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Energy Choices Revisited : An Examination of the Costs and Benefits of Maine's Energy Policy

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OF MAINE'S ENERGY POLICY

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PREFACE

Maine has been successful in developing cogeneration and small power production facilities and encouraging utility investment in energy efficiency technologies. At the same time, utility rates have been rising significantly. Policymakers in the state are asking whether Maine's historical energy policy should be changed or redirected.

To respond to this concern, the Mainewatch Institute undertook a unique study to provide policymakers with key information needed to make informed choices with respect to the state's energy policies. In particular, the study examined a range of economic and environmental consequences of the energy policies that have been made in the last ten years.

The study was funded by the United States Department of Energy (DOE), the Energy Foundation, and funds raised from a variety of private sources within the state. Additional funding was provided by grants to the American Council for an Energy-Efficient Economy from both the Energy Foundation and the Joyce Mertz-Gilmore Foundation.

The study was uniquely suited to the mission of the Mainewatch Institute. Mainewatch is an independent non-profit research and educational organization whose purpose is to identify, monitor, and analyze long-term trends and issues that bear upon the environment, the economy, and the people of northeast North America, with Maine as its focus.

The study was conducted by a team of well-established research groups to carry out the requisite analysis on behalf of Mainewatch. This Research Consortium included Economic Research Associates, the American Council for an Energy-Efficient Economy, and the Tellus Institute. The following document includes the analysis and evaluations of the Research Consortium. It does not necessarily represent the views of Mainewatch, the U.S. DOE, or any of the funders. All analysis contained in the report remains the responsibility of the Research Consortium.

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1.0 PROLOGUE AND SUMMARY

1.1 INTRODUCTION

In May 1992, the Maine Commission on Comprehensive Energy Planning reiterated a series of targets for Maine's energy future. Among the stated objectives was the need to reduce the state's level of dependence on petroleum fuels as well as to increase the percentage of renewable energy sources, and to increase statewide energy efficiency. Also included in Maine's energy objectives was the need to stabilize long-term energy prices.[1]

> ***Many now question the growth of renewable energy and energy efficiency programs because of their rate impacts***

In an era of lagging per capita incomes, the price of all consumer goods is becoming more of a concern for policy makers and the public alike. For that reason, a growing number of Mainers are now questioning the growth of renewable energy and energy efficiency programs within the electric utility supply mix. While they have tended to generate positive economic and environmental benefits, critics also point to these same programs as the causes of conservation "rate-shock," or higher short-term prices for electricity.

The issue of program rate-shock is not limited to the state of Maine alone. In Connecticut, for example, the Department of Public Utility Control expressed concern about short-term price increases from utility conservation programs. As a result, the Department ordered cuts in demand-side management programs as a means to strike "an appropriate balance" between short-term concerns over the state's economy and long-term

1. See, *Final Report of the Commission on Comprehensive Energy Planning*, prepared on behalf of the Commission by the Economics and Energy Policy Division of the Maine State Planning Office, Augusta, ME, May 1992, page 1.

energy planning needs.[2] The Maine PUC recently rejected Bangor-Hydro Electric's "Payload" demand-side management program citing an adverse (i.e., upward) impact on utility rates. The concern was that even modestly higher consumer rate impacts may not be appropriate in a depressed regional economy.[3]

1.2 PROJECT BACKGROUND

Maine law has established a number of energy priorities with respect to electric utilities. In many ways, policies such as the State's "Small Power Production Facilities Act" (MRSA 33, §3302) and the "Maine Energy Policy Act" (MRSA 35-A §3191) have lifted Maine into a national leadership role in the development of conservation and renewable energy resources.[4] That leadership role, however, comes at a price.

That leadership role, however, comes at a price

While renewable energy resources — largely biomass cogeneration facilities and conservation technologies — have met most of the new demand of electricity since 1980, a slowing economy has left "some Maine electric utilities . . . with an over-supply of capacity and energy."[5] Some have indicated that this circumstance may be partly responsible for the substantial increases in electric rates in the 1990s. Others believe that, plain and simple, the "higher prices of the newly purchased power and the costs of demand side management (DSM) programs forced [utility] rates up."[6]

To better understand the dynamic tension between the economic benefits which flow from a new energy investment strategy and the price impact which appears to have followed that investment, the Mainewatch Institute sought an independent review of the costs and benefits of existing energy policies. More specifically, the Mainewatch Board undertook

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2. "Wary of the Economy, Connecticut Orders New Cuts in DSM Programs," *Demand-Side Report*, McGraw-Hill, New York, NY, November 26, 1992, page 3.

3. "Bangor Hydro's 'Payload' Bid Program Rejected in Split Decision by Maine PUC," *Demand-Side Report*, McGraw-Hill, New York, NY, October 14, 1993, page 1.

4. *Report of the Commission on Comprehensive Planning*, *op. cit.*, page 7.

5. "Request for Proposals (RFP)," Energy Choices Revisited Project, Mainewatch, Hallowell, Maine, January 20, 1993, page 1.

6. "Next step on energy," a letter to the Editor by Robert R. Wagner, Chairman, Advisory Board, Maine Energy Coalition, to the *Maine Times*, May 21, 1993, page 10.

a study "designed to identify the economic and environmental tradeoffs which have resulted from Maine's electric policies of the 1980s."[7]

Responding to this initiative, a Research Consortium, led by a Virginia-based independent consulting firm, proposed a research methodology to provide this assessment on behalf of the Mainewatch Institute.[8] The details of the research methodology are described more fully in Chapter 2 of this report.

Measured in constant dollars, Maine's electricity prices fell by 3 percent, while per capita use rose by 28 percent in the period from 1980 to 1992

1.3 Report Findings

Maine's current electricity prices are higher than the U.S. as a whole — 9.05 cents per kilowatt-hour (kWh) in 1992 compared to the national average of only 6.84 cents per kWh.[9] However, when measured in constant 1987 dollars, Maine's electricity rates fell slightly from 7.76 cents per kWh in 1980 to 7.49 cents in 1992 (a 3 percent drop in that period). At the same time, however, per capita consumption for all uses of electricity rose by 28 percent, from 7,256 kWh in 1980 to 9,287 kWh in 1992.

The higher electricity consumption meant that the per capita expenditures for electricity (measured in constant 1987 dollars) rose from $563 in 1980 to $695 in 1992. This is a 23 percent increase in average electricity expenditures which closely follows on the heels

7. See the January 20, 1993 memo accompanying the Request for Proposals which initiated the Mainewatch Project "Energy Choices Revisited."

8. The Research Consortium consists of Economic Research Associates, an independent consulting firm with offices in Alexandria, VA and Eugene, OR; the Tellus Institute, a research and consulting firm based in Boston, MA; and the American Council for an Energy-Efficient Economy, a non-profit research organization in Washington, DC. The principal investigator for the project is Skip Laitner, an economist and principal in the firm of Economic Research Associates. Since the inception of the project, however, Mr. Laitner has accepted a position as a Senior Associate for ACE^3. For more information on this project analysis, or on the research team as a whole, contact Mr. Laitner at the ACE^3 offices, (202) 429-8873.

9. *Statistical Yearbook of the Electric Utility Industry 1992* (Washington, DC: Edison Electric Institute, October 1993, Number 60), page 75.

of a 31 percent increase in per capita income that rose from $11,457 in 1980 to $14,976 in 1992.[10]

Per capita electricity expenditures in Maine rose at a faster rate from 1980 to 1992 than for the U.S. as a whole. While the per capita electric bill in Maine rose 23 percent during that period, it increased only 1.5 percent in the U.S. This increased per capita expenditure in the state appears to be fueled by slightly larger increases in personal income. In fact, as we shall see later in this study, it appears as if there is a strong correlation between the increase in personal income and Maine's electricity use.

In the decade of the 1980s the Maine economy grew stronger relative to that of the United States. In 1980, for instance, per capita incomes in Maine were only 83 percent of the national average. By 1990 that figure rose to 90 percent of the U.S. average. In response to the strengthened per capita income, Maine's homes, schools and businesses played a bit of "catch-up" in their use of electricity.

The greater demand for electricity in the 1980s drove per capita expenditures to a record high in the state

The greater demand for electricity usage drove per capita expenditures for electricity to a record level compared to the nation as a whole — despite the modest overall decline in real electricity prices since 1980. Moreover, Maine has a smaller per capita income as noted earlier, earning only $14,976 per resident (measured in constant 1987 dollars) compared to the average U.S. income level of $16,637 per person. As a result, the state now spends more for electricity as a percent of personal income than does the U.S. as a whole. Electricity expenditures claim about 4.6 percent of personal income for the state, compared to only 3.7 percent for the United States.

State per capita income peaked in 1989. From 1989 through 1992, however, income levels fell by about 0.8 percent.[11] The decline in income coincides with a 16 percent

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10. The sources for these data include the *State Energy Price and Expenditure Report 1991*, Energy Information Administration, U.S. Department of Energy, DOE/EIA-0376(90) Washington, DC, September 1993, Table 13; and state personal income data from the U.S. Bureau of Economic Analysis (Washington, DC: U.S. Department of Commerce, 1993), with data in an electronic file format. Similar trends are shown for the years 1980 through 1989 in the *Final Report of the Commission on Comprehensive Energy Planning*, previously cited. See tables 2, 6 and 10 in that report, for example.

11. See, U.S. Department of Commerce data files on state personal income for 1989-1992, downloaded from the Economic Bulletin Board System (BBS) maintained by the Bureau of Economic Analysis. For more information, contact Paul Christy, BBS Manager, at (202) 482-1986.

increase in the real price of electricity in the same three-year period. These two things added together — especially the sharp drop in income levels — suggest that the electricity prices have taken on more importance for Mainers than might otherwise be expected.

As an example, in 1984 it was thought that statewide sales of electricity would grow at an annual rate of 2.9 percent annually through the year 2000.[12] Plans for future power plant expansion were geared to this level of growth.

In fact, actual sales from 1984 through 1990 grew 3.0 percent annually. With the onset of the economic depression in 1989, electricity sales *fell* one percent annually in the period 1990 to 1992. The average growth rate in the period 1984 through 1992 was, therefore, only 2.0 percent rather than the 2.9 percent as originally forecasted. In effect, the lower growth rate stranded a significant amount of utility investment which tended to increase the overall cost of electric generation.

The lower growth rate stranded a significant amount of utility investment

At the same time, the 1984 price from new power plants was forecast to be in excess of 9.00 cents per kWh.[13] Looking from the perspective of forecasts prepared in 1984, this made a large number of alternative energy strategies appear economically attractive. But a combination of oil prices that were dramatically lower than expected, a change in the mix of power plants actually brought on-line, and a lower than expected growth in electricity sales brought the price of new power plants down to a range that was closer to 6-8 cents per kilowatt-hour.[14]

How much has the change in economic circumstance affected Maine's overall price of electricity? Materials prepared by Central Maine Power Company have suggested that the state's energy policies are responsible for about two-thirds of the rate increases since

12. See, for example, Central Maine Power Company's *Power Supply Issues and Options*, February 1987, Section II entitled "Demand for Electricity."

13. See, for example, Table III on levelized long-term rates, found in the *Decision and Order* of the Maine Public Utilities Commission, Docket No. 82-174, January 9, 1984, page 63.

14. *Energy Resource Planning Issues and Options*, a public discussion document published by Central Maine Power Company, August 24, 1990, page 40. See also the discussion on costs of new plants in chapter 5.

1988.[15] On the other hand, an analysis by a Maine engineering consultant suggests that it is more appropriate to compare today's prices with those *that would have existed* had CMP continued its business-as-usual policies of the early 1980s. In that case, the analysis suggests that ratepayers would have ended up by paying five million dollars more than the current level of expenditures.[16]

The period from 1987 to 1992 is the critical stretch in the development of renewable energy and energy efficiency technologies in Maine. To test the economic impacts of this development, the Research Consortium identified three different scenarios of how Maine's electric generating capacity might have otherwise evolved in the absence of the state's current energy policies. The costs of these three scenarios were then compared to the actual costs paid by Maine ratepayers in that period.

Based upon an analysis of these three alternative scenarios, it appears that Maine's overall electricity prices are 4-12 percent higher than they might otherwise be as a result of the state's energy policies.[17] At the same time, electricity rates rose by almost 36 percent in that same period. This suggests that the higher rates are more attributable to Maine's current economic conditions and other decisions regarding energy supply than to the over-investment in conservation and renewable energy technologies *per se*. This is all the more so since the full benefits of the energy investments will begin to materialize in the period 1994 through 1998.

The Gross State Product has increased by $120 to $220 million as a result of existing energy policies

Yet, there is good news in all of this for the Maine economy. The policies begun in the 1980s have spawned a new energy services industry, one that is anchored by energy efficiency and renewable energy technologies. This new industry directly and indirectly supports about 6,000 jobs in the state. Despite the economic downturn since 1989, the state has actually gained a net of about 1,800 to 3,300 jobs from the emerging energy services industry — even when the higher electricity prices are included in the job impact analysis. As discussed in chapter 6 of the report, this is

15. Central Maine Power Company, Table entitled, "Components of Revenue Changes Implemented from January 1988 through July 1993 Considering Estimated Impact of DSM Related Lost Revenues and Fuel Cost Savings," provided by Public Advocate Stephen Ward, November 15, 1993.

16. See "Comparison of the Cost of QF purchases with the Capacity Expansion Plan Recommended by Central Maine Power Company," an analysis by Richard Darling for the period 1982 through 1992.

17. For a more complete discussion on this point, see chapter 5 of this report.

the equivalent to the jobs supported by the relocation to Maine of 14-26 small manufacturing plants.

The net economic benefit shows perhaps more strongly when measured in terms of the Gross State Product (GSP). Current energy policies appear to have increased Maine's GSP by $120 to $220 million in 1992 compared to strategies that might have otherwise been pursued by the state's utilities. On the other hand, without Maine's apparently successful energy policies, the overall economic activity of the state would have been weaker than is now the case.

Current policies have reduced air pollution costs by $57 to $202 million annually

Maine's current energy policies have also produced significant environmental benefits, lowering air emissions between 2-6 million tons annually. In economic terms, the current path of electricity production and consumption has reduced air pollution costs by $57 to $202 million annually.[18] The biggest gain is the significantly reduced carbon dioxide emissions. Adding the economic benefits and subtracting the environmental costs of the alternative scenarios reviewed in this study indicates that Maine's energy policy has produced a net benefit of $209 to $424 million in 1992.[19]

Perhaps even better news for Maine is that even a modest economic rebound will strengthen the benefits of current energy policies. Projections by Central Maine Power and the U.S. Department of Energy, for example, indicate that growth in economic activity and real personal income will lead to an increase of electricity sales through 1995 and beyond.[20]

As this materializes, Maine will be well-positioned to provide the new supplies of needed electricity — at less cost than might otherwise be the case. These changes will tend to reduce the cost of providing electricity, strengthen the state's employment base, and improve environmental quality when compared to current levels.

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18. There is a wide range of values associated with the reduction of air emissions. The total impacts identified in this study are generally based upon 1992 values published by the Massachusetts Department of Public Utilities. For more discussion on this point, see chapter 7.

19. See the discussion on this point in chapter 8.

20. See, for example, *1993 KWh Forecast Update*, Economic & Load Forecasting Department, Central Maine Power Company, February 1993. See also, *Short-Term Energy Outlook*, Energy Information Administration, Washington, DC, Fourth Quarter, 1993.

2.0 RESEARCH METHODOLOGY

2.1 INTRODUCTION

As a result of a competitive bidding process, the Mainewatch Institute awarded a contract to a team of three well-established research groups to carry out the analysis on its behalf. The lead organization for the Research Consortium was Economic Research Associates, a consulting firm based in Alexandria, VA. The research team also included the Tellus Institute (a second consulting firm based in Boston, MA), and the American Council for an Energy-Efficient Economy (ACE^3), a non-profit research organization based in Washington, DC. The principal investigator of the team was Skip Laitner, formerly a principal in Economic Research Associates and now a Senior Associate with ACE^3.

The Mainewatch Institute established both a Peer Review Panel, consisting of knowledgeable experts disinterested in the outcome of the study, and a Project Advisory Group (PAG), including key decision makers and stakeholders who would likely be affected by the outcome of the analysis.

The Peer Review Panel was generally asked to ensure an appropriate research design, and to check the results of the analysis for critical errors. The PAG members, on the other hand, provided useful insights about data and information that were eventually tapped for use in the study. Both the peer reviewers and the PAG members provided a reality check by reviewing the initial findings of the research team. In short, the purpose was to obtain early input to ensure a balanced and credible research effort. This chapter details the results of the research design effort.

The membership of the Project Advisory Group is referenced in Appendix A. The listing of the PAG membership does not imply either a consensus or an endorsement of the analysis. Instead, it is provided to document the research process of the project.

2.2 SCOPE OF WORK

Work on the project was guided generally by the Research Consortium's proposal, incorporated by reference into the research methodology.[21] In carrying out the identified tasks, the Research Consortium relied only on those economic and environmental analytical tools that provide the Mainewatch Board with a professionally credible and objective work product.

There were two critical elements in developing the research and analytical methodologies. The first was the development of three energy scenarios which could be used to evaluate the actual development of Maine's energy policies for their economic, rate and environmental impacts. The second was the development of the analytical techniques to fairly evaluate the positive and the negative impacts of each scenario. These are described below:

2.2.1 Scenarios

Initially, only one alternative scenario was to be developed for comparison to the historical data. However, after extensive exploration, discussion and input from members of the PAG, it was concluded that the history was too complex and uncertain for one alternative scenario to suffice.

Instead, three scenarios, each representing a plausible interpretation of what might have taken place under different PUC mandates, were created. While it is likely that none of the alternative scenarios would have happened exactly as laid out in this study, they represent a reasonable interpretation of different investment patterns that might have been followed. In effect, the three alternative scenarios represent a range of impacts that might have occurred under different policy choices.

The first alternative scenario traced the energy consumption and production patterns that likely would have occurred had non-utility generators (NUGs) provided only half of their historical level of power. The energy savings programs operated by utilities, referred to as Demand-Side Management (DSM) programs, were dropped entirely from the analysis. The alternatives to NUGs and DSM programs were assumed to have been largely an on-going investment in the Seabrook nuclear plant and the proposed Sears Island coal-fired unit. It was also assumed that there would be some development of oil-fired units and additional hydropower.

21. For more information on the proposal, or about the analysis itself, contact Skip Laitner, American Council for an Energy-Efficient Economy, (202) 429-8873.

The second alternative is similar to the first, except that the replacement power was to come from a combination of Seabrook and Canadian purchased power. The third scenario assumed no NUG capacity with replacement power provided by Seabrook, Sears Island and Canadian purchases. Although some investments in alternative generation facilities occurred in the early 1980s, the critical period in their development began in 1987. For that reason, the time period for these three scenarios was the period 1988 through 1992.

2.2.2 Impact Analysis

Each of the scenarios was evaluated from three analytical perspectives. These were:

1) *Economic Impact:* This analysis evaluated each scenario for its impact on the cost of providing energy services to Maine's consumers and businesses (chapter 5). It also examined the direct and indirect costs and benefits of each scenario. The latter category of economic impact includes the competitive advantages lost or gained from each scenario and the effect of each scenario on statewide job and income creation (chapter 6).

2) *Environmental Impact:* This part of the evaluation process included an inventory of statewide impacts upon air emissions, including carbon dioxide, nitrogen oxide, sulfur-dioxide and particulate matter (chapter 7). The intent was not to complete original research within these areas but to evaluate the three scenarios using established and credible research as a guide in assessing the magnitude of the environmental impacts — whether positive or negative.

3) *Micro Impact:* While the economic and environmental assessments are based on the three alternative scenarios, this analysis focused on impacts from specific projects or enterprises (chapter 3). This analysis resulted in four case studies that developed under the state's energy policies. One project, a stand-alone cogeneration unit, was assessed for its economic benefits (or costs) within a rural community. Two case studies reviewed the economic competitiveness of a major industry or manufacturing plant as a result of the state's policies, while a fourth examined the emergence of a new business enterprise in Maine — energy service companies.

2.3 Research Design

With specific impacts identified for review, a framework for the analysis was established to facilitate the impact evaluation. The more detailed steps creating this framework are described next.

2.3.1 Scenario Development

As noted above, the project compared three alternative scenarios to the historical or "actual" scenario which consisted of Maine's pattern of energy production and consumption from 1988 through 1992. The "alternative" scenarios were based on hypotheses as to what patterns of development might have occurred had either the Maine Legislature or Maine Public Utility Commission (PUC) not encouraged the efficient use of electricity through demand-side management programs and the production of electricity by non-utility generators, or what have become known as qualifying facilities (QFs).

Defining the differences among the scenarios required that we first document the principal policies of the legislature and PUC (as an extension of the legislative policy) which differed from other states. These differences were reflected in state legislation such as the Small Power Production Facilities Act (SPPFA), and in the decisions and orders issued by the PUC in several types of cases. Appendix F highlights those key PUC dockets.

Once the critical PUC policies had been defined, the next step was to examine proposals by the electric utilities concerning the supply plans which were changed due to PUC actions. These plans were reflected in testimony presented before the PUC, in annual resource plans, and in other company planning documents.

Decisions during 1978 through the present necessarily have impacted on each other sequentially. As was pointed out during an initial meeting of the Project Advisory Group (PAG) on May 21, this substantially complicated the choice of which alternative scenarios to develop. If a decision made in, say, 1980, were to be changed, then the relevant alternatives in all future years would be different. Thus, the actual documents and discussion which took place in, for example, 1983 would not reflect the new circumstances created by the 1980 decision.

For this reason, it was not possible to construct an alternative scenario based on purely "objective" reconstruction of historical evidence. Based on a careful reading of utility documents throughout the entire time period, the Research Consortium made a reasoned judgment as to what choices the utilities would have made in the absence of the PUC's innovative policies. The intent was not to "backcast" *the precise scenario* that likely would have developed in a different regulatory environment. Rather, the purpose was to identify *a reasonable pattern* of alternative development scenarios to help Mainers better understand the costs and benefits of current energy policy.

Our procedure in each alternative scenario was first, to remove those sources of electricity supply and DSM spending which would likely not have taken place had the

PUC engaged in more traditional regulatory practices. Estimates were made of the number of kilowatts (kW) and kilowatt-hours (kWh) per year which would be added to the utility's demand and subtracted from non-utility suppliers as a result. Combining these two changes yielded an annual shortfall in meeting expected electricity needs. This shortfall would need to be provided by other, more conventional sources of supply.

The definition of the shortfall was not according to actual sales and peak demand in a given year, but rather in relation to the projections for future electricity use that the utilities were relying on to make planning decisions. Since construction of new plants and/or contracts for outside supplies are normally made years in advance, they must be based on forecasted needs. Decisions to engage in construction or to sign contracts can later be changed, to differing degrees in a given circumstance, but become more fixed as time goes on.

We attempted to replicate a simplified version of the utilities' planning processes. Additional sources of supply were added to the planned mix, according to the utilities' expressed preferences at the time. These were added until the forecasted load requirements were met. If the indivisibility of scale of particular generating plants required that a degree of "excess capacity" exist for some period of time, this was included. A more detailed review of the resources used is provided in chapter 5.

2.3.2 Rate and Economic Impact Analysis

The rate and economic impact analysis consisted of two separate analyses. The first was an evaluation of the bill and rate impacts of each scenario. The second was a review of the indirect costs and benefits which resulted from each scenario. Among the items reviewed in the second category was the jobs and income and the competitive advantages gained or lost.

2.3.2.1 Rate and Bill Impact Analysis

This analysis was performed on an incremental basis for the years 1988 through 1992. This was the period of the largest growth in both NUG capacity and DSM programs. We determined what supply options would have been affected by the PUC rulings of the time period we considered, and we decided how the utilities would have chosen to meet demand in the absence of those decisions.

Given an alternative scenario of how the Maine utilities would have met the demand for power, we determined what impact the alternative scenario would have had on company revenues and total sales. From that information, we then calculated the effect that the alternative scenario would have had on electric rates in Maine. The resulting stream of rate values were then compared to the actual historic rate data in order to determine the difference between what did happen over the past 4 years (1988-92) versus what might have occurred without the PUC orders.

In the alternative scenarios, the items displaced were the DSM programs (in all three alternative scenarios) and all or part of the NUG capacity (depending upon the specific scenario). The resource options that replaced DSM and NUG purchases were different combinations of building new hydroelectric and fossil fuel power plants and signing long-term contracts for Canadian purchased power. It also includes a reversal of the decision to withdraw from partial ownership in the Seabrook I nuclear power plant.

In order to complete the analysis, we first obtained information on the costs and impacts of DSM and NUG power. For the hypothetical new power plants, we forecasted such data as the installed capacity, un-depreciated capital cost, fuel cost, operating and maintenance costs, and capital addition expenditures over time of each such plant. For contracted power, we estimated the availability and prices of such power on the open market. These forecasts were based on the estimates made by Maine's electric utilities at the time, on changes in industry and economic circumstances since then, and on relevant experience of other utilities.

We then estimated the impact that both the resource options that were removed and those that replaced them would have on electric rates in Maine. Due to time and budget limitations, these calculations were not done to the level of precision expected in formal regulatory proceedings. For example, we did not attempt to run dispatch models to minimize costs by time of day, nor did we complete detailed computations of peaking power costs by hour, day, or season.

2.3.2.2 Economic Impact Analysis

With the rate and bill impact analysis completed, the next step was to evaluate the scenario impacts for their larger economic benefits and costs. There were two separate analytical tools that were used for this purpose. The first was extended shift-share analysis which permits an evaluation how well Maine's individual economic sectors grew compared to both the New England Region and the U.S. as a whole. The second was the *IMPLAN* input-output modeling data available for the State of Maine.

Extended shift-share analysis used Maine employment data from the Bureau of Economic Analysis of the U.S. Department of Commerce. It allowed a comparison of the evolution of individual economic sectors within Maine to those same sectors in both the New England Regional and the U.S. economies. It revealed how each of the sectors had grown with respect to other sectors in the State and the New England Region, and it showed how each sector in Maine has grown with respect to that same sector elsewhere in the country. The result of this analytical technique was strong anecdotal evidence of how Maine's economy evolved as a result of national growth, structural change or some unique competitive position that evolved from the energy policies under review.

Input-output (I-O) analysis offers insights into whether a state's economy has become more self-sufficient and diverse over a period of time. It is a tool which can evaluate the multiplier effects of the investments triggered by Maine's current energy policies. Thus, using I-O analysis allowed us to make a reasonable determination about the total employment and income benefits of each alternative scenario.

To complete this larger economic analysis, we used the Maine datasets from the *IMPLAN* model. Complete state, regional and national data are available for the years 1977, 1982, 1985 and 1990.[22]

All of these analytical techniques were supported by interviews with knowledgeable policy-makers and stakeholders as well as a review of other relevant reports and studies. This provided a reality check with respect to the results of the analysis. Whenever possible, the findings of each analytical tool were shared with individuals knowledgeable about those techniques.

2.3.2.3 Environmental Impact Analysis

The environmental analysis was also done on an incremental basis, with only the resource options affected by the change from the actual to the alternative scenario included in the calculation. Therefore, we estimated the emissions from the NUG facilities, environmental impacts from DSM implementation, and from hypothetical new power plants, and from contracted power supplies, including Seabrook.

While there are a variety of environmental impacts, budget constraints limited our analysis to the impact from air emissions. For electric power plants, air emissions from fossil-fuel plants were examined on the basis of the type of plant, fuel source, and pollution-control equipment utilized. For NUG capacity we utilized data concerning the fuel sources and pollution-control devices employed by each facility (or at least for a sampling of the larger ones). The end result was an estimate for each scenario of the total emissions of carbon dioxide, nitrogen oxides, sulfur-dioxide and particulate matter (in tons).

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22. *IMPLAN* is short for *IM*pact Analysis for *PLAN*ning. It was originally a main-frame model developed by the U.S. Forest Service. The current microcomputer model is available from the Minnesota *IMPLAN* Group, St. Paul, MN.

2.3.2.4 Micro Impact Analysis

The analysis to this point produced a largely macroeconomic review of the state's energy policies. To determine other economic advantages or disadvantages that might otherwise have been overlooked, a final step in the research was to briefly examine the development of the alternative energy industry. This was done through the four case studies previously noted. The information generally reviewed the size of the industry in terms of its total sales, production (kWh), and the number of employees, as well as specific contributions it has made to the economic position of the state or region.

The project-level review included sufficient economic detail to better understand how individual projects contribute (or detract) from the well-being of its host community and the alternative industry at large.

2.4 Peer Review and Advisory Group Comments

The initial research was circulated to a variety of peer review panelists, project advisory group members and other knowledgeable individuals within the state. The intent was to actively solicit feedback and suggestions on how the full project can deliver a credible document — one that provides policy-makers with critical insights that will help them decide how best to modify existing energy policies, if at all.

With the research design established, the research team actively sought the views and input of the Project Advisory Group in two separate meetings. The first was held in May and the second in September 1993. These meetings were supplemented by a substantial number of telephone interviews and conference calls.

As the initial scenario data began to emerge, the PAG members were provided with details assumptions and results to ensure the accuracy of the assumptions and data. Indeed, each of the three major utilities in the state provided detailed written comments on the early scenario analysis in November 1993. Based upon those written comments, a number of adjustments were made to the scenarios.

A full working draft report was completed in December 1993 and circulated to both the Mainewatch board members and to the Peer Review Panel.[23] Final comments were received in later January 1994 with a final report issued in February.

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23. The list of peer reviewers can be obtained by contacting either Mainewatch or the American Council for an Energy-Efficient Economy.

3.0 INDUSTRY CASE STUDIES

3.1 INTRODUCTION

In Maine, growing environmental concerns and the oil price shocks of the 1970s and 1980s spawned a new generation of energy management and energy supply strategies. A direct outgrowth of these strategies was the emergence of an important new business enterprise that was virtually nonexistent prior to the 1980s — an energy management service industry anchored by energy efficiency specialists and a greatly expanded biomass industry that provides electricity to the state's power grid.[24] This new enterprise now sustains an estimated 6,000 jobs directly and indirectly for Mainers. It also provides local and state tax revenues and an important market for previously underutilized forest products.

This new enterprise sustains about 6,000 jobs

The accelerated growth of the industry can better be understood by examining Central Maine Power Company's (CMP) electric generation mix and how it has changed since 1982. In 1982 only five percent of CMP's total electricity (measured in kilowatt-hours) was derived from non-utility generators (NUGs). As of 1992 that figure had grown to 38 percent of CMP's total kWh sales.[25] The largest fraction of non-utility generation, about 70 percent, is provided by a variety of biomass facilities which convert wood and wood wastes into electricity.

Indigenous resources such as forest products and biomass wastes have played an important role in much of Maine's historical economic growth, and in its recent energy policies. However, the benefits of developing these renewable energy resources —

24. Technically, biomass refers to organic matter. This includes forest residues, animal waste, agricultural crops and waste, food processing waste as well as wood and wood wastes, among others. For the purposes of this report, biomass refers specifically to wood and wood wastes.

25. See, "Non-Consolidated Statistical Review," *CMP Annual Report 1992*, Central Maine Power Company, August, ME, pages 42-43.

whether for protecting the environment and improving industry competitiveness, or for advancing statewide economic growth and reducing Maine's dependence on foreign oil — have yet to be fully evaluated. This chapter attempts to provide a context for understanding the significance of this new industry by providing case studies for four different enterprises. Three of these businesses convert a variety of biomass materials into electricity while the last is an energy service company that helps CMP customers save electricity through the installation of energy-efficient technologies.

3.2 BACKGROUND

Beginning with the creation of the Department of Energy (DOE) in 1977, the Carter Administration's energy program goals — conservation, energy efficiency and reducing our country's dependence on foreign oil — emerged in the National Energy Policy Act of 1978.[26] A key piece of this first national energy policy, the *Public Utility Regulatory Policy Act of 1978* (PURPA),[27] gave rise to many opportunities for development of renewable energy resources.

Acknowledging these national goals and attempting to accommodate the state's economic growth during the early and mid 1980s (which spurred significant increases in electrical demand and the need for new generating capacity), Maine developed its own set of energy policies to complement the national legislation. These policies have since established energy conservation, economic efficiency and utilization of renewable resources as high priorities. They helped establish the link between the state's economic well-being and an energy supply that includes a diverse mix of energy efficiency and renewable energy resources.[28]

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26. The National Energy Policy Act of 1978 was made up of five separate pieces of legislation including: the *Public Utility Regulatory Policy Act of 1978*; the *Energy Tax Act of 1978*; the *National Energy Conservation Policy Act*; the *Powerplant and Industrial Fuel Use Act*; and the *Natural Gas Policy Act of 1978*.

27. The act, 16 U.S.C. 2601 et seq., administered through the Federal Energy Regulatory Commission (FERC), encouraged the development of cogeneration and small power plants utilizing renewable resources. More specifically, the act exempted those facilities (meeting state and federal guidelines) from regulation as utilities. In addition, regulated utilities were required to allow the "qualifying facilities" to participate in a competitive bidding process for purchased power contracts.

28. This is evident in the *1983 Maine Comprehensive Energy Resources Plan* and the *1987 Energy Resource Plan* which identified reliable, adequate and low cost energy supplies and economic well-being of Maine residents as state energy goals. Similarly, the *Small Power Production Facilities Act* encouraged the development of energy systems using renewable resources; and the *Maine Energy Policy Act*, gave preference first to conservation and demand-side management and then power purchased from qualifying facilities, to meet the state's existing and future energy needs. For more detail on these policies see the

Building upon the PURPA legislation, Maine's energy policies have encouraged the development of cogeneration and small power plants at a pace that greatly exceeds both the New England and the U.S. rates of development. As Figure 3-1 shows, five states provide more than 10 percent of their total generating capacity from renewable resources. Maine heads up that list deriving an estimated 36 percent of its power generation needs from renewable resources, mostly biomass facilities.[29] At the same time, these new facilities have greatly reduced the State's dependence on "outside" energy sources such as petroleum and Canadian purchased power.

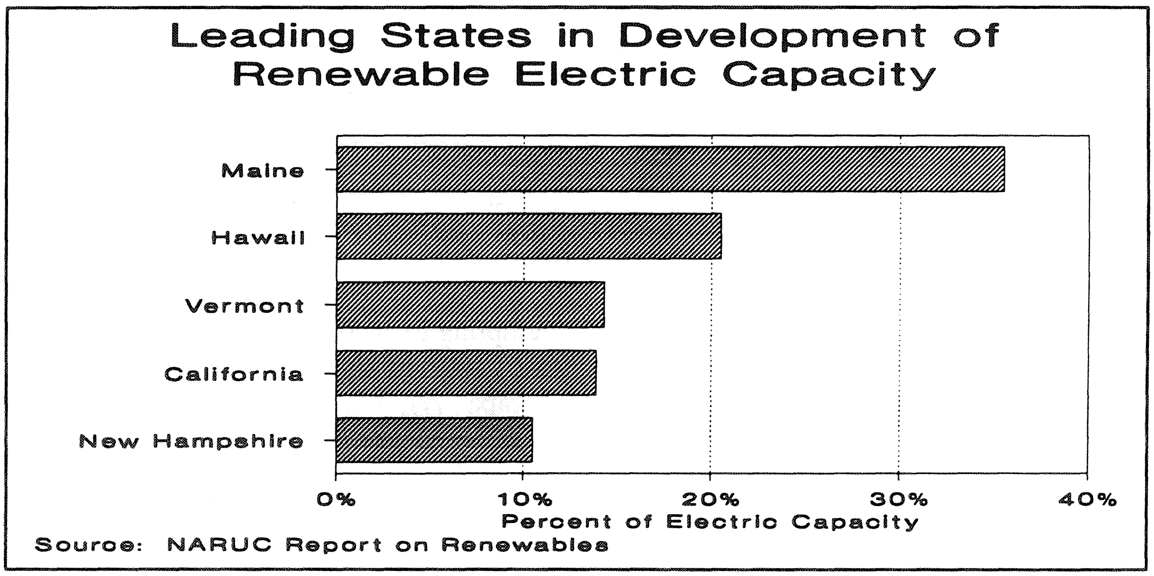

Figure 3-1

As early as 1982 Maine's utilities entered into contracts with two large pulp and paper mills and one small lumber mill to purchase just over 150 megawatts (MW) of generating capacity. At the time, this "purchased capacity" represented only 10 percent of the on-line capacity of Central Maine Power Company, the state's largest utility. Although uncertainty persisted regarding the ability of NUGs to compete with other supply sources, biomass facilities (classified as either cogeneration or independent power producers) found that they could compete with traditional energy costs. Projected rises in oil prices,

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respective plans and acts or the discussion in the *Final Report of the Commission on Comprehensive Energy Planning*, Economics and Energy Policy Division of the Maine State Planning Office, May 1992.

