Maine Public Utilities Commission

2005 Annual Report on Electric Restructuring

Presented to the Utilities and Energy Committee December 31, 2005

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2005 Annual Report on Electric Restructuring
Presented to the Utilities and Energy Committee of the Maine Legislature

2005 HIGHLIGHTS

- *Wholesale electricity prices increased by more than 50% during 2005, driven by similar increases in natural gas prices. The supply and demand balance in global natural gas markets, coupled with hurricane-related damage and production disruption in the U.S., drove these increases.*
- *Large and medium C&I customers continued to exhibit a reasonable and steady level of migration to the retail generation supply market.*
- *Most residential and small commercial customers continued to obtain retail generation supply from standard offer service. The standard offer procurement process remained very competitive and thus residential customers receive the benefits of the competitive electricity market indirectly. A green market remains nascent, but many residential customers with contracts for green power returned to standard offer service when contracts expired.*
- *The Commission and other regulatory agencies investigated two applications to increase transmission capacity between portions of Maine and the Canadian provinces. The Commission approved one proposal, but found no public need for the second proposal.*
- *The number of retail suppliers serving Maine customers remained steady, with consumer purchases dispersed among many suppliers. However, a large share of the retail market is served by a single set of affiliated suppliers.*
- *The significant increases in the cost of wholesale electricity caused Maine's standard offer prices to increase, continuing a trend that began in 2004. In March 2005, residential and small commercial customers experience an increase in the price of standard offer service, some for the first time in three years. Another increase will occur in March 2006.*
- *The Commission implemented a "laddering" approach to the selection of standard offer service for residential and small commercial customers, which will mitigate price volatility over time.*
- *Proceedings to recalculate stranded costs and the auction of generation from Maine's qualifying facilities (QFs) were concluded, resulting in stranded cost rate decreases for CMP and BHE customers.*
- *Well over 30% of Maine's supply was met with renewable and other eligible fuel resources.*
- *Wholesale generation supply costs in Maine continued to be the lowest in New England because of the locational features of New England's regional standard market design.*
- *The Commission continued to actively participate in the FERC's Locational Installed Capability (LICAP) proceeding, whose results could significantly increase the cost of wholesale electricity in Maine.*

I. BACKGROUND

During its 1997 session, the Legislature enacted P.L. 1997 (the Restructuring Act), ch. 306, codified at 35-A M.R.S.A. §3201-3217, which directed comprehensive restructuring of Maine's electric utility industry. Shortly thereafter, the Public Utilities Commission (Commission) disaggregated the vertically integrated electric utilities into delivery and generation functions, established the rates of transmission and distribution (T&D) utilities, and established rules that govern the activities of competitive electricity providers and utilities. Since then, the Commission has purchased standard offer service through competitive bid processes, monitored retail market development, and participated in regional wholesale market activities that affect Maine's electricity consumers. For large and medium customers, Maine's retail market has developed relatively smoothly and effectively in most respects. Small customers benefit from competition in the wholesale market through the standard offer.

Each year, pursuant to the Restructuring Act, the Commission submits a report to the Legislature's Joint Standing Committee on Utilities and Energy, describing Maine's retail market and activities the Commission has taken to comply with the restructuring statute. This report covers 2005.

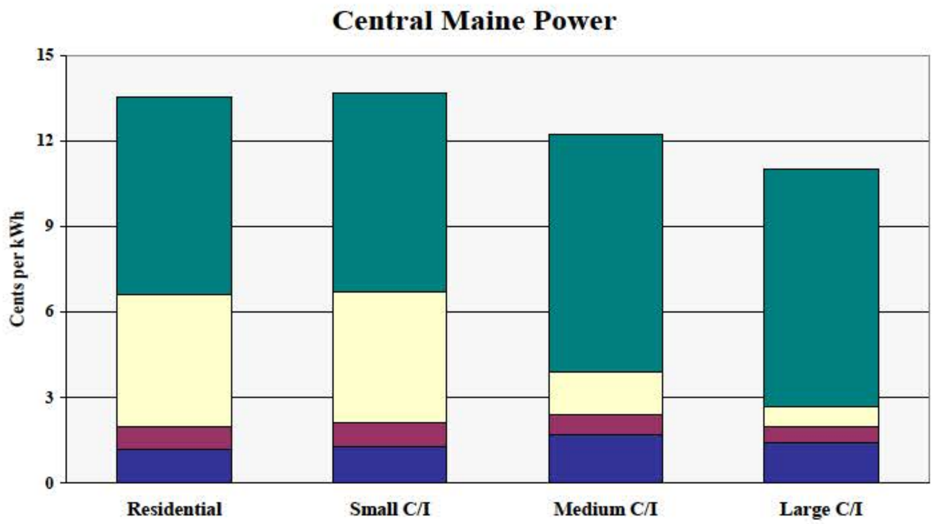
II. CONSUMER PRICES

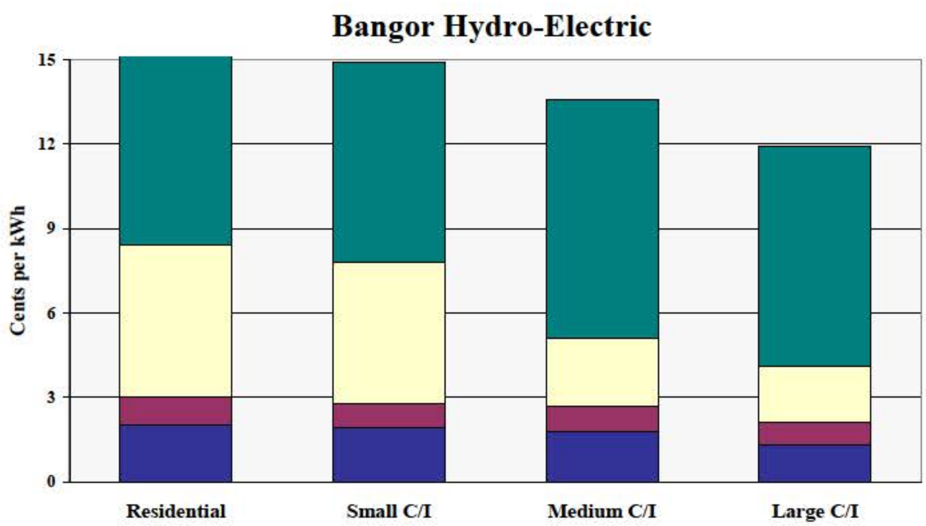
Electricity prices include four distinct components – transmission rates, distribution rates, stranded cost rates, and energy prices. The first three, bundled together, comprise the rate charged by the T&D utility. Transmission rates cover the cost of constructing and operating the transmission system and are regulated by the Federal Energy Regulatory Commission (FERC). Distribution rates cover costs incurred by the T&D utility to construct and operate the local distribution system and are regulated by the Commission. Stranded cost rates reflect the net, above-market costs for generation obligations that utilities incurred prior to industry restructuring, and are regulated by the Commission. Finally, energy prices are unregulated retail prices charged for generation service by competitive electricity providers that, in Maine's restructured environment, operate in the competitive market. Competitive electricity providers are licensed by the Commission. Consumers may obtain generation service directly from a competitive provider or through standard offer service that is obtained by the Commission through a competitive bid process.

