An Assessment of
Retail Rate Trends and
Generation Costs in Maine

Prepared for

Independent Energy Producers of Maine

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I. SUMMARY

The Independent Energy Producers of Maine ("IEPM") asked us to examine retail rate trends and the economics of utility cost-based generation in Maine to inform the currently on-going discussion as to whether the state's transmission and distribution ("T&D") utilities should be allowed to enter the energy supply business. Due to the price spikes in underlying fuel markets in 2005 and early 2006, wholesale market prices and retail rates for electric power in Maine have increased significantly. This has raised the questions of (1) whether Maine's customers have fared poorly as a result of Maine's implementation of electric industry restructuring and (2) whether retail rates could be stabilized and reduced if Maine's T&D utilities were allowed to re-enter the energy supply business by building new generation under traditional cost-of-service regulation.

We find that rates in restructured and non-restructured states have increased very similarly since the advent of restructuring in the late 1990s. While average rates in Maine and other restructured states are above the national average and even further above the average of non-restructured states, that rate differential already existed prior to restructuring. In fact, in Maine and other restructured states, the largest rate increases have happened under the traditional regulatory model in place during the early 1990s, a trend which in part led to restructuring efforts. Importantly, however, rate increases in Maine have been more limited than in other states since restructuring in the late 1990s, both relative to restructured and non-restructured states, as well as on a nation-wide and regional basis. As a result, and despite the significant recent increases, ***Maine's retail rates in 2006 compare more favorably to regional and national averages than they did in the late 1990s, just prior to restructuring.*** For example, while Maine had the second-highest rates in New England during much of the 1990s, it ranked second lowest in 2006. Rate trends in Maine also compare favorably to price trends for other consumer goods and services, in particular other energy products.

The suggestion that retail rates could be reduced and stabilized if the regulated utilities were permitted to build and own new generation ***raises the question of whether regulated utilities would have inherent long-term cost advantages relative to unregulated generation developers in building and operating plants. As we discuss below, we find that they do not.*** Even though lower financing costs are often cited as a benefit of utility-owned generation, a low cost of capital is not the result of plant ownership by regulated utilities. A project's overall cost of capital depends on the risk of the investment, not on who makes the investment. This means the "benefit" of a lower cost of capital can be achieved without utility ownership by making cost-of-service treatment or long-term cost-based contracts that reduce investment risks also available to others. This benefit is achieved only by shifting cost recovery risks to retail customers, including the risk of stranded costs. In fact, ***at the same level of cost recovery risks, unregulated utility affiliates and independent generation developers may even have cost advantages over Maine's T&D utilities due to their larger scale and experience base.***

Both cost-of-service generation and long-term power purchase agreements ("PPAs") have the potential to reduce rate *volatility*. We find, however, that ***most of the available generation technologies do not offer the prospect of rate reductions.*** Adding new natural gas or oil-fired generation would likely fail to reduce rate volatility by further increasing Maine's exposure to volatile natural gas and oil prices. Adding biomass, small hydro, and clean coal generation on a cost-of-service or PPA basis would help reduce the state's exposure to natural gas and oil price volatility, but would likely increase (not decrease) rates, particularly in the near term. ***Adding wind power offers the potential to reduce both the level and volatility of Maine retail rates—although the prospect of long-term rate reductions would be very limited.*** Even adding 500 MW of cost-based wind likely would reduce retail rates in Maine by only approximately 1 percent over the 20 year life of the facilities. In addition, under cost-of-service regulation, most of the rate reductions would occur in later years, while rates might even increase slightly during the first several years.

Importantly, ***any long-term benefits of adding cost-based wind generation are not contingent on utility-ownership of such generation, but could also be achieved through long-term cost-based contracts or cost-of-service arrangements with non-utility generators.*** Similar benefits likely could also be achieved through conventional long-term PPAs. While long-term PPAs would be slightly more expensive than arrangements that directly pass costs on to customers on average, they could offer more attractive (e.g., levelized) pricing paths than traditional cost-of-service regulation and would also reduce the risk imposed on retail customers by leaving more cost recovery risk with the generation developer.

II. RETAIL RATE TRENDS

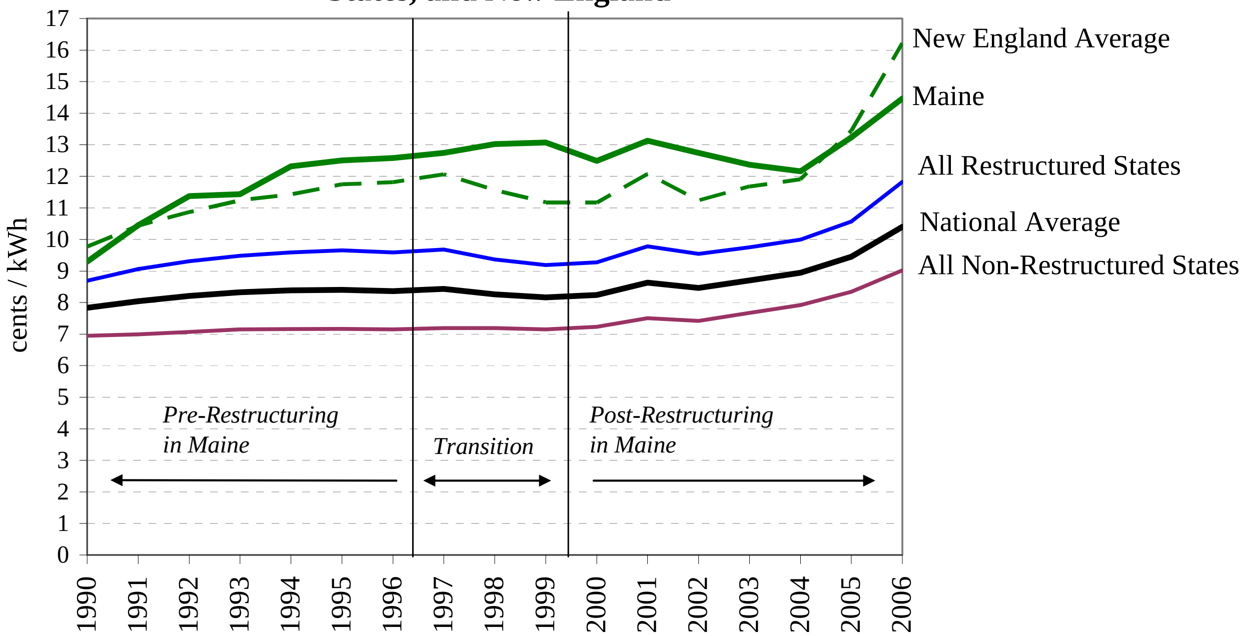
In 1997, the Maine Legislature enacted legislation that directed comprehensive restructuring of its electric power industry under which the incumbent utilities were required to divest their generation resources. In March 2000, retail access was made available to all customers. To ensure that consumers would continue to have access to reasonably-priced power, the Legislature directed the Maine Public Utilities Commission ("MPUC" or "Commission") to procure standard offer service for electricity consumers in the wholesale marketplace. Customers not choosing to be supplied directly by a competitive electric provider receive power at the standard offer rate.

Our assessment of retail rate trends focuses on the standard offer rates resulting from the MPUC's wholesale procurement and, in particular, the residential customer class which remains almost entirely standard offer service. As of July 2007, less than one percent of residential and small commercial load was served by competitive providers in Maine, whereas approximately 90 percent of large industrial load and approximately 40% percent of medium commercial and industrial load were served by competitive energy providers.[1] By focusing on average residential rates, we avoid potential distortions of average rate levels and trends due to reporting differences, changes in customer mix, and changing amounts of self-generation by retail customers in individual states. We note, however, that our general results and overall conclusions would be very similar if rates data for other customer classes were included. All rate comparisons presented in this whitepaper rely upon data published by the Department of Energy (DOE) through various publications, including Form EIA 861, Form EIA 826, and DOE's State Energy Consumption, Price, and Expenditure Estimates (SEDS).

Figure 1 presents a comparison of residential retail rates in Maine with average national and regional rates from 1990 through 2006, as well as average rates for restructured and non-restructured states.

[1] http://www.maine.gov/mpuc/industries/electricity/electric%20restructuring/migrationrates.htm.

Figure 1
Residential Retail Rates in Maine vs.
Averages for U.S., Restructured States, Non-Restructured States, and New England



Source: The Brattle Group, based on EIA Data.

Figures 1 shows that Maine's retail rates, like those of the other states in New England, are well above national averages. This, however, already was the case prior to the restructuring efforts in Maine and other states and is explained in large part by factors such as differences in fuel availability (e.g., very little low-cost coal and hydro power), higher fuel transportation costs (e.g., at the end of major natural gas pipelines), and higher labor and construction costs. Similarly, while it is true that average retail rates in other non-restructured rates are below average rates in restructured states, this was already the case before restructuring efforts were initiated in the now restructured states. Many of the non-restructured states also enjoy unique advantages, such as access to low-cost coal or hydro generation (which in some states accounts for more than two thirds of total generation).