29. These figures exclude utility hydro. See, Jan Hamrin and Nancy Rader, *Investing in the Future: A Regulator's Guide to Renewables* (Washington, DC: The National Association of Regulatory Utility Commissioners, 1993), page 44.

the existence of high projected utility avoided costs and the need for more supply, helped expand this industry.

During the next eight years (1982-1990) the total utility contracts for purchased power from NUGs increased to nearly 700 megawatts (MW) of electric generating capacity. Biomass facilities alone provided about 500 MW of this power supply, including electricity from 13 cogeneration (lumber and pulp and paper mills) and 9 independent power producers. Most of these began selling power after 1987.

The lapsed agreement between CMP and Hydro-Quebec to wheel surplus power from Canada to Maine offers an important example of how the existence of biomass facilities have changed the way utilities generate and sell power in the state. In the mid-1980s CMP proposed to build a large transmission line that would have provided the utility with up to 900 MW of capacity. However, the large number of cost-competitive domestic energy supply proposals received by CMP helped to offset the need for the proposed Hydro Quebec purchase.

Critical to the final decision to drop the Hydro Quebec plans was a power purchase contract that CMP entered into with Boise Cascade. The forest products company proposed to upgrade the biomass power plant operations at its site in Rumford, Maine. The successful implementation of this project provided evidence that biomass facilities were a reliable source of electricity. The agreement had the added benefit of reducing the amount of oil consumed at the mill and lowering air emissions.[30]

3.2.1 Cogeneration and Independent Power Producers

Prior to 1982 the state's utilities considered the biomass resources to be either non-existent or too expensive to develop. For example, a 1980 study completed for CMP stated that "the potential for cogeneration is either too small, too costly, or too geographically diffuse to justify significant cogeneration applications."[31] A second

30. The agreement between Boise Cascade and CMP set the purchase price for electricity below the level offered by Hydro Quebec. As a result, CMP was able to acquire a new power supply that tended to decrease the overall cost of electricity. For more detail on the analysis of the proposed Hydro Quebec power purchase see both the *Final Report of the State Planning Office on the Proposed Hydro-Quebec Power Purchase*, Maine State Planning Office, April 1988; and the *Preliminary Report On The Effects Of The Proposed Purchase of Power From Hydro Quebec*, Maine State Planning Office, May 19, 1987.

31. See, *Sears Island Plant Cogeneration/District Heating Study*, completed by Charles T. Main, Inc. for Central Main Power Company, August 1980, page 2-1. Interestingly, the Main study estimated the overall cogeneration potential to be only 40 MW, or about eight percent of the present level of biomass facilities now on-line in the state.

study done for Maine Public Service determined that a wood-fired power plant would cost nearly three times the anticipated cost of the Seabrook nuclear power plant.[32] By 1987, however, these views had begun to turn around. In a small publication entitled, *Cogeneration and Small Power Production*, CMP wrote that "In general, the industry is maturing and becoming more commercialized and stabilized, and has established itself as a competitive alternative, for the foreseeable future, to central station operation."[33]

The industry has established itself as a competitive alternative, for the foreseeable future

Contrary to the early studies, the opportunities for cogeneration are abundant and decidedly not new to Maine's industries. The most notable users have been the pulp and paper mills, saw mills, furniture manufacturers and other industrial operators. Many of these facilities have traditionally utilized biomass fuels in the form of wood chips, slash, bark, and mill residues to produce process heat or steam. The fuels have been used either alone or in conjunction with other fuels such as coal or oil.

In conventional boiler designs, the excess heat within industrial facilities is simply vented into the atmosphere. By incorporating turbine generators into the industrial process, the excess heat can be converted into useable and marketable electricity; hence the term "cogeneration." Thus, the cogeneration process encourages more efficient use of biomass resources within the facilities. It also helps create new markets for previously unusable forest products or industry wastes.

It is difficult to estimate the number of facilities that are cogenerating and producing electricity since many produce the electricity for in-house use only.[34] There are currently nine cogeneration facilities which are under contract to supply electricity to

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32. *Economic Analysis of Supply Alternatives*, completed by Stone & Webster Management Consultants, Inc. for Maine Public Service Company, March 1982, page 53.

33. *Cogeneration and Small Power Production: Energy Alternatives for Maine's Future* (Augusta, ME: Central Maine Power Company, December 1987), page 15.

34. The most recent published survey of wood energy users in Maine lists 93 facilities, of these only one identifies cogeneration (electricity generation) activities. The survey, titled *The Northeast Directory Of Biomass Facilities*, was published in 1989 by the Coalition of Northeastern Governors Policy Research Center, Inc., Washington, D.C. and is no doubt incomplete. Unfortunately, the survey research for the directory was done in 1986 and 1987, prior to the installation and modernization of many biomass facilities; however the directory is presently in the process of being updated.

Maine's three largest utilities.[35] For a complete listing and description of these non-utility facilities, see Appendix B.

Whereas cogenerators are existing utility customers which have adapted their industrial processes to produce electricity as a by-product of normal manufacturing activities, independent power producers are stand-alone facilities designed only to generate electricity for resale to the utility. They are relatively new to Maine; the first facility went on line in 1986. Although there are a variety of different types, most common in Maine are facilities which utilize wood chips and mill residues in boilers similar to those employed in the cogeneration plants — except that all steam is used to generate electricity. There are currently seven of these stand-alone facilities operating in the state under contract with two of Maine's three largest utilities.[36] See Appendix B for a complete listing of these facilities as well.

3.2.2 Economic and Employment Related Impacts

> ***Small power producers have been one of Maine's largest sources of new employment***

Since introducing these cogeneration facilities and stand-alone power producers into the utility grid in the early 1980s, several studies have attempted to quantify and address the numerous impacts associated with this expanding biomass industry.[37] The studies identify a significant industry contributing to expanded and ongoing economic activity, employment and revenues within the State. The State Planning Office notes, for instance, that "small

35. This information is based on a review of Federal Energy Regulatory Commission (FERC) Form 1 reports December 31, 1992, Purchased Power Section, filed by Central Maine Power Company, Bangor Hydro Electric Company and Maine Public Service Company, respectively.

36. Ibid.

37. For more insight into economic impacts related to wood and wood energy use in Maine see Jim Connors, *The Wood Fired Electric Generating Industry In Maine*, Maine State Planning Office, an unpublished report, 1993; Chris G. Ganotis, *Economic Development From Wood Energy: Maine As A Case Study*, an unpublished presentation, March 1987; *Economic Impacts of Wood Energy In The Northeast*, CONEG Policy Research Center, Inc., Northeast Regional Biomass Program, Washington, D.C. 1985; and the sections on economic and employment impacts in the preliminary and final reports on the proposed Hydro-Quebec power purchase cited above.

power producers, both cogenerators and stand-alone plants, have been one of Maine's largest sources of new employment and investment in the last five years."[38]

Consistent with the location of biomass resources, and consequently the location of the biomass facilities, the employment benefits associated with the direct operation of the plants are concentrated primarily in rural areas with limited employment opportunities. These biomass facilities directly support Maine's labor intensive fuelwood industry (e.g., foresters, harvesters, chipper operators, handlers and truck drivers) which supplies most of its biomass fuel needs.

From harvesting wood in the forests, to transporting chips and mill residues, to producing lumber, paper or electricity and maintaining the facilities, the biomass electric generating industry touches the lives of a vast number of the state's residents. Throughout the process a large number of the state's industries, indirectly related to the wood industry (including parts and equipment suppliers, design and engineering services, construction companies, food and clothing stores, banks and gas stations among others) rely on the biomass energy industry, at least in part, to help sustain them. A significant multiplier or "ripple" effect exists in this industry with broad impacts throughout the state.

The most recent study on the biomass industry by the State Planning Office confirmed earlier estimates of the large contributions made by the biomass electric industry. Reviewing the level of in-state expenditures from 10 of the independent power producers, the report notes that in 1990 they combined to purchase a total of $36.7 million in biomass fuels, spent $23 million on retail and wholesale goods and services, and paid $10.4 million in wages and salaries.[39]

The report also notes that over $2.5 million was paid in local property taxes and 2,780 people were employed either directly or through induced employment. Complementing these expenditures and employment impacts, initial capital expenditures for construction totaled nearly $1 billion for the 23 biomass electricity projects which were developed or in the process of being developed between 1980 and 1993.[40]

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38. See *Final Report of the State Planning Office on the Proposed Hydro-Quebec Power Purchase*, op.cit., page 17.

39. For more details see Jim Connors, *The Wood Fired Electric Generating Industry In Maine*, op. cit., pages 87 through 93. Since the report was compiled (in 1992), three of the ten facilities have been closed as a result of utility contract "buy-outs."

40. Ibid., page 92.

Despite future energy price fluctuations, much has yet to be learned about biomass energy industry employment, expenditure patterns, tax contributions, their effects on the local areas in which they reside, as well as their impacts on the state's economy as a whole. Similarly, the uncertainty regarding adequate wood resources for sustained future electricity generation, contribution to global warming and other potentially damaging air emissions, and ash disposal from biomass burning facilities have all posed serious concerns.

3.2.3 ENVIRONMENTAL IMPACTS

Consistent with growing concerns for global warming trends, toxic waste and air and water pollution, environmental impacts associated with biomass facilities and their impacts on the State's forests have been the center of much attention in Maine and elsewhere. Responding to these concerns, the Solar Thermal and Biomass Power Division of the U.S. DOE summarizes that "More than any other energy technology, biomass power is capable of contributing to the nation's energy needs while decoupling energy production from environmental degradation."[41]

Recent State Planning Office analysis suggests that there are adequate forest biomass resources in the state of Maine to support an additional 300 to 730 MW of wood-fueled electricity generation capacity. The precise level of future capacity depends on the efficiency of technologies used to generate electricity.

There are adequate biomass resources to support an additional 300 to 730 MW of wood-fueled generation

Based on sustainable regeneration (which ensures adequate soil nutrients) of the forests, utilizing unmerchantable dead wood, culls and slash and mill wastes, biomass energy can continue to operate for years to come.[42] In fact a recent study by the Tellus Institute shows that "increased reliance on biomass for energy depends on strengthening

41. See *Electricity From Biomass*, op.cit. It should be noted that the biomass resources do not provide an entirely benign energy supply. Environmental benefits depend on the management and harvesting techniques used to acquire biomass resources, and on the quality of the conversion technologies used to generate electricity.

42. See Jim Connors, *The Woodfired Electric Generating Industry In Maine*, op.cit., pages 29-49; and Chris G. Ganotis, *Economic Development From Wood Energy: Maine As A Case Study*, op. cit., page 1.

reforestation and forest management efforts...in addition to better management of existing forests."[43]

According to the State Forest Service, regeneration is not a problem in Maine's forest. Due to natural reseeding (the most common form of biomass regeneration in the state of Maine), over-regeneration poses a more serious problem.[44] In addition to providing a sustainable source of biomass, the continuous biomass growth provides a sink for atmospheric carbon dioxide that may offset the emissions from the combustion process and diminish global warming concerns.[45]

Biomass can play a role in mitigating the accumulation of greenhouse gases

Although biomass fuels contain sulfur and nitrogen, they are negligible compared with coal or oil fuels. Moreover, these emissions as well as carbon monoxide can be diminished by complete oxidation and the use of air emission controls on the burners. Again, the Tellus Institute notes that "utilized on a sustainable basis, biomass can play a modest but significant role in mitigating the accumulation of carbon dioxide and methane — two major 'greenhouse' gases — in the atmosphere."[46]

Similar to the misconception regarding biomass and its links to deforestation and the greenhouse effect, residual ash from biomass facilities is also being reassessed. Once thought of as a disposal problem, this ash is now being recognized for its nutrient

43. See *The Potential For Biomass To Mitigate Greenhouse Gas Emissions In The Northeastern U.S.*, Tellus Institute, April 1992, referenced in the *Northeast Regional Biomass Program Mission - Accomplishments - Prospects: 1992*, Coalition of Northeastern Governors Policy Research Center, Inc., Washington, D.C., October 1992, page 17.

44. This information is based on personal communications with Ancyl Thurston, Maine Forest Service - Silvaculture, in August 1993.

45. See Richard L. Bain and Ralph P. Overend, "Biomass Electric Technologies: Status and Future Development," contained in *Advances in Solar Energy: An annual Review of Research and Development*, Volume 7, Edited by Karl W. Boer, ASES, 1992, page 455. For a more complete discussion on this point, see chapter 7.

46. See *The Potential For Biomass To Mitigate Greenhouse Gas Emissions In The Northeastern U.S.*, op.cit., page 17.

benefits to plant growth and in many instances being spread on nearby agricultural lands.[47]

The biomass industry studies (noted earlier) have helped identify some of the significant contributions the biomass industry makes to the state of Maine. The industry's ability to address environmental concerns and enhance protection of the environment are key factors in continued success.

3.2.4 Implications For Further Study

In spite of the significant economic and environmental benefits to Maine, recent utility actions have focused on existing avoided costs which are now lower than energy planners had anticipated. This has resulted in the termination (buy-outs) of five power purchase contracts and several others are presently in the midst of negotiations.

The opportunity to sell electricity (i.e., as qualifying facilities under PURPA) may have had (and continue to have) much larger and more far reaching impacts than those noted, especially in the area of cogeneration. As one industry representative noted recently:

> . . . the conclusion is unavoidable that our ability to obtain long-term Power Purchase Agreements in Maine has enabled us to invest more capital, employ more people, purchase more goods and services, and maintain more cost-competitive businesses in the state of Maine.[48]

A better understanding of the true costs and impacts of Maine's energy choices requires more than mere analysis of the avoided costs per kilowatt-hour. With that in mind, the remainder of this chapter is devoted to case studies of several biomass energy facilities and one energy service company.

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47. See Jane Turnbull, *Strategies For Achieving A Sustainable, Clean And Cost-Effective Biomass Resource*, Electric Power Research Institute, Palo Alto, Calif., January 1993, page 8. The beneficial value of spreading ash on fields refers only to ash derived from burning "clean" wood. For a related discussion of the problems associated with burning treated or contaminated wood waste see *Wood Products In The Waste Stream: Characterization And Combustion Emissions*, The New York State Energy Research And Development Authority, November 1992. Also, see a further discussion on this point in chapter 7.

48. This comment was taken from a written response by James A. Corrodi, Vice President and General Counsel, North American Services, Scott Paper Company, to questions posed in August 1993.

3.3 Case Studies

The four industry case studies focus on: Fairfield Energy Venture, an independent power producer in northeastern Maine; Robbins Lumber, a wholesale lumber mill which also produces electricity, located in the town of Searsmont in the mid-coast region; Boise Cascade, a large pulp and paper mill in western Maine near the New Hampshire border; and SESCO, an energy service company located just outside Lewiston.

Each of the biomass facilities studied is a "qualifying facility" with a current power purchase agreement with one of Maine's utilities. Similarly, the energy service company SESCO is also under contract with a utility to provide conservation services to thousands of Maine homes.

The studies are organized into several key sections, including: an overview of the town or region in which the respective business is located; background information on the initial development or upgrading of the facility; a discussion of annual expenditures; information on state and local taxes paid; employment contributions; and finally summary comments.

The information contained in each of the four case studies was derived primarily from a series of personal communications with respective industry representatives. To supplement this information, local town representatives and state officials were contacted and written documents used to obtain necessary and useful information. Every effort was made to obtain the most detailed and accurate data available. However, in some instances, the level of detail required was unavailable or confidential and "educated" estimates were made by the industry representatives. Where appropriate these are noted.

3.3.1 Fairfield Energy Venture

Fairfield Energy Venture is a 32 megawatt (MW) independent small power producer utilizing a variety of biomass fuels to generate electricity. The facility is located within the city of Fort Fairfield, in northeastern Maine near the Canadian border. Fort Fairfield has a population of just under 4,000 and is located in the rural county of Aroostook.

Historically, the local economy has relied heavily on its agricultural base for many of the area's local jobs and income. More recently however, the influx of non-agriculture related industries (e.g., an electronic component manufacturer, a news clipping service, an ink cartridge manufacturer and the energy plant) have helped diversify the employment base. Nevertheless, employment opportunities are still limited to approximately 100 private sector businesses (including in-home businesses), the area schools and other government sector employment. Public and private sector employment opportunities are estimated to supply 1,266 jobs.[49]

Private sector employment includes: farming and agriculture related businesses, forest based industries, a hospital, the energy plant and a variety of retail stores, manufacturers and service oriented businesses. Town offices and the school system are the area's two largest employers followed by a recently down-sized electronics-based industry, a potato processing plant and the energy facility.

COMPANY PROFILE: FAIRFIELD ENERGY VENTURE
FORT FAIRFIELD, MAINE

Plant type	Independent Power Producer
Plant capacity	32 Megawatt (MW)
Number of employees (1992)	38 full-time
Fuel type	Biomass (wood chips, sawdust, slash and bark)
Biomass consumption (1992)	355,000 tons
Electricity sales (1992)	243,748 Megawatt-hours (MWh)
Revenue from electricity sales (1992)	$28,238,591
Contract utility	Central Maine Power (CMP)
Term of contract	15 years (1987-2002)

The Fort Fairfield employment base has diminished sharply in recent years. In addition to two bad farming years (which affected the number of seasonal jobs), the local food processing plant (also one of the area's largest seasonal employers) recently underwent a shift in ownership. The inevitable restructuring resulted in the loss of more than 100 local jobs instead of an expected increase.

49. This information is based on personal communications with Anna Watt of the Fort Fairfield Chamber of Commerce, in August 1993.

Similarly, a local electrical component manufacturer, seeking lower operating costs, recently moved much of their operation out of the country to Honduras. These loses, combined with recent industry losses in the surrounding area (and the upcoming closure of Loring Air Base[50]), have pushed the local unemployment rate up to almost 12 percent.

COMPANY BACKGROUND

Responding to a favorable climate in Maine for developing renewable energy producing facilities in the mid 1980s, and the opportunities for independent power generators inherent in the Public Utility Regulatory Policy Act of 1978, the Fairfield Energy Venture was initiated in 1985. Officially a Limited Partnership, Fairfield Energy Venture consists of several individual investors, U.S. Energy[51] and HYDRA-CO Enterprises.[52]

The investors joined together to finance construction and operation of a biomass fueled electricity generating plant dedicated to producing power for direct sale to a regulated utility. Having the ability to meet PURPA guidelines as a "qualifying facility," the partnership subsequently entered into a power purchase agreement with Central Maine Power (CMP) to provide 32 megawatts (MW) of electricity. The contract began in November 1987 and runs 15 years through the year 2002.

With the agreement signed, the Fairfield Energy facility had its groundbreaking in May of 1986 and construction was complete in early 1988. Total costs for the purchase of the power plant unit and on-site construction were $60 million. Of the total cost, approximately $8.1 million (13.5 percent) of the initial plant construction expenditures

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50. According to Anna Watt the closure of Loring Air Force Base (northwest of Fort Fairfield) is expected to be complete by 1994. Ms. Watt notes that the closure is expected to directly impact approximately one-third of the Aroostook County population. Significant population and revenue losses due to relocation of military personnel, their families and others involved in base related activities, are expected over the next year.

51. US Energy, with its main headquarters in Washington, D.C, was founded in 1984. The corporation is a developer, owner, and operator of small power and cogeneration plants throughout the United States. Of the 280 megawatts of projects developed by U.S. Energy, half utilize energy from biomass combustion. For more information contact Robert Poole, Vice President, at (202) 537-7403.

52. HYDRA-CO Enterprises Inc., headquartered in Syracuse, New York, is an independent subsidiary of Niagara Mohawk Power corporation. In addition to twenty other energy projects (under construction or in operation), HYDRA-CO has four operating biomass facilities generating a total of 130 MW (including the Fairfield facility). For more information contact Don Scholl at (315) 471-2881, Ext. 159.

are estimated to have been spent in the state of Maine. This includes local labor for on-site assembly and construction, purchase of consumables and structural steel.

For more detail on the cost breakdowns see Table 3-1, titled *Initial Construction Expenditures For Fairfield Energy Venture*, on the following page. The remaining $51.9 million is divided between the manufacturer, out-of-state contracting and other services and development costs.[53]

TABLE 3-1. INITIAL CONSTRUCTION EXPENDITURES FOR FAIRFIELD ENERGY VENTURE (IN MILLIONS OF 1987 DOLLARS)

Category	Expenditures		Total
	In-State	Out-of-State	
Labor	$5.3	n/a	$5.3
Consumables	$2.6	n/a	$2.6
Structural Steel	$0.2	n/a	$0.2
Other (power plant, contracting, misc.)	$0.0	$51.9	$51.9
Total	$8.1	$51.9	$60.0

Notes: The information contained in this table is based on personal communications with Don Scholl, Administrator at HYDRA-CO Enterprises. The "other" category of expenditures refers to all "out-of-state" expenditures which could not be itemized at this time.

53. According to personal communication with Don Scholl, Administrator for HYDRA-CO and Peter Powers, General Manager for U.S. Energy Corporation (the plant's operator), in August and September of 1993, the power plant was manufactured in Spain and assembled on-site.

ECONOMIC BENEFITS

Fairfield's contribution to the local economy is not limited to those benefits related to the initial construction. In fact, Fairfield Energy Venture had annual operating expenditures which exceeded $12 million in 1992.[54] Although not all of this money was spent in Maine, almost 80 percent or $9.4 million of it was circulated in the State's economy. The remainder was spent on biomass fuel from Canada and parts, equipment and services which are not available in Maine.[55]

In addition to those dollars spent on biomass fuels (which accounted for almost 60 percent of total expenditures in 1992), Fairfield Energy spent an additional $5 million. Of this, almost 97 percent was spent directly in Maine; this included payments for state and local taxes, employee compensation and benefit packages, utility expenditures, services, parts and equipment. Fairfield also paid in excess of $1 million to Central Maine Power to use their transmission lines to "wheel" electricity to users.

Of the in-state total expenditures, more than $7 million made its way directly into the Fort Fairfield and surrounding area as purchases for biomass fuels and wages and salaries paid to plant employees. For more detail see Table 3-2, on the following page, titled *Fairfield Energy Venture Select Expenditures For 1992.*

54. These expenditures do not include costs relating to debt payments, income taxes, insurance costs or a variety of others which were not available because of their proprietary nature.

55. In some instances Fairfield requires "factory" manufactured parts to repair or replace power plant equipment.

TABLE 3-2. FAIRFIELD ENERGY VENTURE SELECTED EXPENDITURES FOR 1992

Category	Expenditures In-State	Expenditures Out-of-State	Total
Biomass fuels	$4,538,919	$2,444,034	$6,982,953
Other production expenses	$1,144,850	$160,150	$1,275,000
Salaries and wages (including benefits and taxes)	$1,700,000	$0	$1,700,000
Local property taxes	$824,347	$0	$824,347
Other fees and licenses	$114,000	$0	$114,000
Transmission cost (CMP wheeling fees)	$1,100,000	$0	$1,100,000
Total	$9,392,117	$2,604,184	$11,996,300

Notes: The information contained in this table was derived from personal communications with representatives of Fairfield Energy Venture.

According to a representative of the Fort Fairfield Chamber of Commerce, "we [Fort Fairfield residents] consider ourselves lucky to have the energy plant." From the start of the project it appears the town and local area have been winners. Local tradespeople were employed in the on-site construction, parts and supplies were purchased from local outlets whenever possible and the influx of engineers, consultants and temporary out-of-town workers provided substantial benefits to local restaurants, gas stations, motels and food stores.[56]

56. This information is based on personal communications with Anna Watt, a representative of the Fort Fairfield Chamber of Commerce, in August 1993.

And the benefits didn't stop there — increased tax revenues, steady employment, on-the-job training, support for community projects and a host of others have accrued to the State as a whole and the local area.

Benefits include increased tax revenues, steady employment, and support for community projects

LOCAL TAXES

The arrival of Fairfield Energy to the Fort Fairfield area has provided a significant and stable support base for local government funding and the city's schools. Boosting the towns assessed property valuation by almost $30 million, the Fairfield Energy facility has been paying local property taxes annually since 1988, totalling more than $800,000 for the 1992 fiscal year.

Based on city property tax collections of almost $2.8 million for 1992, the energy plant paid almost 30 percent of the total property taxes collected in Fort Fairfield in that year. These figures, and Fairfield's importance to the local area, gain even greater significance when one considers that 55 percent of the property taxes collected in 1992 were dedicated to school funding to meet growing needs and costs.

Since the plant went on-line in 1988 the Fort Fairfield property tax rate (mill rate) has remained stable (the last five years) despite the fluctuations in state revenue sharing dollars.[57] Fairfield Energy's contribution has no doubt played a significant role in offsetting what might otherwise have resulted in tax rate increases for local residents.

In addition to local property taxes, Fairfield Energy pays state sales tax and special fuel use taxes to the State government. In 1992 these combined taxes totalled almost $100,000. Although these monies are not paid directly to the local area, these tax dollars are placed in a general fund which forms the basis for distribution of State dollars to local areas.[58] In light of the recent reductions in the State's Revenue Sharing

57. The Fort Fairfield mill rate increased from $24 per $1,000 of assessed value in 1985, to $27 in 1986, to $28.5 in 1987, and then declined to its present $27 in 1988. This information is based on personal communications with Tony Lavesque of the Fort Fairfield Community Development Department, in September of 1993.

58. According to Marc Cyr, Administrator of the Revenue Sharing Program at the Maine State Treasury Department, state law determines what percentage of sales tax revenues and individual and corporate income taxes are placed in the State Revenue Sharing Program to be distributed to communities. The rate now stands at 5.1 percent. This information is based on personal communications with Mr. Cyr in September of 1993.

Program[59] as well as flat-funding of school matching funds,[60] contributions to state sales tax revenues are an integral part of boosting available funds for local communities.

EMPLOYMENT IMPACTS

The recent closures and downsizing of local industries in the Fort Fairfield area are limiting the region's ability to provide new employment opportunities. Although seasonal employment (i.e., agricultural related) still plays an important role in the area's economy, when the main harvesting and processing periods end the unemployment rate increases sharply. Thus, Fairfield Energy Venture provides an important anchor to the local employment base and is now the fourth or fifth largest employer in the city.

The Fairfield Energy Venture is now the fourth or fifth largest employer in the city

With 38 year-round employees, the energy plant accounted for approximately three percent of the full time jobs in the local area and paid a total of $1.3 million in salaries and wages in 1992 to local area residents.[61]

Contrary to the notion that new industries entering rural areas usually "import" most of their skilled high wage labor, Peter Powers, general manager for Fairfield Energy notes "all but one of our employees were Maine residents prior to being hired by the plant and all live in close proximity to the plant."

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59. The State distribution of revenue sharing dollars went from $19.6 million in 1982 to $63.7 million in 1989, responding to a healthy growing economy. Since then, revenue sharing dropped slightly in 1990 and 1991 to approximately $61 million, but dipped even more dramatically in 1992 to $52.8 million. Mr. Cyr of the State Treasury Department noted that serious fiscal constraints required budget cuts for the program in the first half of 1992, and no appropriations were made to local communities in the month of July.

60. Based on personal communications with Gary Layton of the Maine Department of Management, in September of 1993, the state's funding for schools has decreased relative to levels in the 1980s. Prior to 1990 the State's General Fund school funding program was increasing by at least 10 percent annually, since then the annual increase dropped to 4.1 percent in 1991 and .39 percent in 1992.

61. Salaries and wages do not include taxes, social security payments, group health benefits, unemployment insurance, worker's compensation insurance, or other benefits to employees. Taxes and other benefits amounted to an additional $400,000 for a total salary and wage expenditure of $1.7 million in 1992.

Of those employees working directly with power plant operations, only one had previous experience working in a power plant operation. However, seven of the plants employees (including the general manager) are graduates of the Maine Maritime Academy or have equivalent naval training and are able to utilize their training in steam propulsion.

Many of the other power plant workers (with no related experience) had previously worked at forest related industries (e.g., lumber mills) and were hired at entry level positions.

Fairfield is committed to training these entry level workers (who usually begin as loader operators) to help ensure job advancement and stable employment opportunities whenever possible. The remainder of the employees (maintenance, administration, forestry and managerial) all had previous experience in their respective fields, although none had direct experience working in a power plant operation. Where appropriate they receive in-house training.

In addition to the general manager, operations manager and environmental supervisor, Fairfield Energy has five divisions with a total of thirty-five personnel in the respective divisions. These include electricians, welders, millwrights, loader operators, and a business manager as well as administrative and operations support personnel.

There are numerous other jobs supported by the Fairfield operation

In addition to those employees who work directly for Fairfield Energy Venture there are numerous jobs which are also supported by the Fairfield operation although not as directly. For instance, all of the fuel purchased by the energy plant, a total of 355,000 tons in 1992, at a cost of almost $7 million (not including sales use taxes), was purchased directly from forest industry chip contractors[62] or from local mills within a fifty mile radius. In both cases the purchased biomass is transported to the Fort Fairfield plant by truck.

In the chipper operations a variety of persons are employed to run the harvesting equipment, chippers and other necessary equipment. At local mills supplying biomass fuel, employees are involved in loading trucks for delivery. Based on an average cost of just under $20 per ton for delivered biomass fuels (including chips, bark, sawdust and slash), Fairfield Energy estimates that approximately 30 percent of their fuel expenditures

62. Based on personal communications with Mr. Powers, several of their biomass fuel contracts run for five years. Of these, he notes that one contract is with a Canadian firm which supplies approximately 35 percent of their fuel. Mr. Powers also noted that many of the Canadian drivers fuel-up their trucks and purchase goods in Maine prior to crossing the border back to Canada - to take advantage of lower prices.

go to transportation costs.[63] Based on this estimate, $1.36 million of the $4.5 million spent on in-state fuel purchases entered the local economy in the form of transportation related employment and expenditures in 1992.

SUMMARY COMMENTS

Fairfield Energy's presence in Fort Fairfield has had a very positive effect on the local area. With $12 million in annual expenditures, and much of that spent locally, the plant is a significant contributor to the health and well-being of the local economy. The plant's 38 in-house jobs and the numerous direct and indirect benefits to the region have not gone unnoticed.

An emphasis on creating an environmentally sustainable economic resource

Although difficult to verify or even to quantify, the Fairfield Energy management team reports that they make every effort possible to purchase goods and services — first within the local area, and then within the State as a whole.[64] This emphasis on creating an environmentally conscious and sustainable economic resource within the local area makes Fairfield Energy not only a valuable financial asset (as noted above), but, as Anna Watt of the local Chamber of Commerce notes, "they're a good neighbor."

63. This information is based on a personal communication with Randy Shaw, fuel purchaser for the Fairfield Energy Venture, in August 1993. Mr. Shaw estimates that the cost of biomass fuels (paid to contractors) is divided between trucking costs (30 percent), chipping costs (20 percent) and harvesting costs (50 percent). Of the 50 percent attributable to harvesting costs he notes that 35 percent often goes to the landowner as a stumpage fee and the remaining 65 percent is divided between the contractor, harvesting costs and road building or other necessary tasks. Mr. Shaw also cautions that these cost breakdowns can vary significantly depending upon the particular operation and site location.

64. This refers to the absence of an expenditure-by-expenditure review of Fairfield's purchases for an entire year. Nevertheless, the ratios for in-state versus out-of-state expenditures are based on informed estimates by Mr. Powers.

3.3.2 Robbins Lumber Company

Robbins Lumber Company is not new to Searsmont. In fact, the Robbins' mill has been in operation for four generations in this mid-coast town, dating back to 1881. With a population of 938 in 1990, Searsmont residents rely on Robbins Lumber and a limited number of other private businesses for local employment. The neighboring coastal towns of Belfast and Camden serve as the center for shopping and most necessary services.

More recently, with the influx of new residents to this coastal area, more and more "professionals" are purchasing or building homes in the nearby Searsmont area. In spite of a general statewide building recession, new home construction continues at a steady pace. While this steady increase appears to be affecting the rural nature of the community (creating more neighborhoods), few local jobs, other than construction related, have emerged. As some residents note "Searsmont is rapidly becoming a bedroom community for Belfast."[65]

Nevertheless, with upgrades at the Robbins Lumber mill, an existing building components factory, and the recent opening of a rope manufacturing facility, Searsmont continues to have a small, but stable employment base. In addition to these larger employers, numerous independent logging operations exist in the region contributing to the small number of local job opportunities.

65. This comment is based on personal communications with Claudia Mercer, Town Clerk for Searsmont, in September 1993.

Company Profile: Robbins Lumber Company
Searsmont, Maine

Plant type	Cogeneration (lumber mill and power producer)
Plant capacity	1.2 Megawatt (MW)
Number of employees (1992)	120 full-time (including 4.5 in the power plant and 4 in the woodlands operation)
Fuel type	Biomass (wood chips, sawdust, mill ends)
Biomass consumption (1992)	41,000 tons
Electricity sales (1992)	4,543 Megawatt-hours (MWh)
Revenue from electricity sales (1992)	$316,476
Contract utility	Central Maine Power (CMP)
Term of contract	16 years (1984-2000)

Company Background

Robbins Lumber is primarily a wholesale lumber manufacturer. Producing power for sale to the utility is relatively new to the company. With approximately 5,000 acres of its own woodlands, Robbins utilizes its own trees and purchases others to produce milled lumber. In addition to the milling operation, located on 40 acres in Searsmont, Robbins maintains a chipping operation on its woodlands to convert low grade forest materials into fuel for its boilers.

Due to the unique nature of the mill operations (which include drying kilns), Robbins has been able to utilize excess steam from the boilers to generate electricity. This, combined with the opportunity to sell the electricity[66], resulted in electricity sales to CMP. Robbins initially entered into a power purchase agreement with the utility in 1984. The contract is for a period of 16 years, running through the year 2000.

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66. This refers to PURPA guidelines for qualifying facilities and the State's desire to diversify their energy supply mix and reduce their dependence on imported oil.

In a continuing effort to upgrade the efficiency and competitiveness of their operation, Robbins identified the need for more process steam to get full use from their turbines — providing sufficient steam to meet their drying kiln needs. Responding to these in-house needs and the opportunity to take advantage of available energy credits, Robbins decided in 1986 to increase their boiler capacity and generate enough steam to produce electricity for their operations and excess for sale to CMP.

