $160.49 | $29.74 | 80% | $52.64 | $4.12 | ($7.14) | ($84.15) | ($38.65) | $0.00 | $0.00 | ($0.21) | High | Low | 6 |
| Nuclear | $176.77 | $27.15 | 89% | $49.82 | $0.00 | ($5.72) | ($84.56) | ($40.46) | $0.00 | $0.00 | $0.00 | High | Medium | 10 |
| Solar | $365.00 | $0.00 | 21% | $198.41 | $0.00 | | | | ($6.70) | ($26.09) | $0.00 | High | None | 2 |
| Wind | $181.84 | $4.51 | 33% | $67.41 | $0.00 | | | | ($7.50) | ($25.09) | $0.00 | Medium | None | 5 |
| Wood (CFB) | $187.36 | $39.55 | 83% | $65.32 | $0.37 | ($8.83) | ($84.07) | ($27.59) | ($6.70) | ($26.09) | $0.00 | Medium | Medium | 4 |
| Wood (Stoker) | $188.90 | $44.26 | 83% | $70.24 | $0.74 | ($8.83) | ($84.07) | ($22.66) | ($6.70) | ($26.09) | $0.00 | Low | Medium | 4 |

(1) - Type and scale of technology
(2) - (3) Real levelizeded capacity and energy costs
[4] - Projected capacity factor
(5) - Real levelized all-in cost at representative capacity factor for technology
(6) - Real levelized emissions cost $/Mwh
[7-9] - Projected real levelized capacity and energy market receipts
[10-12] - Other incentives/credits not included in the "All-in" cost in column 5. Note that PTC and EPAct2005 credits only apply to Utility and Coop sponsored scenarios
(13-14) - Relative score reflecting volatility of capacity and energy cost
(15] - Required lead time

### 2.5 Emissions Analysis

Table 1 below ranks the 11 technologies by their estimated emissions rates, as expressed as the mass of effluent emitted for every MWh of energy produced. While these assumptions provide guidance as to the most and least attractive from an emissions standpoint, it is important to remember that this table does not depict the overall environmental footprint of each technology as described further in the technology summaries in Section 2.2. For example, while nuclear is a zero-emissions technology, it has significant land, water, spent fuel storage, and event risk issues that must be considered in order to get a more complete picture of the environmental trade-offs for this technology.

**Table 1: CEA Emissions Rates Assumptions**

| | CO2 (lbs/MWh) | SO2 (lbs/MWh) | NOx (lbs/MWh) | Mercury (tons/MWh) |
|---|---|---|---|---|
| **Coal, CFB** | 1,999 | 1.8 | 0.7 | 0.01 |
| **Coal, PV** | 1,825 | 1.0 | 0.9 | 0.02 |
| **IGCC** | 1,755 | 0.1 | 0.4 | 0.01 |
| **CT (50MW)** | 1,269 | 0.0 | 0.3 | 0.0 |
| **CT (25MW)** | 1,269 | 0.0 | 0.3 | 0.0 |
| **CTCC** | 797 | 0.0 | 0.1 | 0.0 |
| **Fuel Cell** | 725 | 0.0 | 0.0 | 0.0 |
| **Wood, Stoker** | 0 | 0.0 | 1.0 | 0.0 |
| **Wood, CFBC** | 0 | 0.0 | 0.5 | 0.0 |
| **Nuclear** | 0 | 0.0 | 0.0 | 0.0 |
| **Solar** | 0 | 0.0 | 0.0 | 0.0 |
| **Wind** | 0 | 0.0 | 0.0 | 0.0 |

### 2.6 Scenario Analysis

CEA has created sensitivity analyses based on different technology/operational scenarios within each of the three financing scenarios shown above. In CEA's opinion, the factors with the most potential to change the above results are:

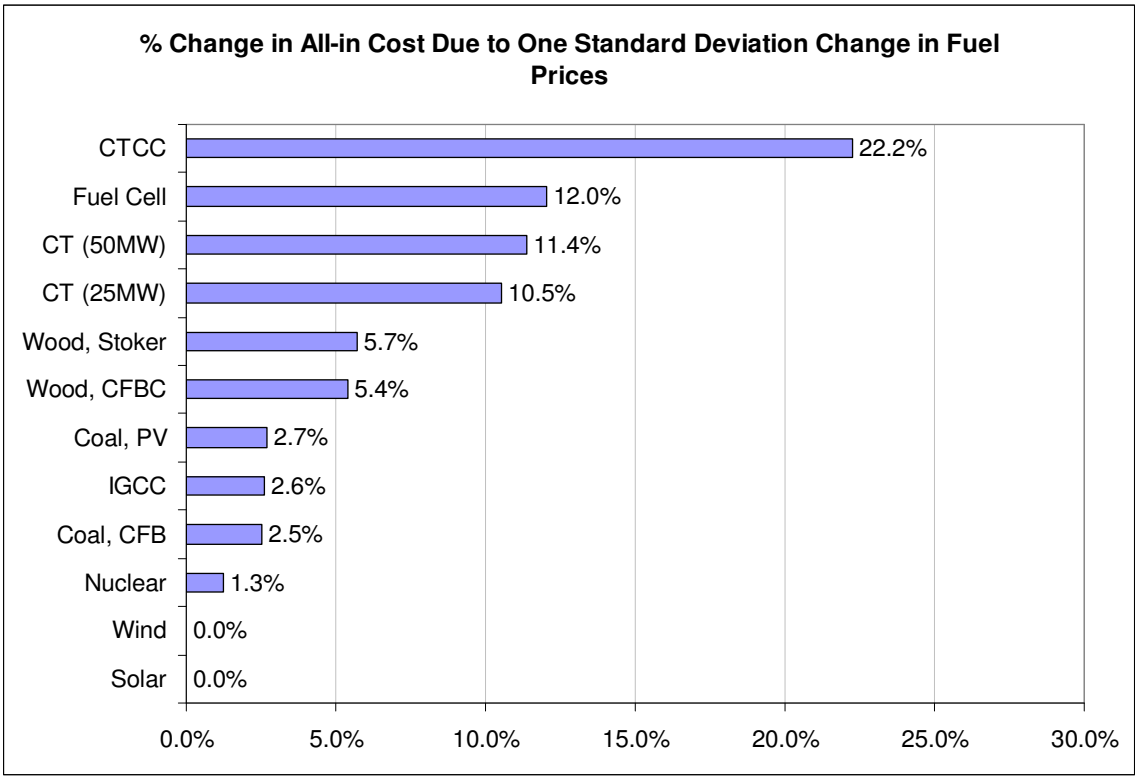
- *Fuel Costs* - The price of fuel for generation has been volatile during the past ten years, particularly with respect to natural gas. Other fuels, including uranium (for nuclear fuel), coal and wood have shown steady but still persistent increases. This sensitivity analysis tests the effects of changes in fuel costs from the base case projections.
- *Capital Costs* - Capital costs for most technologies have escalated recently due to strong demand for generating assets and their components, high and increasing steel prices, and strong demand for skilled labor. This sensitivity analysis tests the effects of changes in capital costs from the base-case assumptions.
- *Capacity Factor* - While capacity factors are usually fairly stable for most technologies in most regions, the number of hours that a certain technology will run can vary considerably in the event of mechanical failure, the development of lower-cost competing supply, disruptions in fuel supply (or meteorological factors, in the case of wind turbine technology), and other factors. This sensitivity analysis tests the effects of changes in capacity factor from the base-case assumptions.

The following charts display the results of sensitivity analyses run off of the Utility-led base-case levelized all-in cost/MWh.

### 2.6.1 Fuel Price Sensitivity

An increase in fuel prices will have more of an effect on a technology for which fuel is a large percentage of the all-in cost/MWh (e.g., CTCC) than on a technology for which fuel is a small percentage of the all-in cost/MWh (e.g., nuclear). Furthermore, some technologies rely on fuels which have had volatile price histories. To measure each technology's sensitivity to fuel prices, CEA calculated the percentage change in the all-in cost/MWh of each technology that would result from a change to the base-case fuel forecast changing of one standard deviation of that fuel's historic price.

**Figure 3**




### 2.6.2 Capital Cost Sensitivity

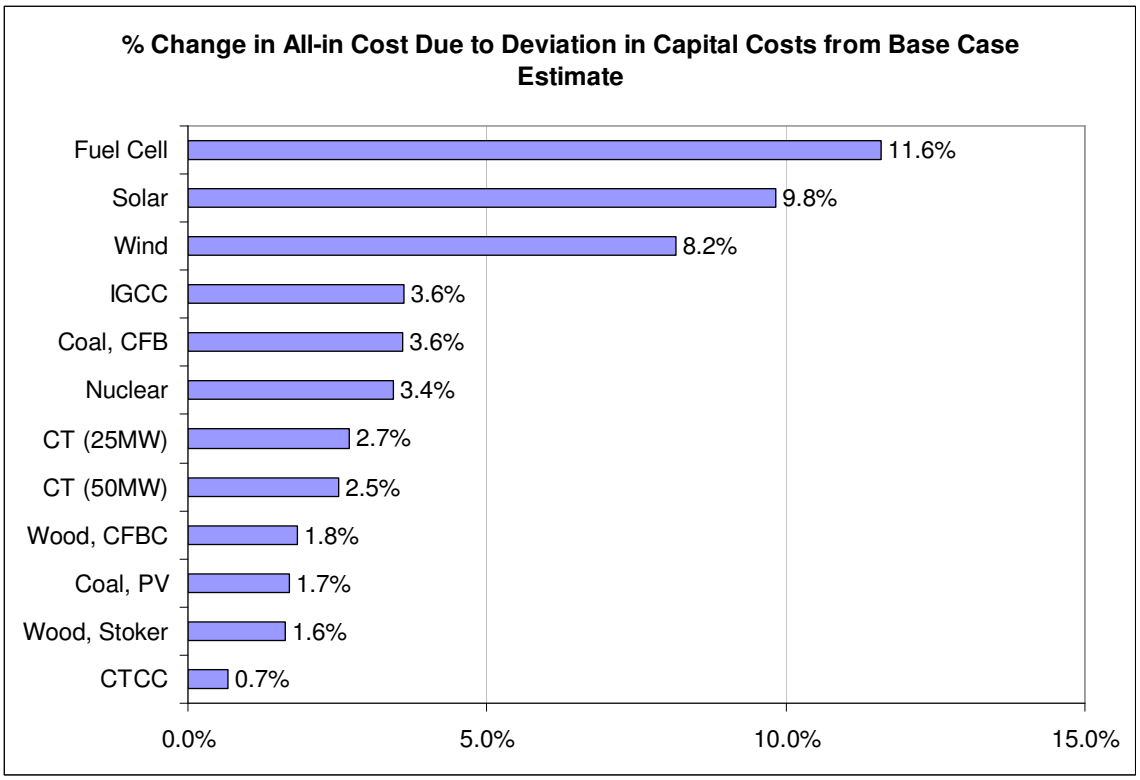
The following chart displays the effect of a deviation from the base-case capital cost estimate on the all-in levelized cost/MWh for each technology. Because cost estimates are likely to be more accurate for mature technologies than for emerging technologies, the percentage deviation for emerging technologies is assumed to be greater. The assumptions underlying Figure 4 are as follows:

*Mature Technologies* – 5% deviation from base-case capital cost estimate: Coal (PV), CT (25MW), CT (50MW), CTCC, Wood (CFBC), Wood (Stoker).

*Semi-Mature Technologies* – 10% deviation from base-case capital cost estimate: Coal (CFB), IGCC, Nuclear, Solar, Wind.

*Emerging Technologies* – 25% deviation from base-case cost estimate: Fuel Cell.