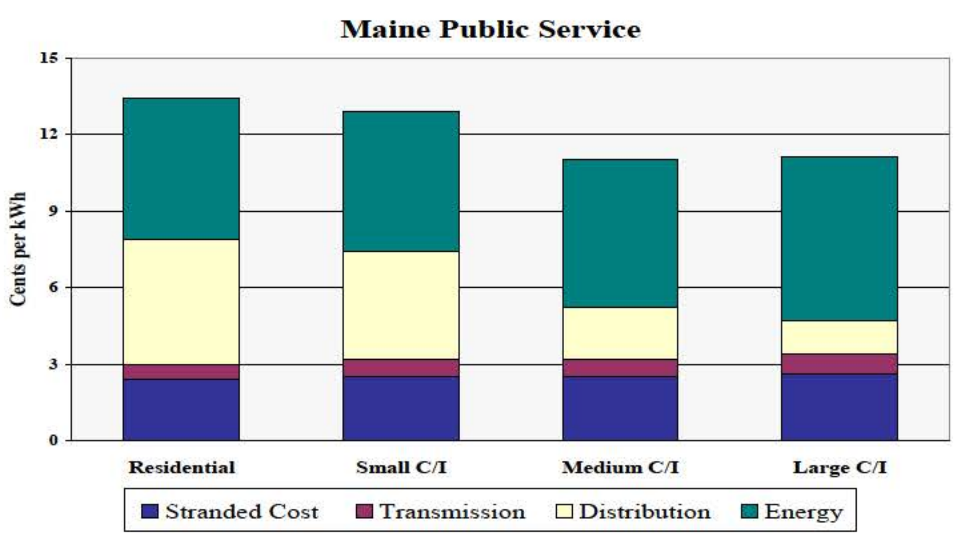
Sections III and IV of this report describe activities in the retail market that influence retail energy prices and Section X describes activities in the region that influence wholesale market procedures and prices. Section V describes events associated with standard offer service. Section VI describes events associated with stranded cost rates.

The charts on the following page display, as of December 2005, the components, on average, of the basic prices for various customer sizes in the service territories of Bangor Hydro-Electric (BHE), Central Maine Power Company (CMP), and Maine Public Service Company (MPS). The displayed energy prices are the average standard offer rates; customers receiving generation from the open market may have lower or higher energy prices. In addition, many customers receive service under special rate contracts that have T&D prices below tariff rates. Finally, rates for large industrial customers that receive transmission level service are lower than rates for customers receiving distribution level service because the cost of serving customers at transmission voltage is lower than at distribution voltage. When compared with 2004 electricity rates, 2005 stranded costs represent a smaller portion of total rates and energy prices represent a larger portion.

Components of Electricity Rates in December 2005







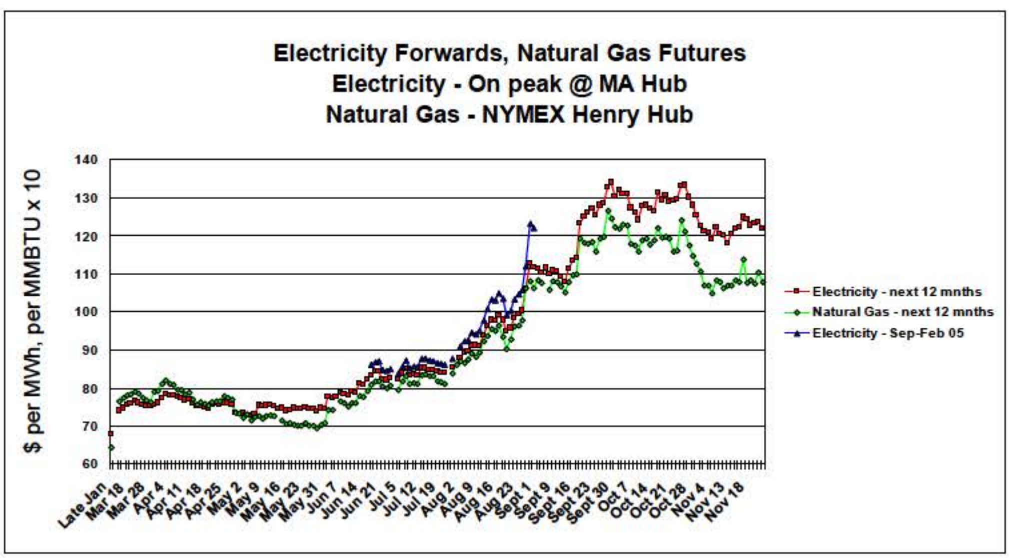
III. FUEL PRICES AND THE GENERATION MARKET

The deregulation of the generation market removed the control of generation investment from regulators and State government. In the deregulated environment, market investors rather than utilities and regulators decide whether to build or upgrade generating facilities, where construction or upgrades will occur, and what types of generating facilities (peak load or base load; wind, biomass, or natural gas) will be constructed. This change was intentional, designed to place the risk of poor investment decisions on market participants rather than ratepayers and to allow market forces to drive the lowest-cost generation sources.

However, this approach has disadvantages as well. State regulators and legislators have much less influence over fuel types used to generate electricity and over whether investments respond to factors considered important to the State. Furthermore, because the wholesale pricing model results in all wholesale suppliers being paid the price bid by the generating unit on the margin, high fuel prices have a greater influence on the consumer price of all electricity generation.

During 2004 and 2005, forces beyond the State's control have acted to increase the cost of electricity generation. Natural gas has become the fuel of choice for new generation facilities**.** Natural gas is an international commodity; decisions regarding interstate pipeline development and disputes over LNG terminal locations have negatively affected natural gas prices. During 2005, hurricanes in the Gulf Coast seriously disrupted gas infrastructure, resulting in high gas prices and a fear of commodity shortage.

To show the importance of some of these external forces, the following graph displays the relationship between the August and September Gulf Coast hurricanes and wholesale gas and electricity prices.

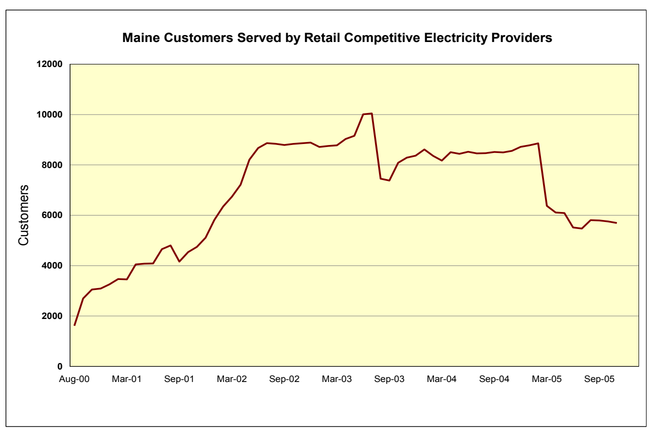


During 2005, several approaches were explored or implemented to respond to rising electricity prices driven by rising natural gas prices. Stakeholders, including consumers, generators, the Commission, and Maine's state and federal elected officials actively participated in regional efforts to develop a mechanism to encourage more generation investment in New England. That effort is described in Section X of this report. The Commission implemented a standard offer bidding procedure that would partially mitigate the effect of price volatility in the wholesale market on residential and small commercial customers; that process is described in Section V. The Legislature is considering methods for increasing the use of indigenous but diverse generation facilities; the Commission has taken an active role in a stakeholder group established by the Legislature for this purpose. Finally, the Commission is working with ISO-NE and other stakeholders to develop demand response programs and energy efficiency programs to blunt the impact of price spikes; that effort is described in Section X.

IV. RETAIL MARKET ACTIVITY

During 2005, the retail market for Maine's medium commercial and industrial (C&I) and large C&I customers[1] continued to exhibit a reasonable level of competitive activity, and bidding for standard offer service was healthy. In addition to attracting a significant number of bidders, the standard offer process resulted in different winning providers during 2005. The market continued to offer minimal competitive choice for residential and small commercial customers. In 2005, a three-year arrangement for low residential and small commercial standard offer prices ended, and newly-obtained arrangements reflected the significant increases in wholesale electricity prices in recent years. Residential and small commercial customers will be somewhat insulated from the volatility of the wholesale market by new procedures the Commission implemented during 2005. These procedures are described in Section V.