This upgrade, involving the installation of a larger boiler and a diesel back-up unit, cost approximately $2.5 million. The necessary funding was obtained through local financial institutions. In addition to those direct expenditures for the plant modifications, approximately $30,000 was paid to a Maine engineering firm for services to assist in the permitting process.

Viewed as an additional opportunity to better meet their needs and add to their bottom line, the income from power sales, just over $300,000 in 1992, is seen as "vital to the operation."[67] Nevertheless, first and foremost, Robbins considers itself a "lumber business" rather than a "power producer."[68]

ECONOMIC BENEFITS

Robbins Lumber has been, and continues to be a local operation. With annual expenditures of approximately $4.1 million in 1992, just over 99 percent was spent in the State of Maine.[69] Out-of-state expenditures totaled only $35,000 in 1992. Of this, nearly half was spent on plant parts and equipment, and half on chemicals which could not be obtained within the state. See Table 3-3 on the following page, titled *Robbins Lumber Selected Operating Expenditures For 1992*, for more detail on the annual expenditures.

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67. According to FERC Form 1 reporting by Central Maine Power Company, Purchased Power (Account 555), Robbins Lumber Inc. received $316,476 in settlement for purchase of 4,543 megawatt-hours of electricity in 1992.

68. These comments are based on personal communications with Bruce McLaughlin, Operations Manager for Robbins Lumber Company, in August 1993.

69. These expenditures do not include costs relating to debt payments, insurance costs, income taxes or other costs which might not be considered direct operating costs or were unavailable.

Robbins Lumber spent just under $2.7 million in the local area in 1992. This included $738,000 to purchase biomass fuels[70], $1.89 million for wages and salaries (this figure does not include employee taxes and benefits), and an additional $70,000 in payments for local property tax assessments to the city of Searsmont.

LOCAL TAXES

Unlike other cities or towns which have recently become home to a significant new industry, Searsmont has relied on Robbins Lumber — a stable and long term resource — for many years. With an assessed value of approximately $8.5 million, Robbins continues to be the City's single largest property tax payer.

TABLE 3-3. ROBBINS LUMBER
SELECTED OPERATING EXPENDITURES FOR 1992

Category	Expenditures In-State	Expenditures Out-of-State	Total
Biomass fuel	$738,000	$0	$738,000
Other production costs	$243,597	$35,297	$278,894
Salaries and wages	$3,040,416	$0	$3,040,416
Local property taxes	$70,000	$0	$70,000
Other taxes and fees	$5,600	$0	$5,600
Transmission costs	$0	$0	$0
Total	$4,097,613	$35,297	$4,132,910

Notes: The information contained in this table was derived from personal communications with representatives of Robbins Lumber.

70. According to Bruce McLaughlin, Operations Manager for Robbins, the plant utilized 41,000 tons of biomass materials for fuel. Of this amount, he notes that 90 percent was primarily whole tree chips - supplied by their own woodlands (some was occasionally purchased on the open market), and the remaining 10 percent was mill residues from their own mill. The cost estimates assume the fuel expenditures reach the economy regardless of their origin (in-house or open market). However, based on an average cost per ton of $18, approximately $664,000 are attributed to wood chipper operations.

With a total assessed valuation of $48.7 million, the city of Searsmont had a committed tax burden of $404,387 in 1992.[71] Of this amount, Robbins Lumber contributed just under 17.5 percent.[72]

Similar to other cities in rural areas which have a single large employer, Robbins' presence in Searsmont has helped offset increases in the City's mill rate which might otherwise have risen more sharply to meet growing fiscal needs.[73] Searsmont's mill rate increased from $13.80 per $1,000 of assessed valuation in 1985, to $18.50 in 1989, then dropped to $17.50 in 1990. Following a citywide property value reassessment the mill rate was lowered to $8.30 in 1992.[74]

In addition to the local property taxes paid by Robbins, they also paid state taxes totalling approximately $4,100 in 1992. This included sales taxes of $2,600 for parts and equipment purchased in the state of Maine and $1,500 in sales use taxes paid on the purchase of biomass fuels. Although these taxes are not returned directly (or as a ratio of local payments) to the Searsmont area, their added contribution to the State's total tax collections help increase the amount of available funds for redistribution to individual cities.

EMPLOYMENT IMPACTS

Located in one of the State's poorest areas (Waldo County), jobs are hard to come by in the Searsmont area. Although the nearby towns of Camden and Belfast contribute retail, service sector, and seasonal recreation related employment to the local region, Robbins Lumber continues to be the single largest and most significant employer in the Searsmont area. Based on an estimated employment base of less than 300 full-time jobs,

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71. The term "committed" refers to the total taxes assessed (in dollars) and billed on local properties for the fiscal year 1992. It does not however, account for outstanding taxes - taxes that have not been paid in full.

72. The total tax burden and the calculation to derive Robbins share for 1992, is based on the existing mill rate of $8.30 per $1,000 of assessed valuation. This information is based on personal communications with Ms. Mercer, in September 1993.

73. This conclusion is more obvious when we consider the ramifications of removing Robbins' tax payments from the total local property taxes collected. Assuming Searsmont had to recover the "lost" $70,000 (paid by Robbins) in revenues, the mill rate (based on current assessed valuation) would have to increase approximately $1.74 per $1,000 of assessed value (21 percent) to meet the existing fiscal needs.

74. According to Ms. Mercer, local properties hadn't been reassessed for "many years" and the drop in mill rate reflected a doubling in assessed valuation for most properties. The lower mill rate reflected an "equalization" of the tax burden - simply accounting for the new higher assessed values.

the 120 jobs associated with the Robbins manufacturing plant account for more than one-third of the total jobs in the nearby area.[75]

Robbins accounts for one-third of the jobs in the area

The Robbins workforce is composed primarily of local residents with a small percentage from neighboring towns. In addition to the 111 full-time positions in the mill operation, the power plant operation requires four full-time boiler operators and another half-time position which alternates between the boiler operation and the mill. Striving to hire from the existing local labor force, Robbins provides on-the-job training to equip workers with the necessary skills to work in their power plant operation.

Robbins' woodland operation employs four persons full-time. This includes: one person to operate the mechanical harvester, one person to operate the chipper/slasher/delimber, one person to operate the grapple skidder, and one person to haul wood chips and firewood.

Providing jobs for a total of 120 full-time employees, Robbins spent in excess of $3 million on wages and salaries and employee related expenditures in 1992.[76] Of this total, approximately $1.89 million is paid directly to employees in wages and salaries. These dollars are then re-spent in the local economy for food, clothing, housing, transportation and other necessary purchases and services. Similarly, Robbins other annual in-state expenditures — for parts, equipment and services — helps to ensure employment opportunities in the respective industry sectors.

SUMMARY COMMENTS

Robbins Lumber has been operating in Searsmont for over 100 years — providing a strong foundation for this rural city. In addition to being a consistent source for much of the area's employment, Robbins' fiscal contributions, in the form of local property taxes, have enabled the city of Searsmont to maintain a relatively low tax rate.

In an effort to upgrade its efficiency and seek out new forms of income, the Robbins' mill has maintained and improved its competitiveness. Needless to say, making use of

75. These estimates are based on calculations of employment in respective businesses in the local area derived from communications with Ms. Mercer in September of 1993.

76. This figure is based on an average wage of $9 per hour and an additional 38 percent for employee taxes, insurance and a benefit package.

previously unutilized biomass resources to produce and sell excess electricity has been an integral part in maintaining the mill's profitability.

This ability to adapt to changing times and conditions has provided many benefits to the local areas as well. With few other significant sources of employment or taxation, Robbins' 120 jobs, and their commitment to the local area, will continue to play an important role in local residents' lives and the region's economy.

3.3.3 THE BOISE CASCADE PLANT

Rumford Cogeneration Company (commonly referred to as the Boise plant) is an 86 MW steam and electricity cogeneration facility operating within the Boise Cascade pulp and paper mill in Rumford, Maine. Rumford is located in western Maine in a rural area approximately 50 miles from the New Hampshire border. Rumford's resident population in 1990 was 7,078.

The city of Rumford has been home to the pulp and paper mill for more than 75 years. The Boise facility (formerly the Oxford Paper Company) has been the region's largest employer since its opening. Although many of the City's residents (as well as residents of the surrounding areas) rely on Boise for employment, other industries, including agriculture, the local hospital, the public sector, and a small retail, commercial and service sector, continue to provide additional steady employment opportunities.

Rebounding from the loss of Diamond Match (Rumford's other large employer) approximately five years ago, and the subsequent loss of several other smaller factories, Rumford and the surrounding areas are attempting to diversify. With vast natural resources in close proximity, Rumford and nearby towns are placing a strong emphasis on recreation and tourism-related industries.

As a result, the region is now experiencing a surge in tourism and the accompanying benefits for restaurants, hotels and the retail sectors that cater to recreation and tourists. Although helping to boost the area's economy, much of this recent diversification and tourism industry growth has resulted in primarily seasonal employment. Boise Cascade and International Paper Company (another pulp and paper mill approximately 30 miles away in Jay, Maine) remain the most significant and stable employers in the region.

Company Profile: Boise Cascade (Rumford Cogeneration Company, L.P.) Rumford, Maine

Plant type	Cogeneration (pulp and paper mill and power producer)
Plant capacity	86 Megawatts (MW)
Number of employees (1992)	1,572 full-time (including 117 in the steam and power generation operations)
Fuel type	30 percent Biomass (bark, wood chips, sawdust and sludge) and 70 percent coal
Biomass consumption (1992)	112,000 tons
Electricity sales (1992)	636,046 Megawatt-hours (MWh)
Revenue from electricity sales (1992)	$45,374,623
Contract utility	Central Maine Power (CMP)
Term of contract	15 years (1990-2005)

Background

The Rumford Cogeneration Company is a limited partnership. The partnership is comprised of Boise Cascade (a general partner which owns 30 percent of the company) and approximately six other limited partners.[77] Boise's decision to develop their cogeneration capabilities and modernize the pulp and paper operation in the late 1980s were based on several important factors. These include:

77. Based on an agreement between Rumford Cogeneration Company and Boise Cascade, Boise is paid a fee, totalling $9.6 million in 1992, by the partnership to operate and maintain the steam and power facilities. All of the low pressure steam produced is sold to the paper mill (Boise) and the high pressure steam is used to generate electricity which is sold to CMP. This information is based on personal communications with Bob Stickney, Region Energy Manager and Cogen Business Manager for Boise Cascade, in August 1993.

* More rigorous environmental regulations requiring reductions in air emissions and water discharges;

* The desire to increase production efficiencies and profitability; and

* The need to improve the reliability and output of the energy production systems.

This combination of factors created strong incentives to modernize and expand the operation in Rumford. However, the pulp and paper facility improvements were estimated to cost between $200 and $300 million dollars. To help offset the significant capital costs required for this upgrade Boise chose (through the formation of the Rumford Cogeneration Company) to upgrade the cogeneration facility and increase their electrical generating capacity. By meeting those guidelines set forth in PURPA legislation for "qualifying facilities," Boise could capitalize on their ability to compete for utility power purchase agreements.

The Rumford Cogeneration Company was formed, and a power purchase agreement was signed with Central Maine Power in 1987 — to run from 1990 through 2005. The modernization project and cogeneration upgrade began in 1988 and was completed in 1991. For a general summary of the upgrading and construction costs see Table 3-4 on the following page, titled *Modernization and Upgrade Expenditures For Boise Cascade.*

TABLE 3-4. MODERNIZATION AND UPGRADE EXPENDITURES FOR BOISE CASCADE

Category	Expenditures (Million$)
Modernization	
Pulp mill	$100
Bleach plant	$28
Lime kiln plant	$30
Paper mill (2)	$50
Water treatment plant	$5
Paper machine	$10
Modernization subtotal	$223
Cogeneration upgrade	$180
Total	$403

Notes: The information contained in this table is based on personal communications with representatives of Boise Cascade in Rumford, Maine. The expenditures reflect costs which occurred between 1988 and 1991.

The modernization and cogeneration upgrade provided many significant immediate and ongoing benefits for the plant, the environment, and the local and state economies. Interviews with Boise personnel suggest that such benefits would not have occurred without the state's present energy policies. The range of benefits include:

1. Initial expenditures of $223 million for Boise's modernization and an additional $180 million for the cogeneration upgrade — much of which went into the State's economy. This includes expenditures for direct employment for construction and assembly,

and purchases of parts, equipment and services within the local area and the State of Maine.[78]

2. An additional several hundred million dollars in sales as a result of increased production capacity and plant efficiencies.[79]

3. Reductions in air emissions and water discharges from improvements in the pulp mill, lime kiln and bleach plant.[80]

4. The ability to sell electricity, valued at just over $45 million in 1992.[81]

5. Reduced need for landfill space for sludge (and the associated costs). New screw presses incorporated into the new water treatment plant now allow for removal of more moisture from plant sludge. The dryer sludge can now be utilized as a fuel in the biomass burners.

6. Additional local property tax revenues as a result of an increase in assessed valuation.

These benefits (noted above) do not reflect any of the non-direct or "multiplier" effects which result when more employees are hired, and consultants and engineers are brought in for special projects. Nor do they account for the numerous employment opportunities that are created to accommodate increased sales and production in other related industry sectors. Locally these include, but are not limited to, expenditures at local restaurants, hotels, retail establishments and gasoline stations.

78. At the time of this writing a breakout of in-state versus out-of-state modernization expenditures was unavailable. However, Mr. Stickney noted that an out-of-state "overall" contractor was hired, who hired primarily local state contractors to do most of the work.

79. This estimate is based on information provided by Mr. Stickney in August and September of 1993.

80. Ibid.

81. This information is based on a review of Federal Energy Regulatory Commission (FERC) Form 1 reports Dec. 31, 1992, Purchased Power section, filed by Central Maine Power Company.

ECONOMIC BENEFITS

The city of Rumford and local residents have continued to receive benefits from the presence of a "modern" pulp and paper mill and the plants capacity to sell electricity. As Rumford's, and the region's, largest employer, the plant employed more than 1,500 persons in 1992 and spent $75 million dollars for labor (this figure includes company paid benefits and state taxes). In addition to providing the most significant number of jobs, the higher than average wages paid by Boise make it an even more desirable place to work.[82]

In addition to a large number of jobs, Boise Cascade pays a higher than average wage

Although direct employment and the personal income derived from the plant are critical to the region, others benefit as well. In 1992, the city of Rumford received more than $6.7 million in property tax payments[83] and local wood chip contractors were kept busy supplying biomass fuels (25 percent of total fuel needs in 1992 — the remainder is coal and, to a smaller extent, sludge). The cogeneration plant purchases all of its biomass fuels from within a 50 mile radius.[84] The cost for the 112,000 tons of tree chips purchased in 1992 exceeded $2 million.

Of these annual expenditures, which totalled more than $83.7 million dollars for 1992, an estimated $83.3 million dollars (or 99.4 percent) went directly into the State and local economies. For more detail see Table 3-5, titled *Boise Cascade Selected Operating Expenditures For 1992*, on the following page.

82. According to Roberta Raney, at the Rumford Information Booth, "Boise pays the best wages in the area, even better than International Paper in Jay [Maine], another big employer."

83. As of the writing of this report a detailed breakout of annual plant expenditures was not available. However, Mr. Stickney did note that the cogeneration (steam and power) portion of the operation accounted for approximately $2.5 million in local property taxes.

84. Boise purchases all of its biomass fuels from local contractors. Although a majority of them are within a 50 mile radius of the plant, Mr. Stickney notes that this reaches into New Hampshire. The exact percentage of fuel purchases from outside Maine were not available at this time. An estimate of 25 percent out-of-state purchases was used in lieu of exact figures.

LOCAL TAXES

Boise's long-term presence in Rumford takes on even greater significance when one considers their contribution to local school funding. With state revenue sharing and school funding remaining relatively flat, local property taxes continue to provide the most stable funding sources for local governments.

TABLE 3-5. BOISE CASCADE SELECTED OPERATING EXPENDITURES FOR 1992

Category	Expenditures		Total
	In-State	Out-of-State	
Biomass fuel purchases	$1,512,000	$504,000	$2,016,000
Salaries and wages (including benefits and taxes)	$75,000,000	$0	$75,000,000
Local property taxes	$6,772,000	$0	$6,772,000
Total	$83,284,000	$504,000	$83,788,000

Notes: The information contained in this table was derived from personal communications with representatives of Boise Cascade and the Rumford City Government. Expenditures for the cogeneration portion of the plant are included in the respective categories due to the integrated nature of the operations.

With an assessed value of just under $400 million in 1992, Boise was Rumford's largest single source of property tax revenues. Boise paid in excess of $6.7 million to the city of Rumford. This total represented more than 70 percent of Rumford's property tax collections in 1992 (just over $9.4 million). From this total, Rumford allocated just over 50 percent ($4.88 million) to fund their portion of the local school budget.

EMPLOYMENT IMPACTS

Similar to other rural areas in Maine, Rumford and the surrounding areas continuously struggle with a relatively limited employment base and the desire to attract new industries and jobs. Although, the existence of Boise Cascade has provided a relatively stable employment base, the region's strong reliance on one industry leaves it overly susceptible to recessionary times and industry changes.[85]

The Boise plant is the area's single largest employer with 1,577 employees in 1992. Consistently employing more than 1,500 persons, Boise attracts Rumford residents as well as those from as far away as Livermore and Andover which are at least 30 miles away.

Although the plant attempts to hire persons with previous experience, this is not always possible in the local region. To meet the growing need for a more skilled labor force, Boise (in accordance with company policies and union guidelines) maintains an extensive on-the-job training program, as well as an ongoing program to ensure employees continue to have the most current levels of proficiency.

In addition to the more traditional and entry level jobs found in pulp and paper mills, Boise employs a variety of more specialized employees. These include: chemical engineers, process engineers, mechanical engineers, maintenance engineers, as well as a variety of persons skilled in steam and power plant operations.

Boise's impact on local employment is not limited to its direct in-house employment. As noted earlier, the purchase of biomass fuels (especially wood chips) provides employment for numerous persons involved in chipper operations, materials handling and transportation of the fuels since Boise doesn't transport any of the fuels itself.[86] Half of Boise's wood purchase contracts are for a one year duration and the other half are entered into "as available."

Similarly, the purchase of coal, which accounts for approximately 75 percent of the plant's fuel supply, provides numerous in-state jobs to handle and transport it for delivery to Boise. Although the coal is not mined in the state of Maine, it is barged to Portland.

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85. This was apparent in the mid 1980s when Boise workers went on strike and the whole town and region suffered financially.

86. Boise estimates that they pay an average of $18 per ton for biomass fuels. This price includes transportation.

From there it must be loaded into box cars and transported by railroad to the Rumford facility.[87]

Boise's contributions are not limited to those dollars which are directly related to the cost-of-doing-business. Boise contributes money, provides space for meetings and support for community activities and citywide projects.[88]

SUMMARY COMMENTS

Boise Cascade, and its predecessor Oxford Paper, have in the past, and continue to provide numerous benefits to the rural Rumford area. As Ms. Raney of the Rumford Information Booth notes, "Rumford would be lost without Boise." This comment aptly describes Boise's impact on the local region.

Continuous plant upgrades, most recently the mill modernization project and cogeneration upgrade (made possible by the opportunity to sell electricity), have helped reduce their net cost of manufacturing. However, the benefits do not remain solely with Boise.

Boise provides, either directly or indirectly, a significant percentage of the region's employment and wage earner income, as well as a large share of local city revenues. The more efficient and expanded operations have allowed Boise to more fully utilize their facility, improve environmental emissions, and thus ensure financial stability and job security for workers. Similarly, local retail and commercial businesses (both in the local area and statewide) benefit daily from direct plant purchases as well as those from the plant's workers and their families.

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87. Mr. Stickney estimates that upwards of 30 percent of the delivered cost of the coal is spent in-state for handling and transportation.

88. Based on personal communications with Roberta Ramey at the Rumford Information Booth, in August 1993, Boise "is well thought of by the community." She noted that Boise has provided assistance for community projects, helped with city clean-ups, contributed needed funds for improving the community center and provided classroom space for college classes and other activities.

3.3.4 SESCO, INCORPORATED

SESCO, Incorporated is an energy service company (ESCo) with its Maine headquarters in Lisbon Falls. Lisbon Falls is located immediately southeast of Lewiston, midway between Lewiston and Brunswick. The community has a population of almost 9,500 and, like other smaller towns in close proximity to larger cities, it is strongly influenced by the regional economics.[89]

Less than twenty years ago much of the regional employment was centered almost exclusively on five large mills and a large shoe factory. This is no longer true, although several mills still exist. Lewiston, Auburn, Lisbon Falls, and the surrounding towns have diversified and are now home to a vast array of new businesses. The "mill town" environment has been replaced by high-tech factories, plastics manufacturers, printers, large bakeries, educational institutions, hospitals, beverage distributors, and a host of smaller and more nationally oriented business.

During the 1980s the Lewiston area experienced an accelerated growth. With that growth came a strong regional sense of economic well-being. So strong was the economic momentum that the recent statewide recession created the mis-impression that the economy was worse than it actually was.[90] Few industry closures have occurred, however, and the region's unemployment rate has increased less than one percent during the last few years.

COMPANY BACKGROUND

With a state policy that emphasizes the use of indigenous resources and reducing the state's reliance on imported oils, energy efficiency has become an important resource strategy. Central Maine Power Company (CMP), for example, expanded demand-side management (DSM) program expenditures from $4 million in 1985 to more than $16 million in 1992. Cumulative program savings have increased from 12,000 to 486,000 megawatt-hours (MWh) in that same period of time.

Power Partners is one of the major energy efficiency programs now operated by CMP. The program has generated a total of 118,800 MWh in electricity savings, more than

89. According to the latest U.S. Census figures the Lewiston/Auburn area has a combined population of just under 65,000 residents. The total county-wide population (Androscoggin County) was approximately 105,000 in 1990.

90. This comment is based on personal communications with a representative of the Androscoggin County Chamber of Commerce, in September of 1993. Androscoggin County includes Lewiston, Auburn, Lisbon Falls and much of the surrounding area.

one-fourth of the savings through 1992. In a competitive bidding process, CMP now has a contracts with three different companies to provide energy savings projects on behalf of the utility and its customers.[91] SESCO is one such company.

SESCO, Inc. is a private company which provides a variety of energy efficiency services.[92] Key company data are shown in the profile on the following page. SESCO entered into its first contract with CMP in 1988 and began work in 1989. Building upon their experience in residential energy efficiency improvements, SESCO contracted with CMP to install a variety of measures (including the installation of items like compact fluorescent bulbs, weatherstripping, caulking, water heater and pipe wrap, and insulation) in the CMP residential service territory. Payment for their services are based on actual customer kilowatt-hour savings and life of the individual measures.[93]

The contract between SESCO and CMP is essentially a "turnkey" operation for CMP. In other words, SESCO provides all of the necessary labor and materials for the program (with no direct contribution by customers). The company has full responsibility for reviewing customer lists, evaluating consumption loads, marketing, contacting customers, scheduling of audits, purchasing materials, installation of measures and ongoing monitoring of electricity savings. CMP monitors program operation and periodically evaluates SESCO installations to verify energy savings.

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91. Information on the CMP programs is taken from the company's *Demand-Side Management Quarterly Report*, 4th Quarter 1992, and from *Central Maine Power: Pilot Efficiency Buy-Back Program* (Boulder, CO: The Results Center, Profile #60, 1993).

92. SESCO, Inc. now provides energy efficiency services to utilities in Maine, New York, and Oregon and is pursuing additional contracts in other regions of the country. The company's main headquarters are in Lakeforest, New Jersey. For more information on SESCO's activities, contact owner Richard Esteves at (201) 663-5125.

93. According to personal communications with Richard Esteves in September 1993, the payments are approximately 80 percent of CMP's avoided cost for electricity.

Company Profile: SESCO, Inc.
Lisbon Falls, Maine

Industry type	Energy service company
Number of employees (1992)	45 full-time
Annual Expenditures (1992)	$4.25 million
Services provided	Energy Efficiency — providing energy audits, installation of residential energy saving measures and monitoring results
Homes serviced (1989-1993)	18,710 residences
Electricity savings	
Customer megawatt-hours	52,500 MWh per year — an average of 2,806 kWh per year per residence
Customer dollars	$5.93 million — an average of $317 per year per residence based on an average CMP residential rate of 11.3 cents per kWh
Contract utility	Central Maine Power (CMP)
Term of contract	1st contract 10,000 homes (1989-1991) 2nd contract 25,000 homes (1992-1995) (*this estimate based on savings of 50,000 MWh per year at completion of contract*)

Economic Benefits

SESCO's contract with CMP provides many distinct contributions to the local area. In addition to the employment of 45 permanent, full-time persons (in Maine) in 1992, SESCO's annual expenditures were just over $4.25 million. As Table 3-6, titled *Selected SESCO Expenditures For 1992* (on the following page) indicates, a large percentage of their annual expenditures — almost 80 percent — were spent within the state.

Table 3-6. Selected SESCO Expenditures For 1992			
	Expenditures		
Category	**In-State**	**Out-of-State**	**Total**
Materials purchases	$552,349	$506,000	$1,058,349
Other purchases	$728,476	$92,000	$820,476
Salaries and wages (including benefits and taxes)	$2,033,895	$300,000	$2,333,895
Taxes, fees and licenses	$44,480	$0	$44,480
Total	$3,359,200	$898,000	$4,257,200

Notes: The information in this table was derived from personal communications and written correspondences with SESCO management in November 1993. There are no direct payments to local property taxes because SESCO leases rather than owns a building.

This high ratio of in-state spending reflects a commitment on the part of SESCO management to ensure that local business (e.g., trades contractors, suppliers, distributors, and local service providers) benefit from SESCO's presence in Maine.[94] SESCO currently utilizes upwards of 77 different suppliers to provide the necessary materials for installation in residences. Of these suppliers, 85 percent (65) are in state.

In 1992 SESCO spent more than $143,000 in Maine to purchase new vehicles; making it the largest purchaser of small trucks and vans at each of the two local dealerships. More than half of the materials installed in Maine residences (including insulation, weatherstripping, compact fluorescent, plumbing fixtures, pipe wrap, etc.) were obtained through purchase agreements with local suppliers and distributors.

94. James Maitilasso, Operations Director and Purchaser for SESCO, stated during a personal communication in October 1993, that "utilizing local suppliers (even when the cost is slightly higher) and subcontractors whenever possible benefits SESCO with reliable and quality services, and provides jobs and income to the local community." He also noted that several local subcontractors have significantly expanded their operations as a result of their involvement with SESCO.

To date SESCO reports they have supplied CMP's program participants with approximately $17.02 million worth of energy conservation improvements.[95] Similarly, although not direct expenditures for conservation improvements, vehicle purchases, office supplies, company uniforms, insurance and more are all purchased locally.

To date SESCO has provided CMP customers with $17 million worth of efficiency improvements.

Unlike other energy producing facilities, SESCO does not have a large capital investment in construction of a facility. Due to the nature of the services they provide (similar to that of construction companies) ,SESCO does not require a factory-type setting with fixed machinery. SESCO currently leases a 5,000 square-foot two story office/warehouse which houses the local office and telemarketing staff, and provides space for storage of materials, supplies and parking for the company's vehicles.

However, the most significant difference between SESCO's contribution to the economy and that of a permanent energy facility or most other industries, is the annual impact on electricity customers. The benefits to the 18,710 residences treated thus far range from reductions in utility bills to improved comfort.

The first 11,848 residences treated yielded 33,246 megawatts-hours of energy savings — equivalent to an annual average electricity savings of 2,806 kWh and $317.08 per year for each residence.[96] Upon completion of the conservation program (two contracts spanning 1989-1995) the combined savings of 75,000 MWh annually will yield annual customer savings of $8.48 million.

The customer dollar savings also provide significant capital which can be reinvested into the economy as payments for other goods and services, or investment in other industries. In addition to the increased purchasing power, residents benefit from improved comfort levels resulting from cutting down on drafts, losses of cooled or heated air, and in general the maintenance of more constant temperatures.

95. According to the Summary Highlights of the CMP-SESCO Residential Power Partners provided by Mr. Richard Esteves, owner of SESCO, the company plans to invest another $7.1 million in residential energy conservation improvements, for a total of $24.1 million during the life of the contracts.

96. These energy and dollar savings are based on actual measured savings provided by Mr. Esteves, in November 1993. Energy savings (measured by CMP and SESCO) are actual metered reductions — derived by subtracting electricity usage after treatment from usage before treatment at each residence treated. The dollar savings are based on an average CMP residential rate of $0.113 per kWh.

TAXES

Similar to other businesses in Maine, SESCO pays state sales tax on a significant percentage of its purchases. In 1992 they paid in excess of $38,000.[97] Unlike other businesses which own their own buildings, SESCO leases and therefore does not pay local property taxes directly.[98]

EMPLOYMENT

SESCO's impact on the local labor market is not as obvious as it would be had they been a large mill or hospital. In fact, the firm's 6 to 8 crews and office personnel (a total of 45 employees) represent a very small percentage of the total labor force estimated at over 40,000 persons in the Lewiston, Auburn and Lisbon Falls area.[99]

Nevertheless, due to the nature of the business, SESCO does provide steady employment for persons with mechanical and construction skills, as well as those with energy auditing skills. The average salary for SESCO's employees in 1992 was approximately $34,000. Total payroll (including salaries, wages, benefits and taxes) for the in-state employees was just over $2.03 million.

Although some of SESCO's employees are originally from out-of-state, SESCO has been able to draw almost entirely from the local labor pool to meet their employment needs.[100]. Of the 45 employees at year-end 1992, 43 were hired in Maine and all but one of the supervisors and crew chiefs were from Maine.

SESCO's hires predominantly full-time workers for year round employment, although occasionally part-time workers are also utilized. Unlike much construction related employment there is little, if any, "down time" due to weather, seasonal variations, or real estate market influences.

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97. This estimate is based on sales tax payments of 6 percent on each dollar of applicable supplies, materials and equipment purchased in the State of Maine.

98. Leasing or renting property rather than owning it does not relieve a business or individual from the burden of property taxes. Lease or rental payments usually reflect these taxes and any other required payments and are alternately paid by the property's owner or agent.

99. This estimate is based on personal communications with a representative of the Androscoggin County Chamber of Commerce, in September of 1993.

100. According to Walter Noe, SESCO's Maine Project Supervisor, of their total number of employees, two or three worked for SESCO previously and came to Maine to work on this project.

In addition to those directly employed by SESCO, a utility hired inspector (paid for by SESCO) and three utility personnel are involved part-time to oversee the SESCO contract. Similarly, 15 local subcontractors (including plumbers, electricians, carpenters, insulation contractors and others) were paid approximately $165,000 for services in 1992. SESCO also utilizes local service providers for vehicle repair and maintenance, janitorial services, advertising, and insurance and medical needs, further contributing to the local economy.

Summary Comments

SESCO is relatively new to Maine, setting up a local office in Lisbon Falls only in the last five years. Nevertheless, at a cost of less than five cents per kWh (considerably below the cost of the biomass facilities reviewed earlier in this section), its operations directly support Maine's energy and economic goals.

SESCO's contribution to the local economy has meant additional jobs for residents and additional income for local business. SESCO has hired almost exclusively local people, purchased approximately 80 percent of its goods and services locally (in 1992) and is helping CMP residential customers save energy and reduce their electricity bills.

As one local business owner notes "Fortunately for the community [Lisbon Falls] and myself, there are businesses like SESCO that help us all succeed."[101]

3.4 Conclusions

The economic contributions from non-utility electricity generators and energy service companies have been significant. Biomass electricity generation and energy efficiency improvements have, and can continue to play a key role in maintaining Maine's economic and environmental well-being.

The biomass related non-utility generators provided new generation capacity when energy demand was growing. It is capacity that will be available to support Maine's emerging economic recovery. The shift away from utility constructed power plants has reduced the costs and the risks associated with conventional power plant construction and operation. These power purchase contracts with non-utility generators have also allowed utilities to take advantage of relatively short construction times (usually two years compared with six to ten for traditional power plants).

101. Taken from a letter to Economic Research Associates from Pete Champagne, owner of Lisbon Falls Getty Service Station, dated November 9, 1993.

Early concerns about the biomass electricity industry revolved around their overall reliability. In short, utility planners were worried about whether they would continue to meet their contractual obligations and provide an efficient, clean, and reliable energy resource. Despite these concerns, the biomass shortages and escalating biomass prices have not materialized. In fact, the average price per ton of biomass chips has remained relatively constant for the last decade. Greater emphasis on improving forest management practices is taking hold and new markets for previously unutilized forest products have emerged.

Biomass facilities and energy efficiency investments are helping the state meet its energy, environmental and economic goals

As these case studies indicate, biomass facilities to generate electricity and energy efficiency investments both are helping the state meet its energy, environmental and economic goals. They have significantly reduced the state's dependence on imported oil; reduced air emissions from existing utility facilities; contributed to reductions in greenhouse gases; helped increase the life of existing landfills; and provided numerous incentives for many of Maine's industries to become more efficient and more profitable.

This emerging energy services industry has also provided substantial benefits reflected in state and local employment opportunities, annual in-state expenditure patterns, property and sales tax revenues and new construction. In addition to the direct employment and expenditures, the "multiplier effects" of this new industry now supports as many as 6,000 jobs within the state of Maine. This is nearly twice the total number of employees supported by conventional utility expenditures.[102]

The biomass facilities served an important supply function in the late 1980s and early 1990s. The downturn in the state's economy, however, coupled with accelerated efforts to conserve energy created a surplus power supply. This led in 1993 to the termination of several facility contracts totalling almost 6.5 percent of the contracted MW capacity. For a summary of these facilities and their current operating status see Table 3-7, on the following page, titled *Maine Non-Utility Biomass Electricity Generation*.

102. The multiplier effects of the new energy services industry and the conventional utility industry are discussed more fully in chapter 6 of this report.

TABLE 3-7. MAINE NON-UTILITY BIOMASS ELECTRICITY GENERATION (UTILITY PURCHASES) FOR 1992

Category	Number of Facilities	Facility Capacity MW	Utility Contract Capacity MW	Utility Purchases MWh	Utility Purchases Dollars
Stand-Alone (Biomass)					
Existing	7	170.0	161.9	854,529	$117,025,217
Terminated (1992 last year of sales)	3	32.0	27.2	168,121	$14,925,534
Subtotal	10	202.0	189.1	1,022,650	$131,950,751
Cogeneration (Biomass/multi)					
Existing	8	362.0	274.3	2,144,011	$162,893,206
Terminated (1992 last year of sales)	2	2.3	2.3	3,131	$274,248
Subtotal	10	364.3	276.5	2,147,142	$163,167,454
Total	20	566.2	465.6	3,169,792	$295,118,205

Notes: The information contained in this table is derived from personal communications with representatives of the Maine State Planning Office, utility representatives, industry representatives, and data contained in FERC Form I reports for Maine utilities. The Total "Capacity MW" reported does not include the 26.7 MW capacity of the Down East Peat LP facility (which is one of the plants terminated in 1993) since very little of the plant's capacity was contracted for by a Maine utility and the actual utility contract capacity was not available at the time this report was being written. In general, totals in this table may not add up due to individual rounding.

On a cost per kWh basis, energy efficiency programs provide even greater economic benefits than current biomass facilities. For instance, whereas non-utility generators are providing power at an average of 9.1 cents per kWh, customer energy efficiency programs save electricity at an equivalent of 4.9 cents per kWh.[103] Based upon current CMP program design, energy efficiency programs will save CMP's residential, commercial and industrial customers in excess of 486,000 MWh each year. This is about 15 percent of the 1992 production from biomass facilities shown in Table 3-7. For a summary of the projected DSM savings, see Table 3-8, titled *Central Maine Power Energy Efficiency Purchases*.