Importantly, however, Figure 1 documents that, ***since restructuring was initiated, the retail rate increases in Maine compare favorably to the rate increases experienced nation-wide, in other restructured and non-restructured states, as well as in New England***. As summarized in

Table 1, residential rates in Maine have increased 13.5 percent since 1997. This compares to an average residential rate increase of 23 percent nation-wide, a 25 percent rate increase in non-restructured states, a 22 percent increase in other restructured states, and a 35 percent average residential rate increase in New England.[2]

Table 1
Residential Retail Rate Trends in Maine
Compared to Trends in Other States and Regions

Increase in Maine Rates	1997-2006	13.5%
Increase in New England Rates	1997-2006	34.5%
Increase in US Rates	1997-2006	23.4%
Increase in Restructured State Rates	1997-2006	22.1%
Increase in Non-Restructured State Rates	1997-2006	25.4%
Rank of Maine's Rates among All States	1999	4th Highest
Rank of Maine's Rates among All States	2004-2006	7th or 8th Highest
Premium of Maine's Rates over US Rates	1999	4.91 cents/kWh
Premium of Maine's Rates over US Rates	2006	4.07 cents/kWh
Rank of Maine's Rates among New England States	During 1990s	2nd Highest
Rank of Maine's Rates among New England States	2006	2nd Lowest

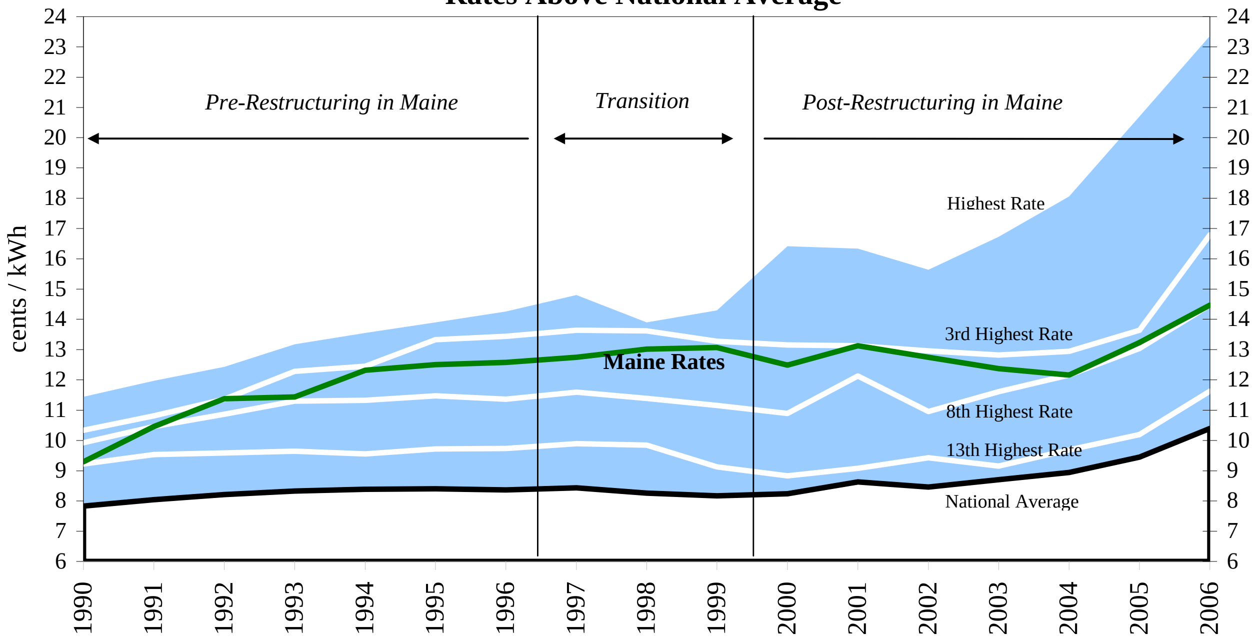
Source: The Brattle Group, based on EIA data.

As also shown in Table 1, Maine had the 4th highest residential rates in the country in 1999, the year prior to implementing full retail access. Since 2004, however, Maine has only had the 7th or 8th highest rates. While the difference between the residential rates in Maine and the nationwide average was approximately 5 cents/kWh in 1999, this differential had decreased to approximately 4 cents/kWh in 2006. Table 1 also shows that Maine's position improved within New England. Maine had the second-highest residential rates in the region during the early to late 1990s, prior to implementing retail access. By 2006, Maine's average residential rates were the second-lowest in New England.

2 1997 is not only the year in which Maine passed restructuring legislation, but it is also the last year before some of the now restructured states implemented retail access and restructuring-related rate reductions. For example, Illinois implemented retail access in 1998 along with residential rates for standard offer service that were up to 20% below 1997 regulated rates.

Figure 2 illustrates how Maine's residential rates compare relative to the national average and the full range of states with above-average residential rates. Again, the figure documents that, since restructuring was implemented, Maine has not only improved its relative ranking, but has also been able to reduce the rate discrepancy relative to other states. Even the significant rate increases Maine experienced over the last 2 years are very similar to the rate increases nationwide.

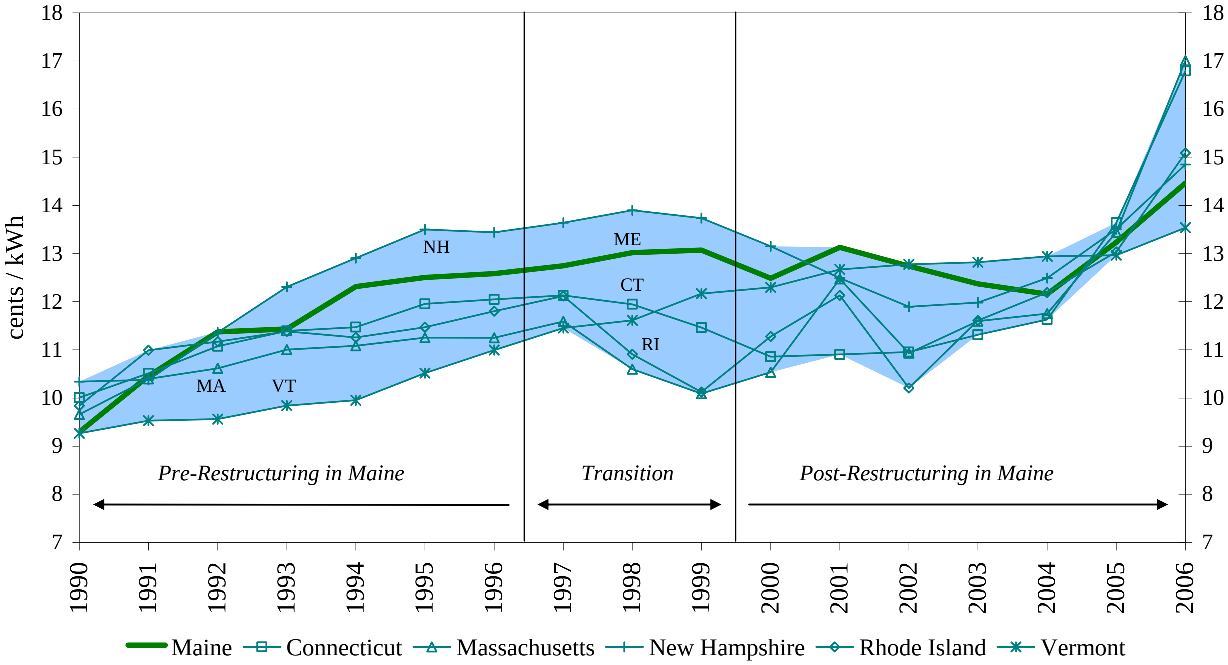
Figure 2
Residential Rates in Maine Compared to Range of Rates Above National Average



Source: The Brattle Group, based on EIA Data.

Figure 3 shows a similar comparison with only the New England states. Consistent with Figure 1, Figure 3 again illustrates that the most significant rate increases happened in the early 1990s, when all of New England was still under traditional cost-of-service regulation. In this regard, Maine's rate trend is very similar to that of the rest New England.