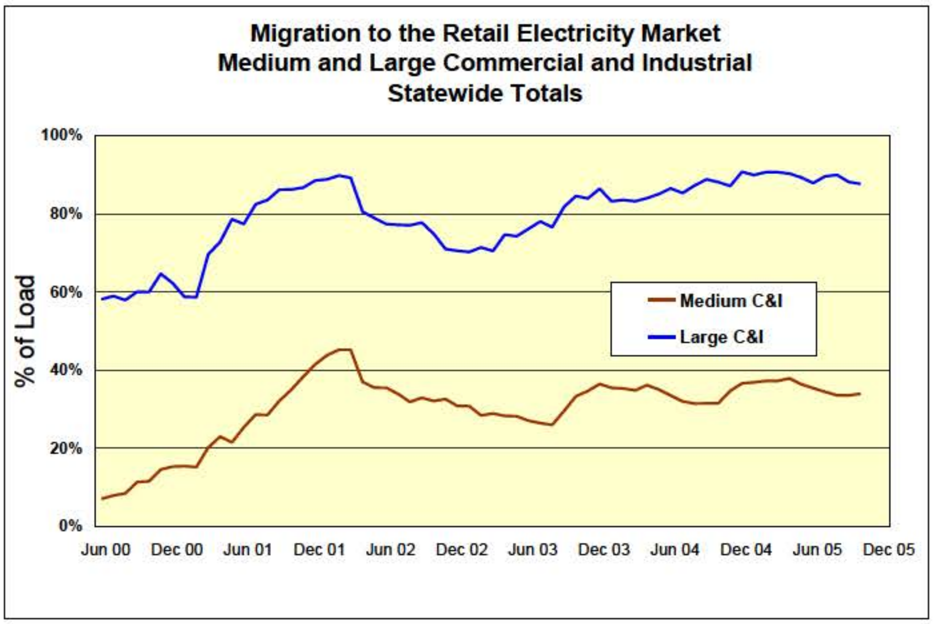
As shown on the graph to the right, customers showed steady migration to the open market throughout the first two years of restructuring, followed by steady participation through 2004. In 2005, approximately 900 residential and small commercial customers who were purchasing a green product returned to standard offer service.



[1] Commission rules establish three standard offer classes: residential and small commercial, medium commercial and industrial (C&I), and large C&I.

Migration from Standard Offer – Medium and Large Customers

Since the beginning of restructuring, the vast majority of large customers and a substantial number of medium customers have chosen to participate directly in the retail market. When customers' supply contracts expire, they may choose between a return to standard offer service or an open market contract, based on their expectation of future market prices and their desire for price predictability.[2] While migration to and from the competitive market[3] is influenced to some extent by the relationship between standard offer and non-standard offer prices, the prevailing trend is for customers to remain in the open market once they have left the standard offer. The graph below shows migration among medium and large customers, and reflects the overall trend toward migration to the open market.



The Commission's standard offer selection procedures tend to remove the likelihood that changing market prices per se will cause migration to or from the open market. In 2003, the Commission concluded that medium and large class standard offer prices should track wholesale prices closely and accordingly has accepted bids for 6-month terms since that time. Prices for BHE and CMP medium and large standard offer customers increased generally between 0.2%

[2] To avoid significant disruption to standard offer service load requirements, Commission rules require large and medium customers that take standard offer service after being in the competitive market to remain on the standard offer for a year or pay an opt-out fee. Customers may petition the Commission for exemption from the fee, and a significant number have done so. The Commission generally grants such requests when there is no evidence that the customer is "gaming" the process.

[3] Standard offer service providers are chosen through a competitive bid process, so all customers receive service through a competitive market. For convenience, non-standard offer providers are often referred to as competitive providers.

and 3.5% in March 2005 and between 22% and 27% in September 2005. These increases followed standard offer price increases of 8% and 14% in March 2004 and between 2% and 7% in September 2004. Prices for customers in the retail market are established by their individual contracts, and medium and large customers seeking a longer-term price have an incentive to buy in the retail market.

Migration is more prevalent among the larger customers in the Medium group. During 2005, the Commission presented seminars throughout the State to the smaller business customers. The seminars discussed the rules and procedures relevant to the retail market and the advantages and disadvantages of purchasing electricity from open market competitors. Suppliers who served these customers were invited to discuss their supply options during the seminars. Migration patterns in subsequent months show no indication that these customers chose to end standard offer service based on the additional knowledge they obtained, suggesting that the possible price and stability advantages of the open market do not offer sufficient advantages to induce the smaller Medium customers to switch from standard offer service.

Migration from Standard Offer – Residential and Small Commercial Customers

Marketers indicate that the costs to acquire and service small customers are significant, and no substantial retail market has developed. However, because Maine’s standard offer providers are chosen through competitive bidding based on price, all residential and small commercial customers are effectively purchasing generation from competitive market suppliers. Vigorous competition among bidders for standard offer service in BHE and CMP territories resulted in attractive standard offer service rates for smaller customers through 2004 and competition remained vigorous during the 2005 bidding process.

In CMP and BHE service territories, fewer than one percent of customers have left standard offer service. These customers generally chose a green power option. In March 2005, the contract term expired for many of these customers, resulting in their return to standard offer service. It is uncertain whether these customers allowed their contracts to lapse intentionally or through a lack of understanding of the contracting procedures. In MPS territory, a larger percentage of residential customers migrated to the open market, but more than half have returned to standard offer service. This may be due in part to the departure of one of the two suppliers in the region, but more likely is because standard offer service is currently priced below market.

The table to the right shows the number and percentage of residential and small commercial customers[4] in CMP, BHE and MPS service territories that were receiving competitive market electric supply in late 2005.

Residential and Small Commercial Customers that have Left Standard Offer, November 2005

	number	percentage
CMP	467	<1%
BHE	500	<1%
MPS	1644	5%

During 2003 and 2004, "green" products, featuring hydroelectric, biomass, wind, low-impact hydro generation, and "green tags" became available through residential and public sector aggregation groups. The Maine Green Power Connection provided information regarding green power, and the State Energy Program provided modest funding for information outreach.

Finally, as described in Section VII, northern Maine retail activity was considered in Commission proceedings during 2005. In the early days of restructuring, there were only two suppliers active in the northern Maine retail market – Energy Atlantic (EA) and WPS Energy Services, Inc. (WPS-ESI). Energy Atlantic no longer serves customers in northern Maine, leaving WPS-ESI as the only provider of open market and standard offer service in all rate groups. Thus, the retail market in northern Maine is considerably less competitive than the market in the remainder of the State. The standard offer bidding process disciplines price to some extent, and prices in MPS territory are reasonable relative to the rest of Maine and New England. However, we continue to study this situation.

Retail Supplier Activity

Throughout 2005, approximately 20 retail electricity suppliers were licensed to serve customers in Maine.[5] Fewer than ten suppliers (including standard offer suppliers) actively served multiple customers, and another ten obtained a supplier's license to serve themselves directly from the wholesale market. Two suppliers sold virtually all of the power purchased at retail in the residential market. CMP and BHE's C&I markets show a dispersion of sales among suppliers, although one set of affiliated companies has a large market share. As discussed above, only one supplier provides retail services in MPS's territory.

[4] Residential and small commercial customers comprise the "small" standard offer class, and their migration rates are combined for tracking purposes.

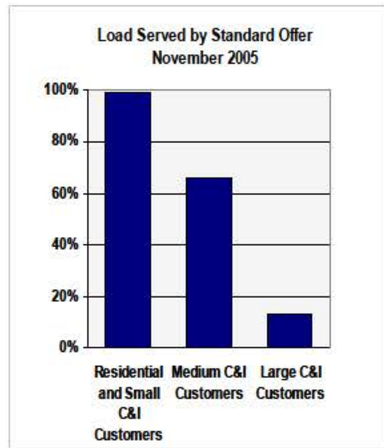
[5] The Restructuring Act authorizes the Commission to license suppliers before they may provide generation service to customers. In some instances, a licensed competitive electricity provider owns its own generation, while in others, the supplier purchases its generation through the wholesale market. In addition, the Commission licenses aggregators and brokers, who assist customers in obtaining generation but do not supply the generation themselves. Twenty-three aggregator/brokers and twenty-five competitive electricity providers are currently licensed.