103. The non-utility generator costs are taken from 1992 data found in chapter 5 of this report, while the cost of electricity savings are 1992 working estimates derived from documents provided by CMP.

TABLE 3-8. CENTRAL MAINE POWER ENERGY EFFICIENCY PURCHASES		
Category	**Number**	**Projected Savings (MWh)**
Energy Service Company contracts		
Residential		
Existing	1	50,000
Completed (in 1991)	1	25,000
Commercial/Industrial		
Existing	2	120,000
Completed (in 1991)	2	55,000
Other DSM Programs (through 1992)	n/a	236,000
Total Program Activity	6+	486,000

Notes: The information contained in this table is derived from personal communications with John Lynn, an energy conservation program representative at Central Maine Power Company, various industry representatives and documents.

In addition to the obvious energy savings, these programs have helped to establish an energy service industry in Maine. Maine residents and businesses alike have reaped the benefits of the new jobs which were created by these companies (installing the energy technologies) as well as the additional dollars spent for materials and services. These expenditures, coupled with the annual utility customer dollars saved — from reduced consumption — are contributing to on-going growth in other sectors of the economy.

Although the state as a whole has benefitted from this non-utility energy industry growth, more obvious are the positive impacts on the numerous rural communities - now home to these energy producing facilities and energy saving companies. Biomass and conservation related employment have provided a stable income base and tax revenues for these communities in what many characterized as "good times" and more recently during recessionary times.

Recessionary times have hit all of Maine's communities hard since 1989, but in communities with already limited opportunities the impacts seem far worse. The deterioration of the real estate market, bank failures,[104] closures of military installations and long standing businesses, and the widespread reductions in consumer and industry spending resulted in the loss of almost 25,000 jobs statewide between 1989 and 1991. This 3.49 percent decrease in total employment compares with a decrease of only 0.48 percent for the U.S. as a whole.[105]

In reviewing Maine's economy and the faster than expected economic growth in the U.S., Maine's Consensus Economic Forecasting Commission noted that the longer term outlook for economic growth in Maine is optimistic, however they also added "...Maine's economy is now entered on a growth path that is below not only the trend of the late 1980s but also of the average growth trend from 1976-1992."[106]

Renewable energy will ensure that more of Maine's energy related dollars stay in Maine

Based on these forecasts, the contributions from the biomass related industries, as well as that from energy service companies, will be needed to help Maine businesses through the anticipated slower economic growth period in the years ahead. Continued investment in renewable energy technologies and energy efficiency improvements will help ensure that

104. Like other industries in Maine, the financial institutions have also been hit by the recession. Foremost among these is Maine Savings Bank. Riding the boom of the 1980s, the bank invested heavily in commercial real estate. The declining economy and depressed real estate market was evident in half completed construction projects and the sharp increase in the number of non-performing loans by project developers and contractors . Banks were forced to foreclosure and in many instances (specifically Maine Savings) they were unable to market the properties - which eventually led to the failure of the institution. This information is based on personal communications with Chris Pearson, a representative of the Maine Bureau of Banking, in September 1993.

105. These figures are based on calculations using total employment data for the state of Maine and the U.S., compiled by the U.S. Department of Commerce, Economics and Statistics Administration, Bureau of Economic Analysis, Regional Economic Information System, Washington, D.C., and reported in their series titled *Full-time and Part-time Employment by Industry (SA25), 1969-1991*, September 1992.

106. See Richard Brace, Charles S. Colgan, Michael Donihue, Laurie LaChance, and Raymond Monahan, *Report Of The Consensus Economic Forecasting Commission On The Outlook For The Maine Economy, 1993-1995*, April 28,1993, page 2. This report was prepared at the request of the Governor.

most of Maine's energy related dollars stay in-state, rather than being spent on non-indigenous energy resources with few benefits to Maine's residents.

The implementation of PURPA and the importance of the biomass electric industry is further emphasized in the key findings of a recent study on income and job benefits of using wood and other biomass resources to produce electricity in the United States. The authors note, "With much of this activity in the rural sector, biomass power can be a substantial pathway for revitalizing rural America."[107]

107. See Meridian Corporation and Antares Group Inc., "Economic Benefits Of Biomass Power Production In The U.S.," *Biologue*, September/December 1992, page 12. The study was completed for the U.S. Department of Energy's Biomass Power Program.

4.0 ENERGY & ECONOMIC OVERVIEW

4.1 INTRODUCTION

Energy is the lifeblood of the economic process. It is needed to power office equipment and transport both people and freight. It provides light, heat and air conditioning for homes, schools and businesses. It is a critical ingredient for a diverse set of consumer goods that range from medicines and plastics to food and clothing.

In 1992, Maine residents and businesses spent about $2.8 billion for all of their total energy use. The annual energy bill represents about 12 percent of the state's personal income in 1992, or about $2,200 for every person in the state.

On a per capita basis, Maine uses only about 91 percent as much energy as the United States as a whole. But average energy prices are about 14 percent more expensive than for the United States. Meanwhile, per capita income is only 90 percent of the U.S. average. The end result is that families and businesses in Maine spend about 20 percent more of their income budget for energy than does the average U.S. resident or business.[108]

A growing concern is the impact of alternative energy strategies on electricity prices.

There is a growing concern in Maine about the impact of alternative energy strategies and generation facilities on the price of electricity. One example of this concern is a 1992 petition filed with the Maine Public Utilities Commission (PUC). In essence, the formal petition asked for an investigation into Central Maine Power (CMP) Company's contractual arrangements with alternative generation facilities.

108. The state's total energy expenditures for 1992 are calculated by the American Council for an Energy-Efficient Economy using data supplied Edison Electric Institute and the Energy Information Administration. The population and income data are taken from the Bureau of Economic Analysis, U.S. Department of Commerce.

The impetus behind the petition was that if the investigation led to cheaper power contracts, this would lead, in turn, to cheaper electricity prices. In response to that petition, CMP representatives noted that the PUC had previously "found that these activities had 'benefitted ratepayers and shareholders by lowering costs, broadening alternatives and reducing risk.' Nothing has happened since to undermine those conclusions."[109]

But to better understand how the current policies contribute to higher electricity prices (or not), a framework for that analysis needs to be created. The purpose of this chapter is to briefly explore the economic setting of Maine. That is followed by a review of how energy — specifically electric energy — is used and produced in the state and what its costs are.

4.2 Economic Profile of Maine

Energy consumption and expenditure patterns depend upon the social and economic make-up of a state or region. In general, the greater the population, employment and income levels, the greater use of energy. CMP, for example, uses these kind of variables to forecast the sales of electricity within its service territory.[110] The first step in this analysis, therefore, is to understand something about the profile of Maine's population and the nature of the state's economy.

4.2.1 Population and Income

The historical population and income levels for Maine are summarized in Table 1 of Appendix B. Based upon that data, Maine's population rose from 997,000 persons in 1970 to 1,250,000 people in 1992. This is a 24 percent increase since 1970. By comparison, the U.S. population rose by 25 percent in that same period.

Interestingly, Maine has a higher percentage of adults with a high school degree than does the U.S. — 78.8 percent of persons 25 years old and over in 1990 versus 75.2

109. Letter from Arthur W. Adelberg, CMP attorney, to Mr. Charles A. Jacobs, Administrative Director, Maine Public Utilities Commission, Docket No. 92-123, May 1, 1992, page 3.

110. See, *Prefiled Testimony and Exhibits of Laurie G. Lachance*, sales forecast testimony on behalf of CMP in PUC Docket No. 92-345, March 1, 1993. Since that testimony, Ms. LaChance has accepted a position with the Maine State Planning Office.

percent, respectively. On the other hand, only 18.8 percent of Maine's adults have a bachelor's degree or higher compared to 20.3 percent for the U.S.[111]

In 1980, Maine's per capita income of $8,218 was only 83 percent of the average per capita income in the U.S. By 1992 this figure had risen to a record high of $18,100, about 90 percent of the U.S. level for that year.[112] As mentioned later in the chapter, this 120 percent increase in the per capita income is at least partly responsible for the 28 percent increase in per capita electricity consumption since 1980. Again for comparison, the per capita electricity usage for the nation as a whole increased by only 17 percent in that same 12-year period.

In 1992, Maine's per capita income of $18,100 was 90 percent of the U.S. average.

TABLE 4-1. SELECTED POPULATION PROFILE DATA

Category	United States	New England	Maine
Rural Population (% of total)	24.80%	25.60%	55.40%
Population Density (per square mile)	71.3	210.1	40.0
Persons Per Household	2.63	2.58	2.56
Dependency Ratio	45.3%	58.9%	62.9%

Source: *U.S. Statistical Abstract 1992*, using 1990 Census data found in a variety of tables.

As shown in Table 4-1, Maine is a highly rural state with more than half of its population located in non-urban areas. This is more than double the ratio for both the

111. See, *Statistical Abstract of the United States 1992* (Washington, DC: Bureau of the Census, U.S. Department of Commerce, 1992), as downloaded from the Census electronic bulletin board as spreadsheet file ME.WK1.

112. It should be noted that when the income levels are discounted for inflation, the level of per capita income actually peaked in 1989. Again, see Table 1 of Appendix B.

U.S. and the New England region. Further highlighting this point is the extremely low population density (measured as the number of persons per square mile) compared especially to New England. Maine also has a slightly smaller number of persons living in a household than the U.S. average. One factor that can influence per capita income and economic vitality is the state's dependency ratio. For purposes of this chapter, dependents are defined as residents less than 18 years of age and more than 64 years of age. The dependency ratio reflects the total number of dependents as a percent of a region's working age population.

Using this benchmark, the United States has a dependency ratio of about 45 percent. New England's dependency ratio is 59 percent. Maine shows a ratio of 63 percent — about 40 percent larger than the U.S. figure. In other words, there is a larger population of dependents in the state. This, by definition, tends to lower the per capita income for the region.

4.2.2 Employment Patterns

A detailed 1992 summary employment profile for Maine is provided in Table 2 of Appendix B. In 1992 the Maine economy supported nearly 687,000 jobs. Measured on a per capita basis, the employment level in the state compares favorably to the United States as a whole.

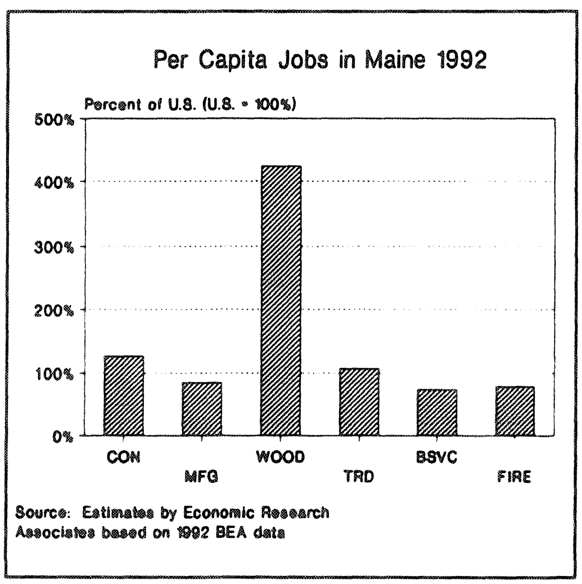

Figure 4-1

In 1992, the Maine economy supported 103 percent of the per capita number of jobs as in the U.S., including both wage and salary workers, proprietors and the self-employed. A surprising source of strength is the number of non-farm proprietors in the state, about 39 percent above the national average.

Figure 4-1 illustrates the 1992 job intensities in selected Maine economic sectors. The chart indexes Maine's per capita employment in each sector to that of the United States. Sectors having a per capita job intensity greater than 100 percent are those which provide more employment compared to same sectors in the United States. Similarly, those sectors with a per capita employment of less than 100 percent provide fewer jobs compared to those same sectors for the nation as a whole.

Table 4-2. Gross State Product for the U.S., New England and Maine (in Millions of 1989 Dollars)

Sector	United States		New England		Maine	
	GSP	Pcnt	GSP	Pcnt	GSP	Pcnt
Farms	88,587	1.72	1,505	0.48	311	1.32
Ag/Forest Svcs, Fishing	24,896	0.48	1,908	0.61	354	1.51
Mining	80,254	1.55	232	0.07	12	0.05
Construction	247,721	4.80	16,326	5.23	1,739	7.41
Manufacturing	965,997	18.70	62,580	20.06	4,527	19.29
Transportation/Utilities	460,863	8.92	22,219	7.12	1,909	8.13
Wholesale Trade	339,468	6.57	21,352	6.84	1,314	5.60
Retail Trade	485,979	9.41	30,929	9.92	2,609	11.11
F.I.R.E.	896,652	17.36	57,588	18.46	3,984	16.97
Services	970,539	18.79	67,903	21.77	3,876	16.51
Government	603,805	11.69	22,388	7.18	2,840	12.10
Total	5,164,671	100.00	311,942	100.00	23,474	100.00
Per Capita	20,925	n/a	23,664	n/a	19,241	n/a

Notes: The term "F.I.R.E." refers to finance, insurance and real estate. "GSP" refers to Gross State Product while "Pcnt" refers to the sector's percent of total GSP for its given region, whether the U.S., New England, or Maine.

Source: 1989 data from the U.S. Department of Commerce, Bureau of Economic Analysis, Washington, DC.

Based upon Figure 4-1, the state's economy shows surprising strength in a number of sectors, namely construction, lumber and wood products (including pulp and paper mills), and trade (including wholesale and retail trade). The state is a little weaker, however, in manufacturing activities other than the wood products industry, in business services, and in the finance, insurance and real estate (F.I.R.E.) sectors.

4.2.3 Other Economic Indicators

Table 4-2, on the previous page, contains data on the Gross State Product (GSP) for the United States, New England and Maine. Comparison of these figures offers yet another insight into how the state uses energy as part of its economic process. Most notable is Maine's per capita GSP. At $19,241, the state's share of the economic pie is 92 percent of the U.S. average and only 81 percent for the New England region.

While we might note that Maine has roughly the same employment intensity as the U.S., its per capita GSP is significantly lower. This is an indication that the state's energy intensity is also smaller than the U.S. As is shown in Table 4-3, this is the case. There, the per capita energy use in Maine is only 293 million Btus (MBtu) compared to 322 MBtu at the national level.

TABLE 4-3. 1991 PER CAPITA REGIONAL ENERGY USE (IN MILLION BTUS)

End-Use Sector	United States	New England	Maine
Residential	64.9	64.3	64.0
Commercial	51.6	51.8	47.3
Industrial	117.4	45.3	96.5
Transportation	87.7	65.7	85.5
Total	321.7	227.0	293.3

Source: This data is taken from the *State Energy Data Report 1991* (Washington, DC: Energy Information Administration, U.S. Department of Energy, DOE/EIA-0214(91)), May 1993.

What is surprising about Table 4-3, however, is the extremely small per capita energy use of 227 MBtu for the New England Region. This means that New England uses 23 percent less energy per capita than Maine even though its per capita GSP is 23 percent larger. The implication is that New England is able to obtain a higher level of value-added product per million Btus compared to Maine.

Part of the gap in the New England energy intensity can be explained by Maine's higher transportation uses, reflecting a substantially larger rural population and smaller population density (shown in Table 4-1). Still, the industrial energy use is an even more significant difference. To get at the heart of that difference, we need to examine the mix of industrial activities as shown by the employment patterns.[113]

It turns out that Maine has significantly stronger employment levels than New England in several energy-intensive industries — including lumber and pulp and paper products. New England, on the other hand, has a stronger presence in higher-value added, high tech industries that use more secondary manufacturing processes which are less energy-intensive.

4.3 Electricity Use Patterns in Maine

4.3.1 Electricity Consumption

Table 3 in Appendix B maps out the historical electricity consumption in Maine since 1970. Based upon that data, several key indicators can be created. Table 4-4, on the following page, summarizes this information for two different periods of time. The first is for the years 1970-1992 to provide a full historical perspective of electricity sales. The second embraces the mid-1980s to compare the period of accelerated growth in Maine with the longer historical view. Much of the planning for the current generation of alternative energy facilities was based upon the growth of electricity usage in the latter period.

113. Although not shown in this report, the same employment data shown for Maine in Appendix 3-A-2 is also available for the New England region.

TABLE 4-4. KEY ELECTRICITY CONSUMPTION INDICATORS

End-Use Sector	1992 GWh Sales (%)	1970-1992 Growth Rate (%)	1981-1989 Growth Rate (%)
Residential	3,830 (34%)	3.7%	3.5%
Commercial	2,719 (24%)	4.7%	5.9%
Industrial	4,748 (42%)	3.2%	3.8%
Total	11,297 (100%)	3.7%	4.2%

Source: Historical data contained in Appendix 4-A-3. Note: The term "GWh" means gigawatt-hour, or one million kilowatt-hours.

In the period 1970-1992, electricity consumption grew at an annual rate of 3.7 percent compared to a 3.1 percent in the U.S. as a whole. The mid-1980s were a period of a particularly robust growth, averaging a 4.2 percent annual increase. During this same period in the U.S., electricity consumption grew by only 2.6 percent.

During the 1980s Mainers did not appear to be especially price sensitive with respect to electricity sales. For instance, in evaluating the total growth in kWh sales in the period 1984 through 1992, it appears that each 10 percent increase in the price of electricity lowered demand by only 1.0 to 1.2 percent.

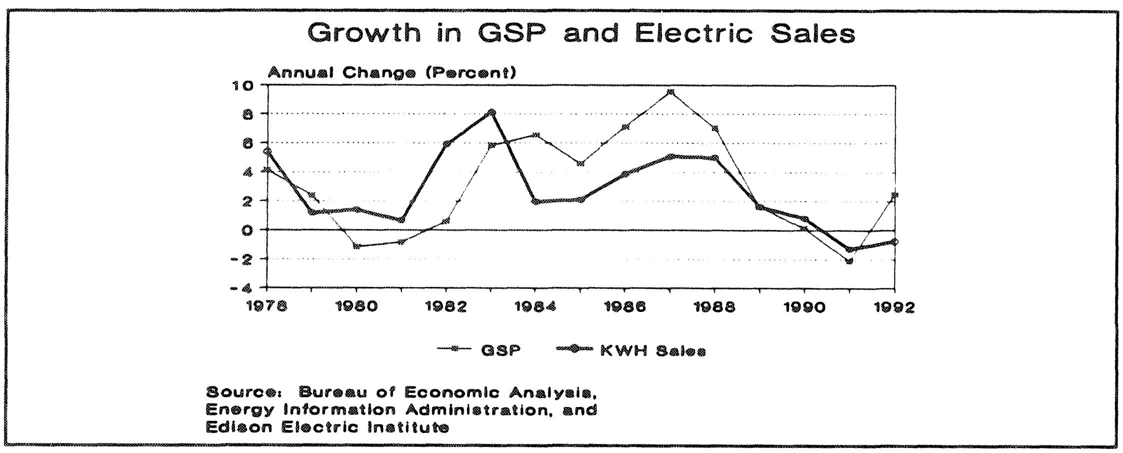

Figure 4-2

At the same time, each 10 percent increase in the state's GSP appears to have prompted a 5.2 percent increase in electricity sales.[114] In other words, a 10 percent growth in state income has about five times the effect on electricity sales as a 10 percent increase in electricity prices. These findings are similar to those established by Central Maine Power in its own forecasting model.[115] Figure 4-2, on the previous page, also shows this correlation by tracking the annual percentage changes in GSP and electricity consumption.

The so-called "boom" years in the 1980s show a particularly strong link between GSP and electricity sales. Fueled by the robust economic activity in the mid-1980s, it appears that Mainers were, in effect, playing catch-up with their U.S. counterparts. The state's per capita use of electricity for all uses rose from 5,083 kilowatt-hours (kWh) in 1970 to 9,287 kWh in 1992.

This growth increased per capita usage levels from 74 percent of the national consumption in 1970 to 86 percent by 1992. Again, as Figure 4-2 illustrates, the trend mirrors the changes in the Gross State Product and personal income during that period of time.

4.3.2 Electricity Production

Historically both Maine and the New England states have depended heavily upon oil-fired electricity generation. Following the 1973-74 Oil Embargo and growing concern about environmental issues, there was a clear mandate to reduce the state's petroleum dependence.

In achieving this goal, Maine was quite successful. As one utility stated in its 1991 annual report: "Maine has established itself as a national leader in energy policy that aims at reduced oil

Maine has established itself as a national leader in renewable energy policy

114. This phenomenon is referred to as price and income elasticities. As part of this study, the American Council for an Energy-Efficient Economy (ACE^3) completed a brief analysis of the impact of price and income on Maine's electricity consumption. The ACE^3 review suggests a typical value of -0.096 and +0.518 for price and income elasticities, respectively.

115. See, for example, *February 1993 kWh Forecast Update: Documentation* (Augusta, ME: Economic & Load Forecasting Department, Central Maine Power, February 1993). According to CMP, the residential sector is shown to have price and income elasticities of -0.12 and +0.21, respectively. On the other hand, the commercial sector is shown with elasticities of -0.16 and 0.62, respectively.

reliance, increased diversity, promotion of renewable resources, and a priority for cost-effective conservation."[116]

Two other observers noted that "the combination of Maine's heavy reliance on imported oil, the 1979 [sic] Public Utilities Regulatory Policy Act, and an abundance of otherwise unusable wood left by a century of human and natural changes made Maine a national leader in wood utilization for electricity production."[117]

As noted previously, the period from 1987 to 1992 was the critical period of development for alternative generating facilities. In 1992 the installed electric generation capacity was 2,107 megawatts (MW). The non-utility generators (NUGs) provided 672 MW of total capacity, or about 32 percent of total plant capacity.[118] Much of this capacity is in the form of biomass generation. Table 4-5 outlines the evolution of Maine's generation mix for the years 1987 and 1992. It is shown as a percent of total megawatt-hours (MWh).

The most significant change shown in the Table 4-5, on the next page, is the movement away from oil-fired capacity and the increased purchase of non-utility generation. While generation of oil-fired electricity dropped from 28 to 16 percent in the period shown, NUG purchases increased from 13 to 34 percent, respectively. Nuclear capacity decreased slightly in this same period. At the same time, the outside purchases from Canadian sources and the New England Power Pool also decreased their shares of the Maine generation capacity.

116. *CMP Annual Report 1991* (Augusta, ME: Central Maine Power Company, 1991), page 3. CMP went on to say that "CMP supports those policies. We have more than 80 contracts in force for non-utility purchases."

117. Charles S. Colgan and Lloyd C. Irland, "The Sustainability Dilemma: Observations from Maine History," *Toward a Sustainable Maine: The Politics, Economics, and Ethics of Sustainability* (Edmund S. Muskie Institute of Public Affairs, University of Southern Maine, 1993), page 68.

118. The 1992 generation capacity data is taken from the *NEPLAN CELT Report* (Boston, MA: New England Power Pool, April 1993), and from a personal communication with Carroll Lee, Vice President - Operations, Bangor Hydro-Electric Company, November 30, 1993.

TABLE 4-5. GENERATION MIX OF ELECTRIC CAPACITY (PERCENT OF TOTAL MWH)

Type	1987	1992
Hydropower	13%	15%
Nuclear	22%	26%
Oil	28%	16%
Purchases	25%	9%
Non-Utility	13%	34%
Total	100%	100%

Source: Estimated from various annual reports for Central Maine Power, Bangor Hydro-Electric, and Maine Public Service Companies.

4.3.3 Electricity Prices

In 1984 CMP projected the average current price of electricity to rise from about 6.0 cents per kWh in 1982 to 10.7 cents in 1992. When adjusted for the expected inflationary trends, however, the company also indicated that real prices would remain nearly constant within that same time-frame.[119]

Fortunately for Maine, actual prices remained below the forecasted level with CMP's average 1992 price climbing to only 8.9 cents (in current dollars).[120] The statewide average price rose to only 9.05 cents per kWh. While less than originally forecasted in 1984, Maine's electricity prices remain 32 percent higher than for the U.S. as a whole.

119. See, "Prepared Direct Testimony and Exhibits of Darrel R. Quimby," on behalf of Central Maine Power Company, PUC Docket 84-120, August 31, 1984, Table 20.

120. *CMP Annual Report* (Augusta, ME: Central Maine Power Company, 1992), pages 44-45.

New England historically has had relatively high electricity prices compared to the nation. Within the New England region, Maine has the second lowest price based upon total customer sales. This comparison is shown in Table 4-6.

Table 4-6. 1992 Customer Sales and Prices

Region	Total Customer Sales		Residential Customer Sales		
	Average Customer Use (kWh)	Average Revenue (Cents/kWh)	Average Customer Use (kWh)	Average Revenue (Cents/kWh)	Percent of Total Revenue
United States	24,331	6.84	9,383	8.20	120%
New England	17,136	9.74	7,000	10.88	112%
Maine	17,617	9.05	6,627	11.37	126%
New Hampshire	15,065	10.21	6,962	11.36	111%
Vermont	16,500	8.93	7,506	9.71	109%
Massachusetts	17,086	9.66	6,640	10.62	110%
Rhode Island	14,550	10.30	6,043	11.18	109%
Connecticut	18,752	10.04	8,003	11.07	110%

Source: *Statistical Yearbook of the Electric Utility Industry 1992* (Washington, DC: Edison Electric Institute, October 1993), Tables 66A and 67A. The last column is derived by dividing average revenue per kWh for residential customers by the average revenue per kWh for all customers.

Perhaps of more concern to consumers is the average price paid by households. In this regard, Maine is virtually tied with New Hampshire as having the highest residential rate in the region. In fact, the gap between the total customer average and the average residential rate is the largest within the region. As shown in Table 4-6, the residential rates are 126 percent of the average rate for all customers. A review of Table 4 of Appendix B shows this gap to have widened significantly since 1984.

5.0 ALTERNATIVE SCENARIOS

5.1 INTRODUCTION

At this point it is clear that energy efficiency investments, qualifying facilities (QFs), and other non-utility generators (NUGs) are major energy resources in Maine. Moreover, they have "clearly proven they can reliably meet their contractual obligations to supply power to the grid."[121]

But how much has the development of alternative generation projects affected the overall cost of electricity? Materials prepared by CMP have suggested that the state's energy policies are responsible for about two-thirds of the rate increases since 1988.[122] On the other hand, an analysis by a Maine engineering consultant suggests that it is more appropriate to compare today's prices with those *that would have existed* had CMP continued its business-as-usual policies of the early 1980s. In that case, the analysis suggests that ratepayers would have ended up by paying five million dollars more than the current level of expenditures.[123]

It is important to place the question of rate impact in context. The review of past state policies and utility implementation of those policies makes it clear that adverse rate impacts were not expected by either the Maine Public Utilities Commission (PUC) or the utilities themselves. The utility programs to pursue NUG capacity and energy efficiency were designed with the intent and expectation that costs and prices would be lower, not higher.

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121. Comments of John M. Flumerfelt, former Director of Energy Policy, Maine State Planning Office, before the Joint Standing Committee on Utilities, August 27, 1992.

122. Central Maine Power Company, Table entitled, "Components of Revenue Changes Implemented from January 1988 through July 1993 Considering Estimated Impact of DSM Related Lost Revenues and Fuel Cost Savings," provided by Public Advocate Stephen Ward, November 15, 1993.

123. See "Comparison of the Cost of QF purchases with the Capacity Expansion Plan Recommended by Central Maine Power Company," an analysis by Richard Darling for the period 1982 through 1992.

When viewed only from a rate impact perspective,[124] Maine's recent experience, and for that matter, most of New England's experience is a prime example of reasonable and prudent decisions that in hindsight look bad. The entire New England region pursued policies designed to reduce dependence on oil primarily because the cost of oil (and gas) was expected to rise rapidly in the future. Based upon this expectation, utilities around New England made investment decisions. Maine relied upon competitive purchases from NUGs. Other utilities invested in coal conversions or nuclear power. Electricity prices around New England went up as utilities reduced their dependence on oil.

But, contrary to all utility forecasts and the expectations of policy makers, oil prices went down, not up. As things turned out, the benefit of 20/20 hindsight says that the smartest investments in the 1970s and early 1980s were to build new oil-fired power plants and to pursue energy efficiency improvements. In other words, electricity rates would be even lower today if Maine utilities had aggressively pursued energy efficiency on the one hand, and — to meet remaining electricity demand — started buying or building oil-fired power plants while consumers throughout the country were standing in lines at gas stations. Clearly this is not a realistic scenario on either count.

Within this context, the present chapter constructs three alternative resource scenarios that might have occurred had either the Maine Legislature or the PUC acted differently and made different policy decisions. These scenarios were constructed first by examining PUC actions and proposed utility resource plans, and then by identifying and pricing a reasonable mix of alternative (i.e., more conventional) energy supply strategies.

The chapter describes the methodology used to construct the scenarios, describes the three scenarios that were actually constructed, and calculates an estimated electricity rate and bill impact of each scenario compared to the energy choices actually pursued in the state. The rate impact reviews the cost per kilowatt-hour under each scenario. The bill impact explores the change in revenues actually paid by Maine residents and businesses in each scenario. It reflects both the price of electricity as well as the change in consumption levels.

5.2 Methodology

Three steps were taken to identify and understand the basis and impacts of Maine's energy policies since 1978. These are described in the subsections that follow.

124. The tendency is to dwell only upon the rate impacts of various energy policies and utility programs. However, as seen in chapters five and six, despite the modest price impacts there have been substantial economic and environmental benefits for Maine resulting from the state's current energy resource strategies.

5.2.1 Research Design

There were several types of materials used to document the policies and their impacts. PUC Orders describe the policy actions. Utility testimony, exhibits and resource plans were used to understand the utilities' early plans and how their plans adjusted to subsequent PUC orders and decisions. Utility resource plans, submitted periodically to the commission, detail what generating plants and what purchases from outside suppliers (including NUGs), each utility intended to add and retire from its generating capabilities during each year of the planning period. Documents showing actual energy resource selection and costs from other New England states were obtained and used.

The difference between what the utilities originally intended to do, and what they ended up doing, formed the basis for differentiating the "baseline" scenario from the hypothetical, alternative scenarios. The original research design called for constructing a single, alternative scenario. However, after extensive exploration, discussion and input from members of the PAG, it was concluded that the history was too complex and uncertain for one alternative scenario to suffice.

Instead, three scenarios, each representing a plausible interpretation of what might have taken place under different PUC mandates, are created. While it is likely that none of the alternative scenarios would have happened exactly as laid out in this study, they represent *a reasonable interpretation* of different investment patterns that might have been followed. In effect, the three alternative scenarios represent a range of impacts that might have occurred under different policy choices.

5.2.2 Supportable Estimates

Supportable estimates were needed to calculate the amount of energy and capacity that would have shifted from actual energy resource selections to the selections made in the alternative scenarios. This was accomplished for all three alternative scenarios by determining which resources the utilities developed solely as a result of specific PUC actions. Then, assuming there would be no change in energy demand, the capacity acquired directly from these resources was subtracted from the actual generating mix. Each alternative scenario was then built by adding to the mix a combination of resources which the utility might have otherwise pursued.

5.2.3 Production Costs

The costs of producing, purchasing, and conserving electricity are known quantities in the actual scenarios. The corresponding costs for the alternative scenarios, however, must be calculated based not on actual cost information but on estimates. In the same way that each alternative cannot be predicted with 20-20 hindsight, it is not possible to know with precision what construction and operating costs would have been. This problem persists whether Maine utilities would have built their own facilities or purchased power from outside sources. As will be discussed in more detail, related data from inside and outside Maine was used in making cost estimates.

5.3 Key PUC Actions

Both the documentary evidence and discussions with the interested parties indicate that the critical PUC decisions consisted of denying the utilities permission for some generating sources and requiring them to rely on other sources. The decisions below represent the major decisions which most influenced the energy resource choices of the 1980s. They are summarized in Appendix D.

5.3.1 Sears Island Permit Denied

The earliest relevant decision came at the end of 1979 when the commission denied Central Maine Power (CMP) Company's petition for a certificate to construct a 600 megawatt (MW) coal plant at Sears Island (Docket U-3238). Under the proposal submitted to the Commission, CMP would own approximately 80 percent of the unit.

The denial was based on CMP's failure to show that there would be adequate demand for the plant's output and because other supply options, including energy conservation, cogeneration and Canadian purchases had not been adequately explored. Had this plant been approved by the PUC, and built, it would have met a large portion of the energy needs which were later met by other sources. Based upon today's prices it appears that a 300 to 400 MW coal power plant would provide electricity in excess of 7.0 cents per kilowatt-hour (kWh).

5.3.2 Order to Sell Shares in Seabrook

Beginning in 1982 a series of PUC decisions led the three Maine utilities to sell their shares of Seabrook Unit 1 in 1985 to Eastern Utility Association. Seabrook Unit 1 is a

1,197 MW nuclear power plant that was originally to have been on-line in 1983. Con struction and regulatory delays, however, postponed commercial operation until 1990.

The commission felt, as was characterized in the 1982 Maine Public Service Company (MPSC) decision in Docket 81-114, that the investment in Seabrook was not an economical way to meet the future demands. In Docket 84-80 (May 1985), the Commission noted, for example, that because of Seabrook, MPSC's financial condition had been deteriorating to the point where bankruptcy was examined (although not pursued) as an option.

At one point in the review of Seabrook the PUC disallowed approximately 30 percent of the utility investments in Seabrook. At another point, the Commission stated that if the utilities chose to move ahead with Seabrook Unit 1, they could put remaining costs into ratebase, except that they would not be able to charge ratepayers more than a specified amount which would vary in succeeding years, into the next century. These benchmarks were established as part of a May 1985 stipulation in Docket 84-120.

Although it cannot be proven, it is also possible that Maine's actions were an important factor influencing the eventual cancellation of Seabrook Unit 2, in which all three of the utilities also had shares.

5.3.3 Promotion of Power Purchases from Independent Suppliers

Prior to the late 1970s, there was little precedent or expectation that utilities would acquire power from non-utility generators. This changed when the Federal Government enacted the Public Utility Regulatory Policy Act (PURPA) in 1978.[125] This was followed by the enactment of Maine's own version of PURPA in 1979 by the Maine Legislature, the Small Power Production Facilities Act (SPPFA).[126] After extensive hearings, the Maine PUC issued regulations to carry out the PURPA AND SPPFA statutes as Chapter 36 of its administrative rules.

PURPA and the SPPFA required utilities to buy power from independent generating facilities — provided that the facilities met certain, qualifying conditions. Hence, these units came to be known as Qualifying Facilities, or QFs. The degree of QF development has varied greatly from one state to another, depending both on the available resources and on the regulatory environment.

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125. See, Public Law No. 95-617, 92 Stat. 3117, enacted on November 9, 1978. Section 210 of that act encourages the use of cogeneration facilities and independent power production. See, 45 Federal Register 12234, February 25, 1980, promulgating 18 C.F.R. 292.301, et seq (1980).

126. See, 35 M.R.S.A. section 3301, et seq (1988 and Supp. 1992).

One critical condition in the QF or NUG development is the rate the utilities were to pay to purchase power from NUGs. The utility is required by law to pay up to its "avoided cost" — meaning the incremental costs that the utility would have had to incur if the power from the QF was not available. While this is a clear, theoretical concept, commissions across the country have wrestled with the question of how to set equitable avoided cost rates, and there has been on going debate and controversy over this issue. In 1992 Maine utilities paid an average of about 9.2 cents per kWh for non-utility power.