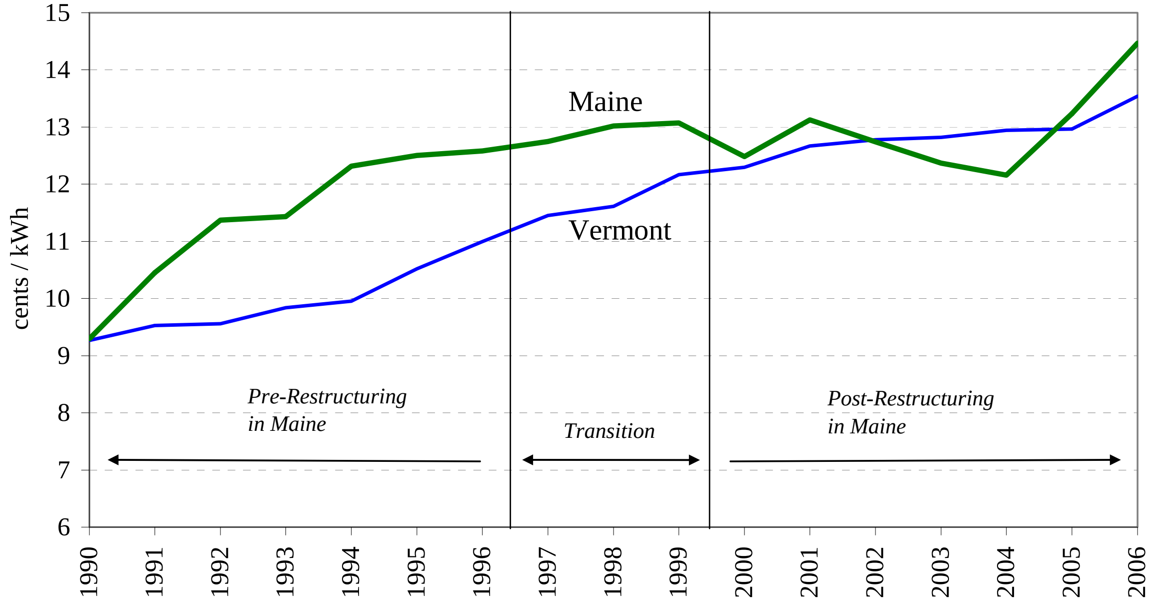
Figure 3
Maine Residential Retail Rates vs. Other New England Rates



Source: The Brattle Group, based on EIA Data.

Figure 4 shows that Maine's rates have trended very similar to rates in Vermont, the only non-restructured state in New England. This is the case despite the fact that the fuel mix in Vermont consists of mostly nuclear and hydro power, a mix which differs substantially from the heavy reliance on natural gas in Maine. Figure 4 also shows that over the 2000 to 2006 period, when retail access was fully available in Maine, the average rate differential between Maine and Vermont was only 0.1 cents/kWh, which is significantly smaller than the approximately 1.4 cents/kWh differential during the ten years between 1990 and 1999, prior to full retail access. However, Vermont's retail rates have trended more steadily, which likely is explained in large part by the very different fuel mix.

Figure 4
Residential Retail Rates in Maine and Vermont

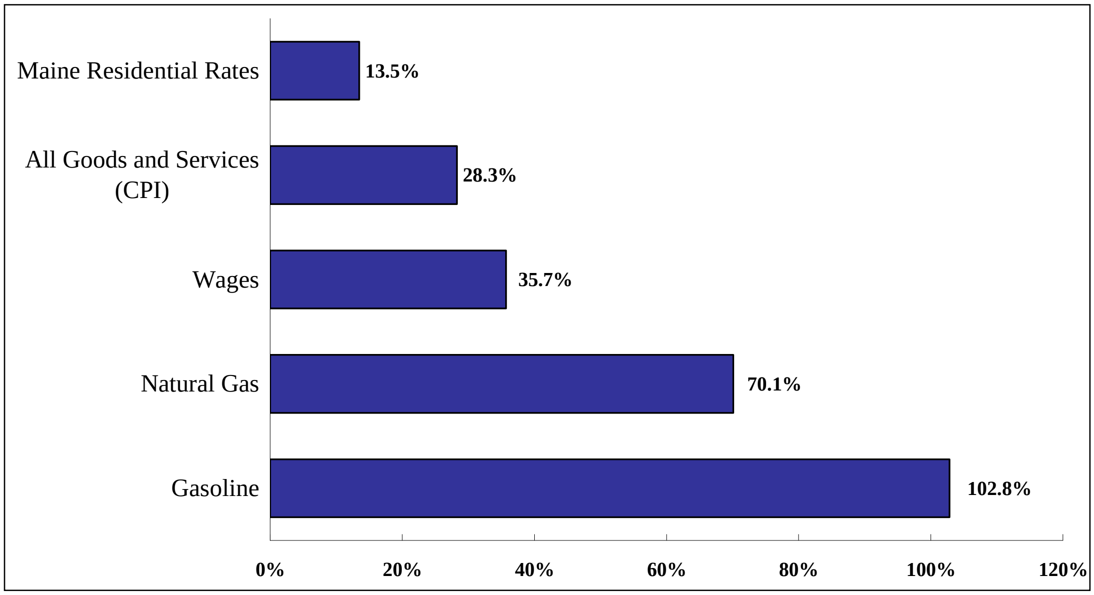


Source: The Brattle Group, based on EIA Data.

Figures 1 through 4 documented that the recent rate increases in Maine compare favorably to rate trends in other restructured, non-restructured, and New England states. Since restructuring was initiated, Maine's retail rates have increased less than the average nationwide and in New England. These rate trends do not suggest that Maine has suffered as a result of restructuring.

In addition, as shown in **Figure 5**, Maine's electricity rate increase also compares favorably to the price increases end users experienced for other goods and services, in particular other energy products. For example, the 13.5 percent average residential rate increase since Maine's restructuring legislation was passed in 1997 compares to a 28 percent increase in the consumer price index, a 36 percent increase in wages, a 70 percent increase in the average retail price of natural gas, and a more than 100 percent increase in gasoline prices.

Figure 5
1997-2006 Changes in Retail Rates Compared to Consumer Prices and Wages



Sources and Notes: The Brattle Group, based on Bureau of Labor Statistics and EIA (*CPI for Northeast, Wages for Maine, Natural Gas and Gasoline for Boston area*).

III. POTENTIAL BENEFITS AND RISKS OF UTILITY COST-BASED GENERATION

The retail rate trends discussed above show that, despite the recent increases, Maine has been able to improve its position relative to the national and regional averages. The data also show that rates in restructured and non-restructured states have increased very similarly. While restructuring may not have lived up to some of its (perhaps unrealistically) high expectations, ***it is far from clear that a full or even partial return to cost-of-service regulation would benefit consumers.***

In fact, we fear that re-regulation efforts could be risky and potentially costly undertakings. This concern is also shared by others. For example, although Standard and Poor's notes that it "does not consider the prospects for significant re-regulation to be broad based" and that thoughtful re-regulation efforts could be even "beneficial for credit quality," the agency also stresses that, "especially in a political environment that is certain to be highly contentious," re-regulation is a "risky proposition that could threaten utility balance sheets, destroy value, and impair credit ratings."[3] In fact, in its April 3 statement, S&P goes on to note further that:

> …it is not definitively clear whether liberalization has succeeded or failed. … Would a return to traditional regulation lower electricity prices? Absent liberalization, would electricity prices have been lower, all else being equal? Forecasting what might have been is always difficult. And, of course, all else is rarely equal, such as the rapid rise in fuel prices and more recently a surge in capital costs. Nevertheless, the introduction of competition into generation resulted in greater efficiencies, lower heat rates, greater reliability, lower nonfuel operating costs, and in general, more widely adopted best practices. Consider how nuclear power plant operations have dramatically improved in competition's short tenure. Would a reversion to regulation preserve these gains? Absent the pressure of competition, it is hard to believe so, given cost-of-service regulation's history.

It has been suggested that allowing T&D utilities to build new generation under cost-of-service regulation may help reduce and stabilize retail rates in Maine. This raises the question of whether regulated T&D utilities would have an inherent long-term cost advantage with respect to new generation developments over unregulated utility affiliates or independent generation developers.[4] As we discuss below, we find that they do not.

A. DO REGULATED UTILITIES HAVE AN INHERENT COST ADVANTAGE?

The question of whether cost-of-service regulated generation owned by T&D utilities offers inherent cost advantages must be analyzed in the context of who bears the significant market, development, and operational risks of generating facilities.

A generating plant's "cost of service" can be reduced by transferring risks from the owner to the buyer of the plant's output—ultimately the customers from whom the cost-of-service is recovered. This reduces the project's cost of capital, which allows for lower-cost financing—a benefit that is often attributed to utility ownership of generating plants. However, the cost of

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3 Standard & Poor's "The Credit Implications of U.S. Electric Utility Re-Regulation," April 12, 2007 and "Re-Regulation of U.S. Electric Utilities: The Toothpaste Challenge," April 3, 2007.

4 It is our understanding that Maine's T&D utilities are already able to form unregulated affiliates that can build and own generation on the same terms as other unregulated generation developers.

capital of utilities under cost-of-service regulation often is lower than the cost of capital faced by merchant generators simply because cost-of-service regulation transfers significant cost recovery risks from the utility to its ratepayers. Imposing such risks on customers can reduce rates under some circumstances but can also be costly. This has been shown by the experience of the late 1990s when significant stranded costs needed to be recovered as part of the restructuring effort.

There simply is no free lunch in capital markets. A project's overall cost of capital depends on the risk of the investment (*i.e.*, the use of funds), not the source of the funds (*i.e.*, not the type of company making the investment or that company's average business risk and associated cost of capital). Thus, as long as the investment is made by financially healthy companies with ready access to capital markets, utilities do not enjoy a lower cost of capital in making generation investments than other companies. The only reason why utilities may face a lower cost of capital for generation investments is that more risks are shifted to ratepayers under cost-of-service regulation. If similarly favorable cost-recovery terms (*e.g.*, cost-of-service treatment or long-term cost-based contracts) are offered to non-utility companies or unregulated utility affiliates, they will generally be able to finance the generation investment at the same low cost of capital.