Nevertheless, there appears to be some level of reduction in the number of entities that are offering supply service to the majority of customers in Maine. The situation presents some cause for concern, which is enhanced by the recently announced merger of FPL Group and Constellation Energy Group. The Commission anticipates conducting an informal review during 2006 to determine whether the number of active suppliers is adversely affecting retail consumers.

V. STANDARD OFFER SERVICE

Overview of 2005

During 2005, the portion of Maine's electric load that receives standard offer service remained steady at slightly over 60%.[6] By customer class, standard offer service supplies about 66% of the load of Medium C&I customers and 13% of the load of Large C&I customers in Maine, as shown by the graph on the right. Standard offer service continues to supply virtually all residential and small commercial customers, as has been the case since retail access began. The same is basically true in other states that have restructured. By T&D service area, standard offer service supplies about 60% of the load of CMP customers, about 70% of the load of BHE customers and about 60% of the load of MPS customers.



The standard offer suppliers during 2005 and the prices they charge are set forth below. The prices shown here are averages; actual prices for the Medium class may vary by month and for the Large class by month and time of day. For more detailed prices, please see the Commission's web page at http://www.state.me.us/mpuc/new%20standard%20offer/standard_offer_rates.htm.

[6] As discussed earlier, the number of customers receiving standard offer service increased in 2005. Because these were primarily residential and small commercial customers, they did not significantly increase total load served by standard offer service.

Average Standard Offer Prices in 2005

	Residential/Small Commercial		Medium C&I		Large C&I	
	Price ¢/kWh	Supplier	Price ¢/kWh	Supplier	Price ¢/kWh	Supplier
CMP						
Jan - Feb	4 95	CPS Maine	6.59	Independence	6.48	Independence & Select
Mar - Aug	6 95	CPS Maine	6.80	Select & Dominion	6.56	Select
Sept - Dec	6 95	CPS Maine	8.31	FPL, Dominion & Suez	8.35	Suez
BHE						
Jan - Feb	5 00	CPS Maine	6.65	Independence	6.26	Independence & Select
Mar - Aug	7.14	Select & Independence	6.88	Select & CPS Maine	6.27	Select
Sept - Dec	7.14	Select & Independence	8.47	FPL	7.79	Suez
MPS						
Jan - Dec	5.46	WPS	5.81	WPS	6.40	WPS

Residential and Small Non-residential Supply Procurement

Effective March 1, 2005, the Commission implemented a hedging program for standard offer supply procurement for CMP and BHE residential and small commercial customers. The process began with the release of RFPs in September 2004 to initiate a "laddering" structure whereby the Commission would secure portions of the required supply at different times, thereby reducing retail customer exposure to the volatility of the wholesale market. Specifically, bids were requested for one-third load segments for terms of one, two and three years.

As a result of this procurement process, Constellation Energy Commodities Group-Maine, LLC was designated to provide service for all three CMP small class segments: a one-third load segment for a one-year term; a second one-third segment for a two-year term; and a third one-third segment for a three year term. For BHE customers, Select Energy Inc (Select) was designated to provide service for the two- and three-year segments and Independence Power Marketing, LLC (Independence) was designated for the one-year segment.[7] The resulting prices were 6.95 cents/kWh for standard offer supply in CMP's territory and 7.1 cents/kWh in BHE's territory, for the period March 1, 2005 through February 2006. These prices reflected the fact that prices in the wholesale energy market had risen substantially in the three years since standard offer supply was last procured for this group of customers. Although the new standard offer prices would by themselves mean an average increase of 17% in the all-in rate of CMP's residential and small commercial customers and of 14% for the same group of customers of BHE, these increases were

[7] Earlier this year, Select announced its intent to divest its standard offer and wholesale business and, as a result, sought and received Commission approval to transfer its BHE small class standard offer obligations to CECG Maine as of January 1, 2006.

somewhat mitigated, particularly in BHE's territory, by simultaneous reductions in the stranded cost component of their bills.

In December 2005, the Commission procured supply for the March 1, 2006 term to replace the expiring one-year, one-third segment arrangements. The resulting March 1, 2006 standard offer prices will be 8.4 cents/kWh for standard offer supply in CMP's territory and 8.7 cents/kWh in BHE's territory, and will result in an average increase of 9% in the all-in rate of CMP's residential and small commercial customers and of 10% for the same group of customers of BHE. In light of the increases in market prices during the past year, the fact that only one-third of the supply was procured at this time was a significant benefit to customers. Going forward, the laddering approach will continue to moderate the extent to which wholesale market volatility affects standard offer prices.

Medium and Large Non-residential Supply Procurement

The Commission completed two solicitations for medium and large class standard offer service during 2005, and a third began before the end of 2005. The solicitations have continued to be competitive, resulting in retail standard offer suppliers and market-based prices for all customer classes.

On December 1, 2004, the Commission issued RFPs for standard offer service for the CMP and BHE medium and large classes for six-month terms beginning March 2005. Suppliers submitted indicative bid prices in December 2004. Staff, utilities, and suppliers negotiated and resolved non-price terms and, in January 2005, suppliers submitted final binding bids. After evaluating the final proposals, the Commission designated Select Energy Inc. as the provider for 60% of the CMP medium and 100% of the CMP large non-residential classes, and Dominion Retail Inc. as the provider for 40% of the CMP medium class. For BHE customers, the Commission designated Select Energy, Inc as the standard offer provider for 80% of the medium and 100% of the large non-residential classes and Constellation Energy Commodities Group-Maine as the provider to 20% of the medium class.

The average prices for standard offer service during the March-August period based on the final bids are shown below:

Standard Offer – Term Beginning March 1, 2005

	CMP	BHE
Medium C&I	6.7963 ¢/kWh	6.880 ¢/kWh
Large C&I	6.5644 ¢/kWh	6.269 ¢/kWh

The second standard offer solicitation for the CMP and BHE medium and large classes, for the six-month term beginning September 2005, began when the Commission issued RFPs in early June 2005. After receiving indicative bids, negotiating contract and other non-price terms, and receiving final bids, the

Commission designated Suez Energy Resources N.A. (Suez) to serve 100% of the CMP large and 20% of the CMP medium classes, and FPL Energy Power Marketing (FPL) to serve 60% and Dominion Retail to serve 20% of the CMP medium class. For BHE customer the Commission designated Suez to serve 100% of the large and FPL to serve 100% of the medium classes. The average prices were set as shown below:

Standard Offer – Term Beginning September 1, 2005

	CMP	BHE
Medium C&I	8.308 ¢/kWh	8.470 ¢/kWh
Large C&I	8.345 ¢/kWh	7.786 ¢/kWh

No solicitations were held to acquire standard offer service for MPS customers because WPS-ESI is currently designated the standard offer provider for a 34-month term ending on December 31, 2006. The average prices under this contract are as shown below:

Standard Offer – Terms in 2005

	WPS
Medium C&I	5.81 ¢/kWh
Large C&I	6.40 ¢/kWh

Consumer-owned Utilities (COUs)

COUs carry out bid processes to procure standard offer service in their territories. The following table displays their current standard offer prices, many of which vary monthly or daily:

Average Standard Offer Prices - Consumer-Owned Utilities

Utility	Price	Supplier
Eastern Maine Electric Cooperative	5.8 ¢/kWh	WPS
Houlton Water Company	5.4 ¢/kWh	WPS
Van Buren Light and Power	6.6 ¢/kWh	WPS
Fox Islands Electric Cooperative	10 ¢/kWh	Vermont Public Power Service Authority
Madison Electric Works	4.6 ¢/kWh	Constellation
Kennebunk Light and Power Co.	9.3 ¢/kWh	Vermont Public Power Service Authority
Monhegan Electric	Exempt	
Matinicus Plantation Electric Co.	Exempt	
Isle au Haut	Exempt	

VI. STRANDED COSTS

The Restructuring Act allows CMP, BHE and MPS to recover stranded costs in the rates they charge for delivery service. Stranded costs reflect the net, above-market costs for generation obligations that utilities incurred prior to industry restructuring. For example, stranded costs include the difference between payments the utilities must make pursuant to pre-existing purchased power contracts (primarily with qualifying facilities (QFs)) and the current market value of that power. Stranded cost rates are re-set for CMP, BHE and MPS every two to three years. The adjustments coincide with the sale terms of the utilities' QF entitlements, because the amounts received from the entitlement sales offset stranded costs and have significant impact on stranded cost rates.