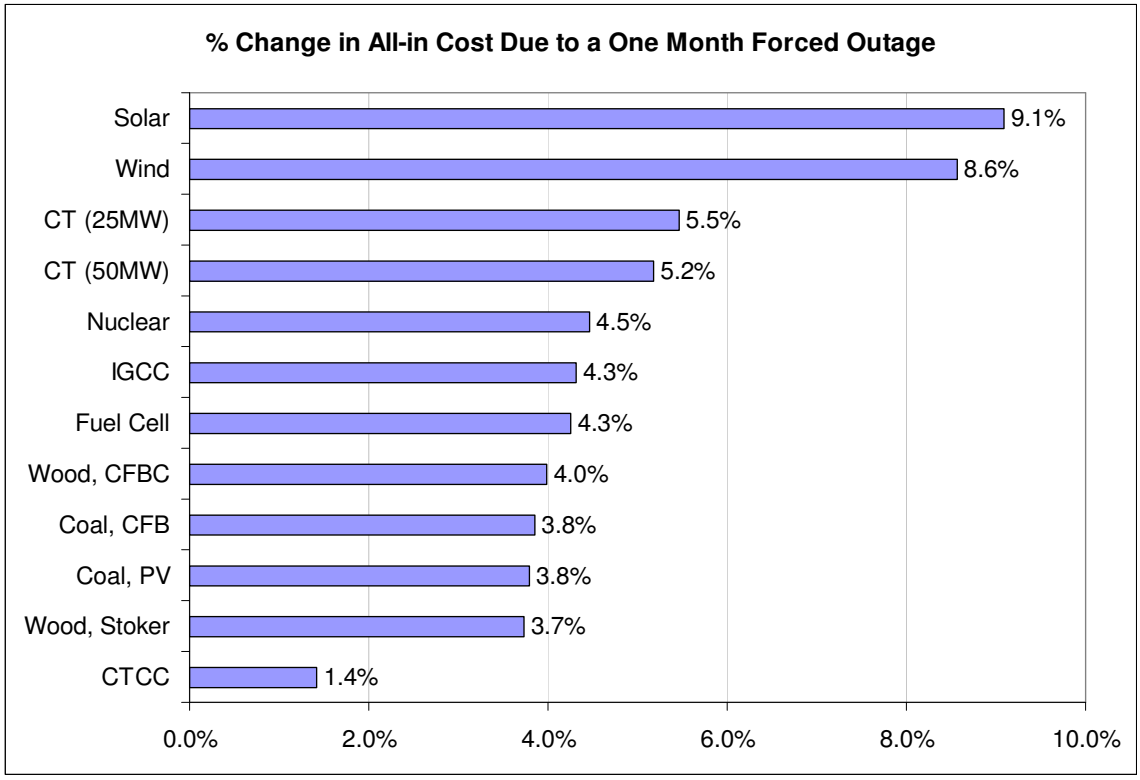
**Figure 4**



### 2.6.3 Capacity Factor Sensitivity

To determine the effect of a reduction in expected capacity factor, we compared the base-case results to the all-in levelized cost/MWh assuming there was a one-month forced outage for each year of the analysis. For example, the base-case capacity factor assumption for the CTCC is 85%. A one month forced outage would reduce the expected capacity factor to 78% (85% - 85% * (1/12)).

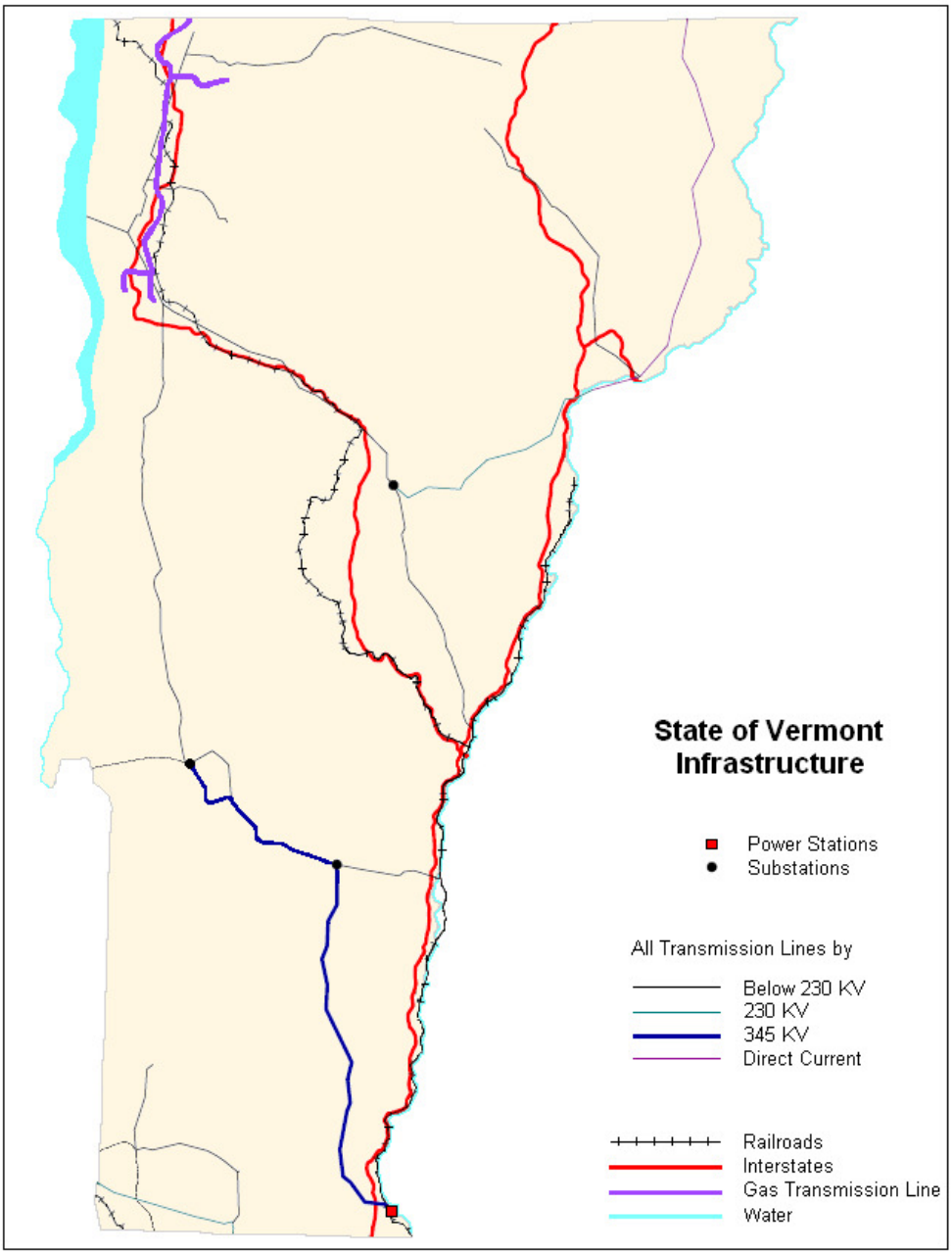
**Figure 5**



### 2.7 Siting Locations and Additional Required Infrastructure

Certain infrastructure or site characteristics must be in place to operate generation technologies considered in this analysis. The map in Figure 6 displays the location of key infrastructure such as interstate highways, gas transmission lines, electric transmission lines, and major waterways.

**Figure 6: Vermont Generation Infrastructure Map**




Access to certain key infrastructure, along with Vermont's rugged topography, makes some locations in the State more feasible and cost effective for siting new power plants than other areas. For example: the operation of any type of large coal-fired plant requires access to a large source of water for cooling and access to a railway or barge route for fuel transportation a nuclear facility similarly

needs access to a major water source a gas-fired power plant (CT or combined cycle) requires access to a gas pipeline system while a wind farm requires a high degree of wind exposure, such as along a major ridgeline.

CEA's financial modeling accounts only for the costs of building a plant and connecting it to required fuel and transmission lines, assuming that these lines are already adjacent to the plant. The construction of some of the larger plants could require significant additional costs in this regard. These costs would depend mostly upon the length of the lines and the terrain and population density of areas across which the lines are built. These costs are described below.

### 2.7.1 Electric Transmission Line Additions

VELCO has indicated that the cost of constructing a 115 kV transmission line is likely to range between $1 and $2 million per mile. These cost estimates refer to conventional overhead construction, as opposed to underground construction, which would be more expensive. The factors that will affect the cost include: presence of existing rights-of-way, construction challenges (size of the corridor, obstructions encountered etc.), time of year, and the speed of construction.[13]

### 2.7.2 Gas Transmission Line Additions

VGS has estimated the cost of transmission system expansion to serve a proposed generation facility to range from $0.9 million/mile to $1.4 million/mile, depending primarily upon the terrain in various parts of Vermont. Significantly bigger pipelines may cost as much as $2.0 million/mile. A table of these detailed costs is provided in Appendix D. The costs presented are high level costs; actual costs will depend on the proposed location, pressure requirements, and peak day demand. In many cases, a dual fuel generation facility will significantly reduce the cost by avoiding the need to install significant gas transmission capacity to serve the plant year-round. VGS is a winter peaking system and has extra capacity in the summer months.[14]

## 2.8 Regulation in Vermont as it Pertains to Generation

There is a broad landscape of regulatory and legislative programs that set the backdrop for new resources of generation in Vermont. Unlike many northeast states, Vermont has not restructured its electricity markets. Electric utilities were not forced to divest their generation assets and instead remain vertically integrated, fully regulated entities charging wholesale generation rates based on a regulated return on their invested capital.

In order to meet their collective obligations to provide consumers reliable, quality service at fair prices, Vermont's electric utilities consider several factors when making resource planning decisions. These considerations include, but are not limited to: cost (both on an absolute level as well as price volatility/risk), reliability, safety, diversification, demand-side management, transmission considerations, and environmental and social impacts. Assessing the feasibility of siting new generation in Vermont should consider those same factors.

[13] Source: VELCO.

[14] Source: Vermont Gas Systems, Inc.

Utility Investment – While the public is best served by a low cost resource of electricity, Vermont's electric utilities must take certain considerations in to account besides the simple all-in levelized cost. For instance:

1. *Prudence review:* Investments made by Vermont's utilities are subject to ongoing prudence reviews by the Department of Public Service. Technologies with high capital costs and long useful lives expose the utilities to a large degree of prudence review risk. As market conditions change, a retroactive review of an investment in generation may result in the determination that it was imprudent or not used and useful. This places additional risk on the utility.

2. *Fuel cost pass-through:* Similarly, fuel costs are reviewed by the Department of Public Service to ensure the have been prudently incurred. There is not a straight fuel cost pass-through clause in the Utilities' rates (unless it is specifically approved through alternative regulation). Hence fuel costs from technologies using fuels with volatile price trends have a higher probability of being not being fully recovered than the same costs generated by technologies with more predictable fuel prices.

Role of Independent Power Producers ("IPPs") - It should be noted that IPPs account for approximately seven percent of both the energy and capacity in Vermont. These entities are not subject to rate regulation. Due to grandfathered legislation known as the Public Utilities Regulatory Policy Act, a significant portion of independent generation is sold to the State's utilities at the utilities' estimated avoided costs at the time the purchases were evaluated. Independent generators continue to investigate the development of projects in Vermont, and may serve as a significant source of generation in the future. However, because this study focuses on Vermont-Utility-led project development, independent power is not considered in CEA's financial modeling.

Sustainably Priced Energy Enterprise Development ("SPEED") Program - Passed in 2005, "Act 61" created the SPEED Program, which is designed to encourage Vermont electric utilities to enter in to power purchase contracts with in-State developers of renewable energy.

Role of Demand-Side Management and the "Energy Efficiency Utility" ("EEU") - On September 30, 1999 the Vermont Public Service Board, approved the creation of an EEU to deliver efficiency services to residential, commercial, dairy, and industrial electric customers throughout Vermont, beginning early in the year 2000. The EEU focuses on reductions in power use in order to reduce the amount of fuel consumed at existing power plants and to reduce the amount of new generation resources required. This puts downward pressure on the utilities' collective need. However, because the rate of implementation by the EEU is subject to the Public Service Board directives, the impact on the state as a whole is somewhat unpredictable. In addition, any specific geo-targeting by the EEU, the impact on any in one utility's service territory adds complexity to each utility's individual projections.

# SECTION 3: FEASIBLE FINANCING STRUCTURES

## 3.1 A PRIMER ON FINANCING GENERATING FACILITIES

The U.S. has over one million megawatts (MW) of electric generation capacity.[15] Assuming that a typical plant has an average thirty year life, over 33,000 MW of capacity must be built each year just to maintain the current U.S. fleet. Electric utilities and independent generating companies alike turn to the financial markets to provide capital for these construction expenditures, which amounted to over $25 billion in 2006.

The financial capital that is needed to construct new generation can either be borrowed (debt), appropriated from cash on hand or raised through sale of stock (equity). The mix of debt and equity in the capital structure is a balance between the interests of the developer and the lender. Most independent generation developers prefer to use as little of their own cash as possible. A capital structure that contains a high proportion of borrowed funds is advantageous in two ways: it boosts the project's percentage return on equity, while also allowing the developer to reduce overall risk by applying a limited supply of equity capital across a portfolio of several projects. Investor-owned utilities typically utilize a balance sheet approach to financing, representing a more conservative mix of debt as a proportion of equity. Municipal utilities and co-operatives typically rely on debt for most if not all of their generation financing.

A lender has similar interests in mind with regard to risk. While it is certainly to the lender's advantage to make loans of substantial size, the lender is also mindful that a project with too much debt is vulnerable to unforeseen changes in its variable costs. Volatile costs may lead to missed payments of interest or principal, a restructuring of capital, or perhaps even bankruptcy. All of these circumstances are at least costly if not disastrous results of over-lending.