Financing costs will be higher for companies with limited access to capital markets. However, this is no longer an issue for many unregulated generation companies and some have credit ratings that exceed those of many utilities. Even many wind power developers, such as FPL or TransCanada, are large companies with a strong corporate balance sheet and ready access to capital markets. Some of these developers also use utility-style "corporate balance-sheet finance" to structure their unregulated investments. In addition, as reported by the Department of Energy, a variety of innovative financing structures have been developed that have significantly reduced financing costs for non-utility wind projects—by as much as 300 basis points in recent years.[5]

Aside from cost of capital, cost advantages could exist due to superior experience and economies of scale or scope. In that regard, however, unregulated utility affiliates or independent generation developers may even have cost advantages over Maine's T&D utilities due to their

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5 U.S. DOE, Annual Report on U.S. Wind Power Installation, Cost, and Performance Trends: 2006, May 2007 ("DOE 2006 Wind Report"), p. 9.

larger scale and experience base. If the objective is to supply retail load with cost-based generation from new power plants, cost-of-service treatment or long-term cost-based contracts could be offered through a competitive procurement process to both utility and non-utility generation developers. Such a process would also pass through to retail customers all or most of the value of any tax and renewable energy credits and allow the selection of the companies that can develop the desired generation projects under the most attractive, most competitive terms.

B. OPTIONS TO HELP REDUCE AND STABILIZE RETAIL RATES IN MAINE

Even if regulated T&D utilities have no inherent cost advantage, the following question remains: could retail rates in Maine be reduced and/or stabilized if some of Maine's retail load was supplied through cost-of-service or long-term power purchase arrangements with new generation facilities rather than through shorter-term purchases at wholesale market prices?

With respect to ***reducing rate uncertainty***, the dominance of natural gas in the New England power market means that increased volatility of natural gas prices translates into increased volatility of wholesale power prices. The extent to which this volatility affects retail rates can be reduced by increasing the contract durations used to supply a portion of retail load (e.g., by increasing the durations of standard offer contracts used to serve residential and other small standard offer customers). This, in turn, could be achieved by supplying some of Maine's retail load through cost-of-service arrangements, cost-based long-term contracts, or conventional long-term PPAs with new or existing generation.

Rate uncertainty could also likely be reduced by adding power plants with operating costs that are less volatile than or that help offset the volatility introduced by natural gas plants. The construction of such power plants (e.g., wind, biomass, hydro, or coal plants) could likely be encouraged through long-term contracts or cost-of-service arrangements. However, while such long-term commitments would likely reduce the volatility of both retail rates and wholesale market prices, it is less clear that they would actually reduce rates. As experience has shown, there is generally a cost to hedging—and "locking-in" prices through long-term arrangements that look favorable under prevailing market conditions could impose significant "out of market" costs down the road. This has occurred in the 1980s and 1990s when changes in market conditions meant that initially "favorable" utility generation investment (e.g., nuclear plants) and QF contracts were very costly and significantly above market after the fact. It also happened in the aftermath of the Western power crisis, when several utilities in California and other Western states signed "favorable" long-term contracts that are now above market by several billions of dollars.

With respect to whether new cost-based generation could ***reduce retail rates***, we explored the relative costs of new natural gas or oil fired generation, coal-gasification plants, biomass plants, small-scale hydro, and wind power plants. To reduce average retail rates, the cost of new generation needs to compare favorably to the cost of purchases out of the regional wholesale markets. The annual average market price for on-peak energy in Maine is currently approximately $65/MWh, with off-peak prices just above $50/MWh, and average annual prices of just under $60/MWh across all hours. Based on current forward market conditions, these market prices are expected to increase approximately 20 percent over the next several years to about $70/MWh (all hours). Capacity payments of approximately $50/kW-yr will generally add less than $10/MWh to average energy market revenues. This means that the average cost of new generation would need to be significantly below $80/MWh to offer the prospect of meaningful reductions in retail rates.

Table 2 summarizes the average cost of different generation technologies under utility cost-of-service treatment based on a recent analysis by the California Energy Commission. While costs in Maine will differ slightly from these estimates (*e.g.*, the fuel cost of coal plants is higher in New England), they will generally be in the same range. ***These estimates show that natural gas generation, coal gasification, biomass, and hydro plants do not offer the prospect of below-market average costs.*** Oil-fired plants similarly would not offer the prospect of savings because the market price of oil does not currently differ substantially from that of natural gas. In addition, adding new natural gas or oil-fired generation would likely fail to reduce retail rate volatility by further increasing Maine's exposure to volatile natural gas and oil prices.

Table 2
Estimated Average Costs of Alternative Generation Technologies
Under Utility Cost-of-Service Regulation

Generation Technology [1]	Fuel [2]	Project Size (MW) [3]	Total Fixed Costs (Net of Tax Credits) ($/MWh) [4]	Total Variable Costs ($/MWh) [5]	Total Levelized Costs ($/MWh) [6]
Conventional Combined Cycle (CC)	Natural Gas	500	$26	$68	$94
Integrated Gasification Combined Cycle (IGCC)	Coal	575	$67	$29	$96
Biomass Combustion - Stoker Boiler	Wood Chips	25	$46	$56	$102
Hydro - Small Scale	Water	10	$116	$4	$119
Wind - Class 5	Wind	50	$67	$0	$67

Sources and Notes:
California Energy Commission, *Comparative Costs of California Central Station Electricity Generation Technologies* , Draft Staff Report, June 2007, Table 4, p. 12. In 2007 dollars.

This cost comparison shows, however, that wind power offers potential (though ultimately limited) savings relative to market prices—at least under cost-of-service regulation or cost-based long-term contracts that shift risks from utilities or non-utility generation developers to retail customers.[6] However, given this potential for rate reductions, we specifically analyzed the costs of wind power in Maine under currently expected future market conditions. With the single exception of wind, no other new cost-based generation investments would likely help reduce Maine's average retail rates.

C. THE COST OF WIND POWER AND ITS POTENTIAL TO REDUCE RETAIL RATES IN MAINE

Our analysis, which is presented in Appendix A, finds that the cost of developing wind power in Maine is approximately 17 percent less (in present value terms) than the estimated total cost of purchasing the same quantity of power in the regional wholesale market over the full 20-year life of the plant. However, due to significant recent increases in the project costs of wind, its regulated cost-of-service likely would be approximately 20 percent more expensive initially. Only as the plant is depreciated over time, savings are realized (starting approximately in year

6 In the California Energy Commission report the average cost of wind power is estimated to be $99/MWh on a pure "merchant" basis (i.e., without the benefit of any medium- or long-term contracts that could reduce cost-recovery risks).

five) due to the combination of increasing market prices, available tax credits, and the value of renewable energy certificates (RECs). Nevertheless, there is also the risk that such savings do not materialize or that wind power could be more expensive than market purchases.

Our analysis shows that each 100 MW wind farm added to total state-wide retail sales in Maine would initially increase average retail rates by as much as 0.3 percent during the first few years, but reduce retail rates by up to 0.6 percent in later years. The average reduction of retail rates over 20 years (in present value terms) is estimated at approximately 0.18 percent. Thus, ***even if five 100 MW wind projects (500 MW in total) were built*** to serve Maine's retail customers under cost-of-service or cost-based long-term contractual arrangements with utilities, utility affiliates, or independent project developers, ***retail rates would be reduced by only approximately 1 percent on average over 20 years***.

We also find that the estimated cost advantage of wind power is entirely contingent on the availability of federal tax credits and RECs. This is not surprising as both tax credits and RECs have been made available specifically to foster development of wind power and other renewable resources. Without tax credits and REC values, the cost advantage of wind would be eliminated and the estimated average life-time costs of wind would be nearly 30 percent higher than market purchases. The cost advantage of wind power could also be eliminated through a combination of higher project costs and lower market prices for energy and capacity. The cost implications of these risks are presented in more detail in Appendix A.

While the benefit of wind could also be significantly higher than in our base-case analysis (e.g., due to higher-than-modeled market prices for energy, capacity, and RECs, or additional value created by future greenhouse gas restrictions), the risk clearly exists that a long-term cost-based commitment to wind may not result in the hoped-for savings. For example, tax credits need to be approved periodically by Congress and several past delays in their approval resulted in substantially reduced wind investments. The high current prices of RECs in Massachusetts and Connecticut are unusual compared to REC prices elsewhere and likely will only be temporary until more and larger renewable projects become operational in New England, New York, and eastern Canada. Under a bill currently pending in Massachusetts, new cost-of-service regulated generation projects would not be able to qualify for RECs in that state.[7]

The construction costs of power plants have increased substantially in the last few years.[8] This increase also applies to wind power. The average cost of wind turbines has increased by more than 60 percent from 2002 through 2006 and further increases must be anticipated at least for the near future.[9] For example, a wind project proposed in Long Island now faces costs that are 100 percent above 2003 estimates.[10] In addition, wind projects in New England tend to be more expensive than on average in the U.S.[11]

The benefits of lower-cost retail supply from wind generation may also be offset in part by higher costs that wind may impose on procuring the remaining supply for retail customers. The amount of wind generation is uncertain on an hourly, daily, seasonal, and annual basis. This will increase the volumetric risk for the remaining retail supply requirements, which would likely increase the balancing costs and risk premiums needed to procure these supplies. Wind integration costs in terms of control-area balancing and regulation costs have been estimated to be in the range of $3/MWh to $10/MWh, depending on the amount of wind that is integrated into the system.[12] Our analysis includes only control-area-related integration costs, which could understate the total procurement-related costs and risk premiums associated with integrating significant amount of wind into retail supply arrangements.