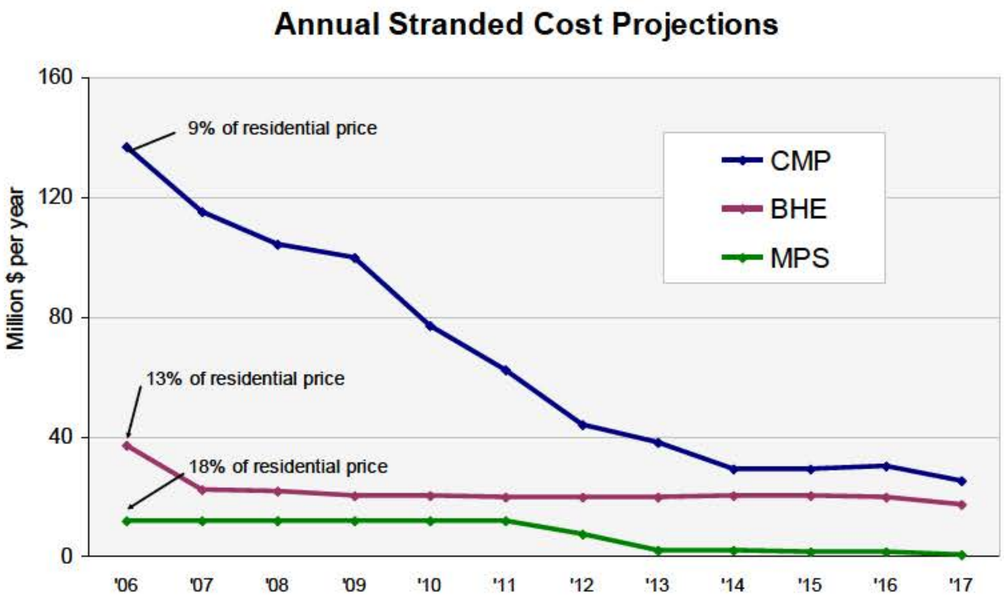
During 2004, the Commission completed a proceeding that established MPS's stranded cost rates for the period between March 1, 2004 and December 31, 2006, to coincide with the period of MPS's sale of qualifying facility entitlements. The proceeding concluded with a stipulation, approved by the Commission, under which MPS's stranded cost rates did not change from their level before March 1, 2004.

During 2005, the Commission completed stranded cost rate case proceedings for both BHE and CMP. On an overall basis, CMP's stranded cost rates were reduced by 9.1% while BHE's stranded cost rates declined by 38.11%.[8] Since we have historically tied the setting of utilities' stranded cost rates with the timing of the sale of the output from the utilities' non-divested QF contracts and generation assets, we will review, and possibly reset, CMP's and BHE's stranded cost rates in 2006 to reflect the expiration of the current sale of part of both CMP's and BHE's non-divested assets.

Both CMP's and BHE's recent stranded cost cases were resolved by stipulation. In both cases, the stipulations approved by the Commission contained provisions for the reconciliation of both stranded cost revenues and costs. In approving the CMP stipulation, we concluded that reconciliation will avoid large winners and losers when estimating stranded cost sales and expenses. We noted that many categories of expenses and revenues had already been subject to accounting orders and thus effectively reconciled and that full reconciliation would be fairer than the piecemeal approach followed prior to March 1, 2005. At the time that CMP and BHE's distribution rates are reset as part of their respective Alternative Rate Plans (ARPs), the Commission will consider additional changes to the utilities' stranded cost rates to address balances that may have accrued as a result of the approved reconciliation mechanisms.

[8] The revenue rates set in the BHE and CMP cases were based on stranded cost projections over the next three years, and reflect projected declines in stranded costs during 2006 and 2007.

The most significant changes in stranded costs will occur when utilities' QF contracts expire. BHE's remaining stranded costs will decline significantly in the immediate future, while CMP's will decline throughout the second half of the decade. Projections of stranded costs are shown in the chart below.



Stranded costs will be reestablished within the next 3 years

The major components of each utility's stranded costs for the year March 2005 – February 2006 and the net present value of future stranded costs are set forth below:

Net Present Value of Stranded Costs

CMP	
Above market QF costs	$375 million
HQ tie line	16
Nuclear plants	114
Total stranded costs	**$505 million**

BHE	
Above market QF costs	$76 million
HQ tie line	3
QF contract restructure	32
Nuclear plants	35
Deferred standard offer	3
Total stranded costs	**$149 million**

MPS	
Above market QF costs	$11 million
QF contract restructure	3
Nuclear plants	22
Deferred fuel	18
Other	1
Total stranded costs	**$55 million**

Total Net Present Value Of Stranded Costs	**$709 million**

Annual Stranded Costs, Year Ending 2/06

CMP	
Above market QF costs	$ 99 million
HQ tie line	4
Nuclear plants	34
Total stranded costs	**$137 million**

BHE	
Above market QF costs	$11 million
HQ tie line	1
QF contract restructure	17
Nuclear plants	7
Deferred standard offer	1
Total stranded costs	**$37 million**

MPS	
Above market QF costs	$7 million
QF contract restructure	2
Nuclear plants	6
Deferred fuel	-3
Total stranded costs	**$12 million**

Total Annual Stranded Costs	**$186 million**

Until recently, stranded costs also included, as an offset, the proceeds from the utilities' generation asset sales (referred to as the Asset Sale Gain Account). In 2001 and 2003, the Commission approved reductions through February 2005 of the stranded cost component of delivery rates for some of BHE's and CMP's medium and large customers to mitigate the impact of significantly increased market generation prices.