This balance between lender and developer therefore depends largely upon the borrower's ability and willingness to make principal and interest payments – otherwise known as its credit. By far the largest factor in determining the credit of a given generation project is whether the owner intends to sell the project's power into the ever-changing power markets on a short-term, ad-hoc or "merchant" basis, or instead whether the project has secured long-term fixed-price contracts with credit-worthy counterparties. The former subjects the project's cash flows to a high degree of uncertainty since energy market prices are notoriously volatile, especially in the natural-gas dependent Northeast. The latter allows the lender to forecast the borrower's cash flow with precision and therefore to make a larger loan. A rate-regulated utility will typically borrow based on the overall credit of the utility.

Nearly equal in importance to the source of repayment is the current credit environment for lending to electric generation projects. This environment is cyclical, and tends to follow the supply and demand balance for generation projects in general. An overview of recent history may be illustrative:

[15] Source: SNLi.

**Figure 7: Abbreviated History of the Credit Environment for Generation**

| Approximate Years | Credit Environment | Description |
|---|---|---|
| 1998 - 2001 | Very good | A surging economy, coupled with widespread electric utility restructuring programs at the State and Federal levels, along with relatively inexpensive natural gas and low interest rates created a boom in new power plant construction. |
| 2002 – 2004 | Very weak | The Enron bankruptcy, along with bankruptcies of several prominent power plant developers, marks this period of oversupply and poor market liquidity. Banks curtail lending and re-trench. |
| 2004 - Present | Strengthening | Learning from their too-liberal lending practices in the 1998-2001 period, banks are lending freely again, but this time with particular attention to strong fundamental credit metrics and deal structures. Power purchase contracts are now almost always required and "merchant"-type transactions are rare. |
| A Possible 2010-2014 Scenario | Given continued demand growth, high fuel costs and environmental and siting concerns, many regions, including New England, are forecasting supply shortages beginning in the 2011-2015 period. This possible build-up in new generation requirements would be a positive driver for the future lending environment. However, the recent curtailment of corporate credit following the collapse of sub-prime mortgages may have an offsetting effect. It is too early in the development of this curtailment to estimate its duration and downstream effects on credit markets in the long term. | |

## 3.2 Sources of Borrowed Funds

There are many ways to borrow money to build power plants. Choosing the right source of funds depends primarily on the type of entity that owns the project, the type of technology to be financed, and the size of the project. The three primary types of debt financing are bank loans, bonds, and government-supported loans.

### 3.2.1 Bank Loans

Bank loans are among the most common type of debt financing for the construction and operation of power plants, and can be found in the capital structure of existing plants ranging from 1MW hydro units to 750MW combined cycle plants. The key virtue of bank loans is that they are private transactions between the borrower and bank and therefore provide a high degree of flexibility with regard to both the structure of the initial loan, and with regard to possible changes in terms at future dates.

Given this flexibility, bank loans tend to be used mostly by non-utility independent developers, who build plants primarily for their financial – rather than strategic – value, and therefore require the flexibility to re-pay, refinance, or otherwise change the terms of the financing on short notice.

The developers themselves are usually not the borrowers, but instead form a new subsidiary company to raise capital and build a plant. This "project financing" insulates the developer from

having to stand behind the loan in the event of default, meaning that the developer can then only lose whatever equity investment was required by the lender.

Terms of a typical bank financing reflect this tentative, short-run approach. Bank financing is often split into a "construction loan", with terms and interest rate specific to the higher-risk construction period, and an "operating loan," with commensurately lower rates and more flexible terms applicable to the post-construction period. Repayment periods are typically five to ten years, but may stretch out to fifteen, largely reflecting the length of the typical power sales and fuel contracts that stand behind the loan. Interest rates are initially structured at the bank's cost of funds, plus a spread that depends on the credit risk of the borrower, but that can be converted into a fixed rate through a separate financial transaction if requested or required.

### 3.2.2 Bonds

Unlike the private nature of bank loans, which exist only among a small group of banks and borrowers, a bond transaction takes place between the borrower and an underwriter who in turn sells the bonds to hundreds or even thousands of ultimate investors. This primary characteristic makes bonds less flexible than bank loans, and they are therefore typically used to support well-secured long-term power plant investments. Borrowers are usually strategic investors whose objective is to build and own the plant as a core part of their long-term power supply. These entities are often electric utilities and their subsidiaries, including municipals, cooperatives and power authorities, but can also be independent generators with particularly large portfolios and long-term investment horizons.

Bonds come in several varieties that depend largely upon the characteristics of the borrower and the security provided. Electric utilities, which must finance generation, transmission, distribution and general corporate assets under one roof in order to serve customers, often provide their complete asset portfolios to the lenders as security in exchange for a relatively low interest rate. These corporate-backed bonds are known as *"first mortgage bonds,"* reflecting the idea of a comprehensive source of security that offers to investors a first interest in all utility assets in the event of default or bankruptcy. First mortgage bonds are typically issued for ten to thirty-year terms, and carry fixed interest rates that reflect the credit standing of the issuing corporation.

Bonds are also available to support entities that either hold only generation assets or pledge only the revenue coming from the generation assets as security. These *"taxable revenue bonds"* are frequently used either by non-regulated utilities in states that have been through wholesale regulatory restructuring, or by state power authorities that raise funds without an explicit pledge of security from the state. Taxable revenue bonds allow for a nearly complete separation of the financing activities of the generation subsidiary from the overall corporate credit of the parent company or sponsoring state or municipality. The bonds are typically issued for the life of the generating assets that support them and usually include tight restrictions on the sale of these underlying assets. Interest is fixed for the life of the security at a rate that reflects the credit standing of the project, which in turn depends largely on the degree to which cash flow from long-term power sales contracts is projected to cover scheduled payments of principal and interest.

When generation projects are created by governmental entities and their power is sold exclusively for the benefit of the public at large the IRS may deem the bonds that support the project to be tax-

exempt. These *"tax-exempt bonds"* carry a lower interest rate than taxable securities, because bondholders are enticed by the fact that they will not have to pay tax on the interest they receive.

Tax-exempt bonds come in two primary forms that roughly parallel their taxable cousins: *"General obligation bonds"* contain a comprehensive pledge, of the full faith and credit of the municipality that issues them, including that municipality's legal right to raise taxes if necessary in order to repay principal and interest. These are typically long-term bonds that support general municipal projects and operations, and carry a relatively low interest rate. Except that their interest is exempt from Federal and sometimes state taxes, *"tax-exempt revenue bonds"* are the same as their taxable equivalent.

However, in order for the IRS to grant a tax-exemption only a small portion of the power from the project can be sold to private entities, and a relatively small amount of the proceeds of the project that supports the bonds can be directed to a private use. The IRS does permit a municipality to issue a small quantity of tax-exempt bonds for quasi-private purposes such as power, affordable housing or student loans, but this issuance is subject to an annual cap.

### 3.2.3 Specific Government-Sponsored Loans for Coops and Municipals

The USDA Rural Utilities Services ("RUS") Electric Program makes direct loans and loan guarantees to electric utilities to serve customers in rural areas. Any entity that provides electric service to rural consumers is eligible for an electric loan or loan guarantee, provided that it meets feasibility requirements both from an engineering and a financial perspective.[16] The Program provides up to 100% financing for eligible generation projects, with loans or loan guarantees from $1 million to over $1 billion. The Program makes loans for as long a term as possible (up to 35 years), up to the useful life of a power plant. The interest rate is set by the Federal Financing Bank, which sets rates equal to Treasury's cost of money for debt instruments with similar maturities and options, plus one-eighth of one percent (0.125 percent). Washington Electric Cooperative ("WEC") is currently the only recipient of the Electric Program's loans in the State of Vermont.

Clean Renewable Energy Bonds ("CREBs") provide another financing option for electric cooperatives and public power systems. Instituted by the Energy Policy Act of 2005, CREBs deliver an incentive comparable to the Production Tax Credit[17] that is available to private developers and investor-owned utilities. A CREB is a special type of bond, known as a "tax credit bond," that offers cooperatives the equivalent of an interest-free loan for financing qualified energy projects for a limited term. Qualified projects include wind, closed-loop biomass, open-loop biomass (including agricultural livestock waste), geothermal, solar, municipal solid waste (including landfill gas and trash combustion facilities), small irrigation power and hydropower. Entities qualified to issue CREBs include governmental bodies, Indian tribal governments, mutual or cooperative electric companies and clean energy bond lenders – namely, the National Rural Utilities Cooperative Finance

[16] To be eligible for financing under USDA's Rural Development Electric Program a borrowing entity must meet the Census Dept's current definition of a rural area. However, an entity that has already received loans through the program, such as Washington Electric Cooperative in Vermont, may continue to receive loans even if it no longer meets the rural definition.

[17] PTC's are described in Section 4.4.

Corporation ("CFC") and Cobank.[18] CFC aggregates the financing needs of cooperatives into a single bond issuance, charging approximately 1% interest to cover their costs. CREBs are not specifically considered in CEA's financial modeling because we have not modeled a purely tax-exempt scenario; but the effect of CREBs is roughly equivalent to PTC's, which are included in all financing scenarios.

## 3.3 Credit Considerations in Borrowing for Generation Projects

### 3.3.1 Structuring the Financing Package With Credit in Mind

All developers need to be mindful of their project's credit profile. It is important to provide bank lenders and/or bond investors enough security and other credit capacity to be able to borrow enough capital both to make the project feasible while also keeping interest costs at a reasonable level.

While banks will evaluate credit on a transaction-by-transaction basis, bond investors will look to the issuers' credit ratings, which are provided one or more credit rating agencies. The leading credit rating agencies are Standard & Poor's Corporation ("S&P"), Moody's Investors Service ("Moody's") and Fitch Ratings ("Fitch"). These agencies analyze the credit capacity of bonds and their issuers, and rate them according to an alphabetical scale. S&P's scale is shown in Figure 8. The ratings sometimes carry a " + " or a " – " sign or numbers "1" through "3" in order to provide more specificity to ratings for credits that lie between two letter ratings.

**Figure 8: Standard & Poor's Credit Rating Scale**

| Rating | Description |
|---|---|
| AAA | Extremely strong |
| AA | Very strong |
| A | Strong |
| BBB | Circumstances may lead to weakening credit; lowest "investment grade" rating |
| BB | Highest rating of those with speculative "non-investment-grade" characteristics |
| B | More vulnerable to changing circumstances, but still able to meet obligations |
| CCC | Vulnerable to non-payment |
| CC | Highly vulnerable to non-payment |
| C | Payments continuing, but bankruptcy filing or similar action has been taken |
| D | Borrower is in payment default |

*Source: S&P, Corporate Ratings Criteria 2006, Page 11.*

A project's credit profile can be enhanced either by ensuring that the project itself provides strong and dependable cash flow to lenders, or by enhancing credit through the financing structure. Project cash flows can be made more secure by signing long-term power sales contracts with credit-worthy counterparties. Project credit can be enhanced by providing a guarantee from the project's parent or by having the parent company borrow the required funds and then dividend the proceeds to the project.

Bond insurance is an additional method to enhance credit. There are several well-capitalized monoline insurance companies that will provide complete guarantees in support of bond issues in return for an up-front premium. Insured issues take on the credit profile of the insurance company,

[18] Source: National Rural Electric Cooperative Association http://www.nreca.org/Documents/PublicPolicy/CleanRenewableEnergyBonds.pdf

which is usually AAA (among the best credit available). These insurance products are priced to provide a slight net benefit to the issuer after considering the lower interest costs of the insured issue, offset by the up-front premium. Bond insurance can be particularly useful for bond issues with weaker credit standing that will be sold to a broad market of investors, for whom the evaluation of credit risk is not a particular strength or interest.

### 3.4 Equity and Ownership Structures

Inextricably tied to the debt financing decision is the project's ownership structure. There are many ways that generation can be owned and financed, including:

1. Regulated utility (private company, municipal system or coop) for the benefit of customers and shareholders;
2. Non-regulated subsidiary of a utility in order to comport with affiliate rules in states that have deregulated the generation segment of their utilities;
3. Non-utility-owned independent generator that contracts with load serving entities for generation;
4. State-created authority; or
5. Minority share by an outside investor.

The choice among these options depends upon the entity seeking to own the generation, the lender's requirements, and the intended contractual arrangements for the sale of power. Within each of these primary structures, there are also a variety of ways to structure ownership through lease payments or otherwise in order to achieve the benefits and minimize the costs of the choice of structure. These options are described in greater detail in Section 3.7.

### 3.5 Credit and Financing Considerations for the Vermont Utilities

Like all prospective project developers, the Vermont Utilities each have individual credit profiles and borrowing capacities that, without support from external partners, may limit their individual and collective ability to build some very large projects at a reasonable cost. Below is a summary of these credit capacities and their practical meaning with respect to the size and types of projects that may be available to each entity as a primary project sponsor.