5.3.4 Establishing Avoided Cost Rates

In 1984, in a series of dockets (82-174, 81-276, 83-264, and 83-303), involving MPSC and CMP, the PUC decided that purchases from QFs could substitute for the power Maine utilities would have received as a result of their ownership in Seabrook 1. This meant that the projected cost of Seabrook was the correct basis on which to calculate avoided cost.

The commission modified this basis by stating its belief that CMP, MPSC, and Bangor Hydro-Electric Company (BHE) would not be able to sell their Seabrook shares for the full value of their investments but would likely obtain only about 80 percent of that value.[127] The other 20 percent of investment costs could therefore not be "avoided." Accordingly, payments to QFs would be based on 80 percent of the forecasted cost of Seabrook.[128]

During this period the utilities in Maine and New England believed that Seabrook would be less expensive than oil or other fossil fuel plants. This belief continued even though Seabrook was, at that time, the most expensive power in the pipeline.

The high cost of Seabrook and the prevailing view that alternatives would be even higher, meant that QFs would be offered rates significantly higher than if avoided costs were based on much lower fuel price forecasts. However, lower fossil fuel prices would have also meant that Seabrook made less economic sense. As it turned out, Seabrook became one of the most expensive plants in New England. Had it remained a part of the

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127. The utilities testified that Seabrook was in fact worth 100 percent of both the sunk and projected investment. Has the PUC adopted such a view, the avoided costs would have been higher.

128. MPSC, in fact, argued that since the company already owned a share of Seabrook the plant was not avoidable, that the company therefore had surplus capacity for many years into the future, and so there should be a *zero* capacity component to its avoided cost rates.

resource mix within the Maine utility system, it is likely to have cost either ratepayers or its utility owners in excess of 14 cents per kilowatt-hour.[129]

5.3.5 Option for Levelized Contracts

Developers of non-utility generating plants are concerned not only with the rates that they will receive, but also with how payments will be made over time. Avoided costs are usually expected to increase over time, as fuel and other costs increase, and utilities have new capacity needs. But the capital costs of non-utility plants are often financed by loans that require repayment in level payments over time.

Often the loans to QFs are to be retired within a 15-year period rather than the more normal 30-year amortization period enjoyed by the utilities. Moreover, non-utility generators often have higher costs of borrowing than do the utilities themselves.[130] It is therefore of great benefit to QF developers to be able to obtain larger portions of their payments in earlier rather than later years, even if they receive the same total present value of payments.

To accommodate QF developers, the PUC required Maine utilities to offer rates to QFs which, in large part, were either levelized or otherwise front-loaded. The term front-loaded simply means that a larger part of the total earnings is paid earlier in a contract period. Table 5-1 illustrates the differences between the hypothetical avoided costs of a utility and the levelized and front-loaded costs.

While the three streams of payments may differ in each of the 10 years shown (measured in nominal cents per kilowatt-hour), they have the same equivalent value when discounted and summed on a present value basis. In this manner, QFs can be paid more of their earnings up-front to accommodate lenders who want their money back in 12 or 15 years rather than the 30-year amortization period referenced earlier.

Front-loading is a two-edged sword for ratepayers. Under either the levelized or other front-loaded scenario, ratepayers are required to pay more for their electricity in early

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129. The final installed cost of Seabrook, according to Public Service of New Hampshire, was $5,530 per kilowatt (kW). Assuming a levelized fixed cost rate of 15 percent, the annual capacity cost is $830 per kW. Assuming a 78 percent capacity factor means that Seabrook's levelized capacity cost would be 12.2 cents per kWh. Annual operating cost are about 2.5 cents per kWh. This brings the total cost to 14.7 cents/kWh.

130. For example, Fairfield Energy (reviewed in Chapter 4) borrowed about 80 percent of its needed investment capital at 14.5 percent over a 12-year period. In 1987 when Fairfield went on line, CMP had a weighted cost of capital of 11.2 percent.

years compared to later years. In the example shown in Table 5-1, customers will pay more per kWh in years one through five, but less during the last five years (compared to the actual avoided costs shown). This accommodation for front-loaded contracts did not mean that all Maine QF contracts were negotiated in this manner, however.

TABLE 5-1. COMPARISON OF QF COSTING METHODOLOGIES (IN NOMINAL CENTS PER KWH)

Year	Avoided Cost	Levelized Cost	Front-Loaded Cost
1	7.35	8.90	9.90
2	7.72	8.90	9.70
3	8.10	8.90	9.40
4	8.51	8.90	9.00
5	8.93	8.90	8.90
6	9.38	8.90	8.70
7	9.85	8.90	8.30
8	10.34	8.90	7.90
9	10.86	8.90	7.60
10	11.40	8.90	7.40
Ten-Year Totals	92.45	89.00	86.80
Present Value	54.68	54.68	54.68

Notes: This illustration shows how different payment streams (in nominal terms) over a 10-year period can sum to the same present value. In this case, the illustration assumes a 10 percent discount rate over the ten-year period.

5.3.6 Promotion of Demand-Side Management Services

The commission also pressed the utilities to engage in higher levels of demand-side management (DSM) than they would have otherwise undertaken on their own. DSM refers to utility programs which provide financial and technical assistance to customers as a means to lower their overall electric utility bill. Presumably, the electricity savings will lower costs for both the customer and the utility.

As a result of the Maine Energy Policy Act of 1988 (Docket 88-178, decided on December 22, 1988), the PUC modified and strengthened the rule and retitled it as Chapter 380 of the PUC's rules. Since 1988 the Maine utilities have greatly accelerated their efforts to increase DSM savings.

As will be seen later in this report, DSM tends to provide the cheapest resource to Maine utilities, costing about 4.9 cents per kWh. In 1992 the cumulative electricity savings was in excess of 388 million kWh, about one-twelfth of the generation from QF resources. Because efficiency is considerably more cost-effective than either QF or conventional resources, an accelerated DSM program could have lowered utility bills compared to the customer bills now paid today.

5.3.7 Rejection of Hydro-Quebec

The commission rejected CMP's request to construct a transmission line and purchase 900 MW of power from Hydro-Quebec. The PUC denied the request by stating that CMP had failed to demonstrate that they had sufficiently explored cogeneration and conservation options in order to be sure that Hydro-Quebec (HQ) was the least cost option.

These PUC decisions were made based upon the well-accepted expectation in the 1980s that oil prices and energy demand would continue to rise. Whatever subsequent rate impact occurred, in adopting these policies, the commission clearly believed that they were setting the course for the least cost energy service option for Maine consumers. Based upon CMP records, it appears that Hydro-Quebec would have had a levelized cost of about 9.5 cents per kWh.

In many ways the push for capacity from Hydro-Quebec underscored a number of critical issues advanced by CMP. The key items were: (1) utilities believed that they needed a lot of additional capacity; and (2) they initially thought that Hydro-Quebec was cheaper than QFs. The commission responded to the HQ proposal by saying the utilities should evaluate the need for capacity and they should also go out to bid for its needs to find what would be the cheapest resource. The results of the re-evaluation bidding process was that QF prices were lower than Hydro-Quebec. Moreover, CMP ended up buying less QF and other capacity than originally intended. Had they gone with the HQ proposal (in the absence of PUC policies), electricity prices would be even higher today.

5.4 Alternative Scenarios

The Commission's policies were intended to result in a least-cost purchase of electricity resources. For example the Commission noted that, while utilities are required by PURPA and SPPFA to purchase power from QFs, this fact by itself, however, did not undermine the responsibilities of the electric utility to act as a prudent purchaser within the framework of its statutory obligations.[131] "The Commission has encouraged the development of generating capacity by QF generators *if it was the least-cost option*."[132] (emphasis added)

Despite the best intentions of commission policy and utility planners, the future can turn out to be significantly different from even the best industry forecasts. In this case, two events have dramatically affected resulting QF prices — the unanticipated drop in the price of oil, and the drop in electricity sales brought about by the 1989 depression. To explore the consequences of these changes and the policy lessons to be learned from them, three alternative scenarios were established and compared to the actual "baseline" scenario. Each is described in turn.

5.4.1 Actual Baseline Scenario

The actual electricity resource mix resulted in large part from six critical decisions in which the PUC:

(1) Rejected Sears Island;
(2) Ordered the utilities to sell their shares of Seabrook 1;
(3) Strongly supported the development of QFs;
(4) Set initial QF rates according to the avoided costs of Seabrook;
(5) Strongly promoted DSM; and
(6) Rejected Hydro Quebec.

Table 5-2, on the following page, reflects the amount of power purchased from QFs and the savings achieved by the DSM program for all Maine utilities. QF purchases and

131. "Policy Statement," in PUC Docket 84-45, dated April 4, 1984, page 3.

132. "Examiners' Report, PUC Docket 92-102, dated September 22, 1993, page 19.

DSM programs rose from 17.0 percent of Maine's total electricity sales in 1987 to about 46.2 percent of sales in 1992. QF purchases clearly dominate the total purchases.

TABLE 5-2. HISTORICAL AMOUNT OF POWER PURCHASED FROM QFS AND SAVINGS ACHIEVED BY DSM PROGRAMS (ALL MAINE UTILITIES COMBINED)

Year	QF MWh	DSM MWh	QF and DSM Total	Total Sales MWh	QF and DSM Percent of Total Sales
1987	1,707,222	61,973	1,769,195	10,421,921	17.0%
1988	2,413,249	88,932	2,502,181	10,959,504	22.8%
1989	2,972,937	142,255	3,115,192	11,138,846	28.0%
1990	4,022,459	228,255	4,250,714	11,220,059	37.9%
1991	4,739,015	320,692	5,059,707	11,073,224	45.7%
1992	4,763,716	388,255	5,151,971	11,161,357	46.2%

Note: The data represents the combined sales and purchases of Maine's three investor-owned utilities.

5.4.2 Alternative Scenarios

The three alternative scenarios are constructed on the premise that either a more conventional legislative approach or a more traditional PUC would have allowed market forces to shape energy resources rather than an aggressive energy policy. The three scenarios vary in two ways: (1) in their assumptions as to the degree of QF/DSM development that would have occurred; and (2) what power supply resources would have otherwise replaced the QF/DSM supply.

All three scenarios assume replacement power for the years 1988 through 1992. This time-frame is used because it corresponds on a large scale with the development of QF facilities and DSM programs. As a result, the impact of the legislative and PUC policies would have been felt most strongly in that period.

The scenarios can be summarized as follows. Alternative scenarios one and two assume that Maine would have acquired QF capacity at a similar percentage of total generation capacity as the New England region rather than its historical levels — or 10 percent of capacity versus 22 percent (see Table 5-5 for this comparison). Scenario three assumes no acquisition of QF power. This third scenario is undertaken for three reasons:

1. It is generally consistent with the views and forecasts of Maine utilities in the relevant years.

2. It is consistent with much of the rest of the nation. Maine likely inspired construction of most of the QFs in the region suggesting that the regional figure of 10 percent might be too high.

3. By assuming that Maine received no contribution from QFs, the full economic and environmental effect of the facilities that were built can be better measured (in Chapters 6 and 7).

All scenarios assume no utility DSM investment. In other words, they reflect only the electricity savings induced by market prices and program activities not operated by or connected to utility investments. Table 5-3, on the following page, describes the replacement sources under each of the three scenarios.

Seabrook Unit 1 is the one replacement resource used in all three scenarios. It enters the scenarios in 1990 based on the actual on-line service date. Prior to 1990, Canadian power fills the resource gap. In scenario one, the planned coal plant at Sears Island meets most of the remaining power capacity needs, with oil purchases and hydropower development making up the balance.

Scenario two assumes that Sears Island was either not begun or terminated at some point during construction. Instead, the balance of the supply needs come from Canadian purchases.

In Scenario three, where QFs supply none of the power, the replacement needs are much higher. Replacement supplies are dominated by Sears Island and Canadian purchases. Hydroelectric power makes a small fraction of the replacement sources. Table 5-3 aggregates the replacement resources for all the utilities. However, each utility varies in how they would need and acquire replacement power.[133]

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133. For individuals wishing to obtain the detailed assumptions and the individual utility data and impacts that fed into the statewide analysis, contact Skip Laitner, American Council for an Energy-Efficient Economy, at (202) 429-8873.

Table 5-3. 1992 Displacement Levels
All Maine Utilities Combined
(All Values in Megawatt-Hours)

Scenario	QF Replaced	DSM Replaced	Replacement Resources					
			Seabrook	Sears Island	Baseload Coal	Small Hydro	New Oil Purchases	Canadian Power
Scenario 1	2,598,391	388,255	734,714	1,741,488	188,975	90,556	230,913	0
Scenario 2	2,519,335	388,255	655,659	0	188,975	0	0	2,062,957
Scenario 3	4,763,716	388,255	767,580	1,774,502	346,454	171,696	0	2,091,739

5.4.3 Cost of Replacement Energy

Table 5-4 below describes the estimated costs of replacement resources. The basis for these numbers is described elsewhere in the text.

TABLE 5-4. REPLACEMENT COSTS FOR CONVENTIONAL ENERGY RESOURCES (CENTS/KWH)

Year	Seabrook One	Sears Island	Oil Plant	Milford Hydro	Veazie Hydro	Basin Mills Hydro	Canadian Power
1988	0.0	7.7	6.6	7.8	9.4	11.9	5.8
1989	0.0	7.6	6.6	7.6	9.2	11.6	6.0
1990	8.2	7.5	6.6	7.4	9.0	11.4	5.6
1991	5.7	7.4	6.7	7.2	8.7	11.2	6.1
1992	8.5	7.2	6.7	6.9	8.4	10.9	6.3

5.4.4 Derivation of Quantity and Cost Estimates

Both the replacement costs (shown in Table 5-4) and the replacement quantities for each resource (Table 5-3) are described below. For each year of each alternative scenario we calculated the total QF and DSM capacity and energy contribution in the actual scenario that would have to be replaced in those alternative scenarios. Our point of departure was the QF and DSM energy for which we had sound documented data. The difference between these costs and the costs of the energy supplied from the replacement resources were the "generation cost difference" between actual and alternative scenarios.

Using the same point of departure — QF and DSM energy in the actual scenario displaced by energy from various replacement resources in the alternative scenarios — we also estimated the capacity differences and their costs between actual and alternative scenarios. This required additional information and assumptions, in particular the capacity factors of the various sources of energy in each scenario.

Specifically, in order to estimate differences in capacity provided, and thus additional capacity that must be built or acquired to effect the same contribution to system reserves and reliability across all scenarios, the capacity factor should represent contribution to system coincident peak.

The capacity factor assumptions were:

Seabrook	78.6%
Sears Island	70.0%
Baseload Coal	85.0%
Canadian Purchase	60.0%
Regional Oil	70.0%
Small Hydro	40.0%
DSM	35.0%
QFs - CMP	64.4%
QFs - BHE	60.9%
QFs - MPS	68.4%

The Seabrook, Sears Island, and Regional Oil capacity factors were those assumed in estimating the energy costs of these resources to calculate the generation cost differences between scenarios. For Seabrook, the capacity factor was obtained from Eugene Sullivan at the New Hampshire PUC. His estimate was based on the performance of the plant over the last three years. For Sears Island it was based on the average capacity factor for a new coal plant built in the late 1980s, and for the Regional Oil plant it was based on a distillate combined cycle combustion turbine (CT) plant. For Canadian purchases it is based on judgment of a typical residual oil plant in New Brunswick.

The DSM capacity factor is based upon judgment and experience with DSM programs that have been implemented to date, particularly in the New England region where DSM has a large space heating component. With these capacity factors, assumed constant over the years of our study, peak capacity contributions were calculated for the energy contributions of each resource for each year.

Finally, the QF capacity factors were based on the energy and capacity information available for one year, 1990.[134] Since the QFs are dominated by thermal units that are available on-peak, the installed capacity data are relevant to our calculation. With their capacity factors established for 1990, the peak capacity contributions from the QFs scaled in each year with their energy contributions.

134. *Cogeneration, Small-Power and Independent Power Facilities in New England* (Boston, MA: New England Governors' Conference, Inc., 1991).

Once the capacity differences were calculated, it remained only to estimate their costs. Here we made the assumption that capacity would be made up by a mix of baseload and peaking resources — e.g., a large new coal unit and new or purchased peaking capacity — priced accordingly.

We assumed a simple 50/50 split between these two resource types, applying appropriate annual carrying charges for a 1988 in-service data to get the annual capacity carrying costs and added fixed operating and Maintenance (O&M) costs. Capital and fixed O&M costs were taken from the 1989 *EPRI TAG*. The calculation of the cents per kWh cost of each of the replacement supply resources can be found in the appendices.

Unit Type	Capital Cost	Fixed O&M Cost
New Coal	$1,411/kW	$28.10/kW-year
New CT	$399/kW	$0.80/kW-year

The narrative below is statewide in its focus. More plant-specific information and assumptions follows in the narrative below.

5.4.4.1 Seabrook

Outlining the role of Seabrook Unit 1 in the scenarios is relatively straightforward. Had CMP, BHE, and MPSC retained their ownership of Seabrook, they would presumably be paying the full costs of construction and operation costs of Seabrook. They also would be obtaining an amount of electricity proportional to their original capacity ownership.

Yet, ratepayers today already are paying for part of the initial investment in Seabrook. The reason is that when the Maine utilities sold their respective shares of Seabrook, they were only able to obtain a small fraction of their market investment — approximately 25 percent of their sunk investment. Since the PUC allowed the utilities to recover 70 percent of their losses from ratepayers over a 30-year period, Maine ratepayers are today paying a large fraction of the capital costs of Seabrook 1. Estimates place this amount at about $245 million for all three utilities.[135]

135. Pulling information from a variety of memos and utility annual reports, it appears that the utilities have been able to place the following amount of Seabrook in rate base: MPSC, $45.2 million; BHE, $58.8 million; and CMP, $141.1 million. Their combined sunk costs are estimated at $480.8 million while they were able to obtain about $122.5 million from the sale of their respective shares of Seabrook Unit 1 to EUA Power.

Based on information provided by Public Service of New Hampshire, the final cost was \$5,530 per kW.[136] At this level, Seabrook is substantially more expensive than conventional baseload plants that might have an installed cost of \$1,411 per kW.

To find the incremental cost of Seabrook for purposes of this analysis, we want to know the difference between what today's ratepayers are paying in the absence of Seabrook, and what they would be paying if the three utilities had not sold their respective shares in the plant.

A convenient estimate of the avoided cost is provided by the previously-mentioned stipulation filed with the PUC in May 1985 (PUC Docket 84-120). In short, the stipulation said that ratepayers could be charged no more than the following amounts:

1990	8.18 cents/kWh
1991	5.67 cents/kWh[137]
1992	8.53 cents/kWh

Since the utilities sold their shares in Seabrook — believing that the additional construction costs would bring a higher cost than these annual benchmark prices — the stipulation was used as the basis for the costs found in Table 5-4.

5.4.4.2 Qualifying Facilities

Forecasting (or backcasting) what would have happened to QFs is more difficult. On the one hand, in the absence of the particular policies of the Maine PUC, there would still have been PURPA, so some amount of QF development would still have taken place. On the other hand, during the 1979-1982 time period (or perhaps longer), CMP and other utilities felt that there was no significant amount of cost-effective QF capacity.[138]

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136. This information is also based upon comments provided by CMP (December 6, 1993) and BHE (November 1993) as part of their critique of an earlier version of this chapter.

137. This apparent dip in the 1991 benchmark price is the result of a stipulated agreement. Because of the agreement, however, it effectively becomes the avoided cost for 1991.

138. See, *Sears Island Plant Cogeneration/District Heating Study*, completed by Charles T. Main, Inc. for Central Main Power Company, August 1980, page 2-1. Interestingly, the Main study estimated the overall cogeneration potential to be only 40 MW, or about eight percent of the present level of biomass facilities now on-line in the state. A study for Maine Public Service determined that a wood-fired power plant would cost nearly three times the anticipated cost of the Seabrook nuclear power plant. See, *Economic Analysis of Supply Alternatives*, completed by Stone & Webster Management Consultants, Inc. for Maine Public Service Company, March 1982, page 53.

Also, PURPA was a federal law that applied all over the country and in most states there had been no development.

Recent reports from the National Association of Regulatory Utility Commissioners (NARUC) and the Department of Energy all state that it is PUC policy, not resource availability that affect QF development. For these reasons, it is likely that if lower avoided cost rates were set, the result would have been substantially less QF development.

To help answer the question of how much QF development and at what cost, other New England states were surveyed to find out how much power they were acquiring from QFs (or non-utility generators (NUGs), and what prices they were paying for this power. A summary of this survey is provided in Table 5-5 below.[139]

Table 5-5. Capacity and Prices of Non-utility Generation by State

State/Region	NUG Capacity as Percent of total (1992)	Cents/kWh (1992)
Maine	22	9.2
New England	10	n/a
Connecticut	n/a	7.8
Massachusetts	n/a	6.5
New Hampshire	n/a	11.1
Vermont	n/a	10.1

These cost levels provide a reasonable picture of the range of prices paid in New England for QF power. The table also shows that excluding Maine, the amount of power New England states derive from QFs is roughly 10 percent of their total capacity.

Compared to 22 percent of Maine capacity, other New England states combined derive only about 45 percent of what Maine derives from QFs (10 percent divided by 22 percent). Note here that the difference between Maine's 22 percent QF capacity and the

139. The detailed data on each state's NUG capacity is available from ACE[3] as previously noted.

40 percent QF electricity sales is the results of QFs that are producing at a much higher capacity factor than other existing plants.

In 1992, New Hampshire and Vermont both paid substantially more for QF power than did Maine, while Connecticut paid substantially less, as did most Massachusetts utilities. It is worthwhile to note that for Maine, New Hampshire and Vermont, almost all the QF capacity was provided from biomass (wood) and water (hydropower) sources, and these states all had relatively high costs.

In Connecticut and Massachusetts most of the QF capacity is from fossil-fuel sources (mainly natural gas, with smaller portions from oil and coal) with much lower, but presumably escalating costs. It seems likely that lower prices for fossil-based plants reflect the sharp drops in fossil-fuel prices in recent years. However, when these plants were built, higher fossil fuel prices were predicted. In 1984, for instance, CMP suggested that oil prices would rise to $50 per barrel by 1990 while they, in fact, fell to $21 per barrel.

The evidence from other New England states supports a scenario that Maine might have had much less QF development without the specific PUC policies that occurred. The evidence on pricing is, however, unclear. It could reasonably be argued that the New Hampshire and Vermont data support a finding that prices would have been just as high with any commission. For that reason, it was assumed in alternative scenario one that purchases of QF power would be priced at the same level as in the actual zero. This implies, therefore, a zero rate differential for QFs in scenario one.

However, as a "conservative" evaluation of the impacts of the PUC's policies, meaning an evaluation that maximizes the estimated costs to ratepayers imposed by those policies, the cost of QF power should also be set 2.0 cents lower in each year. This is in line with the lower cost figures for Connecticut and Massachusetts rather than the higher New Hampshire and Vermont costs. This 2.0 cents lower price differential is used in alternative scenario two.

In alternative scenarios one and two, it is assumed that Maine has approximately 45 percent as much QF power as in the baseline case, the same proportion as in New England. In order to test the sensitivity of the results to changes in this proportion, alternative scenario three assumes no QF development would have taken place in Maine. In that scenario, therefore, these resources must be completely replaced by other generating resources.

5.4.4.3 Demand-Side Management (DSM)

In the discussions with the PAG, there appeared to be a general consensus that, in the absence of the PUC's policies, the utilities would have undertaken little or no DSM on their own. Therefore DSM has been set at zero for all three scenarios. In doing this, a relatively inexpensive portion of energy supply, 4.9 cents per kWh in 1992, is removed from the mix.[140] Again, from Table 5-2 it should be noted that the quantity of energy services provided by DSM is only one-twelfth of that provided by QF resources in 1992.

5.4.4.4 Sears Island Coal Plant

The Sears Island coal plant had been the largest single source of future generating capacity included in the early resource plans of both CMP and MPSC. Although the PUC rejected the company's request for permission to build the plant in 1979, the decision was based upon a lack of need at the time. As a result, it remained on the drawing boards for the 1990s.

Without the large-scale advent of QFs, it appears that Sears Island or a plant with similar characteristics (but located elsewhere) would have been the alternative resource that CMP most likely would have pursued. At the PAG meetings, CMP's representative indicated that it was a "close call" whether or not Sears Island would have been built.[141] It was considered reasonable to include Sears Island in the alternative scenarios in part because even if that particular plant had not been built, another coal plant located either in New England or Canada was included in the utility resource evaluations throughout the planning period.

Despite then what appears to be a compelling argument suggesting that power would have been acquired either from Sears Island or from another coal plant, replacement sources for scenarios one and two differ in an effort to accommodate for this difference in opinion. Scenario one assumes the completion of Sears Island and further presumes

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140. The DSM costs identified in the scenarios are based upon the accounting convention used to add and subtract resources for the various scenarios. Strictly speaking, this does not measure the cost-effectiveness of the DSM resource since it is usually amortized over its effective life. In 1992, for example, the three major utilities paid about $18.9 million for all of their DSM programs. The estimated DSM savings for that year was about 388.3 GWh. In that year, therefore, the utilities paid 18.9 divided 388.3, or 4.9 cents per kWh. In 1992 the utilities added a new increment of 67.6 GWh over the 1991 DSM totals. If the $18.9 million were amortized over a 15-year period at a 10 percent discount rate, then life-cycle cost of 1992 DSM increment would be closer to 3.7 cents per kWh.

141. Indeed, the PUC stated that, "in general, we believe that the Sears Island Proposal has considerable merit." See page 55 of the PUC decision in Docket U-3238, December 31, 1979.

that when it came on line, it would cover most of the remaining supply needs for the state. Again, the exact degree to which different utilities would depend on Sears Island varies. [142]

Scenario two assumes that neither Sears Island nor another coal plant would have been built. In this case, all of the non-Seabrook, replacement power comes from Canadian purchases from either New Brunswick or Hydro Quebec. The less expensive of the two options, New Brunswick Power, is used in this and scenario three.

Scenario three which has no QF power, assumes roughly one third of the replacement power comes from Sears Island. Hydro plant construction and Canadian purchases are also included in this scenario.

In Docket #92-102, in response to Data Request #2, item 15, from the Office of the Public Advocate, CMP provided a sheet titled "Comparison of the cost of QF purchases with the capacity expansion plan recommended by Central Maine Power Company." This sheet shows that Sears Island Coal, if put on-line in 1987, would be projected to have a 1991 cost of 7.6 cents/kwh, and a capacity of 240 MW.

To independently estimate the probable costs of power from a completed Sears Island facility, several sources were used. First, using the EPRI Technical Assessment Guide (TAG), the standard costs for a coal-fired plant of 300 MW, with scrubbers, completed in 1989 was estimated.[143]

Fuel prices were based on Tellus estimates made in an earlier study for Vermont. They assumed a 1.2 percent sulphur content.[144] Annual costs for capital and depreciation were based on a 35 year plant life and a 20 year tax life for a steam plant, yielding annual carrying charge rates.[145] This resulted in annual, total costs, including capital, fuel, and O&M, of 7.6 cents/kWh in 1989, dropping to 7.2 cents in 1992. In 1987, CMP's own data suggests the cost of power from a coal fired plant in that year was greater than 7.0 cents per kWh.[146]

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142. This information on the utility-by-utility variance is also available from ACE[3].

143. EPRI TAG 1989 Electric Supply volume, page 7-15. Assumes use of West Virginia bituminous coal.

144. As referenced in the 1992 Tellus forecast of Vermont fuel prices, using actual 1989 prices and a 2.14% annual escalation rate. See Table 2 of report.

145. Taken from the 1989 NEPLAN "Summary of Generation Task Force Long-Range Study Assumptions," by NEPLAN staff and the NEPOOL Generation Task Force, December 1989, Exhibit 14.

146. CMP Table II.B.6, filed in PUC Docket 87-261, October 28, 1987.

5.4.4.5 New Brunswick Power

Throughout the study period there were many purchases from the New Brunswick Electric Power Commission (NBEPC) by Maine's utilities. It is probable that such purchases could have continued on a large-scale, rather than declining level if the supply of QF power had been smaller.

The prices at which such power would have been available in the recent past (and in the future) is less certain. Most of the purchases made during the 1980s were for energy only, not for firm capacity, and therefore were at a lower cost than would have been the case if Maine's utilities were planning on such purchases to meet their long-term needs.

A letter dated October 18, 1985 from the NBEPC to MPSC indicates that power from its Coleson Cove plant would be available at a 1992 price of 5.8 cents/kWh.[147] In Docket 81-276, the primary avoided-cost determination case for Maine's utilities, MPSC's brief argued that the company should not be required to pay QFs more than the 6.5 cents to 7.0 cents levelized cost that it expected to pay for power from Coleson Cove.

5.4.4.6 Hydro Quebec

CMP proposed in the mid- to late-1980s to enter into long-term contracts to purchase power from Hydro Quebec (HQ). Such purchases were controversial and were not approved by the PUC. In Docket 87-268, CMP witness Daniel Peaco estimated that the first-year cost of HQ purchases, as of 1994, would have been 8.3 cents per kWh.

If it is assumed that with less QF power available the utilities would have sought to buy power from HQ sooner than 1994, the offered price might have been lower. De-escalating the 1994 rate of 8.3 cents by a general inflation rate of 5 percent per year, yields a 1990 rate of 6.8 cents/kWh.

This rate is somewhat higher than the rates which the evidence indicates would have been obtained for purchases from New Brunswick. A recent HQ proposal to the State of Rhode Island indicates a border price that has a significant escalation rate and is tied to the price of oil. Adding transmission line costs and line losses suggests a more recent

147. October 18, 1985 letter from New Brunswick Electric Power Commission to MPSC.

HQ price in the range of 5.6 to 6.3 cents per kWh. It is these rates that were adopted for the analysis in this chapter and shown in Table 5-4.[148]

These prices are likely on the low-side. The avoided costs were dropping throughout the period 1988 to 1992. Had CMP entered into contracts prior to 1992, the price for Canadian power would have been higher, not lower. In effect, we are understating the 1988-1992 contract prices by benchmarking them to the 1993 prices.

5.4.4.7 Hydro Plants

BHE provided the study team with copies of its resource plans for each year throughout the 1980s. Until 1980 these plans showed that all expected future capacity would come from nuclear plants at Seabrook and Point Lepreau, New Brunswick. After 1981, the plans showed "New Hydro" contributing to the resource mix and coming on line in 1988 and beyond. By 1985 BHE had two plausible paths of action in their plan, one plan with and without Seabrook 1. In both cases, the company anticipated three new hydro plants coming on line in 1988, 1991, and 1994, with a total capacity of 30 MW.

BHE's representative to the PAG indicated that the planned plants had not yet obtained permits, and thus it was not reasonable to include them as replacements for QFs and DSM. However, he also acknowledged that due to the availability of QF power, BHE had delayed, by at least a couple of years, its permitting efforts. Therefore, it is considered a reasonable assumption that had such plants appeared to be a necessity during the mid-1980s, earlier permitting would have been pursued, and the plants would have been brought on-line earlier. This opinion is corroborated in the Report from the New England Governor's Conference.[149]

For this reason, scenarios one and three assume hydro plants for Bangor at their planned locations in Milford, Veazie and Basin Mills. Costs projections are made based on BHE-provided materials and range from approximately 6.9 cents per kWh for Milford to 11.9 cents for Basin Mills.

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148. Letter from M. Bernard Guertin, Director, External Markets, Hydro-Quebec, to Mr. James J. Malachowski, Chairman, State of Rhode Island Public Utilities Commission, dated January 19, 1993.

149. For example, in the "Short Run (1987-1991) Recommendations for Power Supply," the Power Planning Committee recommended that the Governors urge the electric utilities to locate sites for the placement of new generating units and begin the licensing process, and that they take steps to expedite the licensing process through the appropriate agencies. See, *Progress Report on Implementation of Regional Electricity Plan*, (Boston, MA: Power Planning Committee of the New England Governors' Conference, November 24, 1987) page 13.

CMP also considered the addition of hydro capacity. As cited above in regard to Sears Island, in Docket #92-102, in response to Data Request #2, item 15, from the Office of the Public Advocate, CMP provided a sheet titled "Comparison of the cost of QF purchases with the capacity expansion plan recommended by Central Maine Power Company." The sheet shows projected 1991 costs for a Brunswick Hydro plant of 6.8 cents/kWh and for a Monty Hydro plant of 7.1 cents/kWh, with capacities of 20 MW and 25 MW respectively.[150]

If a large fraction of their QF purchases were to be eliminated from the mix, these capacities would constitute a relatively small portion of CMP's total capacity needs. They are not included in the scenarios, but the cost estimates cited provide further evidence for the reasonableness of the 7.2 cents/kWh estimate of Sears Island as of 1992.

5.4.4.8 Oil Plants

No Maine utilities had plans to construct new oil plants. However, it is quite possible that they would be buying some residual portion of their energy from other utilities, either in the United States or in Canada. Such purchases can be viewed similarly to purchases of power from New Brunswick or Hydro Quebec.

As a check on the likely prices of such purchases, the costs of power from a new combined cycle plant expected to have been completed in 1988 were estimated. Such a plant would have had a cost of approximately 6.7 cents/kWh as of 1992. This is slightly higher than the estimate for the market price of New Brunswick power, 6.3 cents/kWh. Power purchases from oil-fired plants are included only in scenario one and only make up a small portion of the capacity replacement since Seabrook 1 and Sears Island already meet more than 90 percent of the requirements.

5.4.4.9 The Ultrapower Contract

One QF contract on the BHE system required a special accounting treatment that merits individual attention within the three scenarios. This is referred to as the Ultrapower facility, a 49 MW unit that is dispatched for both capacity (MW) and energy (MWh). For example, while it generated 231,618 MWh in 1988, it provided only 18,400 MWh in 1992. At the same time, payments to Ultrapower increased from $3.3 million in 1988 to $8.7 million in 1992. This difference in payments underscores the point that, unlike

150. There is also evidence that 6.8 cents for Brunswick Hydro is based on averaging old and new capacity. The new capacity additions at the dam were more like 12 cents per kWh. Personal communication with David Moskovitz, Regulatory Assistance Project, Gardiner, ME, October 1993.

other QF facilities, Ultrapower has both a capacity and an energy component. Failing to recognize this accounting difference tends to skew the costing of QF facilities which deliver primarily energy rather than capacity.

The Ultrapower contract allows BHE to decide on an economic basis whether to use Ultrapower energy at its cost (about 3.3 cents per kWh), or to purchase energy available from the region. In general, as dispatch of electric generating facilities occurs on an hour to hour basis, the result is a mix of Ultrapower energy and purchased energy over the year. The Ultrapower thus permitted BHE to purchase economy energy on an opportunistic basis; in effect, it was like a dual fuel plant.

The QF energy purchases that are accounted in the annual reports to the Federal Energy Regulatory Commission include only the direct energy (MWh) generated from each QF including Ultrapower, and total costs paid for those purchases. Given the particular character of Ultrapower, the correct cost calculation should include the energy purchases, and their cost, made in the context of this dispatchable facility.

Ultrapower has an availability of about 85 percent on an annual basis. We thus added to the QF energy an amount representing the opportunity purchases necessary to provide the balance of the energy that Ultrapower would generate at an 85 percent capacity factor; we also added the costs of that economy energy at 2.5 cents per kWh. Thus, the Ultrapower QF energy and overall costs include a mix of its own energy at about 3.3 cents and purchased economy energy at 2.5 cents. The QF energy and costs as a whole were also adjusted to include the economy energy and its costs.