Finally, while current forward prices suggest that wholesale market prices are expected to increase over the next several years, experience shows that significant decreases in market prices are possible. During the last year, for example, average wholesale market prices in Maine were more than 20 percent lower than during the prior 12 month period. Also, DOE's current long-term projection for the generation component of New England's retail rates shows a $16/MWh

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7 Massachusetts House Bill 3333 (2007).

8 The Brattle Group, *Rising Utility Construction Costs: Sources and Impacts*, Report prepared for the Edison Foundation, September 2007.

9 DOE 2006 Annual Wind Report, pp. 15-16.

10 "LIPA Reviews Wind Farm, Cites $291/MWh cost," Megawatt Daily, August 24, 2007.

11 See, for example, DOE 2006 Annual Wind Report, p. 16.

12 See, for example, DOE 2006 Annual Wind Report, p. 20; Northwest Power and Conservation Council, *Interim Review of the Cost of Windpower*, June 29, 2006, p. 3.

decline from 2006 through 2012.[13] Any such decreases in market prices from the currently higher forward prices could also eliminate the long-term cost advantage of wind. This means, while wind power currently offers the prospect of cost savings, these savings are not without risk.

D. ALTERNATIVES TO T&D UTILITY OWNERSHIP OF GENERATING PLANTS

To the extent a long-term commitment to cost-based wind generation (or other generation technologies) offers the potential of reduced and more stable retail rates, utility ownership of cost-of-service regulated power plants is neither the only nor necessarily the most effective option to achieve these goals.

First, if the Commission were to allow cost-of-service treatment for new generation facilities of T&D utilities, such cost-of-service treatment could be offered to both unregulated utility affiliates and independent generation companies. The California ISO's cost-of-service treatment of transmission facilities developed by independent transmission companies (e.g., the "Path 15" upgrade) is an example of making cost-of-service treatment available to non-utility companies.

Second, the Commission or Maine's T&D utilities could offer cost-based long-term contracts to either non-utility companies or unregulated utility affiliates. These contracts could be structured to recover the cost-of-service of particular generation facilities over their useful lives. Such cost-based long-term contracts have been common before market-based-rates were allowed and are still used in certain settings today. However, both cost-of-service treatment of generation and long-term cost-based contracts will achieve some of the potential cost reductions simply by shifting the risk from generation owners to ratepayers.

Third, if the Commission finds that making long-term commitments to supply retail customers are desirable to reduce costs and stabilize retail rates, this objective could likely also be achieved with conventional long-term power purchase agreements. Such long-term PPAs would also reduce the risks imposed on retail customers relative to cost-of-service treatment or cost-based contracts by leaving more cost recovery risks with the generation developer.

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[13] DOE, Annual Energy Outlook 2007, supplemental Table 68 (restated in nominal dollars).

In fact, the analysis presented in Appendix A shows that procuring wind power through long-term PPAs with non-utility developers or unregulated utility subsidiaries could also avoid the higher up-front costs experienced under cost-of-service regulation. Due to higher cost recovery risks imposed on plant developers, the average savings over the 20 year life of a 100 MW wind power plant are somewhat less for non-utility developers (approximately 0.12 percent compared to 0.18 percent under cost of service regulation). However, this is because more cost recovery risks are left with the plant developers (rather than being imposed on ratepayers). These risks include the potential that the expensive siting and permitting process may not result in the approval of wind projects, the possibility of construction cost overruns, unanticipated escalation in ongoing operating and maintenance costs, certain other operating risks, and the premature obsolescence of wind power plants. Under conventional PPAs, many of these risks are (at least in part) assumed by the generation developer.

By making cost-of-service treatment, cost-based long-term contracts, or conventional long-term PPAs available in a competitive procurement setting, independent generation companies also could compete on equal terms with T&D utilities or their generation affiliates. Maintaining a level playing field between regulated and unregulated generation developers would likely result in more efficient outcomes by allowing generation to be developed through a competitive process that selects the most efficient and most qualified companies. In the end, retail customers would benefit from that competition.

However, despite the prospect of lower and less volatile rates, adding long-term commitments to the supply of retail generation service also carries the risk that rates (e.g., for standard offer service) could end up being above or below market. If regulated rates are above market, customers will tend to switch off standard offer service, which could create stranded cost risk as more and more customers attempt to avoid the above-market rates of standard offer service.

To summarize, we find that some cost savings may be realized by developing wind power to supply retail customers on a cost-of-service basis, under cost-based long-term contracts, or under conventional long-term PPAs that leave more risks with developers. However, even assuming the previously-discussed risks and costs do not materialize or are more than offset by upside potential, we find that the ***ability to reduce average retail rates is simply limited by how much***

such generation could be added. As noted, even adding 500 MW of wind generation at its "net" cost-of-service would likely reduce the average cost of supplying Maine's retail load by only approximately 1 percent over the 20-year life of the facilities, with rate increases likely during the first few years.

APPENDIX A: THE ECONOMICS OF WIND POWER IN MAINE

Our base case estimate of the costs and benefits of a 100 MW utility-scale wind power plant is shown in **Table A1**. Column [4] of Table A1 shows that the present value of its revenue requirements (depreciation, return on ratebase, taxes, and O&M costs) amounts to $258 million, which is reduced by tax and REC credits to $175 million as shown in Column [9]. This $175 million "net project cost" (which also includes wind integration costs) is 17% less than the $210 million present values of purchasing the same amount of power from the wholesale markets—which consists of $199 million in energy market value (Column 11]) and $11 million in capacity market value (Column [15]).

The annual impact of the project relative to the wholesale market purchases (energy and capacity), shown in Column [16], is an added cost of $4 million in the first year but a benefit of up to $18 million per year as the plant is fully depreciated. Based on the value of total retail sales in Maine—estimated at approximately $1.6 billion per year in 2009 growing to $3.1 billion over the 20 year period as shown in Column [17]—these savings would reduce average retail rates by up to 0.6 percent annually (Column [18]). As also shown in Column [18], the present value of the estimated 20-year net benefits—$35 million as shown in Column [16]—amounts to only 0.18 percent of the present value total of retail rates paid by customers over the life of the plant.

Examples of the financial implications of downside risks associated with wind projects are presented in **Table A2** (illustrating the financial implications of a loss of tax and REC credits) and **Table A3** (for a scenario of higher costs and lower market prices for energy and capacity). As shown in Column [16] of the tables, these scenarios would result in significantly higher retail rates during the early years of the project (up to $21 million per year or 1.3 percent of retail rates for the 100 MW wind project) that are only partially offset by lower retail rates during the later years of the project (up to $14 million per year or 0.4 percent of retail rates). The savings in later years are created by the fact that the traditional cost of service declines over time as the plant is depreciated, while the market price of power tends to increase over time due to inflationary pressures.

Table A4 presents an analysis of wind-related costs under a long-term PPA. The *net* PPA contract costs are based on (1) capital charges and tax credits that have been levelized over the 20 year project life; (2) the projected nominal costs for O&M, lease payments, taxes and insurance costs; and (3) the value of RECs, which the owner of the plant would pass on to the contract holder. The initially low but increasing net costs shown in Columns [4] and [5] reflect the projected decrease in the REC prices that are currently available in southern New England from $40/MWh to an estimated equilibrium value of $15/MWh, which is more in line with REC prices observed in other market areas and projected by DOE.[14] Based on the future market conditions and costs reflected in our analysis, column [18] shows that developing 100 MW of wind under this option would reduce average retail rates in Maine by 0.12 percent (as compared to 0.18 percent under the traditional cost-of-service or cost-based contractual option). This difference is entirely due to a higher cost of capital that reflects the higher project cost recovery risks imposed on the developer under more conventionally structured long-term PPAs. However, unlike the cost-of-service option shown in Table A1, the PPA option also avoids the initial rate increases caused by the more front-loaded cost recovery under cost-of-service regulation.

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[14] See, for example, DOE 2006 Annual Wind Report, p. 12 (showing REC prices in outside New England in the $2/MWh to $15/MWh range); and DOE, *Impacts of a 15 Percent Renewable Portfolio Standard*, June 2007, p. 5 (showing that a nation-wide 15 percent RPS standard would lead to renewable energy credit prices that would generally be below $19/MWh).