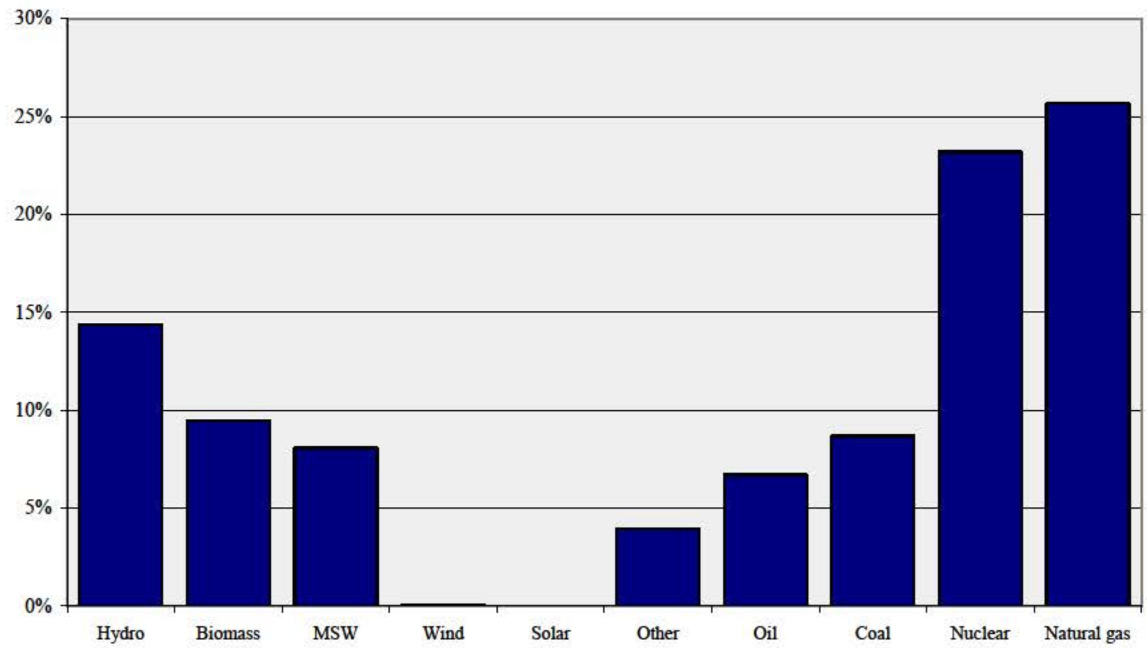
VII. GENERATION RESOURCES

Resource Mix Used to Serve Maine's Customers

The Restructuring Act establishes a 30% resource portfolio standard (RPS) that requires electricity suppliers (including standard offer suppliers) to supply 30% of their Maine load from "eligible resources." The Act defines eligible resources to be generating units whose capacity does not exceed 100 megawatts and that produce electricity from tidal, fuel cells, solar, wind, geothermal, hydroelectric, biomass, or municipal solid waste in conjunction with recycling, that qualify as small power producers under federal regulations, or that are efficient cogeneration units.

As shown in the chart below, during 2004,[9] approximately 35% of Maine's load was supplied by eligible resources. Virtually all eligible supply was provided by hydro, biomass, or MSW, with a small fraction provided by eligible fossil fuels, wind, or solar.

Resources Serving Maine's Electricity Customers in 2004



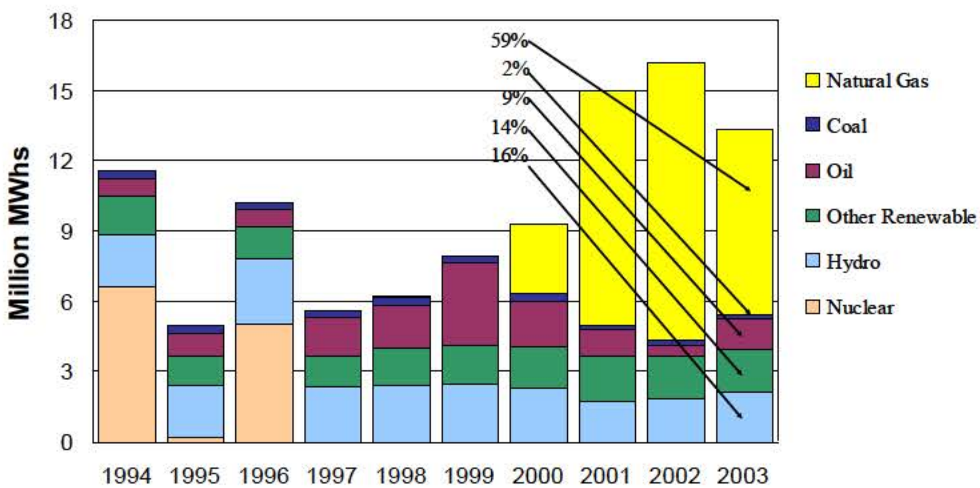
The generation that fulfills the 30% RPS may come from a variety of locations. The generation that suppliers assign to load in Maine may be generated in Maine, in another New England state, in Canada, or (less frequently) in the Middle Atlantic states. Since 2002, competitive providers in the ISO-NE territory have operated under a "tradable attribute" certificate system known as the Generation Information System (GIS). The GIS allows suppliers to trade electricity attributes (e.g., fuel source and emissions levels) separately from the energy commodity. Suppliers in the ISO-NE area demonstrate compliance with Maine's 30% RPS through GIS certificates. This process reduces supplier compliance costs and allows for accurate verification.

[9] The Commission will receive information about suppliers' 2005 resource mix when suppliers file their annual reports in June 2006.

Electricity Generated in Maine

In recent years, five electric generating plants fueled by natural gas have been built in Maine. This phenomenon is the result of both electric restructuring and the completion of new natural gas transmission facilities within the State. Publicly available information summarizes the resources used in each state to generate electricity (which may in turn be sold in other states), and shows the dramatic change in Maine's generation mix. Generation data is not available beyond 2003. However, the amount of electricity generated from Maine's natural gas facilities diminished in 2003, most likely because of the increasing price of natural gas. While no publicly available data is available, it is likely that generation from facilities fueled by biomass increased during 2005.

Electricity Generated in Maine by Fuel Type
1994 - 2003



RPS Issues

During 2004, the Legislature enacted a law that exempts suppliers from complying with the 30% RPS when supplying electricity to customers in designated Pine Tree Zones.[10] During 2004 and 2005, no supplier used this exemption.

During 2005, the Legislature directed Maine's Department of Energy Independence and Security to form a stakeholder group to consider issues associated with using renewable fuel sources to generate electricity within Maine. The group met throughout 2005 and will report its activities and recommendations to the Utilities and Energy Committee when the Legislature convenes in 2006. The Commission has played an active role in this process.

[10] Pine Tree Zones are State-designated economic development areas in which new and expanding businesses may receive economic incentives prescribed by law.

Uniform Disclosure Labels

The Restructuring Act directs the Commission to ensure that comparative information regarding electricity supply is disseminated to customers. The Commission implemented this directive by designing a uniform information disclosure label that contains a supplier's resource mix and emissions information. Residential and small commercial customer suppliers must provide a disclosure label to their customers quarterly, and suppliers to larger customers must provide the label upon request. Labels for standard offer providers may be found on the Commission's web page. A representative label is contained in Appendix A.

Voluntary Renewable R&D Fund

The Restructuring Act directs the Commission to establish a program to allow electricity customers to make voluntary contributions to fund renewable resource research, development, and demonstration projects. To date, customers have donated approximately $250,000 through one-time or monthly contributions through their electricity bills. The State Planning Office, which administers the program, has contracted with the Maine Technology Institute (MTI) for distribution of the funds to take advantage of MTI's existing grant process infrastructure and to leverage other grant funds. In 2004, MTI provided funding for a Chewonki Foundation and Hydrogen Energy Center project to develop an energy system using hydrogen generators, storage, and fuel cells. The project is being funded through a variety of sources, including $40,000 from the Voluntary Renewable R&D Fund. No additional projects were funded in 2005.

VIII. NEW TRANSMISSION

The Commission, through approval of a stipulation, issued a Certificate of Public Convenience and Necessity authorizing Bangor Hydro-Electric Company to construct an 85 mile, 345 kV transmission line from Orrington, Maine to the Canadian border just north of Baileyville, Maine (referred to as the Northeast Reliability Interconnect or NRI). The NRI will interconnect with a 65 mile, 345 kV transmission line to be constructed, owned and operated by New Brunswick Power. The NRI is expected to cost approximately $99 million.

Upon construction, the NRI would provide a second transmission line between the New England and New Brunswick regions. This additional link will improve system reliability, increase import/export transmission capacity, and reduce line losses. Because the NRI's benefits are regional in nature, the ISO-NE has determined that the cost of the project will be shared among all electricity customers in New England.

Construction of the NRI is expected to begin during winter 2005/2006. The project is expected to be complete by the end of 2007.

IX. NORTHERN MAINE SYSTEM RELIABILITY

The Commission conducted an extensive investigation of bulk system reliability in northern Maine. The investigation was in the context of a Maine Public Service Company proposal to construct an additional transmission link between its territory and New Brunswick Power's transmission system. The Commission also considered whether, based on system reliability concerns, it should direct MPS to enter into a contract with Loring Bio Energy to facilitate the construction of a 55 MW generation plant.