When QF energy and costs were subtracted from the actual scenario to derive the energy and costs that would need to be supplemented by other resources in the alternative scenarios, the average price of QFs were calculated including the energy and costs of the economy purchased "against" the Ultrapower capacity. When roughly one-half of the QF energy was subtracted in scenarios one and two, it was (in effect) one-half of the total QF energy — including economy purchases.

In reassembling the replacement energy and capacity to compensate for the QF and DSM energy not taken in the alternative scenarios, the Ultrapower energy and capacity was assumed to be replaced by additional coal-fired power supply, at the cost of Sears Island or its equivalent. This is plausible given the high capacity factor embodied in the Ultrapower QF, and given the character of the utility plans during the period in which these decisions were taken.

5.4.4.10 The Impact of Forecasts on Alternative Scenarios

It is rather difficult to evaluate in hindsight what decisions Maine's utilities would have made. Once construction of generating plants begins, they acquire a great deal of momentum, and utilities are usually reluctant to cancel them. Moreover, even though oil prices stabilized and began dropping (in real terms) during the mid- to late-1980s, most analysts continued to predict that they would begin rising again.

Especially with the forecasted demand for electricity rising rapidly in Maine in the early to mid-1980s, it is likely that prudent utility planners would have committed themselves to constructing generating plants that did not rely on oil for their fuel, rather than gambling on being able to purchase firm capacity at reasonable prices from other utilities' oil-fired plants. Figure 5-1 shows the results of different forecasts that were typical in this period.

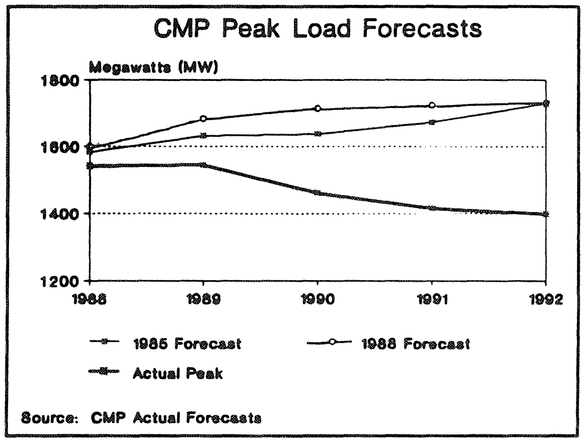

Figure 5-1

In addition, the expectation that energy supplies would be long and that oil prices would be low, flies in the face of the forecasts and wisdom of both the utility industry and the New England Governor's conference. As recently as the mid to late-1980s, utility and government sources warned of an energy supply shortfall in the mid-1990s. The issue dominated the agenda of the New England Governors at that time.

In September 1985 the New England Power Pool (NEPOOL) gave a presentation to the New England Governors' Conference "which raised concern about the ability of the electric utilities in the region to meet the projected demand for electricity in the region through the year 2000."[151]

A year later NEPOOL provided the Power Planning Committee with a short-term 1987-1991 load and capacity scenario because "it is about this more immediate, near-term period that NEPOOL feels the greatest concern about the region's power needs."[152] Then in a letter from NEPOOL to the Power Planning Committee of New England

151. *Progress Report on Implementation of Regional Electricity Plan* (Boston, MA: New England Governors' Conference, Power Planning Committee, November 27, 1987), page 1.

152. *A Plan for Meeting New England's Electricity Needs* (Boston, MA: New England Governors' Conference, December 1986), page 8.

Governor's Conference (November 13, 1987), it was noted that: "New England will have a tight power situation that requires our industry's full attention."

5.5 Impacts on Rates and Bills

This section estimates the impacts of electricity costs on customers bills and rates during the years 1988 through 1992. The fact that the study is structured to focus on the past, rather than on the future introduces a certain type of bias to the results. For any project with high, fixed capital costs relative to operating costs, the inflation-adjusted costs will tend to decline over time. This would apply, in particular, when contracts are levelized or front-loaded, of which there are a number of examples in Maine.

Analyses that extend over a long future period would tend to put the QFs with levelized or front-loaded contracts in a more favorable light. Their costs would tend to decline over time as discussed in section 5.3.5. How favorable these costs would look would depend on the forecasted costs for other resources, especially fossil fuel.

In the last year, 1992, the actual cost of QF power is estimated at 9.2 cents for the three Maine utilities combined. A 4.9 cents rate is used for DSM. Together QFs and DSM cost 8.7 cents.

For the replacement resources, annual costs rather than levelized costs are used. This allows for a better comparison between the actual annual costs from QFs and DSM and the estimated costs for the replacement power. While the specific timing of completion for each of the replacement plants is highly uncertain, for simplicity it is assumed that all plants were completed in 1988.

Due to the impacts of depreciation on the capital cost recovery of utilities, the costs to ratepayers for these plants falls gradually over time, as shown in Table 5-4. For 1992, Seabrook 1 (net of the losses to ratepayers when the utilities' sold their shares of the plant) is estimated to cost 8.5 cents. Sears Island costs 7.2 cents. The hydropower plants planned by BHE range from 6.9 cents to 10.9 cents per kWh.

Canadian power, which as explained earlier use the costs based upon a recent proposal by Hydro Quebec, is 6.3 cents per kWh, making this the lowest cost resource in the mix. Oil-fired power, which could come either from domestic purchases or from a facility owned by CMP, is slightly more expensive than New Brunswick, at 6.7 cents/kwh in 1992.

Once the generation costs are estimated for the alternative scenario, it remains to determine the capacity differences between the alternative and actual scenarios. The assumption is that the utilities would likely have the same level of capacity under both the actual and alternative scenarios. A capacity credit was given to the alternative scenario based upon: (1) the anticipated capacity factors for the replacement resources; (2) the capacity difference between the alternative and the actual scenarios; and (3) the difference in capacity costs as reflected in the mix of resources available in each scenario.

The net cost of each alternative scenario is the generation (MWh) cost less the capacity (MW) credit. The resulting impacts on electricity rates and bills for all of Maine's ratepayers are described in Tables 5-6 through 5-8 on the following pages.[153]

5.5.1 Scenario 1 Impacts

To summarize alternative scenario one, we assume that only 10 percent of the capacity is from QF Power, there is no DSM, and replacement power is largely from Seabrook and Sears Island. Moreover, it was assumed that the Maine utilities paid the same price for QF power in this scenario as in the actual scenario. In other words, the QF price differential between the actual and alternative scenario one is zero.

Table 5-6 shows that the additional cost to ratepayers due to the PUC's policies began at about $5.4 million in 1988, dropping to $5.6 million in 1992. The $5.6 million increase in scenario one reflects the difference between higher generation costs of $29.2 million and a capacity credit of $23.6 million. Under these assumptions, the $5.6 million revenue increase represents only a 4.1 percent impact on rates in 1992.

153. As noted elsewhere, the specific utility impacts are available from ACE[3].

TABLE 5-6. ACTUAL SCENARIO VERSUS ALTERNATIVE SCENARIO 1: ALL MAINE UTILITIES ('000 $)

Year	Generation Cost Difference*	Capacity Cost Difference*	Actual Revenues	Alternative Sales (MWh)	Alternative Revenues	Actual Rate ($/kWh)	Alternative Rate ($/kWh)	PUC Rate Impact	Percent Bill Increase
1988	($107)	($5,321)	$730,828	11,048,436	$736,356	0.067	0.0676	0.1%	-0.7%
1989	$17,593	($8,213)	$775,968	11,281,101	$766,588	0.070	0.0685	2.5%	1.2%
1990	$19,581	($15,434)	$854,226	11,448,314	$850,079	0.076	0.0741	2.5%	0.5%
1991	$41,440	($19,635)	$950,235	11,393,916	$928,430	0.086	0.081	5.3%	2.3%
1992	$29,225	($23,616)	$1,008,295	11,549,612	$1,002,685	0.090	0.087	4.1%	0.6%

Notes:

* Calculated by subtracting the alternative scenario total from the actual scenario total.

TABLE 5-7. ACTUAL SCENARIO VERSUS ALTERNATIVE SCENARIO 2: ALL MAINE UTILITIES ('000 $)

Year	Generation Cost Difference*	Capacity Cost Difference*	Actual Revenues	Alternative Sales (MWh)	Alternative Revenues	Actual Rate ($/kWh)	Alternative Rate ($/kWh)	PUC Rate Impact	Percent Bill Increase
1988	$55,550	($793)	$730,828	11,048,436	$676,072	0.067	0.061	9.0%	8.1%
1989	$75,069	($1,792)	$775,968	11,281,101	$702,691	0.070	0.062	11.9%	10.4%
1990	$91,343	($8,992)	$854,226	11,448,314	$771,874	0.076	0.067	12.9%	10.7%
1991	$114,463	($10,952)	$950,235	11,393,916	$846,724	0.086	0.074	15.5%	12.2%
1992	$92,113	($12,530)	$1,008,295	11,549,612	$928,712	0.090	0.080	12.3%	8.6%

Notes:

* Calculated by subtracting the alternative scenario total from the actual scenario total.

TABLE 5-8. ACTUAL SCENARIO VERSUS CONVENTIONAL SCENARIO 3: ALL MAINE UTILITIES ('000 $)

Year	Generation Cost Difference*	Capacity Cost Difference*	Actual Revenues	Alternative Sales (MWh)	Alternative Revenues	Actual Rate ($/kWh)	Alternative Rate ($/kWh)	PUC Rate Impact	Percent Bill Increase
1988	$15,066	($6,759)	$730,828	11,048,436	$722,522	0.067	0.065	2.0%	1.1%
1989	$44,597	($7,719)	$775,968	11,281,101	$739,089	0.070	0.066	6.3%	5.0%
1990	$59,272	($14,429)	$854,226	11,448,314	$809,383	0.076	0.071	7.7%	5.5%
1991	$105,921	($15,974)	$950,235	11,393,916	$860,288	0.086	0.076	13.7%	10.5%
1992	$83,534	($17,527)	$1,008,295	11,549,612	$942,288	0.090	0.082	10.7%	7.0%

Notes:

* Calculated by subtracting the alternative scenario total from the actual scenario total.

For 1992 the difference in rates under the actual and the alternative scenario is calculated in two steps. First, the alternative rate impact is estimated by dividing projected revenues of $1,002.685 million by the revised sales of 11,549,612 MWh.[154] This yields a new rate of 8.7 cents per kWh. Second, the actual rate of 9.0 cents is compared to the new rate of 8.7 cents, showing a rate impact of 4.1 percent.

In the period 1988 through 1992, the actual rates increased from 6.7 cents to 9.0 cents per kWh, a 35.5 percent increase in that time. Under alternative scenario one, they would have increased from 6.7 cents to 8.7 cents, a 29.9 percent increase. This very small difference suggests that while QF power is partially responsible for rate increases, there are clearly other factors at play.

With the presence of significant DSM spending, however, focusing on rates alone does not provide a fully accurate picture of the impact of the PUC's policies. DSM reduces the use of electricity and, therefore, the utility bills of many customers. To estimate this impact, we need only compare the revenues of the alternative scenario to the baseline or actual revenues. Dividing $1,008.3 million by $1,002.7 million suggests an average bill increase of only 0.6 percent. This means that, under the assumptions established in scenario one, the average electricity bill in Maine rose by less than one percent in 1992 due to the PUC's policies.

5.5.2 Scenario 2 Impacts

Scenario two differs from scenario one in that it relies heavily on Canadian purchases rather than on Sears Island. It assumes that Maine's utilities paid a QF price that was two cents less per kWh than in the actual scenario.

Table 5-7 shows a 1992 rate impact of 12.3 percent rate impact resulting from PUC policies. When the DSM effect is taken into consideration, the average bill increase for Maine's electric utility customers was 8.6 percent in 1992.

5.5.3 Scenario 3 Impacts

In Scenario three we assumed no QF power and no DSM programs. In addition, the replacement power is drawn largely from Sears Island and Canadian purchases. The

154. From Table 5-2 the 1992 actual electricity sales are shown as 11,161,357 MWh. But since we are replacing the DSM sales as well as QF power, the DSM impact of 388,255 MWh are added to actual sales yielding the alternative scenario sales of 11,549,612 MWh.

1992 statewide rate impact shown in Table 5-8 is 10.7 percent. When the effect of DSM expenditures is considered, the bill increase to electric utility customers in Maine was 7.0 percent in 1992.

5.6 CONCLUSIONS

Through extensive historical documentation, discussions with interested parties, and calculations based on actual data and on the resource plans of the state's electric utilities, several significant conclusions concerning the past 15 years of electric utility regulatory policy in Maine can be drawn.

The most critical energy policies in Maine — or those which differed in major ways from other states — concerned PUC decisions to reduce dependence on oil and to minimize involvement in new coal and nuclear facilities, as well as to increase participation in purchases from qualifying facilities and in demand-side management programs.

The quantities and prices of QF power that would have been available under different regulatory policies are of greatest consequence to the rate and bill impacts on ratepayers. While estimates of these hypothetical parameters are difficult to derive, evidence from the other New England states, during the same time period (focusing on the most recent few years), does provide evidence of what might have happened in Maine.

Other New England states had less than half as much QF development, proportionally to their total capacity, as did Maine. Unfortunately, the data is incomplete and highly uncertain in terms of the prices that would likely be paid for generation facilities under different scenarios. It appears that both New Hampshire and Vermont were paying QF contractors substantially more than Maine.

Connecticut and Massachusetts utilities, on the other hand, were paying substantially less. A major reason for the price difference has to do with the fuel type. Eighty percent of the Massachusetts QFs are fueled by natural gas. These prices are largely tied to oil which, contrary to expectations, have declined since the initial QF contracts were signed.

Considering that neither gas nor oil were a serious option for Maine, the results could be used to conclude that the Maine PUC's impacts on the pricing of QF power were probably negligible. In scenarios one and two, where only half of the actual QF supplies are retained, this conclusion would eliminate most of the impacts that were estimated from the PUC's policies.

To fully bracket the possible QF pricing alternatives, scenario one assumed a zero pricing differential. To be conservative, however, and to serve as a sensitivity case, Connecticut and Massachusetts values were used as a standard for scenario two. In doing this, it is assumed that with different regulatory policies the average price for QF power would have been 2.0 cents/kWh lower, in each year, than it actually was.[155] This determines the ratepayer impacts from the retained QF supplies in scenarios one and two.

For the QF supplies that were eliminated in scenarios one and two, the 100 percent that are removed in scenario three, and the DSM energy savings that are removed in all three scenarios, the electricity must be replaced by other sources.

In scenario one, replacement power is provided by Seabrook 1, Sears Island, hydro plants and oil. At a cost of 8.5 cents per kWh, the 1992 Seabrook cost was about 0.7 cents lower than the average 9.2 cents for QF supplies. But Seabrook is much higher than the 4.9 cent DSM cost. Sears Island was about 2.0 cents less expensive than QFs which were assumed to be priced at the same level as in the actual scenario. Hydro plants ranged in cost from 6.9 to 10.9 cents and oil-fired power cost 6.7 cents.

In scenario two, rather than coal-fired power from Sears Island and new hydro power for BHE, all of the power needs beyond Seabrook 1 are assumed to be met by Canadian power purchases. Since these purchases are estimated at 6.3 cents per kWh, rather than the 7.2 cent cost of Sears Island, and since it is assumed that the alternative scenario would have paid 2.0 cents per kWh less for QF power, this substantially increased the rate and bill impacts compared to the actual scenario. Scenario three assumes no QF development. Replacement power is supplied by Seabrook 1, Sears Island, Canadian power, and hydro plants.

The final results, as shown for all Maine ratepayers in Tables 5-6 through 5-8, are increases in utility costs to generate or to purchase power, due to the Maine PUC's policies, ranging from 4.1 percent to 12.3 percent as of 1992. The latter figure is an extreme case, in which it is assumed that Maine's utilities chose not to construct any of their own capacity due to lower availability of QFs, but instead signed long-term contracts for lower-cost power from Canada. With DSM taken into consideration, actual bill increases due to PUC policies ranged from only 0.6 to 8.6 percent.

155. In fact, it is likely that the most expensive QF facilities would have been displaced under the alternative scenarios which would have brought the average price down for the remaining units. A cursory review of this approach also indicates a 2.0 cent price differential.

If Not QFs, Why Such a Sharp Rate Increase?

At 12.3 percent, scenario two shows the highest rate impact of the three alternative scenarios. Since the QF policies appear to have played only a limited role on the overall rate increases since 1988, the question arises as to what were the primary causes of those increases? It was not within the scope of this study to attempt to provide a full answer to that question. However, it appears that several forces were at work. Table 5-9 below summarizes at least one way to explain four possible influences on the 35.5 percent rate increases in the period 1988 through 1992. It is based upon the revenue impacts from scenario two.

TABLE 5-9. ESTIMATED INFLUENCES ON MAINE REVENUE INCREASES

Influence	Estimated Revenue Impact	Percent of Total Impact
Inflation	$120.0 million	43%
QF Policy	$68.4 million	25%
Consumption	$33.1 million	12%
Seabrook	$27.4 million	10%
Miscellaneous	$28.6 million	10%
Total	$277.5 million	100%

Source: The worksheet calculations are provided as Appendix E.

Total revenues from electricity sales increased by $277.5 million between 1988 through 1992. The most obvious impact on this increase is inflation. Using the GDP deflator for this period, it appears that inflation is responsible for just under one-half of the total revenue impact (43 percent). The QF revenue impact (expressed in constant 1988 dollars) is responsible for about one-fourth (25 percent) of the revenue increase. Electricity consumption in this period increased by just under five percent in this period. It responsible for about 12 percent of the increased revenues (also in 1988 dollars).

Seabrook Unit 1 is perhaps the most surprising influence listed. As noted previously, the PUC allowed about $245 million of Seabrook into the ratebase of the three utilities. Assuming an annual carrying cost in 1992 of about 13 percent (including a return, depreciation and taxes), $31.9 million was collected in the revenue stream for Seabrook. In 1988 dollars, this is $27.4 million, or about 10 percent of the total revenue impact.[156]

Finally, there is a miscellaneous amount of about 10 percent. It appears to be related to such things as increased transmission, distribution and administrative expenses associated with an increased number of customers in this period (net of increased electricity sales). However, the analysis in this report does not extend beyond the impact of QF and DSM policies. As a result the "miscellaneous" portion will stand "as is."

156. Strictly speaking, Seabrook was not part of the revenue increase in this period since the PUC authorized it to be included in ratebase as early as 1985. However, it is a significant part of the revenue stream and an important influence on QF policies so that it is included here. Moreover, had the unit not been allowed in rates at all, the amount of revenues collected would have fallen by the amount included in this analysis.

6.0 ECONOMIC IMPACTS

6.1 INTRODUCTION

In adopting the Small Power Production Facilities Act (SPPFA), the Legislature found "that using renewable resources of small energy production facilities will have a significant and beneficial effect upon the State."[157] The policy has been clearly successful. John M. Flumerfelt, former Director of Energy Policy, Maine State Planning Office, commented that "the development of non-utility generation in Maine appears to be one of the most successfully implemented government policies we have ever enjoyed."[158]

Non-utility generation reduces oil dependence and supports the Maine economy.

Central Maine Power Company (CMP), the state's largest electric utility, appears to at least partially agree, noting that "CMP's non-utility energy purchases reduce oil reliance, diversify the energy mix, promote the use of indigenous and renewable resources, support the Maine economy and may offer long-term savings." At the same time, CMP cautions that, "as with implementing policy-driven energy management programs, the short-run price impacts can be significant."[159]

It is clear that the transition from an oil-based electric generation system to one anchored by biomass resources has contributed to higher electricity prices in the short-term. But

157. See, 35 M.R.S.A., §2322, as cited in Statement of Factual and Policy Basis, and Order Adopting Rule, MPUC Docket 82-78, Re: Chapter 36 - Cogeneration and Small Power Production, July 9, 1982, page 3.

158. Comments of John M. Flumerfelt, before the Maine Legislature's Joint Standing Committee on Utilities, August 27, 1992.

159. See, *Annual Report 1991* (Augusta, ME: Central Maine Power Company, 1991), page 4.

the question to be asked at this point is whether Maine's energy policy has, in fact, supported the overall development of the state's economy?[160] Based upon the review carried out in this study, it appears that Maine has gained an important competitive advantage as a result of the alternative energy policies. This can be seen in terms of the increases in both employment and overall economic activity.

The confirmation of these findings are based upon a two-part analysis. First, such things as job growth and economic competitiveness have been evaluated and compared to both the U.S. and to the New England region.[161] Second, an economic tool referred to as input-output modeling was adapted to measure the pattern of employment and other economic changes brought on by Maine's energy policies.

While the first step uses actual employment and income data to compare the state's performance to that of the U.S. and the New England region, it is more qualitative in its conclusions. The use of the input-output modeling technique, however, offers a more concrete measurement of the advantages or disadvantages of the energy policy with respect to the scenarios described in the previous chapter.

6.2 Evaluating Economic Competitiveness

Has Maine's economic competitiveness been compromised in its pursuit of current state energy policy? One way to answer this question is to compare changes in Gross State Product (GSP) over time. The data used for this comparison is the published BEA data for the U.S. and for the individual states.[162]

Figure 6-1, on the following page, shows that Maine's GSP growth rate significantly outperformed the growth rate for the U.S. Gross Domestic Product (GDP) in the years 1982 through 1989. This was a key period of development for biomass and cogeneration facilities in the state. CMP's reliance on non-utility generators, for example, rose from only 5 percent of its total resource mix in 1982 to 23 percent in 1989. At the same time, CMP's oil generation fell from 38 percent to 20 percent in that same period.

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160. As noted elsewhere, economic impact is one of the four "fundamental attributes" of Maine energy policy cited in the *Report of the Commission on Comprehensive Energy Planning*, op. cit.

161. As defined here, the New England region refers to the states of Connecticut, Massachusetts, New Hampshire, Rhode Island and Vermont. Unless otherwise indicated, Maine is omitted from the New England data to permit a more complete comparison between the two economic entities.

162. BEA refers to the U.S. Department of Commerce's Bureau of Economic Analysis. Both the GSP and GDP data is available on CD-ROM format. See, Regional Economic Information System (REIS), USDOC, BEA, REMD (BE-55), Washington, DC 20230. The GSP data is currently available only through 1989. The remaining data is estimated using state personal income through 1992.

In 1989 both New England and Maine experienced an economic downturn compared to changes in the U.S. economy. Thus, the GSP growth rate fell below national levels in 1990 and 1991. During this time, the utilities continued to increase their share of non-utility generation. CMP's non-utility generation rose to a record high of 38 percent.[163]

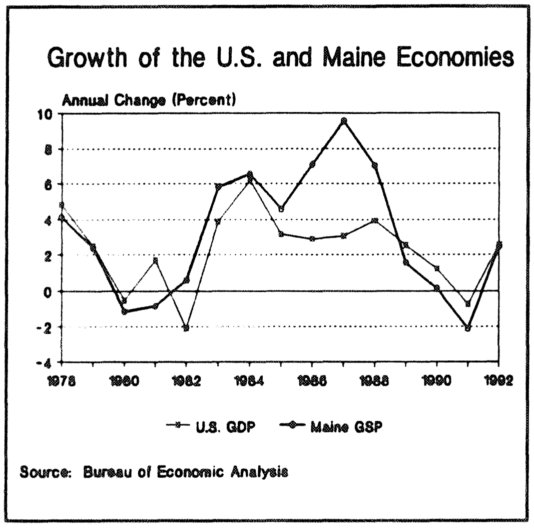

Figure 6-1

As we shall see later in this chapter, the continued development of the biomass and cogeneration resources provided Maine with a net increase in overall GSP and employment through 1992. Thus, the continued economic downturn in 1989-1992 was more related to the national economic performance than to the state's energy policy. In fact, had the energy policy not been in place, the 1989 economic downturn in Maine would have been somewhat worse.

Still another way to explore this issue is to review overall employment changes in Maine, New England and the U.S. This is shown in figure 6-2. In this case the analysis extends the full period of the study, from 1978 through 1992. The data used is the previously referenced BEA data which includes both proprietors and the self-employed.

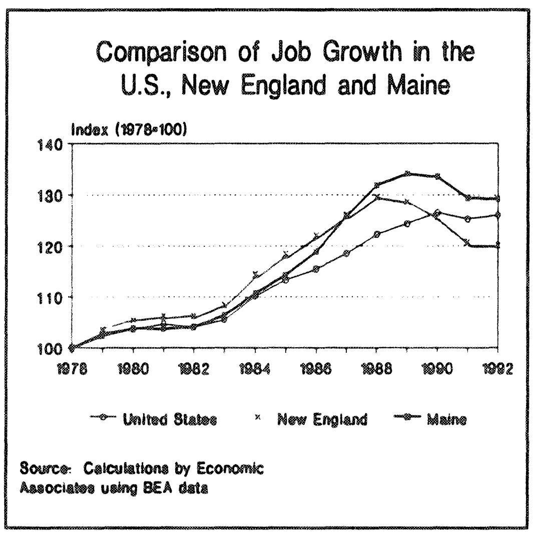

Figure 6-2

The employment gains are indexed so that the year 1978 equals 100. By 1992, for example, the Maine employment base has grown to 129, or 29 percent above the employment levels recorded in 1978. At the same time, the New England values show only a 20 percent gain, or a 1992 index of 120. The U.S. employment index of 127 rose to nearly the same value as for Maine. In short, it appears that Maine's energy policy have given the state an additional edge to maintain a slightly higher index than for the U.S. as a whole.

163. *Annual Report 1992* (Augusta, ME: Central Maine Power Company, 1992), pages 42-43.

One way to gauge the influences on job creation in Maine is to apply a statistical tool known as shift-share analysis. Shift-share analysis examines the causes behind the employment gains and losses in the economy over a designated period of time.

Shift-share analysis assumes that the sum of three different effects — national economic growth, changes in the mix of industries, and regional competitive advantage — are responsible for determining the net gain (or loss) of jobs within a state or region. Figure 6-3, below, examines the net employment changes in Maine and New England in 1984 and 1992. They span the key years for development of non-utility generation within the region.

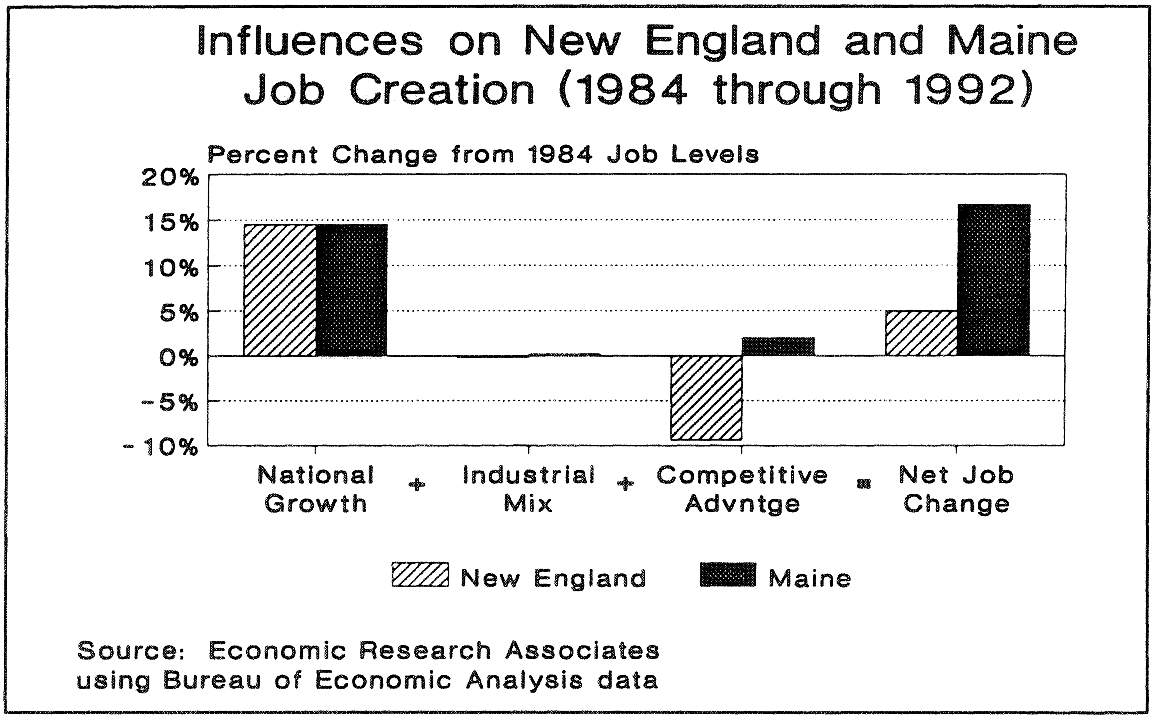

Figure 6-3

The first impact on regional employment is *National Growth*. It refers to the percent increase in the number of jobs that should have been created as a result of national economic momentum in the period 1984 to 1992. Based on that criterion, both Maine and New England should have expanded their employment by about 15 percent.

Industrial Mix refers to the jobs created relative to other sectors in the economy. In other words, did the Maine or New England economy stay ahead of, or fall behind, the structural changes within the U.S. Both Maine and New England show job impacts of less than one percent with Maine slightly positive and New England slightly negative.

Finally, *Competitive Advantage* measures the performance of individual sectors within each region and compares it to the same sectors at the national level. In the aggregate, Maine's economic sectors tended to be more competitive — that is, they grew at a faster rate — than the same sectors in the U.S. By this measure, Maine's employment base showed a small competitive advantage of about two percent. On the other hand, New England lost about nine percent employment in this category.

> ***Maine showed a small competitive advantage of about 2 percent in this period while New England lost about 9 percent***

The sum of these three influences — National Growth, Structural Mix and Competitive Advantage — equals the *Net Job Change* between 1984 and 1992. As Figure 6-3 suggests, Maine's total employment did, in fact, grow by 17 percent in this critical period. New England struggled a bit more in this period, generating only a five percent net increase in its overall employment levels.

A more complete sectoral analysis for Maine (in the years 1984 through 1992) is provided in Appendix F. A number of results are quickly evident from the information presented there. For example, Maine's economy grew at a slightly faster rate the than U.S. economy in this period (17 percent versus 15 percent, respectively). New England, on the other hand, lost a significant employment base relative to the U.S.

In Maine there are three important sectors where the state shows a competitive advantage and which are (at least indirectly) impacted by the state's energy policy — proprietors (in all sectors), special trade contractors, and business services.

Engineering services also show significant growth in Maine. However, since the standard industrial code classification did not specifically reference this sector until 1987, a full shift-share analysis is not possible. We can, however, compare the growth rates in Maine, New England and the U.S. for the years 1988 through 1992. In that regard, both Maine and the U.S. engineering services grew by about 11 percent in this time. New England engineering services grew by only three percent.

There is other qualitative evidence to establish a link between Maine's economic performance and the state's energy policy. The source is annual data from a series of reports entitled, *The Development Report Card for the States.*[164] In this case we are

164. *The Development Report Card for the States: Economic Benchmarks for State and Corporate Decision Makers* (Washington, DC: Corporation for Enterprise Development). The 1991, 1992 and 1993 editions were used to gather information back on the period 1988 through 1993.

looking at state rankings given in the years 1988 through 1993. More specifically, we are comparing the state of Maine to the New England region. Table 6-1 summarizes the information.[165] The reports provide a series of grades for three key indicators: *Economic Performance*, *Business Vitality, and Development Capacity*. All performance indices are composites of as many as 8 to 20 other performance measures. All are graded on a scale from *A* to *F*, with *A* representing the top score.

Economic Performance refers to a weighted index measuring such factors as job creation, annual pay, environmental quality and health conditions. Business Vitality refers to a weighted index measuring sectoral diversity and competitiveness and entrepreneurial activity. Development Capacity is a weighted index that refers to such things as human resource and technology development, financial capacity, and infrastructure improvements.

In 1993, Maine held onto its "A" rating in business vitality

In 1988 both New England and Maine had top scores in economic performance. Maine received an "A" in the 1988 scoring for business vitality while New England earned only a "B" rating in this category. In the area of development capacity, Maine received a "D" while New England had an "A". By the time the 1993 reports were issued (based largely on 1990-1992 data), both regions scored only a "C" in economic performance. New England's business vitality rating fell to a "C" while Maine held onto its "A" rating. This performance in business vitality continued despite the on-going lack of development capacity in the state. In this last area, Maine has consistently scored only a "D".

The high marks in business vitality make sense when the information is examined even further. According to the 1993 report card, Maine ranked 4th in the nation in dynamic diversity — essentially a reflection of whether all of the state's major industries declined at the same time, or whether it had sufficient diversity that declining industries did not negatively impact other economic sectors.

Maine also ranked 8th in capital investment, 14th in new small business jobs and 19th in new companies. These findings compare favorably with the analysis referenced in the shift-share analysis. For example, Maine had a significant competitive advantage among the (nonfarm) self-employed and business proprietors. All of these point in the direction of a positive relationship between Maine's economy and the state's energy policy.

165. The New England scores are a population-weighted average for the states of Connecticut, Massachusetts, New Hampshire, Rhode Island and Vermont.

TABLE 6-1. REGIONAL DEVELOPMENT REPORT CARD

Region	1988			1993		
	Economic Performance	Business Vitality	Development Capacity	Economic Performance	Business Vitality	Development Capacity
New England	A	B	A	C	C	A
Maine	A	A	D	C	A	D

Source: *Development Report Card for the States* (Washington, DC: Corporation for Enterprise Development, 1991, 1992 and 1993). See the text of the report for an explanation of the benchmark scores.

6.3 POLICY IMPACTS

With the qualitative measures suggesting at least a supportive economic role for the state's energy policy, we can now employ a more direct and quantitative measure of the energy policy impacts. To accomplish this task we adapt the information contained in the various scenario analyses found in chapter 5 and link it with input-output impact analysis, or what some policy analysts refer to as "multiplier analysis."

In this subsection of the report, we first provide a conceptual overview of how multiplier analysis is adapted. Next we review the relevant scenario data as it might be formatted for use in such an analytical model. Finally, we provide a summary of the impacts themselves. The results are measured in terms of changes in employment, wage and salary income, and Gross State Product.

6.3.1 USE OF INPUT-OUTPUT ANALYSIS

One tool that can assist in the evaluation of the job and income benefits resulting from different energy strategies is referred to as input-output analysis, sometimes called multiplier analysis.

Input-output analysis can be thought of as a means to evaluate and sum the job and income benefits (i.e., the "output") which are likely to result from the changes in spending patterns (the "inputs") created by the investment in alternative electric generation facilities and energy efficiency technologies.[166]

To better explain how these impacts are evaluated, let us assume that an electrical (special trade) contractor has been hired to install $1.0 million of improvements in a manufacturing facility. To determine the total economic outcome of the efficiency investment, three separate effects from the project improvements must be examined.

> **Direct Effect:** These are the on-site jobs created by an expenditure. In the case of installing new technologies in a manufacturing plant, the direct effect would be the on-site jobs of the contractor crew hired to carry out the work.
>
> **Indirect Effect:** This refers to the support a contractor receives to carry out the efficiency improvements. It includes such people as the banker who finances the contractor's operation, the accountant who keeps the books for the firm, and the manufacturing company which produces the equipment that will actually be installed.
>
> **Induced Effect:** As the people who are directly and indirectly employed by a project spend their weekly paychecks, they are said to "induce" other activity. This refers to money received by the grocer, for instance, who hires people to work in the store.