Table A1
Traditional Cost of Service Treatment
(Base-Case Cost and Revenue Assumptions)

Year	Project Size (MW) [1]	Annual Output of Project (GWh) [2]	Total Project Revenue Requirements (Capital and O&M) Per MWh ($/MWh) [3]	Total Project Revenue Requirements (Capital and O&M) Total ($ Millions) [4]	Wind Integration Costs ($/MWh) [5]	Federal Tax Credits ($/MWh) [6]	Renewable Energy Certificate Prices ($/MWh) [7]	Net Project Costs Per MWh ($/MWh) [8]	Net Project Costs Total ($ Millions) [9]	Energy Market Energy Prices (Wind) ($/MWh) [10]	Energy Market Energy Market Value ($ Millions) [11]	Capacity Market Capacity Prices ($/kW-yr) [12]	Capacity Market Plant Capacity Factor During Summer Peak [13]	Capacity Market Capacity Prices (Wind) ($/MWh) [14]	Capacity Market Capacity Market Value ($ Millions) [15]	Total Project Net Benefits (Costs) ($ Millions) [16]	Approx. Maine Retail Revenues ($ Millions) [17]	Annual Net Benefits (Costs) As % of Maine Retail Revenues [18]
2009	100	275	$144	$40	$5	$20	$40	$89	$24	$70	$19	$49	19%	$3.4	$0.9	($4)	$1,600	-0.3%
2010	100	275	$134	$37	$5	$21	$35	$83	$23	$69	$19	$50	19%	$3.5	$1.0	($3)	$1,700	-0.2%
2011	100	275	$124	$34	$5	$21	$30	$78	$21	$67	$18	$51	19%	$3.6	$1.0	($2)	$1,700	-0.1%
2012	100	275	$115	$31	$5	$22	$25	$73	$20	$66	$18	$53	19%	$3.6	$1.0	($1)	$1,700	0.0%
2013	100	275	$105	$29	$5	$23	$20	$67	$18	$69	$19	$54	19%	$3.7	$1.0	$1	$1,800	0.1%
2014	100	275	$95	$26	$5	$23	$15	$62	$17	$68	$19	$55	19%	$3.8	$1.1	$3	$1,800	0.2%
2015	100	275	$92	$25	$5	$24	$15	$59	$16	$73	$20	$57	19%	$3.9	$1.1	$5	$1,900	0.3%
2016	100	275	$90	$25	$5	$24	$15	$55	$15	$74	$20	$58	19%	$4.0	$1.1	$6	$1,900	0.3%
2017	100	275	$87	$24	$5	$25	$15	$52	$14	$76	$21	$60	19%	$4.1	$1.1	$8	$2,000	0.4%
2018	100	275	$84	$23	$5	$26	$15	$49	$13	$79	$22	$61	19%	$4.2	$1.2	$10	$2,100	0.5%
2019	100	275	$82	$22	$5	$0	$15	$72	$20	$81	$22	$63	19%	$4.3	$1.2	$4	$2,200	0.2%
2020	100	275	$79	$22	$5	$0	$15	$69	$19	$83	$23	$64	19%	$4.4	$1.2	$5	$2,300	0.2%
2021	100	275	$76	$21	$5	$0	$15	$66	$18	$86	$24	$66	19%	$4.6	$1.3	$7	$2,400	0.3%
2022	100	275	$74	$20	$5	$0	$15	$64	$18	$87	$24	$68	19%	$4.7	$1.3	$8	$2,400	0.3%
2023	100	275	$71	$20	$5	$0	$15	$61	$17	$91	$25	$69	19%	$4.8	$1.3	$9	$2,500	0.4%
2024	100	275	$69	$19	$5	$0	$15	$59	$16	$93	$26	$71	19%	$4.9	$1.3	$11	$2,600	0.4%
2025	100	275	$66	$18	$5	$0	$15	$56	$15	$96	$26	$73	19%	$5.0	$1.4	$12	$2,700	0.5%
2026	100	275	$63	$17	$5	$0	$15	$53	$15	$99	$27	$75	19%	$5.2	$1.4	$14	$2,800	0.5%
2027	100	275	$61	$17	$5	$0	$15	$51	$14	$101	$28	$76	19%	$5.3	$1.5	$15	$2,900	0.5%
2028	100	275	$58	$16	$5	$0	$15	$48	$13	$108	$30	$78	19%	$5.4	$1.5	$18	$3,100	0.6%
Net Present Value (in 2009 @ Regulatory WACC):				**$258**					**$175**		**$199**				**$11**	**$35**	**$19,100**	**0.18%**

Assumptions:

Capital Structure	50% Debt, Cost of Debt = 6%, Cost of Equity = 11%	Average Plant Capacity Factor	32%, based on ISO-New England Final Scenario Analysis Modeling Assumptions
Tax Rate	40%	Transmission Losses to Central Maine	2.0%
Useful Life	20 Years	Wind Integration Costs ($/MWh)	$5 Flat
Tax Depreciation	5 Years	Federal Tax Credits ($/MWh)	$19 / MWh ($2006) for 10 Years
Investment Costs ($2009 / kW-Yr)	$2,000	Renewable Energy Certificate Prices ($/MWh)	$40 in 2009 declining to $15 by 2014
Fixed O&M and Lease ($2006 / kW-Yr)	$30 (in 2006, escalated at inflation)	Avg. Central Maine Energy Prices for Wind ($/MWh)	$70/MWh in 2009 grown at nominal DOE path for New England generation
Property Taxes and Lease Payments	1% of net book value	Capacity Prices in Maine ($/kW-Yr)	$49 in 2009, grown at inflation
		General Inflation	2.5%

Sources and Notes:

[1]: Assumed project size.
[2]: = ([1] x 8760 hours x 32% x (1 - 2.0%)) / 1000. Accounts for capacity factor and line loss assumptions.
[3]: = (Revenue Requirements + Fixed O&M + Property Tax @ 1% of Book Value) / ([2] x 1000].
[4]: = [2] x [3] / 1000.
[5]: DOE and Northwest Power and Conservation Council.
[6]: = $19 / MWh ($2006) for 10 Years.
[7]: Based on REC prices in other markets and DOE projections.
[8]: = [3] + [5] - [6] - [7].
[9]: = [2] x [8] / 1000.
[10]: Based on current forward prices for 2008-2010 adjusted for Central Maine location and typical wind profile.
[11]: = [2] x [10] / 1000.
[12]: FCM Settlement for Summer 2009, grown at inflation.
[13]: Based on ISO-New England Final Scenario Analysis Modeling Assumptions.
[14]: = [1] x [12] x [13] / [2].
[15]: = [2] x [14] / 1000.
[16]: = [11] + [15] - [9].
[17]: Maine retail revenues for 2006 (Form EIA-826), with estimated generation component grown at 1% for load growth plus percentage change in energy prices from [10], and estimated transmission and distribution component grown at 3.5%.
[18]: = [16] / [17].

Table A2
Traditional Cost of Service Treatment
(No Tax or Renewable Energy Certificate Credits)

Year	Project Size	Annual Output of Project	Total Project Revenue Requirements (Capital and O&M) Per MWh	Total Project Revenue Requirements (Capital and O&M) Total	Wind Integration Costs	Federal Tax Credits	Renewable Energy Certificate Prices	Net Project Costs Per MWh	Net Project Costs Total	Energy Market: Energy Prices (Wind)	Energy Market: Energy Market Value	Capacity Market: Capacity Prices	Capacity Market: Plant Capacity Factor During Summer Peak	Capacity Market: Capacity Prices (Wind)	Capacity Market: Capacity Market Value	Total Project Net Benefits (Costs)	Approx. Maine Retail Revenues	Annual Net Benefits (Costs) As % of Maine Retail Revenues
	(MW)	(GWh)	($/MWh)	($ Millions)	($/MWh)	($/MWh)	($/MWh)	($/MWh)	($ Millions)	($/MWh)	($ Millions)	($/kW-yr)		($/MWh)	($ Millions)	($ Millions)	($ Millions)	
	[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]	[9]	[10]	[11]	[12]	[13]	[14]	[15]	[16]	[17]	[18]
2009	100	275	$144	$40	$5	$0	$0	$149	$41	$70	$19	$49	19%	$3.4	$0.9	($21)	$1,600	-1.3%
2010	100	275	$134	$37	$5	$0	$0	$139	$38	$69	$19	$50	19%	$3.5	$1.0	($18)	$1,700	-1.1%
2011	100	275	$124	$34	$5	$0	$0	$129	$36	$67	$18	$51	19%	$3.6	$1.0	($16)	$1,700	-1.0%
2012	100	275	$115	$31	$5	$0	$0	$120	$33	$66	$18	$53	19%	$3.6	$1.0	($14)	$1,700	-0.8%
2013	100	275	$105	$29	$5	$0	$0	$110	$30	$69	$19	$54	19%	$3.7	$1.0	($10)	$1,800	-0.6%
2014	100	275	$95	$26	$5	$0	$0	$100	$27	$68	$19	$55	19%	$3.8	$1.1	($8)	$1,800	-0.4%
2015	100	275	$92	$25	$5	$0	$0	$97	$27	$73	$20	$57	19%	$3.9	$1.1	($6)	$1,900	-0.3%
2016	100	275	$90	$25	$5	$0	$0	$95	$26	$74	$20	$58	19%	$4.0	$1.1	($5)	$1,900	-0.2%
2017	100	275	$87	$24	$5	$0	$0	$92	$25	$76	$21	$60	19%	$4.1	$1.1	($3)	$2,000	-0.2%
2018	100	275	$84	$23	$5	$0	$0	$89	$25	$79	$22	$61	19%	$4.2	$1.2	($2)	$2,100	-0.1%
2019	100	275	$82	$22	$5	$0	$0	$87	$24	$81	$22	$63	19%	$4.3	$1.2	($0)	$2,200	0.0%
2020	100	275	$79	$22	$5	$0	$0	$84	$23	$83	$23	$64	19%	$4.4	$1.2	$1	$2,300	0.0%
2021	100	275	$76	$21	$5	$0	$0	$81	$22	$86	$24	$66	19%	$4.6	$1.3	$3	$2,400	0.1%
2022	100	275	$74	$20	$5	$0	$0	$79	$22	$87	$24	$68	19%	$4.7	$1.3	$4	$2,400	0.2%
2023	100	275	$71	$20	$5	$0	$0	$76	$21	$91	$25	$69	19%	$4.8	$1.3	$5	$2,500	0.2%
2024	100	275	$69	$19	$5	$0	$0	$74	$20	$93	$26	$71	19%	$4.9	$1.3	$7	$2,600	0.3%
2025	100	275	$66	$18	$5	$0	$0	$71	$19	$96	$26	$73	19%	$5.0	$1.4	$8	$2,700	0.3%
2026	100	275	$63	$17	$5	$0	$0	$68	$19	$99	$27	$75	19%	$5.2	$1.4	$10	$2,800	0.3%
2027	100	275	$61	$17	$5	$0	$0	$66	$18	$101	$28	$76	19%	$5.3	$1.5	$11	$2,900	0.4%
2028	100	275	$58	$16	$5	$0	$0	$63	$17	$108	$30	$78	19%	$5.4	$1.5	$14	$3,100	0.4%
Net Present Value (in 2009 @ Regulatory WACC):				**$258**					**$271**		**$199**				**$11**	**($62)**	**$19,100**	**-0.32%**