The Commission concluded, based on extensive evidence, that there is not a current need for MPS to commit ratepayer funds to either transmission or generation construction so as to maintain adequate system reliability. Specifically, the Commission concluded that current system resources are sufficient to meet projected system load in northern Maine in the near and intermediate terms and that there are several possible resource additions that may develop over the next few years that may provide sufficient resources to meet northern Maine's needs well into the future. To the extent such resources do not develop, the Commission found that there is adequate time for MPS, along with other stakeholders in the region, to explore and implement potentially more cost-effective approaches for dealing with reliability issues that may arise in the future.

X. REGIONAL ACTIVITY

With the restructuring of the electricity market, Maine has become part of a broader regional market for wholesale electricity. The existing electric transmission system allows generation within roughly 1,000 miles of the state to compete to serve Maine customers and allows Maine's generators to compete for load over a similar area. The Legislature anticipated this and in 1997 enacted 35-A MRSA §3215, which directs the Commission to participate in regional and national activities to protect "the interests of competition, consumers of electricity, or economic development of the state."

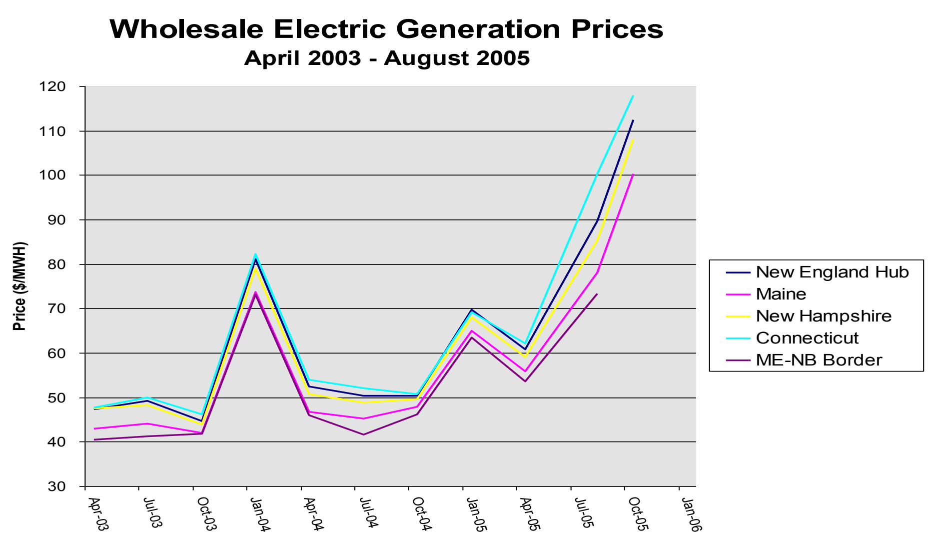
The New England electric market is, and will remain for the foreseeable future, a hybrid of competitive and regulated elements. The fundamental goal is to develop and maintain a workably competitive wholesale generation market that will provide the benefits of strong competition among suppliers while simultaneously producing a reliable electric system and acceptable prices.

The market operates under a set of rules approved by the Federal Energy Regulatory Commission (FERC). New England's Independent System Operator, ISO New England (ISO-NE), is the day-to-day operator of the electric grid and the generation markets. ISO-NE, in turn, operates under contract with the New England Power Pool (NEPOOL), a New England organization comprised of generators, competitive electricity providers, T&D utilities, municipal electric systems, and representatives of end-use customers. NEPOOL or ISO-NE files changes to market rules for approval by FERC. These changes are developed through NEPOOL committees, each of which is chaired by ISO-NE. In some cases, these filings have close to unanimous support. In others, there is a wide range of conflicting positions. While the Commission is not a NEPOOL member, it often takes an active role in the committees. The Commission also intervenes and takes positions at FERC on matters affecting the competitiveness of the wholesale electric markets, reliability, or prices paid by Maine electricity consumers.

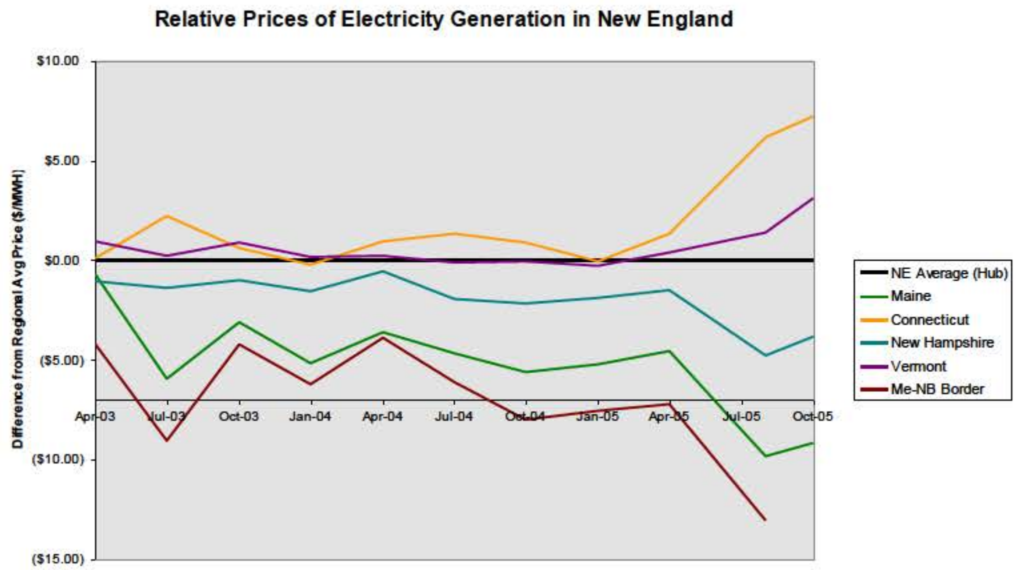
This section of the report outlines the changes in the wholesale market over the past year and describes the Commission's regional activities.

Notable Trends and Events in the Past Year

Much of the region's electric generation is fueled by natural gas and oil and these generators often set the wholesale market price. Substantial increases in the cost of fuel, particularly natural gas and oil, have led to significant increases in the cost of wholesale, and ultimately retail, electricity. The fuel price increases have been driven by a number of factors, but the two most notable are the overall increase in world petroleum prices coupled with the impact of Hurricanes Katrina and Rita on the Gulf of Mexico and the associated damage to petroleum and natural gas production from that region. The hurricane damage has also raised concerns about the availability of electricity and the fuels used to produce it during the winter of 2005-06.



Despite the increase in wholesale electricity prices during the year, prices for delivery in Maine continue to be the lowest in New England. In late spring 2005, wholesale prices began to rise fairly dramatically. However, at the same time, the Maine prices moved from about $5 per MWH (or 0.5 cents per kwh) below most of New England to about $10 per MWH lower than the rest of the region. We expect that the state will continue to hold a relative price advantage for the foreseeable future, although the size of the advantage is difficult to predict.



Major Cases Currently Being Litigated at FERC

While there are numerous ongoing cases in which the Commission, either through NECPUC or individually, has participated by submitting comments to FERC and participating in the NEPOOL committees, the Commission has taken a lead role or shared leadership with other state commissions in the following three cases that are set for hearing at FERC.

Locational Installed Capability (LICAP). FERC has ruled that New England should adopt a LICAP mechanism to ensure there is enough generation capacity to provide reliable service throughout New England. On September 1, 2004, ISO-NE filed a proposal with FERC to implement such a mechanism. The Maine Commission actively participated in this case individually and as part of NECPUC. Specifically, we provided testimony and briefs in opposition to major portions of the ISO-NE filing. While we agreed with the goal of ensuring that enough generation is available to provide reliable service, we disagreed with the way the ISO proposed to reach this goal. Specifically, the ISO LICAP proposal administratively establishes prices which, in our view, not only require consumers to buy more capacity than is necessary to maintain reliability but imposes substantial costs even when there is a significant surplus in existing generation capacity. We opposed the ISO's proposal, because it will impose substantial and unwarranted costs on consumers, and because even with all of these payments to existing generation suppliers, there is no requirement for the suppliers receiving the payment to build new capacity or even be available in the long term when the system may no longer have a substantial surplus. Thus, there is no assurance that the increased costs will, in fact, improve reliability or reduce price spikes.