The sum of these three effects yields the **Total Effect** of a given expenditure. Even at this point the analysis is incomplete since it only deals with the direct, indirect and induced effects of the efficiency investment. To understand the full range of economic influences, two additional impacts must be examined for their direct, indirect and induced effects as well. They are the:

> **Substitution Impact:** Once the new technology has been installed, the energy efficiency improvements are effectively "substituted" for some amount of electricity use. If that amount generates a net savings, the result is (hopefully) increased local spending equal to the energy savings.
>
> **Displacement Impact:** Any money saved by the efficiency improvements may create a loss of income for the local utility. If it occurs, such a displacement may create an economic loss to the community.

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166. For a more complete review of how input-output analysis might be adapted for use in energy scenarios, see, Howard Geller, John DeCicco and Skip Laitner, *Energy Efficiency and Job Creation: The Employment and Income Benefits from Investing in Energy Conserving Technologies* (Washington, DC: American Council for an Energy-Efficient Economy, October, 1992).

From this discussion, therefore, it can be seen that a complete multiplier analysis captures the total effects of each major change in local expenditure patterns. One analytical tool used to estimate the full range of these impacts is the *IMPLAN* input-output model, a 528-sector input-output and database available on the commercial market. *IMPLAN* has data available at the national, state and county levels. In this case, we adapted a 1990 database for the state of Maine.[167]

In summary, *IMPLAN* permits a complete impact analysis by capturing the direct, indirect and induced effects of changes in:

1. Higher investment costs associated with the installation of energy efficiency technologies or construction of alternative electric generating facilities; and

2. Expenditures on other goods and services made possible by lower utility bills as well as the utility revenue losses which result from the changes in ratepayer expenditure patterns.

Once the information appropriate to the region is obtained, the benefit-cost information about the efficiency investment can be used to evaluate the improvements for the net impact on local employment and income. In other words, the change in expenditures resulting from the alternative investment becomes the basis on which to predict employment and income benefits in the state's economy.

Each sector of the economy — whether agriculture and construction, or health and electric utility services — supports different levels of employment. This is usually expressed as the number of jobs per million dollars of expenditure. As the level of expenditures are increased or decreased, the level of employment supported by a given sector will rise or fall.

Table 6-2, on the following page, summarizes the appropriate multipliers for selected sectors in the Maine economy. Using the *IMPLAN* database for the state of Maine, it turns out that electric utility services will typically support about 10.9 total jobs for every million dollars collected from utility customers. Manufactured goods, however, will

Utility services support about 10.9 total jobs per million dollars while manufacturing supports about 24.1 total jobs

167. For more information on the use of this model and its supporting databases, see, Doug Olson, Scott Lindall and Wilbur Maki, *Micro IMPLAN User's Guide, Version 91-F*, (Minneapolis, MN: Minnesota IMPLAN Group, January 1993). IMPLAN is short for "IMpact analysis for PLANning."

support on average 24.1 jobs per million dollars of revenue. Finally, an electrical contractor might support 26.4 jobs per million dollars of investment or expenditure.

TABLE 6-2. TOTAL REQUIREMENT MULTIPLIERS FOR SELECTED MAINE ECONOMIC SECTORS

Sector	Output	Jobs	Wages
Agriculture	2.147	23.5	0.409
Mining	1.389	10.5	0.169
Construction	2.344	26.4	0.538
Manufacturing	2.302	24.1	0.532
Pulp and Paper Mills	2.116	16.8	0.443
Transportation/Communications	2.660	32.5	0.730
Electric Utilities	1.690	10.9	0.262
Trade	2.735	50.9	0.856
Finance/Insurance/Real Estate	1.843	18.1	0.313
Services	2.892	47.4	0.867
Government	3.213	54.5	1.160

Notes: Output is a ratio that refers to the total increase in economic activity as a result of a one dollar change in expenditures. Jobs refer to the total number of jobs supported by a one million change in expenditures. Finally, wages refer to the change in employee compensation from a one dollar change in expenditures.

Source: IMPLAN model using the 1990 database for the state of Maine. While the information is provided for as many as 528 sectors in the U.S. (328 for Maine which has a smaller economy), the data have been aggregated to these 11 sectors for use in this analysis.

The assumption is that we are interested in the **net effect** of employment and other economic changes. This means we must first examine all changes in business or consumer expenditures — both positive and negative — that result from a movement toward energy efficiency.

As we've seen, each change in expenditures has a direct, indirect and induced effect represented by a total multiplier. Thus, each change in expenditures must be multiplied by the coefficient that is appropriate for that sector. The sum of these products will then yield the net result for which we are looking.

To illustrate how this analysis is done, we will use the example of a manufacturer that installs $1.0 million of efficiency improvements. The results of this example are summarized in Table 6-3, on the following page.

The assumption used in the example is that the investment will pay for itself in an average of five years. If we anticipate that the efficiency changes will have an expected life of 10 years or more, then we can establish a 10-year period of analysis. Let us further assume that the efficiency upgrades take place in the first year of the analysis, while the energy savings occur in years one through 10. A final assumption is that electric energy prices will increase 5.3 percent (in nominal terms) annually while inflation will rise five percent each year.[168]

With this information we can identify four separate changes in expenditures, each with their separate multiplier effect. The first is the expenditures made by the electrical contract to actually make the desired improvements. As shown in Table 6-3, the construction activity might sustain 26.4 total jobs for each million dollars of investment. Thus, as the investment is made, the Maine economy is improved by 26.4 jobs.

However, the money necessary to make the improvements had to be raised in one way or another. In this example, the assumption is that the manufacturer generates funds from its normal operating budget to pay for the investment. The assumption is that had the funds been spent on normal business activities, about 24.1 total jobs would be supported.

The implication is that by pulling the million dollar investment out of normal business expenditures, the Maine economy will contract by 24.1 jobs. At this point, then, the economy is ahead by a net of 26.4 less 24.1, or an average of 2.3 jobs. There are still two additional changes that need to be reviewed in the analysis, however.[169]

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168. The numbers used in this example are for illustration purposes only. While they do not reflect any specific efficiency improvement, they do represent reasonable "real-world" costs and benefits of efficiency improvements in general.

169. In reality, the size of the Maine economy is unlikely to contract, *per se*. This discussion really involves an opportunity cost with the question being asked, should we spend our money in a way that supports 24 jobs, or one that will provide 26 jobs, or an extra two jobs (in the year the money is spent)?

Assuming the five-year payback period, the energy bill of the industrial plant will be reduced by $200,000 in the first year of the 10-year period. This figure needs to be adjusted for anticipated increases in rising energy costs and inflation over the full 10 year period of analysis. When the appropriate adjustments are made, the electricity bill savings is set at about $2.03 million (in constant dollars). So, the state economy now moves from an initial gain of 2.3 jobs to a further gain of 2.03 times 24.1, or 48.9 jobs in the future.

TABLE 6-3. ILLUSTRATION OF EMPLOYMENT IMPACTS FROM INDUSTRIAL ENERGY EFFICIENCY IMPROVEMENTS

Expenditure Category	Amount ($ Million)	Job Multiplier	Impact (Job-Years)
Industrial Efficiency Improvements in Year One	$1.0	26.4	26.4
Raising Investment Revenue to Fund Efficiency Improvements	-$1.0	24.1	-24.1
Energy Bill Savings in Years One through Ten	$2.03	24.1	48.9
Lower Utility Revenues in Years One through Ten	-$2.03	10.9	-22.1
Net Ten-Year Change	**$0.0**		**29.1**

Notes: These estimates made by American Council for an Energy-Efficient Economy assume a 10-year time horizon. They further assume that the installation of efficiency improvements are completed early in year one while the energy savings occur in years one through ten.

The calculation of energy bill savings is based upon a five-year payback with energy costs projected to rise 5.3 percent annually. The energy savings, and therefore the lost energy revenues, are deflated five percent annually to convert the values to constant dollars.

The job multipliers represent the total change in the number of jobs as a result of each $1.0 million increase or decrease in expenditures. The multipliers have been drawn from the 1990 Maine database of the *IMPLAN* input-output model referenced in Table 6-2.

The results of this simplified analysis suggest that for each $1.0 million of efficiency improvements made within a manufacturing plant (assuming a five-year payback), employment would increase by 29.1 job-years over the 10-year period of analysis. This translates into an average of 2.91 more jobs than the economy would otherwise support each year if the efficiency improvements are not made.

One final adjustment is needed to complete the analysis, and that is to account for the impact of reduced utility revenues. This lowers the future employment benefits by 2.03 times 10.9, or 22.1 jobs. With the series of calculations now complete, we have the full picture of the employment impacts sustained by the energy efficiency improvements in the industrial plant used in this example.

As Table 6-3 indicates, the future impact is a net gain of 29.1 job-years of employment over the 10-year period. As noted at the bottom of the table, the total of 29.1 job-years translates into a net increase of 2.91 jobs each year for 10 years. This is 2.91 more jobs each year than the economy would be able to support if the efficiency improvements had not otherwise been installed.

While the example here involves efficiency improvements at a manufacturing facility, a similar analysis would be carried out to evaluate the larger economic impacts of the Maine Energy Policy. This is described next.

6.3.2 Key Expenditure Data

There are four basic steps in completing this part of the analysis. The first step is to estimate the magnitude of the investment and/or expenditure for each of the major impact categories (e.g., installation, substitution or displacement impacts). The next step is to identify a period of analysis and convert the dollar flows to 1990 dollars since that is the base year of the IMPLAN model. In this case, 1992 is selected as the year of analysis. This means that all 1992 prices must be deflated to 1990 dollars.

In the third step, each of the major categories of expenditures — whether in the baseline or any of the three alternative scenarios — must be allocated to appropriate sectors within the Maine economy. In the case of electricity expenditures, IMPLAN already has an identified sector. In the case of QF facilities and DSM operations, however, estimates need to be made. The fourth and final step is to estimate the percent of expenditures that will be spent within the state of Maine.

Because electric utility services are already an established sector, non-QF and non-DSM revenue streams from the baseline scenario are allocated to that sector. Since leakages are implicit in the development of the utility multiplier, the revenues received directly by the state's utilities are set at 100 percent of the appropriate output, employment and income multipliers.

Since there is neither a "QF" nor a "DSM" sector, payments to those sectors are allocated to other existing *IMPLAN* sectors following an accounting of expenditures similar to the case study examples reviewed in chapter 4. These expenditures have been calculated with a retention rate of 42 and 75 percent for QF and DSM payments, respectively.[170] Customer savings from each of the alternative scenarios are allocated on a weighted average of kWh savings. To be conservative, household savings are treated as income with only 70 percent of that return spent within the state. Table 6-4 summarizes the key expenditure data that will be matched with the IMPLAN model.

TABLE 6-4. SUMMARY OF SCENARIO EXPENDITURES (IN MILLIONS OF DOLLARS)

Category	Retention	Actual	Scenario 1	Scenario 2	Scenario 3
Base Expenditures	100%	$557.9	$581.6	$570.5	$575.5
In-State	100%	n/a	$162.3	$13.7	$169.6
Out-State	0.0%	n/a	$62.7	$185.9	$197.3
NUGs	42%	$431.5	$196.1	$158.4	$0.0
DSM	75%	$18.9	$0.0	$0.0	$0.0
Savings	varies	$0.0	$5.6	$79.8	$66.0

Notes: The term "in-state" refers to alternative generation facilities that would likely be located within the state of Maine. This includes Sears Island, oil-fired generation and additional hydropower facilities. The "out-state" facilities include Seabrook and Canadian purchase power.

6.3.3 IMPACTS OF MAINE'S ENERGY POLICIES

With the accounting of the baseline and alternative scenario expenditures established, the data from the *IMPLAN* model can be used to evaluated total impacts. The results are presented and reviewed in the two subsections that follow. The first examines the impacts of the baseline expenditures while the second explores the economic changes that might result from any of the alternative scenarios.

170. For comparison, data from the *IMPLAN* model's direct requirements table suggest that electric services retain only about 27 percent of total revenues. It is this lower in-state expenditure that explains much of the considerably smaller multipliers for electric utility services shown in Table 6-2.

6.3.3.1 Baseline Impacts

In 1992 Mainers spent just over one billion dollars for electricity. Using the *IMPLAN* analysis, this level of expenditure supported an estimated 9,064 total jobs. It generated an estimated $190.4 million in total wage and salary income, and contributed about $556.4 million to Maine's Gross State Product. Table 6-5, below, lists and summarizes the impacts from this baseline expenditure.

TABLE 6-5. IMPACTS FROM 1992 ACTUAL SCENARIO

Impact Category	Employment	Wages	GSP
Non-Utility Generators	5,462	$113.0	$352.5
Utility Services	3,100	$67.2	$177.4
DSM Programs	501	$10.1	$26.6
Total Expenditures	9,064	$190.4	$556.4

Notes: The numbers represent the total economic impact (i.e., including the direct, indirect and induced effects) of each economic impact category. Contributions to wages and GSP are in millions of 1992 dollars.

Using the employment figures as a reference point, the alternative energy services industry (including both non-utility generators, or NUGs, and DSM program services) supports nearly 6,000 total jobs within the Maine economy. This is two-thirds of the jobs total despite receiving only 43 percent of the electricity revenues. Two reasons account for this impact. First, the energy services industry is slightly more labor intensive. Second, more of the revenues received are spent locally compared to conventional electricity revenues.

Are these numbers within the boundary of reasonableness? The multipliers shown in Table 6-2 as well as two previous Maine studies can be used as benchmarks to test the reasonableness of the impacts. The first of the studies is an analysis presented in a PUC hearing on the Hydro-Quebec issue while the second is a report from the Maine State Planning Office.

Based upon the total employment impact of 9,064 jobs, it appears that electricity sales support about 9.0 total jobs per million dollars of expenditure. This is about 83 percent of the multiplier value shown for electric utility services in Table 6-2. However, when the 1992 expenditures are deflated to 1990 dollars and an allowance is made for productivity changes, the value is closer to 10.0 jobs — still lower than the published value but within 10 percent of the estimate.

In 1988 hearings on Hydro-Quebec, Dr. Frank Ackerman estimated that biomass facilities would provide about 8 permanent jobs per megawatt (MW) of capacity.[171] With an estimated NUG capacity of about 700 MW, the findings in this analysis show a return of about 7.7 jobs/MW — also a low figure, but within a reasonable boundary.

The State Planning Office (SPO) found that about 2,700 total jobs were supported by the operating expenditures of ten stand alone biomass facilities in Maine. This translates into an estimated 14.4 jobs per million of revenues.[172] The analysis summarized in Table 6-5 suggests a ratio of 12.7 jobs per million dollars — again a conservative but realistic estimate.

6.3.3.2 Alternative Scenario Impacts

With a reasonable baseline established for the actual 1992 expenditures, the impact of the three alternative scenarios can now be compared. This comparison is highlighted in Table 6-6, on the next page.

The conclusion from this evaluation is that even though the baseline (actual) scenario required a higher level of customer revenues, it also yielded a net economic and employment benefit for the state.

The baseline scenario supported between 1,800 to 3,300 more jobs than the alternative scenarios

The difference between the baseline and alternative scenarios suggest that Maine's economy supported a low of 1,800 to a high of 3,300 more jobs (comparing scenarios

171. See, reference to Dr. Ackerman's testimony in the consolidated Commission order for PUC Docket Numbers 88-111 and 87-261, January 23, 1989, page 119

172. See, Jim Connors, *The Wood-Fired Electric Generating Industry in Maine* (August, ME: State Planning Office, Revised Draft, 1993), page 86-87. In fact, Connors analysis showed an average employment ration of 37.1 jobs. However, this was based upon operating expenses only for the 10 facilities. When adjusted for full revenues, including interest payments, depreciation and profits, the ratio is reduced to about 14.4 jobs.

two and three, respectively). There are two reasons for this results: (1) the money spent on Maine's emerging energy services industry (in the actual scenario) has a higher level of *local expenditures* compared to the expenditure patterns in all three alternative scenarios; and (2) the energy services industries support a higher level of jobs per dollar expended compared to conventional electricity generation.

TABLE 6-6 NET BENEFITS OF ACTUAL SCENARIO COMPARED TO ALTERNATIVE SCENARIOS (1992 IMPACTS)

Scenario	Revenues	Jobs	Wages	GSP
Actual to Scenario 1	($5.6)	2,306	$46.3	$151.4
Actual to Scenario 2	($79.8)	1,796	$34.9	$122.6
Actual to Scenario 3	($66.0)	3,257	$64.6	$221.4

Notes: All monetary values are in 1992 millions of dollars. The values in the revenue column (in parentheses) reference the lost revenues associated with the actual scenario compared to each of the three alternative scenarios reviewed in chapter 5. Jobs refer the actual gain in employment. The Jobs, Wages and GSP impacts refer to the net benefit of the actual scenario compared to each alternative scenario.

The results of Table 6-6 make a bit more sense when compared to the data in Tables 6-4 and 5-3 (in the previous chapter). The biggest employment gap, for example, is shown in the scenario three analysis in which the actual scenario provides almost 3,300 more jobs compared to its alternative. This occurs despite a higher consumer cost of $66 million in the actual scenario.

The reason for the significant difference is that in scenario three, the NUG expenditures have been zeroed out while the out-state expenditures have been increased over the actual 1992 expenditures. In effect, both the out-state expenditures in scenario three (shown as $197.3 million in Table 6-4) and the reliance on NUG and DSM services ($431.5 and $18.9 million, respectively) in the actual scenario more than offsets the relatively small level of energy bill savings in the alternative scenario ($66.0 million).

6.4 CONCLUSION

Maine has enjoyed a relative economic advantage in recent years compared to the New England region. A qualitative review of the data all points to the state's energy policies as among the reasons for this relative advantage. Input-output analysis provides specific estimates which confirm the positive employment and other economic benefits associated with the state's energy policies.

The study shows that personal income and Gross State Product are both increased under the existing energy policies. Moreover, the economy supports in the neighborhood of 1,800 to 3,300 more jobs as a result of the initiatives. If we think of the job benefits as if they were provided by the relocation of a series of small manufacturing plants to Maine, then we can say that the energy policies have produced the equivalent output of 14 to 26 new industrial plants.[173] More importantly, these are jobs that tend to be more evenly distributed throughout the state.

Perhaps another way to look at this issue is to see how the unemployment rate would have changed with the current energy policies. In mid-1992 Maine had an unemployment rate of about 6.6 percent with an estimated 45,300 people unemployed. Without the energy policies in place, the number of unemployed persons would have risen to between 47,100 to 48,600 persons. The unemployment rate would have risen similarly to 6.9 and 7.1 percent, respectively.[174] From these insights, then, it seems clear that — despite the modest rate impacts in the early years of the various NUG contracts — Maine's energy policies have had a clear economic benefit. Indeed, they properly belong in the category of an important economic development strategy.

173. A small manufacturing plant might support on the order of 50 jobs directly. From the IMPLAN data referenced earlier, each direct job supports about 2.5 total jobs. Thus, an equivalent new manufacturing plant will support a total of 125 Maine jobs, directly and indirectly. Dividing this number into the net employment gains yields a working estimate of the total "new plants equivalent."

174. These numbers are based upon the Bureau of Labor statistics data for Maine, taken from, *Employment and Earnings* (Washington, DC: U.S. Department of Labor, August 1993), Table D-3, page 136.

7.0 ENVIRONMENTAL IMPACT

7.1 INTRODUCTION

There has been a growing recognition in Maine of the importance of a healthy environment to an equally healthy economy. In a 1990 public discussion document, for example, Central Maine Power (CMP) Company noted that "global warming and electromagnetic effects are examples of the rapidly changing environmental concerns affecting energy planning."[175] Environmental impacts were included in the primary goals of the 1993 Maine Energy Commission Report.[176]

In March 1993 an estimated "200 citizens from all of Maine's 16 counties gathered at Bowdoin College to discuss the economics, politics, and ethics of a 'sustainable' Maine." Among the sponsors of that conference were Bath Iron Works, Central Maine Power Company, Maine AFL-CIO, and the University of Southern Maine.[177] With this growing concern, Mainewatch Institute wanted to include an environmental analysis as part of the assessment of the state's energy policies.

Budget and time constraints limited the environmental analysis to an assessment of the impacts from air pollutants in each of the alternative scenarios. Yet, air pollution is one of the nation's oldest environmental problems, and it has been studied rather extensively in the United States. For instance, in a study focusing on the emissions of particulate matter, the U.S. Environmental Protection Agency found that air pollution accounts for an estimated 60,000 deaths a year. This makes air pollution among the top causes of

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175. *Energy Resource Planning Issues and Options* (Augusta, ME: Central Maine Power Company, Public Discussion Document, August 1990), page 8.

176. The other goals included cost, reliability, and economic impact. See, *Report of the Commission of Comprehensive Energy Planning*, op. cit.

177. Richard Barringer, editor, *Toward a Sustainable Maine: The Politics, Economics, and Ethics of Sustainability* (Portland, ME: Edmund S. Muskie Institute of Public Affairs, University of Southern Maine, 1993).

death each year in the United States.[178] The review of air emissions, therefore, should provide a working indication of whether the state's energy policy is promoting Maine's overall environmental well-being.

7.2 METHODOLOGY

The burning of fossil fuels and vegetation, combined with rapid deforestation, is responsible for a significant portion of the air pollution problem the world faces today. Transportation (primarily automobiles, trucks and buses) is the largest single sector source of air pollution. This is followed by electric power plants (burning coal or oil) and industry (primarily steel mills, metal smelters, oil refineries, and pulp and paper mills). Although the list could be much longer, five key pollutants were analyzed in this study:

Nitrogen Oxides (NO_x). Nitric oxide (NO) and nitrogen dioxide (NO_2) are formed in fossil fuel combustion when nitrogen in the air or fuel combine with oxygen in the air at high temperatures. Nitrogen oxide is also a main precursor to acid rain. NO_x is the pollutant responsible in large part for the yellowish-brown cloud that forms over many large cities. Exposure to NO_x can lead to lung and respiratory ailments.

Sulfur Dioxide (SO_2). Sulfur oxides are corrosive gasses that result from the oxidation of sulfur contained in fossil fuels. Emissions of SO_2 are primarily linked to power plants that generate electricity with coal. Sulfur oxides are one of the major causes of acid rain. The human health impacts associated with exposure to sulfur dioxide include respiratory ailments and increased incidence of asthma. The annual emission of SO_2 peaked in 1975. However, the emission levels have remained essentially unchanged since 1982.

Total Suspended Particulate (TSP) and Particulate Matter (PM). Particulate matter is matter suspended in the air as solid or liquid particles. It is generated by fuel combustion, road traffic, agricultural activities, certain industrial processes, and natural abrasion. Particulate matter primarily affects the respiratory tract. Those at most risk include the elderly, the very young, and those already affected by respiratory conditions. The annual emissions of particulate matter have decreased by 69 percent since 1940.

Hydrocarbons or Volatile Organic Compounds (VOCs). This is a broad group of chemicals containing hydrogen or carbon. These chemicals are primarily the

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178. "Air Pollution: a smoking gun in U.S. deaths," *Eugene Register-Guard*, May 13, 1991.

result of an incomplete combustion of fossil fuels, the evaporation of gasoline and solvents, and petroleum refining. Some hydrocarbons combine with NO_x to form smog. These active chemical agents react with other substances and can have adverse affects on human health and vegetation. The annual U.S. emission of VOCs peaked in 1970 at 27.5 million tons and steadily fell to 20.4 million tons in 1989.

Carbon Dioxide (CO_2). The burning of fossil fuels and vegetation consumes oxygen and releases CO_2. It is not considered a toxic air pollutant with direct health affects on humans. However, the long-term effects of increased carbon dioxide appear to be much more far reaching — enhancement of the greenhouse effect and the resulting global climate change. These changes may eventually cause flooding, change wind, rain and temperature patterns, and potentially cause a shift in where crops can be grown, where industry locates, where people are able to live, and how energy is used.

The quantity of emissions per year of each of these pollutants was estimated for the three alternative scenarios, and compared to the actual scenario. We assumed that DSM and the hydro and nuclear facilities have no emissions of these pollutants.[179]

7.2.1 QF Emission Factors

For the QFs, we determined the amount of the QF power from wood fueled power plants, waste fueled generators, and cogeneration facilities. This was determined by using the 1990 QF sales for Maine provided in a 1991 report by the New England Governors' Conference.[180] According to that report, in 1990 Maine produced 9.39% of their QF power from refuse powered plants, 29.71% of their QF power from small wood powered plants, and 40.3% of their QF power from cogeneration facilities using wood fuel. The remaining fraction of the QF power was produced by hydro QF facilities.

For all of the QF plants, the emission factors for CO_2 were assumed to be zero. For those facilities burning either wood or refuse to produce the power, we assume that the CO_2 emitted from combustion of organic carbon in the fuel is offset by approximately

179. For the conventional pollutants analyzed in this study DSM has essentially no emissions. Hydropower could have some emissions of methane from the biomass loss/decomposition in area flooding. Both nuclear and other fossil would have upstream emissions from fuel extraction, fabrication and delivery. These have all been ignored in our analysis here.

180. *Cogeneration, Small-Power and Independent Power Facilities in New England* (Boston, MA: The New England Governors' Conference, 1991 Fall Update).

the same amount of CO_2 taken up from the atmosphere in the growth cycle of the biomass. This assumes that the biomass used to power the facilities (wood, paper, etc.) is grown at the same annual rate as it is used.[181]

The emission factors for the other pollutants were obtained from *America's Energy Choices*.[182] The emission factors for the cogeneration facilities and the small wood-fired QF plants were taken from the data for a new wood fired power plant. The emission factors for the refuse-fired QF facility were taken from the data for a new municipal solid waste power plant.

7.2.2 Power Plant Emission Factors

The emission factors for the power plants that were used to replace the QFs in the three scenarios were obtained from a couple of sources. For the Sears Island coal plant, we used emission factors for a new AFBC coal plant with a scrubber, from *America's Energy Choices*. For the new distillate combined cycle plant we used values from the externalities rule from the Nevada PUC.[183] For the Coleson Cove residual oil plant, which was assumed to be the source of power for the Canadian power purchases, the emission factors were taken from *America's Energy Choices* for the average existing oil-steam plant in the Northeastern U.S. The emissions factors are:

Table 7-1. Power Plant Emissions Factors (Pounds Per Million Btu)

Pollutant	Sears Island	Wood QFs	Refuse QFs	Cogen QFs	Canad Oil	New Dist CC
CO_2	213	0	0	0	173	163
NO_x	0.181	0.101	0.18	0.1	0.39	0.100
SO_2	0.083	0.008	0.011	0.008	1.29	0.315
TSP	0.014	0.005	0.003	0.005	0.068	0.001
VOC	0.0028	0.077	0.042	0.077	0.006	0.017

181. Even where there is a mass balance for carbon between uptake in plant growth and emissions in combustion, for the case of solid waste there is a net reduction in global warming contribution if the release from landfill (rather than incineration) would otherwise occur. Release of carbon from landfill is 50% in CO_2 and 50% in CH_4 which, when the relative molecular weights and global warming contributions of the two gases are taken into account, is more than is taken up in the growth of the organic matter. Thus there would be a net carbon reduction credit for burning the fuel for electric generation rather than letting it be released from landfill.

182. *America's Energy Choices: Investing in a Strong Economy and a Clean Environment* (Cambridge, MA: Union of Concerned Scientists, 1991), Technical Appendices, "Appendix I: Emissions.

183. See, PUC Decision in Docket No. 89-752, January 22, 1991.

7.2.3 Emissions Calculations

To calculate the annual emissions of each pollutant, for each year of each scenario, the Megawatt-Hours (MWh) that would be produced by the various facilities were in each case multiplied by those facilities' emissions factors and heat rates. We have focussed here only on the emissions from the facilities that differ between the alternative and actual scenarios, rather than on the total system emissions for those scenarios.

Table 7-2. Power Plant Emissions Factors (Pounds/MWh)

Power Plant (Heat Rate)	**Sears Island** (10.0)	**Wood QFs** (17.0)	**Refuse QFs** (16.25)	**Cogen QFs** (5.0)	**Canad Purch** (10.0)	**Dist Oil CC** (8.5)
Pollutant						
CO_2	2130	0	0	0	1730	1386
NO_x	1.81	1.717	2.925	0.86	3.90	0.85
SO_2	0.83	0.136	0.178	0.040	12.90	2.68
TSP	0.14	0.085	0.049	0.025	0.680	0.01
VOC	0.028	1.309	0.683	0.385	0.060	0.14

By way of comparison, these figures are comparable to values published by CMP,[184] with several exceptions. In all cases CMP has significantly larger emission factors for CO_2, NO_x and TSP for wood-fired facilities than those listed above. For SO_2, CMP suggests a zero value while this analysis assumes at least some emissions. Apparently the CMP data offers no "credit" for carbon uptake in its wood-fired units. The result is a significant level of carbon dioxide emissions in its analysis compared to the results listed here.

Offsetting this trend, the Sears Island emission factors show a much smaller impact for CO_2, NO_x and TSP than cited by CMP. In any case, the emission levels are clearly site- and technology specific. For that reason, the resulting analysis that follows should be seen more as a pattern of benefits rather than a precise estimate of total impact.

184. See, *Energy Resource and Planning Issues*, op. cit., Table E-4, page 42.

7.3 Environmental Impacts

With the framework of analysis established by the scenarios referenced in Chapter 5, both the environmental benefit (or cost) of the state's energy policy can be evaluated. This is done for each scenario, both in physical units (tons of emissions) and economic impact (dollars). The results are presented below.

7.3.1 Emissions

The amount of CO_2 emitted in each alternative scenario is higher than in the actual scenario, since the differential generation in the actual scenario is from QFs for which net carbon dioxide emissions are zero. In the alternative scenarios the energy that was provided by QF generation and reduced by DSM for the actual scenario is provided instead by thermal generating resources — Seabrook, Sears Island, Canadian or regional oil-fired generation — some of which (the fossil resources) have carbon dioxide emissions in the production of electricity.[185]

For every other pollutant that we studied, with the exception of VOCs, the emissions in the alternative scenarios were significantly higher than in the actual case. For VOC's, the opposite was true. In all three alternative scenarios, the VOC emissions were significantly lower than in the actual case. This occurs because the VOC emission factor is higher for wood combustion than for fossil fuel combustion. The detailed results can be found in Table 7-3.

185. While the Seabrook nuclear facility does not emit the pollutants analyzed here, it does create radionuclide exposures for people at the facility and the area. Moreover, all of these generating facilities produce the five air pollutants (and Seabrook, additional radionuclides) in the extraction and processing stages of the fuel cycle. None of these impacts are taken into account in this analysis, which thus tends to underestimate the environmental impacts of the alternative scenarios.

TABLE 7-3. TOTAL EMISSIONS BY SCENARIO (TONS)

Scenario	CO2	NOx	SO2	TSP	VOC
Actual					
1988	158,688	1,177	387	45	617
1989	92,299	1,460	282	57	791
1990	110,415	1,977	355	78	1,074
1991	132,564	2,329	423	92	1,265
1992	207,237	2,333	564	90	1,250
Scenario 1					
1988	1,271,174	1,603	660	100	326
1989	1,638,589	2,034	858	127	403
1990	1,626,098	2,285	701	143	525
1991	2,223,442	2,936	1,064	184	629
1992	2,461,830	3,124	1,285	194	642
Scenario 2					
1988	985,234	2,688	6,842	385	353
1989	1,274,412	3,445	8,901	490	433
1990	1,431,889	4,010	9,961	564	570
1991	1,917,261	5,176	13,150	741	674
1992	2,070,848	5,495	14,102	793	685
Scenario 3					
1988	2,403,415	2,525	3,366	270	39
1989	3,472,697	4,131	7,288	502	64
1990	4,483,432	5,467	10,084	679	84
1991	5,968,144	7,584	14,965	976	117
1992	6,219,302	7,826	15,210	999	121

7.3.2 Valuing Emissions

In order to compare the overall impacts of the actual and alternative scenarios, taking account of the pollutant emissions, we applied the externality values adopted by the Massachusetts DPU for its integrated resource planning protocols. While the externalities values for Maine could be somewhat different than these, we have nonetheless used them here as indicative of environmental impact costs in the region. Table 7-4, below, provides the Massachusetts externality values, adjusted for inflation, for the five pollutants considered here.

TABLE 7-4. EXTERNALITY VALUES ($/TON)

Year	CO2	NOx	SO2	TSP	VOC
1988	$21	$5,657	$1,480	$3,830	$5,135
1989	$22	$5,904	$1,544	$3,997	$5,359
1990	$23	$6,167	$1,613	$4,174	$5,597
1991	$24	$6,377	$1,668	$4,316	$5,788
1992	$24	$6,500	$1,700	$4,400	$5,900

Source: The values shown above were taken from the externality values published by the Massachusetts Department of Public Utilities (1992).

Table 7-5, on the next page, provides the resulting environmental cost for each pollutant in each scenario. In 1992 the actual scenario shows an economic impact of $28.9 million. This yields a net savings that ranges from a low of $57.3 million compared to scenario one to a high of $202.2 million compared to scenario three. The single largest environmental savings stems from the reduction of carbon dioxide emissions. When the impact of CO_2 is removed from the analysis, the net benefits for 1992 drop to $3.2 and $57.9 million compared to scenarios one and three, respectively.

TABLE 7-5. EXTERNALITY COSTS BY SCENARIO ('000$)

Scenario	CO2	NOx	SO2	TSP	VOC	Total
Actual						
1988	$3,315	$6,657	$572	$171	$3,169	$13,884
1989	$2,012	$8,619	$436	$229	$4,239	$15,534
1990	$2,514	$12,190	$573	$325	$6,014	$21,615
1991	$3,121	$14,848	$705	$395	$7,322	$26,392
1992	$4,974	$15,166	$959	$398	$7,374	$28,870
Scenario 1						
1988	$26,553	$9,069	$977	$383	$1,673	$38,655
1989	$35,720	$12,010	$1,324	$509	$2,160	$51,724
1990	$37,025	$14,093	$1,130	$595	$2,936	$55,780
1991	$52,349	$18,719	$1,774	$792	$3,640	$77,275
1992	$59,084	$20,307	$2,185	$855	$3,790	$86,222
Scenario 2						
1988	$20,580	$15,207	$10,124	$1,475	$1,813	$49,199
1989	$27,781	$20,338	$13,743	$1,994	$2,321	$66,178
1990	$32,603	$24,728	$16,066	$2,355	$3,189	$78,942
1991	$45,140	$33,006	$21,930	$3,198	$3,903	$107,177
1992	$49,700	$35,716	$23,973	$3,488	$4,043	$116,920
Scenario 3						
1988	$50,204	$14,285	$4,980	$1,032	$200	$70,701
1989	$75,702	$24,387	$11,254	$2,006	$342	$113,690
1990	$102,085	$33,713	$16,264	$2,836	$472	$155,369
1991	$140,514	$48,357	$24,957	$4,212	$677	$218,716
1992	$149,263	$50,871	$25,857	$4,395	$712	$231,099

7.4 CONCLUSIONS

Based upon the analysis in this chapter it is clear that the current energy policies provide an important environmental benefit for Maine. In terms of the amount of pollutants, the actual scenario reduces total air pollutants from 1.9 to 6.0 million tons annually compared to the three alternative scenarios studied here (based upon the 1992 emissions levels).

What is the avoided environmental costs associated with this level of reduction? The number is harder to provide because of the uncertainties surrounding such estimates. Adopting the externality costs used for planning purposes in Massachusetts suggests that the benefits range from $57 to $202 million annually.