#### 3.5.1 The Investor-Owned Utilities (CVPS and GMP)

S&P provides the following credit ratings for bond and preferred stock issues of CVPS and GMP:

| | CVPS | GMP |
|---|---|---|
| Long-Term Issuer Rating: | BB+ | BBB |
| Senior Secured Debt | BBB | BBB[19] |

S&P provides the following descriptions for its CVPS credit ratings:

> The ratings on Rutland-based Central Vermont reflect a challenging regulatory environment, material off-balance-sheet debt obligations, relatively weak credit measures, and limited flexibility with regard to certain capital expenditures." These

[19] Moody's Investors Service upgraded GMP's senior secured debt to A3 (equivalent to S&P's A-) on August 7, 2007.

concerns outweigh Central Vermont's good customer mix, supply contracts at below-current-market rates, and minimal operating risk.[20]

S&P provides the following descriptions for its GMP credit ratings:

Strengths – Low operating risk, beneficial long-term supply contracts, and limited fuel price risk. Weaknesses – Challenging regulatory environment, material off-balance sheet obligations, and relatively weak cash flow metrics.[21]

Given their current credit standing, CVPS and GMP have a limited amount of debt that could be added to their balance sheets in order to build new generation. In particular, CVPS's below-investment-grade rating may make the interest rate on its new debt issues approximately one to two-percent higher than that of GMP, based on current yields. In order to help determine the amount of the potential generation project size that could be accommodated by GMP and CVPS, CEA has analyzed the approximate effect that a $300 million jointly-owned project may have on the credit metrics that S&P and Moody's would use to analyze each utility. This hypothetical project would be financed with 50% equity ($75 million) and 50% debt ($75 million) at each utility. The results are shown in Figure 9.

**Figure 9: Implied Effect on CVPS and GMP Credit Ratings Of Issuing $75 million in Long-Term Debt**

| CVPS | Credit Metric Before Issuing New Capital | Credit Metric After Issuing New Capital | Implied Downgrade Due to Additional Debt? |
|---|---|---|---|
| FFO / Interest Coverage | 4.14 | 3.36 | YES |
| FFO / Total Debt | 0.26 | 0.21 | YES |
| Total Debt / Capital | 0.41 | 0.44 | NO |

| GMP | Credit Metric Before Issuing New Capital | Credit Metric After Issuing New Capital | Implied Downgrade Due to Additional Debt? |
|---|---|---|---|
| FFO / Interest Coverage | 3.31 | 2.82 | NO |
| FFO / Total Debt | 0.23 | 0.19 | NO |
| Total Debt / Capital | 0.46 | 0.48 | NO |

Note: The above credit metrics are calculated by CEA for the express purpose of estimating the possible credit rating effects on GMP and CVPS of issuing new debt and equity. They are not intended to provide an estimate of any current or future actual credit rating for either company. Further, our analysis does not reflect calculations that would be performed by rating agencies under similar circumstances. For example, unlike the practice of the several of the

[20] Source: Standard & Poors Corporation.

[21] Source: Standard & Poors Corporation.

rating agencies, particularly S&P, CEA has not imputed onto CVPS's and GMP's balance sheets the debt-like qualities of long-term purchased power commitments. Due to data constraints, before-new-debt metrics are calculated as of 3/30/07 for CVPS and 12/31/06 for GMP. "Credit Metric After Issuing New Debt" is calculated on an all-else-remaining-equal basis. Credit metrics, rating standards and formulas are a blend of same as provided by Moody's (Source: Moody's Investors Service, "Rating Methodology: Global Regulated Electric Utilities", March 2005, p. 8.) and S&P (Source: S&P "Corporate Ratings Criteria - 2006", p. 43).

Figure 9 illustrates that an incremental $75 million in debt combined with $75 million in incremental equity on either the CVPS or the GMP balance sheet would likely have a negative effect on the key credit metrics that underlie their credit ratings. The study also shows that GMP's credit metrics may be less affected by this change than would CVPS's. In addition, GMP's acquisition by Gaz Metropolitain ("Gaz Met") may help support GMP's credit profile, as recognized by Moody's recent decision to upgrade GMP's long-term issuer rating to A3 from Baa1. Gaz Met's backing may improve GMP's ability to negotiate new power contracts as part of this larger credit-worthy entity, and may also be a source of equity capital.

However, given the above test, an incremental $150 million in total financing at a 50% debt/capital ratio is, for either company, a reasonable approximate threshold beyond which there may be potential negative effects on credit. This means that, together, CVPS and GMP have the capability to fund approximately $300 million in new generation projects before seeking external sources of capital. For reasons noted above, this threshold is likely to be more restrictive for CVPS than for GMP. This threshold may place a limitation on the size of the projects that these utilities can undertake without seeking an additional source of outside capital through partnering.

There are two key benefits of a financing by the investor-owned utilities. First, it is a tried-and-true process, and few if any new structures or mechanisms would need to be put in place in order to complete the financing. Second, if the new plant provided more power than current customers of GMP and/or CVPS could use, the excess power could be sold to other utilities. This second point stands in contrast to a coop financing, which would generally be limited to building a plant to fit its customer base.

Precedent for Financing Generation through the Utility Rate-Base at CVPS and GMP

Searsburg wind farm, a 6.0 MW facility owned by GMP, was financed in 1997. EPRI grants funded approximately $4 million of the approximate $12 million capital cost. GMP placed the remaining costs in rate base and included these in retail cost of service.[22]

GMP also owns an 11 percent portion of the 50-MW McNeil Station. The company financed its roughly $7 million ($1984) share of construction costs as a traditional utility rate base investment, supported over the long term by an approximately even mix of debt and equity.[23]

CVPS owns a 20 percent portion of the 50-MW McNeil Station. CVPS did not finance its share of the project with debt or equity directly tied to the project. The company instead funded cash calls

[22] Source: Communication with Doug Smith, GMP on June 21, 2007

[23] Source: Communication with Doug Smith, GMP on July 23, 2007

for its $13.4 million ($1984) share of construction costs through a subsidiary, CV Realty. CVPS met its obligations by tapping into its short-term line of credit, which at various points it rolled into long-term financing through issuance of common equity or first mortgage bonds.

Precedent for Partnerships between the Vermont Utilities

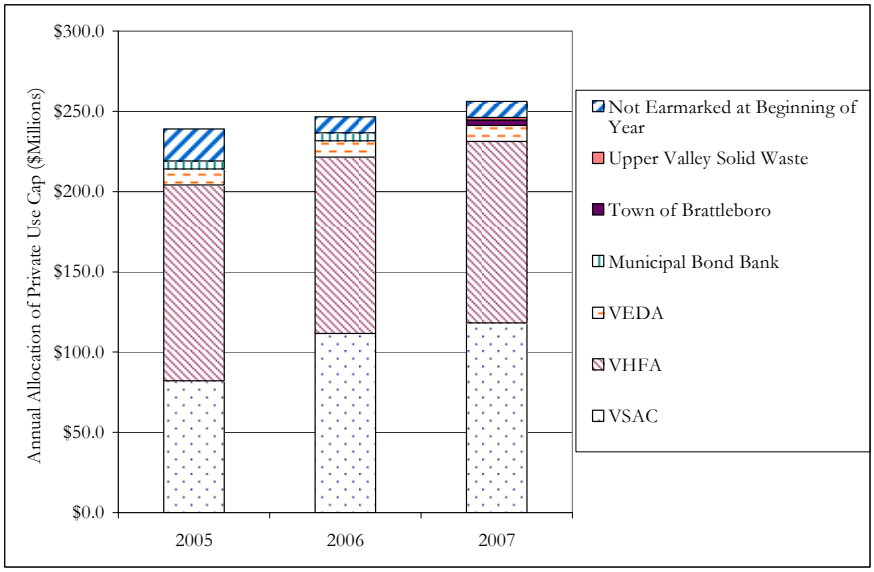
The State's two investor-owned regulated utilities and major public power entities partnered to construct and assume joint legal ownership of the 50-MW McNeil Station. The facility is owned by Burlington Electric District (BED) (50%), Central Vermont Public Service (20%), Vermont Public Power Supply Authority (19%) and Green Mountain Power (11%). Several of the Vermont Utilities also jointly own the 225MW Highgate converter, which serves to connect Vermont and Canada electrically. Finally, several of the Vermont Utilities were joint owners in Vermont Yankee prior to its sale to Entergy Corporation in 2002.

### 3.5.2 The State of Vermont

A second potential project sponsor and/or debt issuer is the State of Vermont itself. The State boasts a AAA credit rating by both Moody's and S&P, which provides the residents of Vermont access to unusually low-cost capital through regular tax-exempt municipal bond issues. All of Vermont's currently outstanding bonds are general obligations of the State, and so are backed by its full faith and taxing powers.

However, the clear benefits of a purely State-backed tax-exempt financing are not likely attainable if any significant amount of the power from the new project is to be sold to private enterprises such as CVPS and GMP, since doing so would violate the IRS's restrictions with respect to the "private use" of Federal tax-exempt funds. The State is permitted to direct an amount of its tax-exempt financing programs to "private use" projects. However, as illustrated in Figure 10, this amount is limited to approximately $250 million in a given year and already has significant demands upon its use from other State-backed quasi-private entities such as the Vermont Student Assistance Corporation ("VSAC"), the Vermont Housing Finance Agency ("VHFA") and the Vermont Economic Development Authority ("VEDA").

**Figure 10: Allocation of Vermont's Cap on Private Use Of Tax-Exempt Financing**




Source: Office of the Vermont State Treasurer.

Moreover, a debt offering that is backed by all Vermont taxpayers may not be equitable if the relatively low-cost power derived from such an offering were to be offered to some but not all of Vermont's electric utility customers. This may pose some practical considerations, as it would be cumbersome to sign wholesale power sales contracts of an equitable size with every retail electric provider in Vermont. However, this type of financing was undertaken in the case of the Hydro Quebec contract, where participants grouped themselves into the Vermont Joint Owners ("VJO"). A separate proceeding and negotiation was then held in order to allocate the parts of the VJO contract to entities throughout Vermont and elsewhere in New England.

Instead, a related alternative would be for the State to form a power authority (not unlike VEDA, VHFA and VSAC in structure). The newly-formed authority would issue taxable debt in the form of revenue bonds, and would build and own one or more generation projects with the proceeds. Power from the projects could be sold to any municipality, authority or corporation, both within and outside the State of Vermont, and the bonds would be backed by these long-term contracts. While the primary security for the new authority's bonds would be the cash flow from the project(s) itself, the State of Vermont could provide a "moral obligation," which means that it would stand behind the bonds to the extent that the State legislature chose to appropriate funds to do so in the event of default. This additional form of security may slightly reduce interest costs.

As noted above, the State of Vermont would have no legal requirement to use taxpayer funds to stand behind payment for the Authority's revenue bonds in the event of project default. However, given that the Authority will have been formed by the State, the State may feel the political prerogative to stand behind the bonds in this extreme case. Therefore, the authority's debt should be sized to be in keeping with the State of Vermont's existing tax-supported debt obligations, which stand at approximately $440 million.[24] Further, as a State authority, projects owned and financing sponsored by the new authority should be sized to be in keeping with the power needs of in-State

[24] As of 12/31/2006. Source: Office of the Vermont State Treasurer.

electric customers. Together, these factors imply that the new authority's project costs should not exceed approximately $500 million in total. As shown in Figure 11, this would exclude the most capital intensive technology types from those that could be financed by the new authority.

However, it is entirely possible that one or more outside equity partners could be located to acquire a portion of a larger project. Partnering may solve not only financing limitations, but would also allow the State to take advantage of economies of scale and cost advantages of some of the larger technology options. Finally, a partner may provide technological expertise to the project.

Two drawbacks to the state authority structure are that bond issuance could be complex since this would be a newly formed entity issuing a bond backed by a to-be-built power facility. Further, the authority structure would detract from the relative autonomy that the State's electric utilities currently have when it comes to generation planning and reliability.

Precedent for Project Sponsorship by State-Sponsored Power Authorities

There is significant precedent for forming holding companies within the state level for the purpose of financing generation for the primary benefit of in-state electric customers. Over the past four years, state-owned utilities in New York and South Carolina have issued securities to finance the construction of major new generating facilities.

The New York Power Authority ("NYPA") is the nation's largest state-owned power organization and one of the state's leading electricity suppliers. A non-profit, public benefit energy corporation, NYPA does not use tax revenue or state credit, but rather finances its projects through bond sales to private investors.[25] NYPA issued $172.5 million in revenue bonds in January 2006 to finance new construction at the Poletti power plant, which added 500 MW of gas-fired combined cycle capacity. These bonds, some of which were insured, carry interest rates between 3.2% and 5.0%, and maturities from three to 15 years.[26]

Santee Cooper is South Carolina's state-owned electric and water utility, serving over 155,000 residential and commercial electric customers. Between April 2004 and February 2006, Santee Cooper issued over $1 billion in both taxable and tax-exempt revenue obligations to finance a portion of two new 600 MW units at the Cross pulverized coal-fired plant. These AA- rated bonds, have interest rates that range from 4.41% to 5.18%.