Assumptions:

Capital Structure	50% Debt, Cost of Debt = 6%, Cost of Equity = 11%	Average Plant Capacity Factor	32%, based on ISO-New England Final Scenario Analysis Modeling Assumptions
Tax Rate	40%	Transmission Losses to Central Maine	2.0%
Useful Life	20 Years	Wind Integration Costs ($/MWh)	$5 Flat
Tax Depreciation	5 Years	Federal Tax Credits ($/MWh)	$0
Investment Costs ($2009 / kW-Yr)	$2,000	Renewable Energy Certificate Prices ($/MWh)	$0
Fixed O&M and Lease ($2006 / kW-Yr)	$30 (in 2006, escalated at inflation)	Avg. Central Maine Energy Prices for Wind ($/MWh)	$70/MWh in 2009 grown at nominal DOE path for New England generation
Property Taxes and Lease Payments	1% of net book value	Capacity Prices in Maine ($/kW-Yr)	$49 in 2009, grown at inflation
		General Inflation	2.5%

Sources and Notes:

[1]: Assumed project size.
[2]: = ([1] x 8760 hours x 32% x (1 - 2.0%)) / 1000. Accounts for capacity factor and line loss assumptions.
[3]: = (Revenue Requirements + Fixed O&M + Property Tax @ 1% of Book Value) / ([2] x 1000].
[4]: = [2] x [3] / 1000.
[5]: DOE and Northwest Power and Conservation Council.
[6]: = $0.
[7]: = $0.
[8]: = [3] + [5] - [6] - [7].
[9]: = [2] x [8] / 1000.
[10]: Based on current forward prices for 2008-2010 adjusted for Central Maine location and typical wind profile.
[11]: = [2] x [10] / 1000.
[12]: FCM Settlement for Summer 2009, grown at inflation.
[13]: Based on ISO-New England Final Scenario Analysis Modeling Assumptions.
[14]: = [1] x [12] x [13] / [2].
[15]: = [2] x [14] / 1000.
[16]: = [11] + [15] - [9].
[17]: Maine retail revenues for 2006 (Form EIA-826), with estimated generation component grown at 1% for load growth plus percentage change in energy prices from [10], and estimated transmission and distribution component grown at 3.5%.
[18]: = [16] / [17].

Table A3
Traditional Cost of Service Treatment
(High Costs and Low Market Prices)

Year	Project Size (MW) [1]	Annual Output of Project (GWh) [2]	Total Project Revenue Requirements (Capital and O&M) Per MWh ($/MWh) [3]	Total Project Revenue Requirements (Capital and O&M) Total ($ Millions) [4]	Wind Integration Costs ($/MWh) [5]	Federal Tax Credits ($/MWh) [6]	Renewable Energy Certificate Prices ($/MWh) [7]	Net Project Costs Per MWh ($/MWh) [8]	Net Project Costs Total ($ Millions) [9]	Energy Market Energy Prices (Wind) ($/MWh) [10]	Energy Market Energy Market Value ($ Millions) [11]	Capacity Market Capacity Prices ($/kW-yr) [12]	Capacity Market Plant Capacity Factor During Summer Peak [13]	Capacity Market Capacity Prices (Wind) ($/MWh) [14]	Capacity Market Capacity Market Value ($ Millions) [15]	Total Project Net Benefits (Costs) ($ Millions) [16]	Approx. Maine Retail Revenues ($ Millions) [17]	Annual Net Benefits (Costs) As % of Maine Retail Revenues [18]
2009	100	275	$167	$46	$5	$20	$40	$111	$31	$60	$16	$30	19%	$2.1	$0.6	($14)	$1,500	-0.9%
2010	100	275	$156	$43	$5	$21	$35	$105	$29	$59	$16	$30	19%	$2.1	$0.6	($12)	$1,500	-0.8%
2011	100	275	$144	$40	$5	$21	$30	$98	$27	$57	$16	$30	19%	$2.1	$0.6	($11)	$1,500	-0.7%
2012	100	275	$133	$36	$5	$22	$25	$91	$25	$57	$16	$30	19%	$2.1	$0.6	($9)	$1,500	-0.6%
2013	100	275	$122	$33	$5	$23	$20	$84	$23	$59	$16	$30	19%	$2.1	$0.6	($6)	$1,600	-0.4%
2014	100	275	$110	$30	$5	$23	$15	$77	$21	$59	$16	$30	19%	$2.1	$0.6	($4)	$1,600	-0.3%
2015	100	275	$107	$29	$5	$24	$15	$73	$20	$63	$17	$30	19%	$2.1	$0.6	($2)	$1,700	-0.1%
2016	100	275	$104	$29	$5	$24	$15	$70	$19	$64	$17	$30	19%	$2.1	$0.6	($1)	$1,800	-0.1%
2017	100	275	$101	$28	$5	$25	$15	$66	$18	$65	$18	$30	19%	$2.1	$0.6	$0	$1,800	0.0%
2018	100	275	$98	$27	$5	$26	$15	$62	$17	$68	$19	$30	19%	$2.1	$0.6	$2	$1,900	0.1%
2019	100	275	$95	$26	$5	$0	$15	$85	$23	$69	$19	$30	19%	$2.1	$0.6	($4)	$2,000	-0.2%
2020	100	275	$91	$25	$5	$0	$15	$81	$22	$71	$19	$30	19%	$2.1	$0.6	($2)	$2,000	-0.1%
2021	100	275	$88	$24	$5	$0	$15	$78	$22	$74	$20	$30	19%	$2.1	$0.6	($1)	$2,100	0.0%
2022	100	275	$85	$23	$5	$0	$15	$75	$21	$75	$21	$30	19%	$2.1	$0.6	$0	$2,200	0.0%
2023	100	275	$82	$23	$5	$0	$15	$72	$20	$78	$21	$30	19%	$2.1	$0.6	$2	$2,300	0.1%
2024	100	275	$79	$22	$5	$0	$15	$69	$19	$80	$22	$30	19%	$2.1	$0.6	$4	$2,400	0.1%
2025	100	275	$76	$21	$5	$0	$15	$66	$18	$82	$23	$30	19%	$2.1	$0.6	$5	$2,500	0.2%
2026	100	275	$73	$20	$5	$0	$15	$63	$17	$85	$23	$30	19%	$2.1	$0.6	$6	$2,600	0.2%
2027	100	275	$70	$19	$5	$0	$15	$60	$16	$87	$24	$30	19%	$2.1	$0.6	$8	$2,600	0.3%
2028	100	275	$67	$18	$5	$0	$15	$57	$16	$93	$25	$30	19%	$2.1	$0.6	$10	$2,800	0.4%
Net Present Value (in 2009 @ Regulatory WACC):				**$299**					**$216**		**$171**				**$5**	**($39)**	**$17,200**	**-0.23%**

Assumptions:

Capital Structure	50% Debt, Cost of Debt = 6%, Cost of Equity = 11%	Average Plant Capacity Factor	32%, based on ISO-New England Final Scenario Analysis Modeling Assumptions
Tax Rate	40%	Transmission Losses to Central Maine	2.0%
Useful Life	20 Years	Wind Integration Costs ($/MWh)	$5 Flat
Tax Depreciation	5 Years	Federal Tax Credits ($/MWh)	$19 / MWh ($2006) for 10 Years
Investment Costs ($2009 / kW-Yr)	$2,300	Renewable Energy Certificate Prices ($/MWh)	$40 in 2009 declining to $15 by 2014
Fixed O&M and Lease ($2006 / kW-Yr)	$34.50 (in 2006, escalated at inflation)	Avg. Central Maine Energy Prices for Wind ($/MWh)	$60/MWh in 2009 grown at nominal DOE path for New England generation
Property Taxes and Lease Payments	1.15% of net book value	Capacity Prices in Maine ($/kW-Yr)	$30 Flat
		General Inflation	2.5%

Sources and Notes:

[1]: Assumed project size.
[2]: = ([1] x 8760 hours x 32% x (1 - 2.0%)) / 1000. Accounts for capacity factor and line loss assumptions.
[3]: = (Revenue Requirements + Fixed O&M + Property Tax @ 1.15% of Book Value) / ([2] x 1000].
[4]: = [2] x [3] / 1000.
[5]: DOE and Northwest Power and Conservation Council.
[6]: = $19 / MWh ($2006) for 10 Years.
[7]: Based on REC prices in other markets and DOE projections.
[8]: = [3] + [5] - [6] - [7].
[9]: = [2] x [8] / 1000.
[10]: Based on recent market prices for Central Maine location and typical wind profile.
[11]: = [2] x [10] / 1000.
[12]: Projected 2010 capacity prices based on demand curve proposed by ME and VT.
[13]: Based on ISO-New England Final Scenario Analysis Modeling Assumptions.
[14]: = [1] x [12] x [13] / [2].
[15]: = [2] x [14] / 1000.
[16]: = [11] + [15] - [9].
[17]: Maine retail revenues for 2006 (Form EIA-826), with estimated generation component grown at 1% for load growth plus percentage change in energy prices from [10], and estimated transmission and distribution component grown at 3.5%.
[18]: = [16] / [17].

Table A4
Levelized Long-Term PPA Payments
(Base-Case Cost and Revenue Assumptions)

Year	Project Size	Annual Output of Project	PPA Payments (Levelized Capital + nominal O&M) Per MWh	PPA Payments (Levelized Capital + nominal O&M) Total	Wind Integration Costs	Federal Tax Credits (Levelized)	Renewable Energy Certificate Prices	Net Project Costs Per MWh	Net Project Costs Total	Energy Market Energy Prices (Wind)	Energy Market Energy Market Value	Capacity Market Capacity Prices	Capacity Market Plant Capacity Factor During Summer Peak	Capacity Market Capacity Prices (Wind)	Capacity Market Capacity Market Value	Total Project Net Benefits (Costs)	Approx. Maine Retail Revenues	Annual Net Benefits (Costs) As % of Maine Retail Revenues
	(MW)	(GWh)	($/MWh)	($ Millions)	($/MWh)	($/MWh)	($/MWh)	($/MWh)	($ Millions)	($/MWh)	($ Millions)	($/kW-yr)		($/MWh)	($ Millions)	($ Millions)	($ Millions)	
	[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]	[9]	[10]	[11]	[12]	[13]	[14]	[15]	[16]	[17]	[18]
2009	100	275	$104	$29	$5	$15	$40	$54	$15	$70	$19	$49	19%	$3.4	$0.9	$5	$1,600	0.3%
2010	100	275	$104	$29	$5	$15	$35	$58	$16	$69	$19	$50	19%	$3.5	$1.0	$4	$1,700	0.2%
2011	100	275	$104	$29	$5	$15	$30	$63	$17	$67	$18	$51	19%	$3.6	$1.0	$2	$1,700	0.1%
2012	100	275	$104	$29	$5	$15	$25	$68	$19	$66	$18	$53	19%	$3.6	$1.0	$0	$1,700	0.0%
2013	100	275	$104	$29	$5	$15	$20	$73	$20	$69	$19	$54	19%	$3.7	$1.0	($0)	$1,800	0.0%
2014	100	275	$104	$29	$5	$15	$15	$78	$22	$68	$19	$55	19%	$3.8	$1.1	($2)	$1,800	-0.1%
2015	100	275	$104	$28	$5	$15	$15	$78	$21	$73	$20	$57	19%	$3.9	$1.1	($0)	$1,900	0.0%
2016	100	275	$104	$28	$5	$15	$15	$78	$21	$74	$20	$58	19%	$4.0	$1.1	($0)	$1,900	0.0%
2017	100	275	$104	$28	$5	$15	$15	$78	$21	$76	$21	$60	19%	$4.1	$1.1	$0	$2,000	0.0%
2018	100	275	$104	$28	$5	$15	$15	$78	$21	$79	$22	$61	19%	$4.2	$1.2	$1	$2,100	0.1%
2019	100	275	$104	$28	$5	$15	$15	$78	$21	$81	$22	$63	19%	$4.3	$1.2	$2	$2,200	0.1%
2020	100	275	$104	$28	$5	$15	$15	$78	$21	$83	$23	$64	19%	$4.4	$1.2	$2	$2,300	0.1%
2021	100	275	$104	$28	$5	$15	$15	$78	$21	$86	$24	$66	19%	$4.6	$1.3	$3	$2,400	0.1%
2022	100	275	$104	$29	$5	$15	$15	$78	$22	$87	$24	$68	19%	$4.7	$1.3	$4	$2,400	0.2%
2023	100	275	$104	$29	$5	$15	$15	$78	$22	$91	$25	$69	19%	$4.8	$1.3	$5	$2,500	0.2%
2024	100	275	$104	$29	$5	$15	$15	$78	$22	$93	$26	$71	19%	$4.9	$1.3	$5	$2,600	0.2%
2025	100	275	$104	$29	$5	$15	$15	$78	$22	$96	$26	$73	19%	$5.0	$1.4	$6	$2,700	0.2%
2026	100	275	$104	$29	$5	$15	$15	$79	$22	$99	$27	$75	19%	$5.2	$1.4	$7	$2,800	0.2%
2027	100	275	$104	$29	$5	$15	$15	$79	$22	$101	$28	$76	19%	$5.3	$1.5	$8	$2,900	0.3%
2028	100	275	$104	$29	$5	$15	$15	$79	$22	$108	$30	$78	19%	$5.4	$1.5	$10	$3,100	0.3%
Net Present Value (in 2009 @ Regulatory WACC):				**$270**					**$187**		**$199**				**$11**	**$23**	**$19,100**	**0.12%**

Assumptions:

Capital Structure	60% Debt, Cost of Debt = 7%, Cost of Equity = 14%	Average Plant Capacity Factor	32%, based on ISO-New England Final Scenario Analysis Modeling Assumptions
Tax Rate	40%	Transmission Losses to Central Maine	2.0%
Useful Life	20 Years	Wind Integration Costs ($/MWh)	$5 Flat
Tax Depreciation	5 Years	Federal Tax Credits ($/MWh)	$19 / MWh ($2006) for 10 Years (Levelized)
Investment Costs ($2009 / kW-Yr)	$2,000	Renewable Energy Certificate Prices ($/MWh)	$40 in 2009 declining to $15 by 2014
Fixed O&M and Lease ($2006 / kW-Yr)	$30 (in 2006, escalated at inflation)	Avg. Central Maine Energy Prices for Wind ($/MWh)	$70/MWh in 2009 grown at nominal DOE path for New England generation
Property Taxes and Lease Payments	1% of net book value	Capacity Prices in Maine ($/kW-Yr)	$49 in 2009, grown at inflation
		General Inflation	2.5%

Sources and Notes:

[1]: Assumed project size.
[2]: = ([1] x 8760 hours x 32% x (1 - 2.0%)) / 1000. Accounts for capacity factor and line loss assumptions.
[3]: = (Levelized Capital Charges + Fixed O&M + Property Tax @ 1% of Book Value) / ([2] x 1000].
[4]: = [2] x [3] / 1000.
[5]: DOE and Northwest Power and Conservation Council.
[6]: = $19 / MWh ($2006) for 10 Years (Levelized).
[7]: Based on REC prices in other markets and DOE projections.
[8]: = [3] + [5] - [6] - [7].
[9]: = [2] x [8] / 1000.
[10]: Based on current forward prices for 2008-2010 adjusted for Central Maine location and typical wind profile.
[11]: = [2] x [10] / 1000.
[12]: FCM Settlement for Summer 2009, grown at inflation.
[13]: Based on ISO-New England Final Scenario Analysis Modeling Assumptions.
[14]: = [1] x [12] x [13] / [2].
[15]: = [2] x [14] / 1000.
[16]: = [11] + [15] - [9].
[17]: Maine retail revenues for 2006 (Form EIA-826), with estimated generation component grown at 1% for load growth plus percentage change in energy prices from [10], and estimated transmission and distribution component grown at 3.5%.
[18]: = [16] / [17].