8.0 CONCLUSIONS

8.1 NET BENEFITS

Under the assumptions described in earlier chapters, the Maine energy policies have created a positive economic and environmental benefit for the state. But it still takes money to make money. Thus, while the state enjoyed a net employment gain of 1,800 to 3,300 jobs in 1992, and a net increase in GSP of $120 to $220 million, it required an investment to make it all happen. The investment, in this case, was in the form of a more costly revenue requirement in the actual scenario compared to the alternative scenarios. In that regard, Table 8-1, below, summarizes both the revenue impacts and the environmental and economic benefits among all four scenarios.

TABLE 8-1. SUMMARY OF 1992 SCENARIO IMPACTS

Scenario	Revenue Impact	GSP	Environmental Cost	Net Benefit
Actual	$1,008.3	$556.4	$28.9	$527.50
One	$1,002.7	$405.1	$86.2	$318.90
Two	$928.7	$433.9	$116.9	$317.00
Three	$942.3	$335.1	$231.1	$104.00

Notes: All values are in millions of dollars. The Revenue Impact is taken from the Chapter 5 scenario analysis. The estimates for Gross State Product are taken from chapter 6. The figures for Environmental Cost are drawn from chapter 7. The Net Benefit column is GSP less Environmental Cost.

Table 8-1 indicates that utility customers have, indeed, seen a boost in their average electric utility bill resulting from QF purchases. The actual revenue increases range from $5.6 million to $79.6 million (compared to scenarios one and two, respectively). On the other hand, the net benefits — measured as the contribution to GSP less environmental costs — are highest in the actual scenario compared to the any of the alternative scenarios. The difference ranges from $209 million (compared to scenario one) to $424 million (compared to scenario three).

8.2 LESSONS LEARNED

To many readers the scenarios themselves will be the focus of the report. But the real question should be whether the state's energy policies met the four primary goals outlined by the 1992 Commission on Comprehensive Energy Planning[186] — that is, cost, reliability, environmental impact, and economic impact. As one policy analyst testified before the Maine Legislature, "we did very well on reliability, and on environmental and economic impact."[187]

The one question is in the area of electricity prices. Yet, prices increased by only 4-12 percent as outlined in chapter 5. In light of the significant economic and environmental benefits shown in chapters 6 and 7, this very modest increase in electricity rates may prove to be a reasonable and important investment for the state. Inasmuch as the scenarios bracket a reasonable range of impacts, arguing about which scenario is more or less representative of the actual impact is likely to be a worthless exercise. The reason is that the lessons for the future are the same in all scenarios. The lessons learned are:

(1) Utility planning and investment is necessarily based on long-term projections of costs and electricity demand.

(2) Forecasts will be wrong and the direction of error is, more often than not, unknown.[188] Notwithstanding uncertainty inherent in planning, decisions must still be made by both the utilities and the Public Utilities Commission (PUC).

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186. *Report of the Commission on Comprehensive Planning*, op. cit.

187. Comments of John M. Flumerfelt, former Director of Energy Policy, Maine State Planning Office, before the Joint Standing Committee on Utilities, August 27, 1992.

188. Perhaps the best example of this is the mid-1980s expectation that oil prices would rise significantly. They did not, and all planning decisions based upon this expectation proved to be more costly as a result.

(3) Good planning and policy should lead to minimizing the likelihood and the consequences of forecasted error. Steps in that direction include an increased role for energy efficiency investments as well as the development of QF capacity — where clearly shown to be cost-effective. They also include improvements in the bidding system used to acquire future resources with final acceptance of those bids anchored by a review of how well they meet the other state planning objectives of reliability, environmental impact, and economic impact.

(4) Past state and PUC policy has minimized the consequences of error by assuring the state would receive substantial economic and environmental benefits even if forecasts were in error. This point has been borne out by the net gains shown in Table 8-1. The practice of minimizing the impact of future error can be strengthened by increasing the diversity of resource acquisitions as suggested in item 3 above.

The good news for Maine in all of this is that even a modest economic rebound will strengthen the benefits of current energy policies. Projections by Central Maine Power and the U.S. Department of Energy, for example, indicate that growth in economic activity and real personal income will lead to an increase of electricity sales through 1995 and beyond.[189]

As this materializes, Maine will be well-positioned to provide the new supplies of needed electricity — at less cost than might otherwise be the case. These changes will tend to reduce the cost of providing electricity, strengthen the state's employment base, and improve environmental quality when compared to current levels.

In sum, "the development of non-utility generation in Maine appears to be one of the most successfully implemented government policies we have ever enjoyed."[190] The question that Maine needs to address in light of these findings is whether (and how) the state wants to move ahead with future energy policies.

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189. See, for example, *1993 KWh Forecast Update*, Economic & Load Forecasting Department, Central Maine Power Company, February 1993. See also, *Short-Term Energy Outlook*, Energy Information Administration, Washington, DC, Fourth Quarter, 1993.

190. Statement of John Flumerfelt, op. cit.

9.0 APPENDICES

Appendix A. Project Advisory Group Members

Appendix B. Maine Historical Data

Appendix C. Maine Non-Utility Biomass Generators With Power Purchase Agreements

Appendix D. Relevant PUC Dockets

Appendix E. Estimating Influences on Revenue Increases

Appendix F. Extended Shift-Share Analysis For Selected Sectors in Maine

APPENDIX A. PROJECT ADVISORY GROUP MEMBERS

Stephen J. Adams, Director, State Planning Office
Steve Buchsbaum, EEs Inc.
James Corrodi, Scott Paper Co.
Peter Chamberlin, Airco Industrial Gases
Senator John J. Cleveland
Christopher Hutchins, Alternative Energy Inc.
Angus King, Northeast Energy Management, Inc.
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Beth Nagusky, Natural Resources Council of Maine
Steve McGraw, Keyes Fibre Co.
Robert Nault, National Semiconductor
Elizabeth Paine, Commissioner, Maine Public Utilities Commission
Glenn Poole, Champion International
H. Dana Smith, U.S. Energy Corporation
Stephen Ward, Public Advocates Office
Senator Harry Vose
Gordon Weil, Weil and Howe, Inc.
Frederick Woodruff, Central Maine Power Co.

Thomas Tietenberg, Colby College, Project Advisor

As noted in the main text of the report, the Project Advisory Group served strictly as advisors to this project. Their names here are not intended to imply full support of all the conclusions in the study.

TABLE B-1. MAINE POPULATION, EMPLOYMENT AND INCOME

Year	Population (1,000)	Employment	Personal Income ($MM)	Wages ($MM)	Per Capita Income	Average Wage	Deflator (1987=100)	Per Capita Income (Constant $)	Average Wage (Constant $)
1970	997	444,580	$3,390	$2,166	$3,401	$4,873	0.352	$9,662	$6,173
1971	1,016	442,240	$3,628	$2,258	$3,572	$5,106	0.371	$9,628	$5,990
1972	1,035	451,102	$3,965	$2,470	$3,831	$5,475	0.388	$9,874	$6,150
1973	1,046	469,064	$4,479	$2,712	$4,281	$5,783	0.413	$10,366	$6,279
1974	1,060	476,873	$4,980	$2,932	$4,698	$6,148	0.449	$10,463	$6,160
1975	1,073	473,949	$5,310	$3,108	$4,948	$6,558	0.492	$10,057	$5,887
1976	1,090	496,604	$6,118	$3,553	$5,613	$7,154	0.523	$10,732	$6,232
1977	1,105	511,847	$6,657	$3,857	$6,022	$7,535	0.559	$10,773	$6,244
1978	1,115	531,620	$7,376	$4,303	$6,612	$8,095	0.603	$10,965	$6,401
1979	1,125	544,581	$8,241	$4,763	$7,326	$8,746	0.655	$11,185	$6,463
1980	1,128	552,040	$9,266	$5,275	$8,218	$9,555	0.717	$11,462	$6,522
1981	1,133	551,956	$10,263	$5,713	$9,058	$10,351	0.789	$11,480	$6,391
1982	1,137	553,776	$10,977	$6,117	$9,657	$11,045	0.838	$11,524	$6,419
1983	1,145	565,892	$11,879	$6,535	$10,376	$11,548	0.872	$11,899	$6,545

TABLE B-1. MAINE POPULATION, EMPLOYMENT AND INCOME

Year	Population (1,000)	Employment	Personal Income ($MM)	Wages ($MM)	Per Capita Income	Average Wage	Deflator (1987=100)	Per Capita Income (Constant $)	Average Wage (Constant $)
1984	1,156	588,826	$13,124	$7,157	$11,355	$12,155	0.910	$12,478	$6,804
1985	1,163	608,020	$14,142	$7,656	$12,159	$12,591	0.944	$12,880	$6,973
1986	1,170	632,268	$15,462	$8,347	$13,213	$13,201	0.969	$13,636	$7,362
1987	1,185	668,993	$16,871	$9,257	$14,240	$13,837	1.000	$14,240	$7,812
1988	1,204	700,953	$18,403	$10,237	$15,285	$14,604	1.039	$14,711	$8,183
1989	1,220	712,693	$19,957	$11,003	$16,358	$15,439	1.085	$15,076	$8,312
1990	1,231	709,541	$20,915	$11,414	$16,988	$16,086	1.132	$15,007	$8,191
1991	1,234	687,509	$21,293	$11,311	$17,249	$16,452	1.178	$14,643	$7,781
1992	1,235	686,951	$22,360	$11,743	$18,100	$17,094	1.209	$14,971	$7,865

Source: All data is from the U.S. Bureau of Economic Analysis (BEA), U.S. Department of Commerce. The information is available in electronic file format in tables SA5 and SA25, personal income and employment data, respectively. The deflators are taken from the implicit GDP price deflators published by BEA. Please note that since BEA's employment data include agricultural workers and reflect both proprietors and the self-employed, the job totals are higher than those available from the Bureau of Labor Statistics.

TABLE B-2. MAINE EMPLOYMENT TOTALS FOR 1992

SECTOR	JOBS	PERCENT OF TOTAL JOBS	PERCENT OF U.S. PER CAPITA JOBS
TOTAL EMPLOYMENT	686,951	100.00%	102.62%
WAGE AND SALARY	549,212	79.95%	97.23%
PROPRIETORS	137,739	20.05%	131.80%
FARM	6,968	1.01%	66.26%
NONFARM	130,771	19.04%	139.13%
FARM	11,603	1.69%	78.99%
NONFARM	675,348	98.31%	103.15%
PRIVATE	566,368	82.45%	102.81%
AGRIC. SERV., FORESTRY, FISHERIES	13,066	1.90%	182.04%
FISHERIES	5,896	0.86%	1269.85%
MINING	497	0.07%	11.23%
CONSTRUCTION	40,279	5.86%	127.26%
GENERAL BUILDING CONTRACTORS	8,562	1.25%	122.32%
HEAVY CONSTRUCTION CONTRACTORS	4,388	0.64%	117.43%
SPECIAL TRADE CONTRACTORS	27,329	3.98%	130.67%
MANUFACTURING	101,586	14.79%	112.09%
NONDURABLE GOODS	52,059	7.58%	133.83%
FOOD AND KINDRED PRODUCTS	6,767	0.99%	83.82%
TEXTILE MILL PRODUCTS	5,346	0.78%	162.33%
APPAREL AND TEXTILE PRODUCTS	2,983	0.43%	58.70%
PAPER AND ALLIED PRODUCTS	16,492	2.40%	493.03%
PRINTING AND PUBLISHING	5,840	0.85%	73.22%
CHEMICALS AND ALLIED PRODUCTS	1,197	0.17%	22.64%

TABLE B-2. MAINE EMPLOYMENT TOTALS FOR 1992

SECTOR	JOBS	PERCENT OF TOTAL JOBS	PERCENT OF U.S. PER CAPITA JOBS
PETROLEUM AND COAL PRODUCTS	339	0.05%	45.23%
RUBBER AND MISC. PLASTICS	2,901	0.42%	68.10%
LEATHER AND LEATHER PRODUCTS	10,189	1.48%	1702.65%
DURABLE GOODS	49,527	7.21%	95.74%
LUMBER AND WOOD PRODUCTS	14,298	2.08%	364.77%
FABRICATED METAL PRODUCTS	2,905	0.42%	44.68%
MACHINERY AND COMPUTER EQUIP.	4,464	0.65%	46.98%
ELECTRONIC EQUIP., EXC. COMPUTER	7,082	1.03%	95.13%
TRNSPRT EQUIP. EXCL. MTR VEHICLES	12,795	1.86%	258.43%
STONE, CLAY, AND GLASS PRODUCTS	3,350	0.49%	112.99%
INSTRUMENTS, RELATED PRODUCTS	1,000	0.15%	22.19%
MISC. MANUFACTURING INDUSTRIES	1,369	0.20%	62.89%
TRANSPORTATION/PUBLIC UTILITIES	28,666	4.17%	90.72%
RAILROAD TRANSPORTATION	818	0.12%	64.24%
TRUCKING AND WAREHOUSING	12,262	1.78%	118.27%
LOCAL/INTERURBAN TRANSIT	1,765	0.26%	83.73%
TRANSPORTATION BY AIR	863	0.13%	24.23%
TRANSPORTATION SERVICES	1,019	0.15%	45.96%
COMMUNICATIONS	4,829	0.70%	76.76%
ELECTRIC, GAS, SANITARY SERVICES	5,443	0.79%	113.81%
WHOLESALE TRADE	26,829	3.91%	84.24%
RETAIL TRADE	125,737	18.30%	113.99%
BUILDING/GARDEN MATERIALS	5,212	0.76%	127.68%
GENERAL MERCHANDISE STORES	11,668	1.70%	93.48%

TABLE B-2. MAINE EMPLOYMENT TOTALS FOR 1992

SECTOR	JOBS	PERCENT OF TOTAL JOBS	PERCENT OF U.S. PER CAPITA JOBS
FOOD STORES	21,530	3.13%	125.40%
AUTO DEALERS/SERVICE STATIONS	13,353	1.94%	121.41%
APPAREL AND ACCESSORY STORES	6,518	0.95%	104.59%
HOME FURNITURE/FURNISHINGS STORES	3,922	0.57%	83.98%
EATING AND DRINKING PLACES	35,874	5.22%	103.80%
MISCELLANEOUS RETAIL	27,660	4.03%	137.54%
FINANCE, INSURANCE, REAL ESTATE	40,045	5.83%	78.81%
CREDIT INSTITUTIONS.	9,470	1.38%	77.12%
OTHER FINANCE, REAL ESTATE	30,575	4.45%	79.35%
SECURITY & COMMODITY BROKERS	793	0.12%	30.71%
INSURANCE CARRIERS	7,277	1.06%	99.41%
INSURANCE AGENTS, BROKERS	5,632	0.82%	92.62%
REAL ESTATE	15,261	2.22%	84.17%
HOLDING/OTHER INVESTMENT	1,612	0.23%	36.48%
SERVICES	189,663	27.61%	98.57%
HOTELS AND OTHER LODGING PLACES	12,392	1.80%	146.29%
PERSONAL SERVICES	11,918	1.73%	102.42%
PRIVATE HOUSEHOLDS	7,215	1.05%	110.88%
BUSINESS SERVICES	29,722	4.33%	74.11%
AUTO REPAIR, SERVICES, AND PARKING	7,223	1.05%	105.51%
MISCELLANEOUS REPAIR SERVICES	3,311	0.48%	103.85%
AMUSEMENT/RECREATION SERVICES	8,625	1.26%	101.57%
MOTION PICTURES	1,562	0.23%	67.14%
HEALTH SERVICES	55,211	8.04%	117.53%

TABLE B-2. MAINE EMPLOYMENT TOTALS FOR 1992

SECTOR	JOBS	PERCENT OF TOTAL JOBS	PERCENT OF U.S. PER CAPITA JOBS
LEGAL SERVICES	5,928	0.86%	89.82%
EDUCATIONAL SERVICES	10,018	1.46%	98.86%
SOCIAL SERVICES	11,484	1.67%	114.48%
MUSEUMS	268	0.04%	76.88%
MEMBERSHIP ORGANIZATIONS	7,465	1.09%	76.79%
ENGINEERING/MANAGEMENT SERVICES	16,622	2.42%	82.74%
MISCELLANEOUS SERVICES	699	0.10%	73.89%
GOVERNMENT	108,980	15.86%	104.97%
FEDERAL, CIVILIAN	17,369	2.53%	113.10%
MILITARY	14,667	2.14%	115.71%
STATE AND LOCAL	76,944	11.20%	101.52%

SOURCE: All data are taken from the U.S. Bureau of Economic Analysis.

NOTES: Totals may not add because of rounding. Some sectors have been omitted for space considerations.

TABLE B-3. MAINE ELECTRICITY USAGE (IN GIGAWATT-HOURS)

Year	Residential	Commercial	Industrial	Total
1970	1,723	975	2,370	5,068
1971	1,888	1,054	2,376	5,318
1972	2,129	1,173	2,525	5,827
1973	2,263	1,257	2,612	6,132
1974	2,408	1,240	2,767	6,415
1975	2,487	1,568	2,477	6,532
1976	2,771	1,698	2,652	7,121
1977	2,859	1,750	2,961	7,570
1978	2,996	1,817	3,164	7,977
1979	3,016	1,721	3,335	8,072
1980	2,998	1,717	3,470	8,185
1981	3,033	1,787	3,419	8,239
1982	3,182	1,831	3,714	8,727
1983	3,218	1,917	4,302	9,437
1984	3,369	2,276	3,978	9,623
1985	3,419	2,338	4,067	9,824
1986	3,578	2,490	4,135	10,203
1987	3,726	2,642	4,351	10,719
1988	3,904	2,744	4,606	11,254
1989	4,009	2,826	4,599	11,434
1990	3,932	2,847	4,750	11,529
1991	3,817	2,857	4,709	11,383
1992	3,830	2,719	4,748	11,297

Notes: The term gigawatt-hour is equal to 1,000,000 kilowatt-hours. The information is taken from EIA's *State Energy Data Reports* (Washington, DC: Energy Information Administration, U.S. Department of Energy, DOE/EIA-0214(91), May 1993).

Table B-4. Maine Electricity Prices (in Cents per Kilowatt-Hour)

Year	Current Prices				Constant Prices (1987$)			
	Residential	Commercial	Industrial	Average	Residential	Commercial	Industrial	Average
1970	2.77	2.68	1.20	2.02	7.87	7.62	3.41	5.74
1971	2.76	2.70	1.23	2.06	7.44	7.26	3.31	5.56
1972	2.87	2.85	1.34	2.20	7.40	7.35	3.44	5.68
1973	2.95	2.92	1.39	2.28	7.14	7.07	3.37	5.52
1974	3.44	3.26	2.04	2.80	7.65	7.26	4.54	6.23
1975	3.98	3.99	2.20	3.31	8.09	8.10	4.48	6.73
1976	3.76	3.87	2.08	3.16	7.19	7.40	3.97	6.04
1977	4.17	4.27	2.30	3.46	7.46	7.63	4.11	6.19
1978	4.29	4.46	2.37	3.57	7.11	7.39	3.93	5.91
1979	4.99	5.22	3.09	4.25	7.62	7.97	4.71	6.49
1980	6.25	6.55	4.49	5.56	8.71	9.14	6.26	7.76
1981	7.17	7.45	5.08	6.36	9.09	9.44	6.44	8.07
1982	7.41	7.70	4.88	6.39	8.84	9.19	5.83	7.63
1983	7.38	7.58	4.68	6.19	8.46	8.70	5.37	7.10
1984	7.63	7.57	4.97	6.52	8.38	8.32	5.47	7.16

TABLE B-4. MAINE ELECTRICITY PRICES (IN CENTS PER KILOWATT-HOUR)

Year	Current Prices				Constant Prices (1987$)			
	Residential	Commercial	Industrial	Average	Residential	Commercial	Industrial	Average
1985	8.09	8.08	5.17	6.88	8.57	8.56	5.48	7.29
1986	8.18	8.03	4.82	6.79	8.45	8.29	4.98	7.00
1987	8.12	7.06	4.82	6.52	8.12	7.06	4.82	6.52
1988	8.25	7.22	5.07	6.70	7.94	6.95	4.88	6.44
1989	8.51	7.54	5.37	7.01	7.84	6.95	4.95	6.46
1990	9.31	8.19	5.96	7.65	8.22	7.23	5.26	6.76
1991	10.46	9.25	6.71	8.60	8.88	7.85	5.70	7.30
1992	11.37	9.27	6.91	9.05	9.40	7.67	5.72	7.49

Source: The electricity prices are derived from the *State Energy Price and Expenditure Report 1991* (Washington, DC: Energy Information Administration, U.S. Department of Energy, DOE/EIA-0376(91), September 1993); and the *Statistical Yearbook of the Electric Utility Industry 1992* (Washington, DC: Edison Electric Institute, October 1993).

Appendix C. Maine Non-Utility Biomass Generators With Power Purchase Agreements In 1992

Facility	Location	Contact	Phone	Facility Type	Utility Served	Utility Contract Capacity MW	Contract Term Yrs	Startup Date	1992 Utility Purchases MWh	1992 Utility Payment Dollars	Fuel Type
A.R. Lavalley	Sanford	Terry Walters	324-3350	Lumber	CMP	1.25	15	Oct. 82	2,505	$272,125	Biomass chips, sawdust
Babcock Ultrapower	West Enfield	Roger Day	732-4151	SA	BHE	24.50	15	Nov. 87	3,566	$15,341,194	Biomass chips
	Jonesboro	Kevin Crossman	434-6500	SA	BHE	24.50	20	Nov. 87	14,834	$15,680,437	Biomass chips
Beaverwood Joint Venture / Alt. Energy Inc.	Chester	Chris Hutchins	947-0774	SA	BHE (term)	15.40	30	Nov. 86	111,468	$10,547,576	Biomass chips
Boise Cascade / Rumford Cogeneration Co. LP	Rumford	Bob Stickney	364-4521	Pulp&Paper	CMP	75.00	15	May 90	636,046	$45,374,623	Bark, chips, sawdust and coal
Champion Cogenerating	Bucksport	Glen Poole	469-1230	Pulp&Paper	CMP	32.70	20	Aug. 88	194,977	$15,171,657	Biomass/multi
Dirigo Dowels Inc.	New Portland	Gerald Strictland	628-4101	Wood Products	CMP	0.30	13	Nov. 85	622	$51,959	Mill residues
Down East Peat LP	Deblois	Paul LePage	638-2811	SA	BE (term)	23.00	20	Jun. 89	n/a	n/a	Peat/biomass
					BHE (term)	n/a	n/a	n/a	13,456	$358,611	
Fairfield Energy Venture LP / US Energy	Ft. Fairfield	Peter Powers	473-7592	SA	CMP	32.00	15	Nov. 87	243,748	$28,238,591	Sawdust, slash, chips, bark
					MPS	n/a	n/a	n/a	25	$304	
Forster Manufacturing	Strong	Robert Sween	645-2574	Wood Products	CMP (term)	1.25	12	Nov. 84	2,533	$241,352	Mill residues
	Mattawamkeag				BHE (term)	1.00	12	Nov. 84	598	$32,896	Mill residues
Gorbell-Thermo Electron Power Co.	Athens	Ray Barriault	654-2097	SA	CMP	13.80	20	Dec. 87	87,999	$9,349,615	Mill residues, chips
Greenville Steam Co. / Swift River Hafslund Co.	Greenville Jct	Ray Kushe	774-6400	SA	CMP	13.80	20	Feb. 87	76,847	$8,113,698	Mill residues, chips

Appendix C. Maine Non-Utility Biomass Generators With Power Purchase Agreements In 1992

Facility	Location	Contact	Phone	Facility Type	Utility Served	Utility Contract Capacity MW	Contract Term Yrs	Startup Date	1992 Utility Purchases MWh	1992 Utility Payment Dollars	Fuel Type
Lewiston Steam and Power	Lewiston	Rod Mize	784-5022	SA	CMP (term)	11.80	28	Oct. 85	43,196	$4,019,347	Chips, mill residues
Robbins Lumber Co.	Searsmont	Bruce Mclaughin	342-5221	Lumber mill	CMP	1.20	16	Oct. 84	4,543	$316,476	Sawdust, chips, mill ends
Scott Paper Company / SD Warren Company		Jim Corrodi	215-5228801	Pulp&Paper					1,305,318	$101,706,366	
	Somerset				CMP	85.00	30	Dec. 82			Pulp liquor,bark/wood waste, coal, oil
	Westbrook				CMP	60.00	15	Oct. 82			Pulp liquor, bark/wood waste, wood pellets, tire chips, oil
	Winslow				CMP	18.80	15	Jun. 89			Shipping pallets, paper cores, bark/wood waste, oil
Stratton Energy Associates	Stratton	Dan Noel	246-2252	SA	CMP	36.80	20	Aug. 89	295,642	$27,218,749	Chips, mill residues
Wheelabrator-Sherman Energy Co.	Sherman Station	Ray Soulard	365-4251	SA	MPS	16.50	25	Jul. 86	131,868	$13,082,629	Chips, mill residues
Total						488.60			3,181,908	$295,386,978	

Notes: The electricity purchases (MWh and payments) are taken from 1992 FERC Form 1 reporting by the respective utilities. The notation "term" refers to contracts that have been terminated by the utility; "SA" refers to stand-alone facilities — independent power producers; "MPS" refers to Maine Public Service Company; "CMP" refers to Central Maine Power Company; "BHE" refers to Bangor Hydro Electric Company, "BE" refers to Boston Edison Consolidated; and "$0.00" million reflects a payment of $304 — a number too small to appear in the table given the number of decimal places reported. The Total "Capacity MW" reported includes the 26.7 MW capacity of the Down East Peat LP facility although very little of the capacity was contracted for by a Maine utility. The actual utility contract capacity (the small percentage of the facilities total capacity) was not available for the Down East Peat LP or for the small capacity sold by Fairfield Energy Venture to MPS and is noted with an "n/a." Consequently, these capacities are not included in the Total "Contract Capacity MW" column.

Appendix D. Relevant PUC Dockets

Several dozen Commission decisions from 1979 through the present have been reviewed. Those which appeared to be of the greatest significance, based on review and on input from members of the Policy Advisory Committee, including the utilities, are summarized below.

12/31/79, U-3238 - petition for certificate to erect coal plant at Sears Island

The PUC turned down CMP's petition, taking the position that CMP had not shown that the capacity was needed. The Commission differed with CMP's demand forecasts.

5/7/81, Docket 80-268 - PUC adopted rule for Chapter 36

This docket established the basis for determining avoided capacity and energy costs. The Commission stated that it would "compare two generation expansion plans; the utility's current plan and a plan which is revised to reflect a lower level of demand."

10/14/82 - Docket 81-114, MPSC, Investigation of power supply planning and purchases

The PUC decided that Stone & Webster's sales projections on behalf of MPSC were too high. The PUC stated that it "cannot find that MPSC's investment in Seabrook is an economic means to meet the future demands..." But the Commission decided to reopen the record to "allow for a recalculation by the parties of the economics of Seabrook on the basis of the corrected assumptions with respect to the cost of Seabrook and the load forecast."

1/9/84, Docket 82-174, CMP and Scott Paper, consolidated proceedings to establish long-term cogeneration and small power production rates

The PUC indicated that it based its ruling not on PURPA but on the Maine Small Power Production Facilities Act of 1979. The Commission decided that Seabrook I was not avoidable, because the plant might not be saleable. But the Commission concluded that Seabrook II was saleable at a discount, so it ordered CMP to use 88 percent of the capital cost of Unit II as the avoided cost.

2/10/84, Docket 81-276, 83-264, 83-303, Decision and Order, MPSC, Sherman Power, AEC, Investigation on standard long-term rates for cogeneration and small power production

This case is cited by most parties as one of, and perhaps the, most important decision of the PUC during this period. It set the basis for determining avoided costs for payments to QF's. The PUC decided that Seabrook I is avoidable, but that Seabrook II should be excluded from the base case. The utility was ordered to count Seabrook I's value at a 20 percent discount (MPSC's undiscounted cost of Seabrook I was $50.2 million) for purposes of calculating avoided costs.

"MPS could obtain capacity and energy, presumably from Coleson Cove, over a possible fifteen-year period at 65-70 mills."

MPSC's response to our data request #1 stated that "This was the one PUC docket which significantly altered MPS'S energy supply planning." In response to our request #2, MPSC said that in Docket 81-276 it first argued that since the company already owned a share of Seabrook the plant was not avoidable, and as a result MPSC had surplus capacity. Therefore, avoided costs should contain no capacity component. Once that argument was lost, MPSC argued that Seabrook I's market value was zero, again indicating a zero capacity component. As an alternative, MPSC witness Louridas argued that the avoided capacity cost should be $45.50/kw/year, based on purchases from New Brunswick.

12/22/87, Docket 86-242 Bangor Hydro-Electric Company, Investigation of Reasonableness of Rates

The Public Advocate contended that events had changed since the PUC's 1984 decision on using Seabrook 1 as avoided costs. The Advocate argued that Seabrook's costs had risen, and oil prices had fallen, so Bangor should have reevaluated its estimates of avoided costs. Bangor stated (page 68) that they chose to sign contracts with the QFs because they believed that if the PUC had determined avoided costs for BHE in 1984, these would have been higher than the estimates BHE was using.

Immediately after signing the contracts, Bangor sold 25 mw of power to UNITIL - at a levelized rate of 8.5 cents/kwh. The Advocate argued that this sale indicated that the contracts were overpriced — if Bangor did not need the power, then the avoided costs should have been lower.

12/22/88, Docket 88-178, Demand side energy management programs by electric utilities (Chapter 380), Order adopting rule and statement of factual policy basis.

The Commission stated that the purpose of this rule is to set standards and reporting requirements for utility DSM programs, but that utilities are already required to undertake DSM programs by "both Chapter 36 of the Commission's Rules and Regulations and the Maine Energy Policy Act of 1988, 35-MRSA 3191. The amended Chapter 380 rule itself became effective on January 1, 1989.

Dockets 88-111, 87-261 Order Denying Certificate Constructing Transmission Line to Link with Hydro Quebec.

Referencing the growing success of QFs and DSM programs, the PUC denied a request to construct a transmission line that eventually would have provided CMP with up to 900 MW of capacity from Hydro Quebec.

In its order, the Commission noted that "Over the past decade the Commission has moved steadily in the direction of creating a workable, competitive, balanced, and least cost energy planning process for the state. In large part, CMP has responded positively to the development of the integrated planning process and has over the past several years greatly improved and refined its ability to conduct sophisticated analysis of power supply alternatives. The procedures which have evolved here and the success we have realized in our energy mix have, in some particulars, made Maine a model for the rest of the country."

APPENDIX E. ESTIMATING INFLUENCES ON REVENUE INCREASES

Calculation or Category of Impact			Amount ($Million)
(1)	Actual Revenues in 1988 - Current Dollars		$730.8
(2)	Actual Revenues in 1992 - Current Dollars		$1,008.3
(3)	Inflation 1988-1992 Using GDP Deflator - 120.9/103.9 * 100		16.42%
(4)	Change in 1988-1992 Revenues - Current Dollars		$277.5
(5)	Actual Revenues in 1988 - Constant 1988$		$730.8
(6)	Actual Revenues in 1992 - Constant 1988$		$866.1
(7)	Change in 1988-1992 Revenues - Constant 1988$		$135.3
(8)	Alternative 1992 Revenues - Constant 1988$		$797.7
(9)	QF Impact ($866.1 - $797.7)		$68.4
(10)	Seabrook Impact ($245 M * 0.13 / 1.1642)		$27.4
(11)	Consumption Impact ((11,549 GWh/11,048 GWh-1) * 730.8)		$33.1
(12)	Inflation Impact ($730.8 * 0.1642)		$120.0
(13)	Miscellaneous Impact ($277.5 - $120.0 - $68.4 - $27.4 - $33.1)		$28.6
(14)	Percentage of Impacts		
	Inflation	$120.0	43.2%
	QF/DSM Policy	$ 68.4	24.6%
	Consumption	$ 33.1	11.9%
	Seabrook	$ 27.4	9.9%
	Unexplained	$ 28.6	10.3%
	Total	$277.5	100.0%

Note: The data is taken from the information found in chapter 5 of this report

APPENDIX F. EXTENDED SHIFT-SHARE ANALYSIS FOR SELECTED SECTORS IN MAINE - 1984 THROUGH 1992

Economic Sector	National Growth Effect	Industrial Change Effect	Competitive Advantage	Net Job Change
Total Employment	85,288	1,045	11,792	98,125
Wage and Salary	70,668	(5,429)	(3,917)	61,322
Proprietors	14,620	6,474	15,709	36,803
Farm	2,123	(4,675)	(501)	(3,053)
Nonfarm	83,166	5,720	12,293	101,178
Private	68,811	6,384	16,105	91,300
Mining	62	(209)	217	70
Construction	4,790	(2,411)	4,831	7,210
General Building Contractors	1,477	(2,527)	(583)	(1,633)
Heavy Construction Contractors	584	(1,060)	832	356
Special Trade Contractors	2,729	964	4,793	8,487
Manufacturing	16,894	(23,698)	(8,247)	(15,051)
Nondurable Goods	9,778	(9,915)	(15,314)	(15,451)
Food and Kindred Products	1,154	(936)	(1,418)	(1,200)
Textile Mill Products	1,049	(1,758)	(1,184)	(1,893)
Apparel and Other Textile Products	714	(1,449)	(1,215)	(1,949)
Paper and Allied Products	2,648	(2,413)	(2,029)	(1,793)
Printing and Publishing	715	(130)	323	907
Chemicals and Allied Products	140	(111)	197	227
Petroleum and Coal Products	36	(69)	120	88
Rubber and Misc. Plastics Products	573	(106)	(1,520)	(1,053)
Leather and Leather Products	2,748	(9,836)	(1,698)	(8,786)

APPENDIX F. EXTENDED SHIFT-SHARE ANALYSIS FOR SELECTED SECTORS IN MAINE - 1984 THROUGH 1992

Economic Sector	National Growth Effect	Industrial Change Effect	Competitive Advantage	Net Job Change
Durable Goods	7,116	(11,864)	5,149	400
Lumber and Wood Products	2,429	(2,157)	(2,743)	(2,471)
Primary Metal Industries	81	(192)	(452)	(562)
Fabricated Metal Products	492	(810)	(175)	(493)
Machinery and Computer Equipment	665	(1,215)	423	(127)
Electronic Equipment, Exc. Computers	1,348	(4,239)	665	(2,226)
Trans. Equip. Excl. Motor Vehicles	1,375	(1,591)	3,515	3,299
Stone, Clay, and Glass Products	245	(319)	1,733	1,659
Instruments and Related Products	92	102	171	365
Miscellaneous Manufacturing Industries	193	(231)	72	34
Transportation and Public Utilities	3,613	(563)	670	3,720
Communications	738	(982)	(21)	(265)
Electric, Gas, and Sanitary Services	644	(407)	762	999
Wholesale Trade	3,355	(1,056)	1,370	3,669
Retail Trade	14,330	1,821	10,654	26,805
Building and Garden Materials	630	(191)	424	863
General Merchandise Stores	1,551	(729)	135	958
Food Stores	2,680	728	(383)	3,026
Automotive Dealers and Service Stations	1,578	(482)	1,367	2,462
Apparel and Accessory Stores	720	(66)	889	1,544
Home Furnishings Stores	504	43	(109)	439
Eating and Drinking Places	3,851	1,633	3,803	9,287
Miscellaneous Retail	2,815	959	4,452	8,226
Finance, Insurance, and Real Estate	4,514	(196)	4,564	8,882