Precedent in Vermont for forming Partnerships with Non-Vermont Entities for Generation Development

Vermont Yankee nuclear power plant, which entered service in 1972, was developed by a partnership of regulated electric utility companies and public power entities. At the time of construction, the co-owners were: Central Vermont Public Service, which owned 31.3%; Green Mountain Power, 17.9%; New England Power, 17.9%; Northeast Utilities subsidiaries Connecticut Light & Power Co., Public Service of New Hampshire, and Western Massachusetts Electric Co., a combined 16%; Central Maine Power, 4%; Cambridge Electric Light, 2.5%; Montaup Electric, 2.5%; and Burlington Electric Department, 3.6%; with the remaining 4.3% held by the Village of Lyndonville (Vt.) Electric Dept., WEC, and Vermont Electric Cooperative ("VEC").

[25] Source: SNLi

[26] Source: 2006 NYPA Annual Report

### 3.5.3 The Vermont Electric Cooperatives

A third possible source for sponsorship of new generation development is the Vermont cooperative electric utilities, including VEC and WEC. These cooperatives have historically built or purchased capacity for their members on an as-needed basis. For example, WEC completed its $8.5 million 6.0MW Coventry landfill project, which now provides for approximately one-half of the power needs for that co-op's members.[27] VEC currently purchases all of its capacity under long-term contracts.[28]

Day-to-day operating fund and maintenance capital for co-ops is typically financed through first-mortgage bonds or government-sponsored loans. However, new generation projects of significant scale are more likely to be financed through taxable revenue bonds and/or government sponsored loans, both of which would be backed solely by cash flows from the project itself.

As long as the project credit is separated from that of the cooperative itself, the size of the project and its financing is practically limited by the size of the resource requirements of the sponsoring cooperative(s), which exist primarily to serve their membership. VEC has a peak demand of approximately 95MW, while WEC's peak demand is approximately 13MW.

Precedent in Vermont for Co-op Generation Financing

For example, WEC recently financed its 6.4 MW Coventry Landfill power plant through a combination of federal programs. In 2005, WEC borrowed $7.32 million of the $8.5 million cost of the original project (three engines) from U.S. Department of Agriculture (USDA) Rural Utilities Service (RUS) and covered the rest of the cost internally. The interest rate was fixed at 4.125% at the time of financing and the term of the loan is 25 years. Financing of the fourth engine, which was installed in 2007, is in the form of a loan from the National Rural Utilities Cooperative Finance Corporation (CFC), at an effective rate of approximately 1.0%. As noted above, CFC is an issuer of CREBs on behalf of WEC and other electric cooperatives.[29] The fourth unit at Coventry was financed as part of a $325 million bond issue and the term of WEC's loan is 10 years, with an interest rate covering CFC's transaction costs only.

### 3.5.4 Vermont Public Power Supply Authority ("VPPSA")

A final possible generation project sponsor is the VPPSA. VPPSA currently supplies power to 19 cooperatives and municipal systems in New England. It is a party to a variety of power purchase contracts and owns a 19% share of the McNeil wood-fired generation facility in Burlington, VT. VPPSA is in the planning stages for the purchase and installation of a 40MW plant, consisting of two 20MW combustion turbines at Swanton, VT. VPPSA's long-term debt consists solely of tax-exempt revenue bonds, currently rated A-, which were used to finance the McNeil facility.

CEA has not explicitly modeled VPPSA as a potential sponsor and owner of large generation alternatives because it was considered to be focused specifically on serving smaller municipal loads.

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[27] Source: Press releases.

[28] Source: VEC 2004 Integrated Resource Plan.

[29] Communication with Avram Patt, WEC on July 18, 2007

Precedent for Project Sponsorship by Municipal Power Authorities

In addition to the example of McNeil Station above, other recent precedent exists for municipal power entities issuing debt in order to finance the construction of new generating facilities. In the past two years, municipal entities in California and Connecticut have issued securities to finance new plants.

Sacramento Municipal Utilities District ("SMUD") is one of the country's largest municipally-owned electric utilities and has the power to fix rates and charges for commodities or services furnished, to incur indebtedness and issue bonds or other obligations, and, under certain circumstances, to levy and collect ad valorem property taxes. SMUD issued approximately $500 million in debt securities in 2006 to finance the 530 MW Cosumnes gas-fired combined cycle power plant. These bonds, which have maturities from one to 25 years, carry interest rates ranging from 3.0% to 5.0%.[30]

The Connecticut Municipal Electric Energy Cooperative ("CMEEC") is a publicly directed joint action supply agency formed by the state's municipal electric utilities.[31] CMEEC is owned by the municipal utilities of several cities and also provides all the power required by other participant utilities. In 2006, CMEEC issued $58 million in revenue bonds to finance the construction of the Pierce Project, an 84 MW dual fuel (natural gas and fuel oil), CT. The bonds, which have maturities from four to 16 years, were insured and carry interest rates ranging from 3.5% to 5.0%.

### 3.6 Generation Sponsorship and Ownership Options

The Vermont Utilities are a diverse group, including investor-owned utilities (GMP and CVPS), cooperatives (VEC and WEC), and municipals (indirectly through the VPPSA). CEA understands that the Vermont Utilities represent all the Vermont electric customers in their efforts to identify feasible generation alternatives.

Given this diverse group of interested parties, there are a large number of possibilities for developing generation in Vermont. CEA focused on the alternatives that achieve:

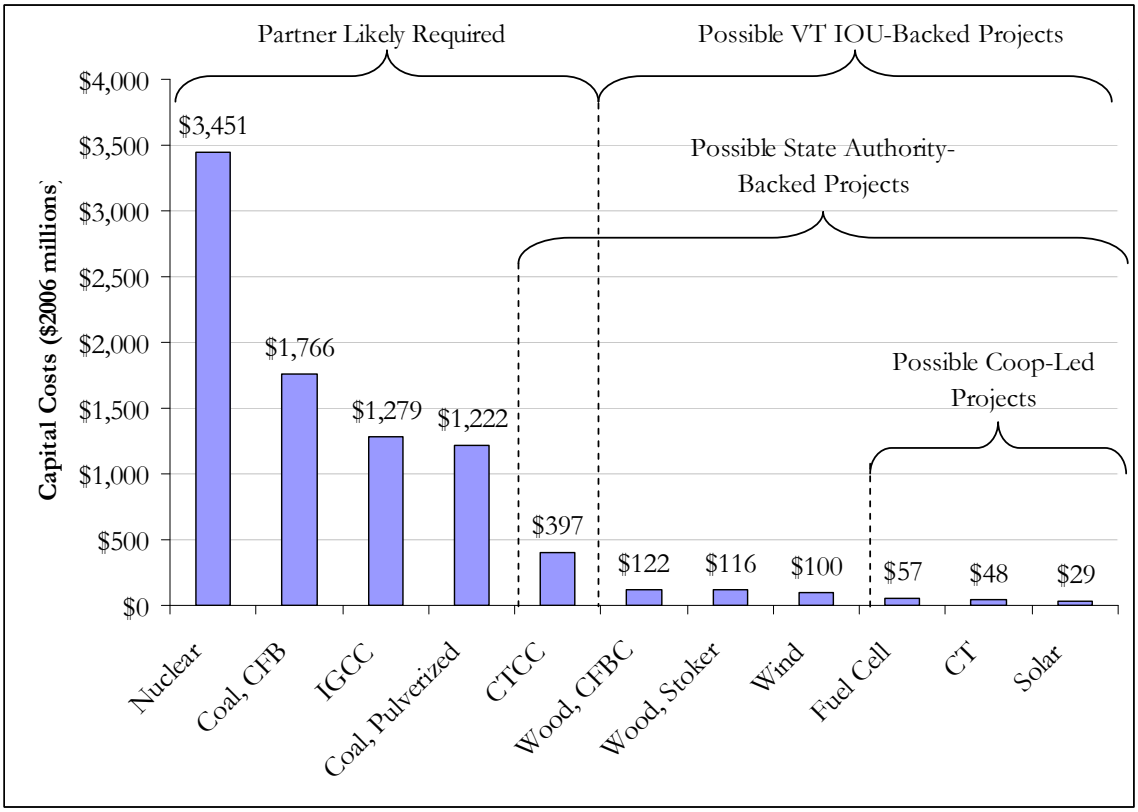
1) The broadest applicability to all Vermont customers;
2) The lowest cost; and
3) The highest degree of feasibility of completing financing and construction within the 2012-2014 time period, based in part on the sponsors' credit standings.

The ownership and financing scenarios selected will depend in part on the size of the selected generation technology and in part on the credit capabilities of the issuer. For example, representatives of larger groups of customers, such as GMP and CVPS, are better suited to developing and owning larger technologies, such as nuclear and coal-fired plants. However, even as partners these utilities do not possess the scale or credit capabilities to construct a very large generation project without additional external capital. Alternatively, owners of smaller systems may find that they can best fulfill the bulk of their power supply through contracts, supplementing this supply through the construction of smaller or renewable technologies. This relationship between ownership and the size of likely projects is illustrated in Figure 11.

[30] Source: SMUD 2006 Annual Report.

[31] Source: http://www.cmeec.com/.

**Figure 11: Reasonably Feasible Project Investment Sizes For Various Possible Ownership Structures**




CEA observes that, while the larger generation technologies may serve to contribute to baseload capacity needs, most of these technologies have such large capital costs that some source of equity capital external to Vermont will be required for their construction. These external partners may also contribute technical expertise to the financing, construction and operation of the projects. On the other end of the spectrum, most of the smaller and renewable projects also have an important role in the Vermont Utilities' portfolio, and we find that their generally lower total capital cost makes them the right size for sponsorship by one or more of the Vermont Utilities.

Given the size of this baseload technology, we therefore conclude that one ownership scenario must include either 1) a consortium of CVPS and GMP and perhaps a third outside investor, which together have significant capital and technological expertise, or 2) a newly-formed State-backed authority that would be capitalized sufficiently to build the necessary generation, and would sell its power to the State's various load-serving entities.

### 3.7 Description of Modeled Ownership Options

Figure 12 is a summary of the three ownership scenarios selected for financial modeling as part of this report. A great many additional ownership models and financing structures are possible. The three scenarios below were selected because they are among some of the more straightforward of the possible approaches.

Municipal ownership is not explicitly considered in the model. Although ownership through VPPSA or through direct ownership by one or more municipal utilities is perfectly feasible, this scenario was observed to be applicable to a sufficiently small number of potential electricity customers so as not to warrant explicit financial modeling.

**Figure 12: Summary of Modeled Ownership and Financing Scenarios**

| Scenario | Utility Rate Base | New State-Sponsored Power Authority | Coop Ownership and Financing |
|---|---|---|---|
| **Project Sponsor(s)** | CVPS, GMP, or together for larger projects | State of Vermont | Vermont cooperatives |
| **Debt-Issuing Entity** | CVPS, GMP, or together for larger projects | Newly-formed power authority | Newly formed project finance entity owned and financed by cooperative(s) |
| **PPA Participants** | None or few. Costs recovered from rate base | Broad participation across Vermont load-serving entities | None or few. Costs recovered from membership tariffs |
| **Form of Financing** | Utility financing at weighted average cost of capital | Taxable revenue bonds. | 50/50 blend of taxable revenue bonds and Federally-sponsored loans |
| **% Debt in Capital Structure** | 45.8% Debt (based on most recent rate cases for GMP and CVPS) | 100% Debt | 100% Debt |
| **Weighted Average Financing Cost** | 8.72% | 6.37% | 5.98% |

### 3.7.1 Utility Rate Base

The Utility Rate Base scenario envisions that CVPS and GMP would form a 50/50 joint venture to build one or more projects. For modeling purposes, CEA assumes that the joint venture would be financed at the average equity cost and project structure as provided in the most recent rate cases of the two utilities.[32] The debt cost, which is not provided in those rate cases, is assumed to be the average yield on 20-year Baa Corporate Bonds.[33] The prudently incurred costs of the new project would be recovered as a rate-base investment.

[32] Cases D-7191 and D-7175, respectively.

[33] As of July 27, 2007. Source: U.S. Federal Reserve.

### 3.7.2 New State-Sponsored Power Authority

The New State Sponsored Power Authority scenario envisions that a new authority of the State would be formed to issue taxable revenue bonds and to construct one or more generation projects. In addition, a "moral obligation" provided by the State is assumed to reduce interest costs by 0.25%. For modeling purposes, CEA assumes that the authority would be financed with 100% debt at a rate approximating the yield on 20-year Baa Corporate Bonds.

### 3.7.3 Co-op Ownership and Financing

The Co-op Ownership and Financing scenario envisions that one or more co-ops would form a company to finance, build and own one or more generation projects. For modeling purposes, CEA assumes that the new company would be financed with 100% debt at a rate equal to the average of the yield on 20-year Baa bonds and a USDA-provided loan at 20-year Treasury bonds, plus 1/8$^{th}$%. This blended rate reflects an assumed 50% probability of qualifying for the USDA loan in order to be conservative, although CEA sees no particular obstacles to qualification, especially for moderate-sized projects.

### 3.7.4 A Note About Financing Costs

It is important to note that each of the scenarios above has a financing cost that reflects the risk that the project sponsors would be asking the providers of capital to assume. In other words, while the overall risk of the project is the same in each scenario, this risk is allocated differently in each case. For example, the Utility Rate Base scenario has a higher financing cost than the other scenarios because it is asking its equity owners to stand behind a portion of the project. Equity owners demand a higher return because they are the last in line to be paid in the event of default. The Coop scenario has a lower financing cost than the State-Sponsored Authority scenario because the Coops benefit from low-cost financing through Federally-sponsored loans. In this case, a portion of the project risk is being shifted to US taxpayers in that taxpayers are providing the loan at a below-market rate.

# SECTION 4: BASE CASE ASSUMPTIONS

## 4.1 DEVELOPMENT AND CONSTRUCTION COSTS

CEA's development and construction cost assumptions are provided in Appendix C on a $2006 basis, excluding AFUDC. CEA generally based its assumptions on data from one of the two DOE reports where such information was available. In instances in which a significant disparity existed between the figures in the two reports, and non-DOE figures seemed plausible, CEA made its assumption by taking an approximate average of the data. Data purchased by the Vermont Utilities from EPRI along with information compiled from recent CEA client projects provided benchmarks against which to compare technology-specific figures in the DOE reports. CEA used other sources of information to supplement the existing data for certain assumptions. For example, CEA communicated with the operations manager of the McNeil Generating Station to obtain cost and performance information for wood stoker facilities.

CEA's construction costs implicitly assume that the installed equipment includes Best Available Control Technology ("BACT") for purposes of emissions. BACT is required by State standards for new emission sources.[34] The primary BACT components are described in Section 2, but CEA has not attempted to estimate prices for these individual emissions control technologies.

### 4.1.1 Adjustment for Cost Differences Due to Geography

CEA has also adjusted certain assumptions to reflect the unique conditions of constructing a generating facility in Vermont. First, the nameplate capacity of certain technologies as reported by DOE appeared to be a mismatch with the State's energy needs and resource constraints. For example, the 2007 Annual Energy Outlook assumes that a typical natural gas combined cycle plant would have a 3-on-2 unit configuration. Because this size seemed excessively large for Vermont's purposes, CEA downwardly adjusted the capacity assumption to match that of a 2-on-1 unit configuration. Also, costs reported in the DOE reports represent a national average, and as such must be escalated to reflect the increased cost of construction in the Vermont. In order to adjust for these differences, CEA multiplied national costs by a factor of 5.3%[35] to obtain Northeast costs, and then multiplied this figure by a further 5.0% to represent Vermont-specific costs.[36] Finally, there is potential for still higher costs due to the fact that Vermont will compete with larger developers who may receive cost advantages due to scale. Because of the situation-specific nature of this potential difference, CEA has not made a specific adjustment in the Base Case, but instead we have created a sensitivity analysis that tests the effect of likely variability in construction costs on the all-in levelized power cost.

### 4.1.2 Adjustment for Cost Increases Due to the Passage of Time

Construction costs for power plants have been increasing rapidly over the past three years, primarily as a result of tight markets for labor and steel, coupled with high demand for power plant components. CEA expects these costs to continue to increase rapidly through 2012 the assumed on-

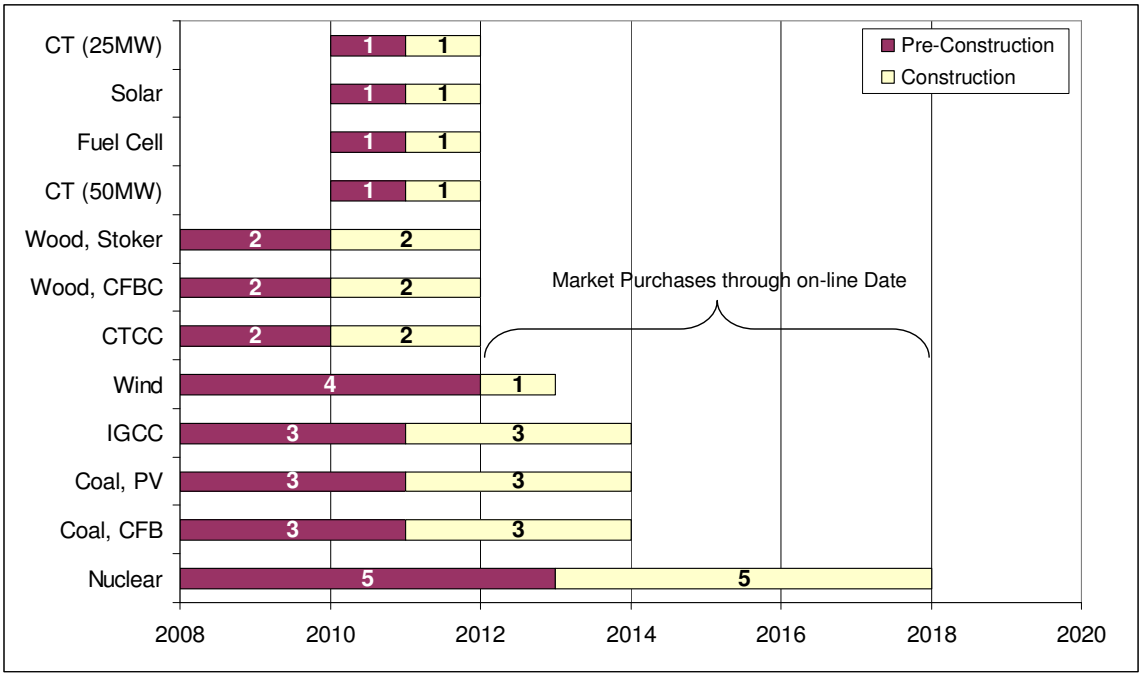
[34] Source: Vermont Agency of Natural Resources.

[35] Based on Handy-Whitman Index.

[36] CEA Estimate.

line date for most of the 11 technologies.[37] CEA's source data for these costs is derived primarily from studies conducted in 2005 and 2006. From these data, CEA escalated these costs in each year through each plant's completion date at a 7.5% annual estimated inflation rate. This rate reflects an estimate of inflation for power plant construction in the Northeast.[38] We expect this trend to continue as steel and other commodity prices increase along with the demand for new generation. Figure 13 shows the required lead time for each of the technologies covered in this report, broken down in to a "Pre-construction, License & Design Period" and a "Construction Period."

**Figure 13: Assumed Development and Construction Lead Times**




CEA's analysis assumes a desired on-line year of 2012. Many of the technologies would not be able to achieve this deadline. Therefore, for modeling purposes, we assume that for technologies which cannot be on line in 2012, the project will have to purchase power in the New England market in order to fill the gap between 2012 and the plant's on line time.

We assumed that 100% of the capital cost is spent evenly over the construction period. We also assumed that two percent of the total construction cost is spent each year of the pre-construction period on permitting and siting (items not included in our overnight capital cost estimate). To arrive at the nominal expenditure each year, we inflated the 2006 capital cost estimate by 7.5%/year (consistent with recent Handy Whitman Index increases).

Below is an example of how CEA translates an overnight 2006 capital cost number into a stream of capital expenditures and eventually a year-one rate-base figure. In this example, the CTCC

[37] 2012 was selected as a first year of the emerging Supply Gap and a reasonable expectation for completing the development and construction of most of the technologies. Due to the complexity in their development and construction, Coal (CFB), Coal (PV, IGCC, are assumed to have a 2014 on-line date, while Nuclear is assumed to have an on-line dates of 2018.

[38] Source: Handy Whitman Index.

technology has a $2006 overnight capital cost estimate of $709/kW. However, by the on-line date, the total amount entering rate base is $1,083. Construction cost inflation, preconstruction permitting and siting costs and AFUDC have increased the $2006 overnight cost by 53%.

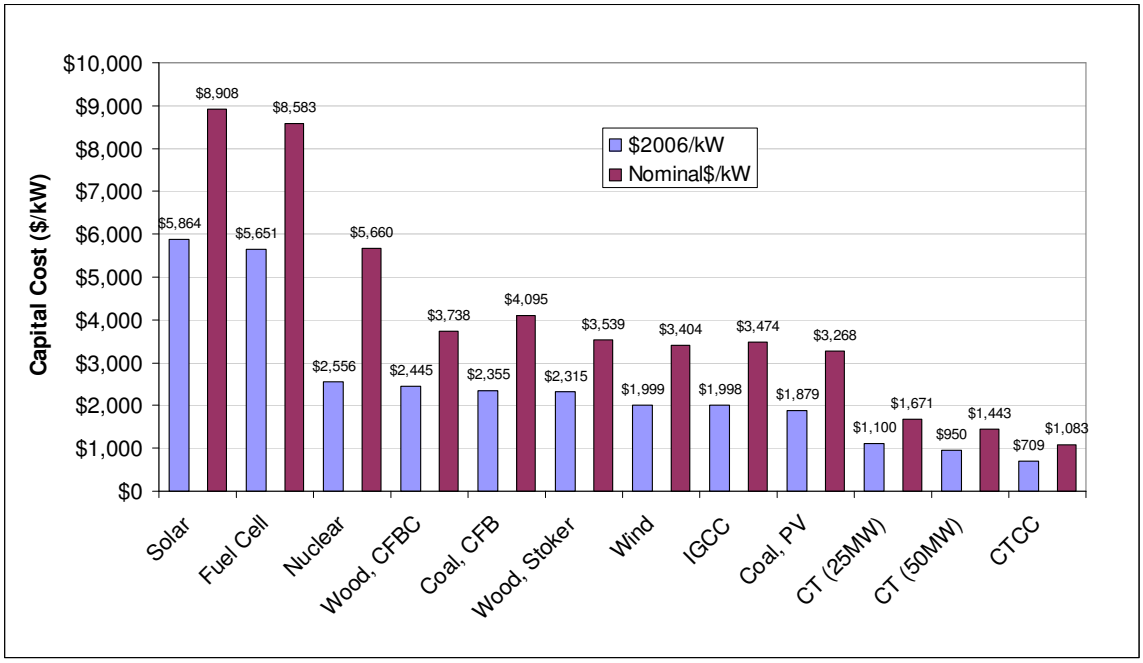
**Figure 14: Sample Translation of Overnight Capital Costs to Nominal Capital Costs**

| | 2006 | 2007 | 2008 | 2009 | 2010 | 2011 | TOTALS |
|---|---|---|---|---|---|---|---|
| | [1] | | [2] | [3] | [4] | [5] | [6] |
| Pre-const. Siting and Permitting Costs | | | 9,129,053 | 9,790,578 | 0 | 0 | 18,919,631 |
| Construction Costs | 396,853,722 | | 0 | 0 | 262,501,010 | 281,522,822 | 544,023,832 |
| AFUDC [7] | | | 456,453 | 991,627 | 13,713,742 | 28,572,566 | 43,734,387 |
| **Total** | **396,853,722** | | | | | | **606,677,850** |
| **Total ($/kW)** | **$709** | | | | | | **$1,083** |

1] 2006 overnight cost of $709/kW ($396,853,722)
[2] 2% of $2006 capital cost escalated at 7.5%
[3] 2% of $2006 capital cost escalated at 7.5%
[4] 50% of $2006 capital cost escalated at 7.5%
[5] 50% of $2006 capital cost escalated at 7.5%
[6] Sum of 2008 through 2011 figures
[7] AFUDC earned on all capital costs (AFUDC rate = 10%)

Figure 15 provides the resulting nominal capital costs for each technology as of their on-line date as compared to their overnight capital costs in $2006.

**Figure 15: Overnight Capital Costs in 2006 vs. Nominal Capital Costs at the Project On-Line Date ($/kW)**



## 4.2 FUELS

CEA developed fuel price forecasts from several sources. This analysis relies primarily on fuel forecast data from DOE/EIA's 2007 Annual Energy Outlook. Fuel assumptions were also drawn from Vermont's 2007 Avoided Energy Supply Cost ("AESC") study, and CEA's internal expertise. Adjustments to the price projections are made for several factors, as noted in the individual fuels sections below. Please see Appendix D for a chart of CEA's fuel price forecast.

### 4.2.1 Natural Gas and Coal

CEA used the fuel price forecast from the 2007 AESC study, which is based on EIA fuel price projections for the electric power industry. The projections apply only to electric generating facilities and combined heat and power plants whose primary business is to sell electricity, or electricity and heat, to the public. The AESC's natural gas price forecast is specific to New England.

### 4.2.2 Hydrogen

Since hydrogen is derived from natural gas, hydrogen prices move in tandem with price changes in natural gas. The model forecasts the price of hydrogen by escalating the current price of hydrogen at the same rate as projected changes in the price of natural gas.

### 4.2.3 Nuclear

CEA's nuclear fuel price forecast is based on CEA research, benchmarked against various proprietary forecasts available to CEA.

### 4.2.4 Biomass

CEA obtained its estimate for the price of wood fuel through conversation with John Irving, Operations Manager of the McNeil Generating Station in Burlington, Vermont, and Bob DeGeus at Vermont Department of Forests, Parks & Recreation. Transportation costs account for approximately half the price of wood fuel. The fuel forecast price assumes an initial price spike resulting from the increased demand for wood, then a leveling-off period as supply catches up with the additional demand.

### 4.2.5 Wholesale Price Forecast

The Locational Marginal Price ("LMP") forecast is used to model the interim costs of purchasing wholesale power between 2012 and the operational start date of potential new generation facilities. This analysis draws the Vermont LMP Price forecasts from the 2007 AESC study for four different periods: summer peak season, summer off-peak season, winter peak season, and winter off-peak season.

## 4.3 TAXES

### 4.3.1 Property Taxes

Town non-residential property tax rates in Vermont apply to real property, which consists of land and improvements. This analysis assumes that the full capital cost of a new generator would be taxable. Since the purpose of this analysis is to forecast the general statewide costs of generation alternatives, rather than forecast the cost of locating a plant in any specific town, we apply a commercial property tax rate that is the average rate of all Vermont cities and towns in 2006.[39]

### 4.3.2 Taxation of Electrical Generating Plants

A Special Tax applies to electric generating plants constructed after 1965 with a nameplate capacity of 200 MW or more. This tax was designed to collect State revenues from the Vermont Yankee unit, but would also apply to any newly constructed large generator. The tax is assessed as follows:

| If megawatt hour production is: | Tax is: |
|---|---|
| Less than 2,300,000 megawatt hours | $2.0 million |
| 2,300,000 to 3,800,000 megawatt hours | $2.0 million plus $0.40 per megawatt hour over 2,300,000 |
| 3,800,001 to 4,200,000 megawatt hours | $2.6 million |
| Over 4,200,000 megawatt hours | $2.6 million plus $0.40 per megawatt hour over 4,200,000[40] |

The modeling analysis assumes that this tax would apply to any new generation alternative with a nameplate capacity of 200 MW or greater.

## 4.4 INCENTIVES FOR DEVELOPING RENEWABLE GENERATION

### 4.4.1 Federal Incentives

The modeling analysis assumes that new generators utilizing renewable sources of energy will be eligible for one of the following two federal incentives.

The Renewable Electricity Production Tax Credit ("REPC") applies a corporate tax credit during the first 10 years of a facility's operation. REPC currently expires on December 31, 2008, meaning that a new generator could receive the tax credit through 2018 at the latest. A House-approved version of the current energy bill extends the REPC to 2012, while the Senate-approved version does not include an extension. Wind, closed-loop biomass, and geothermal generating facilities are eligible for tax credit of 1.9 cents per kWh ($2007).[41]

Given the current wave of investment into renewable sources of electric generation, we do not anticipate that a corporate tax credit of 1.9 cents per kWh will be extended for the long-term. Our

[39] Tax data were obtained from the State Department of Taxes http://www.state.vt.us/tax/pvrannualreports.shtml The commercial property tax rate is the sum of the nonresidential education tax rate and municipal tax rate.

[40] Title 32, Part V, Ch. 213, Subchapter III, § 8661 (a)

[41] Under REPC, a tax credit of 1.0 cents per kWh ($2007) may be applied to open-loop biomass, small irrigation hydroelectric, landfill gas, municipal solid waste resources, and hydropower generating facilities. These facility types are not being considered as generation alternatives by the Vermont Utilities Group.

modeling forecast assumes that REPC will be renewed through 2012 at 1.9 cents per kWh ($2007) and then reduced to 1.0 cents thereafter.

The Renewable Energy Production Incentive ("REPI") provides incentive payments to public utilities during the first 10 years of a facility's operation. Public utilities that utilize eligible technologies may receive incentive payments of 2.15 cents per kWh ($2007), adjusted annually for inflation, subject to the availability of appropriated funds. Eligible technologies include solar thermal electric, photovoltaics, landfill gas, wind, biomass, geothermal, livestock methane, and fuel cells using renewable fuels. Since the EPAct 2005 reauthorized REPI appropriations for fiscal years 2006 through 2026, our modeling forecast assumes that publicly-owned, renewable sources of generation will be eligible to receive an incentive payment of 2.15 cents per kWh ($2007) through 2026.

### 4.4.2 State Incentives

Most State energy incentives in Vermont are targeted at end-use residential, commercial, and industrial customers. A notable exception is the Vermont Clean Energy Development Fund Grant, under which the Department of Public Service makes available $250,000 in funding for large scale, grid-connected renewable systems. The modeling analysis assumes that $250,000 is deducted from renewable project total capital costs to reflect the award of a Vermont Clean Energy Development Fund Grant.

### 4.4.3 Renewable Energy Credits

Vermont does not currently have a mandatory Renewable Portfolio Standard ("RPS") that would require the State's utilities to obtain a minimum level of its energy needs from renewable sources of energy. If such a program were implemented, Vermont would likely develop a market for Renewable Energy Certificates ("RECs"). A Credit is a tradable certificate of proof that one kWh of electricity has been generated by a renewable-fueled source. Credits are denominated in kilowatt-hours (kWh) and are a separate commodity from the power itself. The RPS requires all electricity generators (or electricity retailers, depending on policy design) to demonstrate, through ownership of Credits, that they have supported an amount of renewable energy generation equivalent to some percentage of their total annual kWh sales.[42]

Generating facilities in Vermont are eligible to participate in REC markets in neighboring states. The 2007 AESC study presents a forecast of REC prices in New England states. The study projects that the REC prices will be at parity in all states, including those of potential Vermont RECs, and that prices will decline to zero cents per kWh by 2020.

## 4.5 Emissions Regulations and Allowance Prices

CEA used a mosaic approach to forecast emissions allowance prices, combining information from various sources with our knowledge of the power generation industry. These emission forecast assumptions are described below.

[42] Source: http://www.awea.org/policy/rpsbrief.html

### 4.5.1 Carbon Dioxide Legislation

The regulation of carbon dioxide emissions in Vermont by 2012 seems highly probable. In developing an assumption for the forecast price of $CO_2$ emission allowance, we consider the possibility that either State or federal regulations could be in place.

Vermont is a participant in the Regional Greenhouse Gas Initiative ("RGGI"), a cooperative effort by nine Northeast and Mid-Atlantic states to design a regional cap-and-trade program to limit $CO_2$ emissions from power plants. On August 15, 2006, the participant states adopted a final model rule for the program. State-level adoption of the rule is to take place during 2007-2008. Terms of the model rule are subject to change, particularly concerning the degree to which the program allocates or auctions emission credits. It is not yet clearly defined how a new generation facility in Vermont would be allocated emissions credits, as the State would begin the program with a net surplus $CO_2$ emissions budget.[43] The Model Rule would establish a $CO_2$ safety valve price of $7 per ton ($2005), at which point the limit on offset use increases to 5 percent.

Congress has recently introduced several bills that would impose a federal cap on carbon emissions or a federal carbon tax. The targets and stringency of these proposed programs vary considerably, which makes forecasting the price of $CO_2$ a speculative exercise.

The Low Carbon Act of 2007 introduced in the Senate on July 11 would create a cap and trade approach to curbing $CO_2$ emissions that would allow regulated entities to pay a safety valve price in lieu of submitting allowances. The bill would permit emitters to buy "Technology Acceleration Payments" worth $12 per ton of carbon dioxide in the first year of the program, 2012. After that, the TAP fee would increase 5% a year above the rate of inflation. The other Congressional bills proposing cap and trade approaches to control $CO_2$ emissions do not establish a fixed safety valve price. The Low Carbon Act of 2007 has garnered considerable bipartisan and industry support.
H.R. 2069, the Save Our Climate Act of 2007, would establish a federal tax primary fossil fuels based on their carbon content. The bill would set a tax of $10 per ton of carbon content in the first year, which would increase sharply by $10 per ton in each subsequent year.

Our modeling analysis assumes a $CO_2$ allowance price of $10 per ton in 2012 ($2012), based on the range of regional and federal proposals under review. Since none of these programs has yet to be approved, and given that the programs are not designed for entities to pay considerably more than the safety valve price of $CO_2$ we forecast that the $CO_2$ price will increase at the predicted rate of inflation.

### 4.5.2 Sulfur Dioxide and Nitrogen Oxides

Vermont is not a current participant in federal cap-and-trade programs to reduce emissions of $SO_2$ and NOx. Vermont generators must nonetheless comply with Clean Air Act laws and State Air Pollution Control Regulations governing the emission of these pollutants. This analysis assumes that none of the new generation alternatives would trigger the allocation or mandate the purchase of $SO_2$ or NOx emission allowances, but the tables in Section 2.4 provide the total cost of such purchases if they were to be required.

[43] The State of Vermont would be allocated a CO2 emission budget of approximately 1.23 million tons per year under current RGGI agreements.

The Clean Air Interstate Rule ("CAIR"), implemented by the Federal Energy Regulatory Commission ("FERC") in 2005, will permanently cap emissions of $SO_2$ and NOx across 28 eastern states and the District of Columbia.[44] Several states, including Vermont, New Hampshire, Maine, and Rhode Island, are not included in the CAIR region because they do not contribute to downwind non-attainment of air quality standards. If a new coal-fired power plant were to be constructed in Vermont, the State would not be automatically required to participate in the CAIR cap and trade program.[45]

#### 4.5.3 Mercury

This analysis assumes that Vermont would participate in a federal cap-and-trade program governing the emission of mercury only in the event that a pulverized coal plant was built. EPA issued the Clean Air Mercury Rule ("CAMR") in March 2005 to permanently cap and reduce mercury emissions from all new and existing coal-fired power plants. The first phase cap is 38 tons and emissions will be reduced by taking advantage of "co-benefit" reductions, mercury reductions achieved by reducing $SO_2$ and NOx emissions under CAIR. In the second phase, due in 2018, coal-fired power plants will be subject to a second cap, which will reduce emissions to 15 tons upon full implementation. New coal-fired power plants will have to meet stringent new source performance standards in addition to being subject to the caps. CEA forecasts the mercury allowance price based on the long-term projection of the DOE as stated in the 2007 Annual Energy Outlook.

#### 4.5.4 Other Emissions Costs

The presence of Class 1 federal lands in Vermont (Lye Brook) and in New Hampshire (Great Gulf Wilderness Area and Presidential Range-Dry River Wilderness Area) means that the developer of a new power plant in Vermont may be required to meet more stringent level of pollution controls. Class 1 federal lands include areas such as national parks, national wilderness areas, and national monuments. These areas are granted special air quality protections under Section 162(a) of the federal Clean Air Act. 40 CFR Section 51.307 requires the operator of any new major stationary source or major modification located within 100 kilometers (approximately 62 miles) of a Class I area to contact the Federal Land Managers for that area. CEA has not made specific provisions in the Cost of Service model to reflect these potential restrictions since there is no specific cost, but rather an approval process required.

### 4.6 Forward Capacity Market

ISO-NE has established a Forward Capacity Market ("FCM"), which will serve as partial compensation to existing generators for their capital costs and provide an incentive to construct new generation in the region. The FCM will involve annual auctions for capacity to be provided three years in the future. Participants in the first auction, which will take place in the first quarter of 2008, will bid capacity resources to be available in 2010. While units may bid up to their nameplate value, they will be measured according to their ability to provide physical capacity during certain test

[44] For further information on CAIR visit http://www.epa.gov/interstateairquality/index.html

[45] Communication with Richard Valentinetti, Director the Air Pollution Control Division of the Vermont Department of Environmental Conservation, on July 12, 2007

periods. Therefore, to be conservative, we have assumed that dispatchable capacity will bid only its equivalent availability, and that non-dispatchable capacity will bid its average capacity factor. Figure 16 illustrates our assumptions for each generation technology.

**Figure 16: Availability Factor Assumptions for Forward Capacity Market Bids**

| Technology | Dispatch | Capacity (MW) | Equivalent Availability (%) | Assumed Capacity Bid (MW) |
|---|---|---|---|---|
| Nuclear | Dispatchable | 1,350 | 90% | 1,208 |
| Coal - CFB | Dispatchable | 750 | 85% | 638 |
| Coal - Pulverized | Dispatchable | 650 | 85% | 553 |
| IGCC | Dispatchable | 640 | 85% | 544 |
| Natural Gas Combined Cycle | Dispatchable | 560 | 87% | 487 |
| Natural Gas Simple Cycle | Dispatchable | 50 | 92% | 46 |
| Wind | Non-Dispatchable | 50 | 33% | 17 |
| Solar | Non-Dispatchable | 5 | 21% | 1 |
| Wood Biomass (Stoker) | Dispatchable | 50 | 90% | 45 |
| Wood Biomass (CFB) | Dispatchable | 50 | 90% | 45 |
| Fuel Cell | Dispatchable | 10 | 87% | 9 |

The modeling analysis makes several assumptions concerning future capacity prices in the FCM. During the first two years of the market (2010-2011), we assume the auction floor price of $4.50 kW-month ($2006) prevails, given that ISO-NE is projected to still have a capacity surplus during these years. Over the subsequent four years (2012 – 2015), as ISO-NE moves to a more balanced market, we project the FCM price to increase linearly to meet the Cost of New Entry ("CONE") price of $7.50/kW-month ($2006) in 2015. From 2015 forward, we assume that the capacity price equals CONE in real terms, as new capacity comes on-line in VT to meet demand in the Rest-of-Market zone. Therefore we project the capacity price to escalate at the rate of inflation from 2015 forward.

## APPENDIX A: GLOSSARY

| | |
|---|---|
| Availability Factor | Measure of the ability of power plants, a unit or a plant section to perform its operational function. Equipment availability is the ratio of available time (operating and standby time) to the calendar period. |
| AFUDC | Allowance for Funds Used During Construction. A regulatory mechanism to account for the cost of financing during the construction period. AFUDC is typically added to the capital cost of the plant and is recovered through electric rates. |
| Base Load | The lowest level of power production needs during a season or year. |
| Base Load Plant | A power generating station that is used to meet the base load needs of a system. This is typically a technology that has a relatively high capital cost, but a relatively low operating cost on a per-MWh basis. |
| Capacity | The maximum output, commonly expressed in megawatts (MW), that generating equipment can supply to system load, adjusted for ambient conditions. |
| Capacity Factor | The ratio of the electrical energy produced by a generating unit for the period of time considered to the electrical energy that could have been produced at continuous full power operation during the same period. |
| CFB | Circulating Fluidized Bed. A technology where fuel is fed into a bed of ash that has been fluidized by air jets. The fuel-ash slurry circulates throughout the boiler, allowing contact with sulfur-absorbing chemicals in order to reduce $SO_2$ emissions. |
| Cooperative Electric Utility | An electric utility legally established to be owned by and operated for the benefit of those using its service. The utility company will generate, transmit, and/or distribute supplies of electric energy to a specified area not being serviced by another utility. Such ventures are generally exempt from Federal income tax laws. |
| CT | Combustion Turbine. Essentially, a jet engine that is connected directly to a generator in order to produce electricity. |

| | |
|---|---|
| CTCC | Combustion Turbine Combined Cycle. A CT with a second stage added in order to re-circulate heat to a boiler in order to capture energy that would be otherwise wasted. This second stage makes a CTCC more efficient than a CT, but a higher capital cost. |
| Demand | The rate at which energy is delivered to loads and scheduling points by generation, transmission or distribution facilities. |
| Dispatch | The operating control of an integrated electric system involving operations such as (1) the assignment of load to specific generating stations and other sources of supply to effect the most economical supply as the total or the significant area loads rise or fall (2) the control of operations and maintenance of high-voltage lines, substations, and equipment; (3) the operation of principal tie lines and switching; (4) the scheduling of energy transactions with connecting electric utilities. |
| DSM | Demand-Side Management. The practice of creating incentives for electricity consumers to reduce demand as an alternative to building new generation. |
| IGCC | Integrated Gasification Combined Cycle |
| Investor-owned Utility | A private company that provides a utility, such as water, natural gas or electricity, to a specific service area. The two investor-owned utilities in Vermont are Green Mountain Power and Central Vermont Public Service. |
| All-in Levelized Payment | The same-dollar figure that would be required as a payment in each year of a plant's life in order to pay for all capital and operating costs of the plant during its life, taking into account both the time value of money and the actual schedule of projected plant costs. |
| Load | The amount of electric power supplied to meet one or more end user's needs. |
| Locational Marginal Price | The hourly integrated market clearing marginal price for energy at the location the energy is delivered or received. |
| Mortgage Bond | A bond secured by all assets of the issuer. |
| Municipal Electric Utility | A power utility system owned and operated by a local jurisdiction. |
| MW | Megawatt, which equals one thousand kilowatts (1,000 kW) or one million (1,000,000) watts. |

| | |
|---|---|
| MWh | Megawatt-hour, which equals one thousand kilowatt-hours, or an amount of electricity that would supply the monthly power needs of 1,000 typical homes in the U.S. |
| Net Present Value | The current value of one or more future cash payments, discounted at some appropriate interest rate. |
| NOx | Compounds of nitrogen and oxygen produced by the burning of fossil fuels. |
| Peak Load | The highest electrical demand within a particular period of time. Daily electric peaks on weekdays occur in late afternoon and early evening. Annual peaks occur during periods of extreme hot or cold weather. |
| Peaking Unit | A power generator used to produce extra electricity during peak load times. These plants typically have a relatively low capital cost, but a relatively high operating cost on a per-MWh basis. |
| Rate Base | The value of property upon which a utility is permitted to earn a specified rate of return as established by a regulatory authority. The rate base generally represents the value of property used by the utility in providing service and may be calculated by any one or a combination of the following accounting methods: fair value, prudent investment, reproduction cost, or original cost. Depending on which method is used, the rate base includes cash, working capital, materials and supplies, deductions for accumulated provisions for depreciation, contributions in aid of construction, customer advances for construction, accumulated deferred income taxes, and accumulated deferred investment tax credits. |
| REC | Renewable Energy Certificate, which is a tradable unit that represents the commodity formed by unbundling the environmental attributes of a unit of renewable energy from the underlying electricity. Under most programs, one REC is equivalent to the environmental attributes of one MWh of electricity from a renewable generation source. |
| Reserve Margin | The difference between the dependable capacity of a utility's system and the anticipated peak load for a specified period. |
| Revenue Bond | A bond secured by all the cash flows of a particular project. |
| Revenue Requirement | The total revenue that the utility is authorized an opportunity to recover, which includes operating expenses and a reasonable return on rate base. |

| | |
|---|---|
| Sensitivity Analysis | An analytical test of the degree to which a certain change in a variable effects the conclusions of an analysis. |
| $SO_2$ | Sulfur dioxide. A toxic, irritating, colorless gas soluble in water, alcohol, and ether. SO2 is an emitted by-product of coal combustion and is a source of acid rain as it combines with airborne water vapor to form $H_2SO_4$ (sulfuric acid). |
| Stoker | A basic biomass generation technology in which fuel is fed directly into the boiler. Contrast with CFB. |
| Turbine | A machine for generating rotary mechanical power from the energy of a stream of fluid (such as water, steam, or hot gas). Turbines convert the kinetic energy of fluids to mechanical energy through the principles of impulse and reaction, or a mixture of the two. |
| Useful Life | The number of years that a plant is expected to be economically useful without making capital upgrades beyond basic maintenance. |
| Vermont Utilities | Consortium of utilities composed of Central Vermont Public Service Corporation, Green Mountain Power Corporation, Vermont Electric Cooperative, Washington Electric Cooperative, and the Vermont Public Power Supply Authority. |

Sources:
(A) http://www.energy.ca.gov/glossary/
(B) http://www.eia.doe.gov/glossary/index.html
(C) http://www.euronuclear.org/info/encyclopedia/availabilityfactor.htm
(D) http://www.evomarkets.com/rec/index.php?xp1=2

# APPENDIX B: CEA TECHNICAL ASSUMPTIONS

| Assumption | Coal, CFB | Coal, Pulverized | CT | CTCC | Fuel Cell | IGCC | Nuclear | Solar | Wind | Wood, CFBC | Wood, Stoker |
|---|---|---|---|---|---|---|---|---|---|---|---|
| Capacity (MW) | 750 | 650 | 50 | 560 | 10 | 640 | 1,350 | 5 | 50 | 50 | 50 |
| Total Leadtime | 6 | 6 | 2 | 4 | 2 | 6 | 10 | 2 | 5 | 4 | 4 |
| Total Plant Investment - No AFUDC ($/kW) - 2006$s | $2,355 | $1,879 | $950 | $709 | $5,651 | $1,998 | $2,556 | $5,864 | $1,999 | $2,445 | $2,315 |
| Total Plant Investment - No AFUDC 2006$s | $1,766,150,827 | $1,221,559,237 | $47,500,000 | $396,853,722 | $56,506,086 | $1,278,600,456 | $3,450,912,025 | $29,321,743 | $99,927,820 | $122,248,060 | $115,757,605 |
| Fixed Costs ($/kW-yr) 2006$s | $32.44 | $32.33 | $11.29 | $10.78 | $6.06 | $53.89 | $74.37 | $12.52 | $32.33 | $45.72 | $57.15 |
| Incremental mils/kWh 2006$s | 8.77 | 4.00 | 3.0694 | 2.25 | 46.4427 | 2.5 | 12 | 0 | 0 | 1.28 | 1 |
| Heat Rate at Full Load (Btu/kWh) | 9,700 | 8,800 | 10,300 | 6,719 | 7,873 | 8,922 | 10,400 | 0 | 0 | 12,500 | 14,000 |
| Capacity Factor | 84% | 84% | 10% | 85% | 30% | 80% | 89% | 21% | 33% | 83% | 83% |
| Forward Capacity Market Credit | 85% | 85% | 92% | 87% | 87% | 85% | 90% | 21% | 33% | 90% | 90% |
| Book Life (years) | 30 | 30 | 30 | 30 | 30 | 30 | 50 | 30 | 20 | 30 | 30 |
| Useful Life (years) | 30 | 30 | 30 | 30 | 30 | 30 | 50 | 30 | 20 | 30 | 30 |
| Air Emissions - CO2 (lbs/MWh) | 1,999 | 1,825 | 1,269 | 797 | 725 | 1,755 | 0 | 0 | 0 | 0 | 0 |
| Air Emissions - SO2 (lbs/MWh) | 1.80 | 1.00 | 0.00 | 0.00 | 0.00 | 0.09 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| Air Emissions - NOx (lbs/MWh) | 0.656 | 0.900 | 0.278 | 0.060 | 0.000 | 0.406 | 0.000 | 0.000 | 0.000 | 0.500 | 1.000 |
| Air Emissions - Mercury (lbs/MWh) | 0.000007 | 0.000009 | 0.000000 | 0.000000 | 0.000000 | 0.000004 | 0.000000 | 0.000000 | 0.000000 | 0.000000 | 0.000000 |

## APPENDIX C: ESTIMATED COST FOR NATURAL GAS PIPELINE ADDITIONS

| Zone(s) | Location | Expansion | Estimated Costs ($mm per mile) | Notes |
|---|---|---|---|---|
| 1 | Franklin & Chittenden County | 16-inch Mainline extension | $1.4 | Current 16-inch transmission system ends in St. Albans. VGS may be able to serve a dual fuel generator with no incremental investment in transmission pipe. |
| | Chittenden & Addison | 8-inch Lateral extension | $0.9 | |
| 2 & 3 | Chittenden & Addison County | 10-inch Mainline extension | $1.1 | Middlebury would require approximately 40 miles of pipeline installation. If the pipeline needed to be extended to serve a large demand in Rutland, an additional 30 miles, the design may require a larger diameter pipe. |
| 4 | Rutland County | 12-inch Mainline extension | $1.2 | Rutland could theoretically be served either by extending VGS's pipes south or bringing in service from Niagara Mohawk, located approximately 50 miles west of Rutland. The figures above assume the system would be served from the west. |
| 5 | Bennington County | 10-inch Lateral extension | $1.2 | Assumes the pipeline would be a lateral off the Tennessee Pipeline system in Massachusetts. |
| 8 | Windham County (Brattleboro) | 10-inch Lateral extension | $1.2 | Assumes the pipeline would be a lateral off the Tennessee Pipeline system in Massachusetts. |
| 9 | Orleans County (Newport) | 8-inch Lateral extension | $0.9 | It is assumed that the gas pipeline to the Newport area would originate from the Trans Québec & Maritimes pipeline system. |
| | Caledonia County (St. Johnsbury) | 10-inch Lateral extension | $1.1 | The lateral would be an approximately 35 mile extension of the PNGTS system. |

Source: Vermont Gas Systems, Inc.

## APPENDIX D: FUEL PRICE FORECASTS