While we and others offered an alternative approach which will ensure that capacity is there in the long term, the FERC did not allow consideration of this alternative in the hearing. However, following the administrative law judge's Initial Decision which accepts the ISO proposal, FERC, responding to overwhelming concern expressed by state regulators, consumer advocates, most transmission and distribution companies and the New England Congressional Delegation, delayed the implementation of any proposal until October 2006 and directed the parties to engage in settlement negotiations on alternatives to the LICAP approach. Settlement discussions are scheduled to continue through January 2006 to resolve this case. We are active participants in the settlement negotiations.

Installed Capacity (IC) Requirements. Another important case related to the LICAP proceeding is an annual FERC proceeding involving the determination of how much capacity is needed within a 12- month period to protect reliability. While market participants have always been involved in the stakeholder process leading to the setting of this IC level, the IC proceeding has taken on much greater significance under the ISO's proposed LICAP scheme. This is because under the prices set administratively under the LICAP proposal the price for capacity increases sharply as the amount of additional capacity needed increases. Thus, an increase of only one or two percent in the IC requirement can translate into hundreds of millions of dollars of additional LICAP costs for the New England region.

An additional significant issue in this case is whether states or the FERC should determine the appropriate level of reliability. While the FERC has for many years set the IC requirement, the determination of what level of resource adequacy is required is a matter in which states must play a major role, since ultimately retail consumers will pay the cost of increased levels of reliability. The FERC's approval of an IC requirement that will increase the cost of LICAP if it is implemented and the FERC's decision that it has sole authority to establish the IC requirement are being challenged in federal court. We have intervened in this appeal as part of NECPUC and individually.

Request for Increased Return on Equity (ROE). On November 4, 2003, a collection of New England transmission owners filed a request for approval for a significant increase in the return on common equity component of the regional and local transmission rates under the Regional Transmission Organization for New England (RTO-NE) open access transmission tariff. We took a lead role in developing NECPUC comments protesting the proposed increase. One part of the increase was granted by FERC. A federal court challenge of this FERC decision is currently pending. We participated in the briefing of this challenge both as a member of NECPUC and individually, and an Initial Decision significantly reduces the requested return on equity. As of the drafting of this report, FERC has not yet issued a final decision.

Cold Snap and Winter Fuel Response

During the "Cold Snap" of January 14-16, 2004, New England experienced extreme cold weather conditions that produced record demand for power and threatened the reliability of the electric and natural gas systems in the region. In response to the "Cold Snap," the ISO led an extensive stakeholder process in which generators, end-users, Load Serving Entities, ISO-NE and NECPUC participated. The stakeholder process eventually produced a number of FERC-approved changes to the ISO market rules. These changes, which are in effect through the winter of 2005-06, are designed, among other things, to improve communications among the ISO, the owners of gas-fired generation and the natural gas industry, define obligations of generators during cold snaps and provide additional flexibility to generators to improve their ability to respond to system needs during extreme cold weather. In addition to the cold weather rules resulting from the cold snap, FERC recently approved rules designed to enhance the reliability of New England's bulk power system operations this winter, during which natural gas and other generating fuels may be in short supply due to hurricane damage in the Gulf of Mexico region. These additional rules contain provisions to communicate the need to: reduce consumption in all hours to conserve fuel, encourage the utilization of dual-fuel generating capability, expand demand-side management programs in New England, and complement the cold weather procedures developed as a result of the 2004 Cold Snap.

These provisions will also complement our Efficiency Maine program to reduce residential and small commercial demand this winter through the "10% Save a Watt Challenge." The goal of the 10% Challenge is to help ease regional energy supply and reliability concerns by reducing electric usage by 10%. This program will also yield direct benefits by lowering monthly utility bills and reducing greenhouse gas emissions.[11]

XI. AFFILIATED COMPETITIVE PROVIDERS AND COMPLIANCE COSTS

The Restructuring Act requires T&D utilities and their marketing affiliates to comply with comprehensive standards of conduct and market share limitations. These limitations are intended to prevent utility marketing affiliates

[11] Additional information on the 10% Challenge can be found through the following link: http://www.efficiencymaine.com/saveawattchallenge.htm

from obtaining any undue market advantage by virtue of their corporate relationship with T&D utilities. The Act requires the Commission to determine and report the actual and estimated future costs of implementing these requirements.

During 2005, there were no issues associated with standards of conduct. CMP does not have a marketing affiliate. In 2002, BHE formed a marketing affiliate, Emera Energy Services, Inc. (EES), but EES does not market services in BHE's territory. MPS's marketing affiliate, Energy Atlantic, no longer serves customers in Maine. Costs will continue to be minimal in the foreseeable future.

XI. ACTIVITIES IN OTHER STATES

The Restructuring Act directs the Commission to report on activities relating to changes in the regulation of electric utilities in other states. In general, restructuring activity has stablilized, with most New England and Middle Atlantic states (Vermont is an exception), Texas, and a few other states currently operating in a restructured environment. In 2003, California suspended restructuring.

Appendix A - Uniform Disclosure Label

All residential and small commercial customers receive labels with form and content similar to the following label, which was applicable to residential and small commercial standard offer service throughout 2005:

RESIDENTIAL AND SMALL NON RESIDENTIAL STANDARD OFFER SERVICE
CONSUMER INFORMATION ABOUT YOUR ELECTRICITY SUPPLY
October 2005

Electricity suppliers in Maine must, by Maine law, provide fact sheets, or "uniform disclosure labels" from time to time to educate consumers about their electricity service. Your electricity is *delivered by* Central Maine Power Company, but the *electricity itself* is supplied by:

Constellation Energy Commodities Group Maine, LLC.

This fact sheet provides consumer information about the power sources and air emissions of service provided by this electricity supplier.

Power Sources

(April 01, 2004 - March 31, 2005)

This supplier provided electricity with the following resources:

	Supplier's Mix	New England Mix
Sources meeting Maine's 30% renewable and efficient resources requirement		
Biomass	2.9 %	5.0 %
Municipal Waste	11.2 %	
Fossil Fuel Cogeneration	7.7 %	0.2%
Fuel Cells	0.0 %	0.0 %
Geothermal	0.0 %	0.0 %
Hydro	9.2 %	5.2 %
Solar	0.0 %	0.0 %
Tidal	0.0 %	0.0 %
Wind	0.0 %	0.0 %
Other Choices		
Nuclear	26.9 %	28.7 %
Gas	29.9 %	34.6 %
Oil	6.7 %	10.8 %
Coal	5.7 %	15.5 %
TOTAL	100.0%	100.0%

Air Emissions

(April 01, 2004 - March 31, 2005)

This table compares air emissions from this supplier's electricity mix to average emission levels from all New England power sources.

	Supplier's Mix (lbs/MWh)	
Carbon Dioxide (CO_2)	**902.95**	This is **8.4%** less than the New England Average.
Nitrogen Oxide (NO_x)	**1.82**	This is **25.1%** more than the New England Average.
Sulfur Dioxide (SO_2)	**2.40**	This is **39.7%** less than the New England Average.

Notes: lbs/MWh = pounds per Megawatt-hour
1 Megawatt-hour = 1,000 kilowatt-hours

Additional Information and Required Notes:

Notes:

Power Sources—Maine law requires retail electricity providers to supply no less than 30% of their total annual kilowatt-hour sales with electric energy generated from eligible resources. Either a renewable fuel or an efficient process, such as co-generation, must be used to generate the electricity used to satisfy this requirement. Co-generation sometimes uses fossil fuels, such as gas, coal or oil, and is considered to be efficient because the process yields both electricity and thermal energy.

Emissions—Carbon Dioxide (CO_2) is released when certain fuels are burned. It is considered a greenhouse gas and a major contributor to global warming. Nitrogen Oxides (NOx) form when certain fuels are burned at high temperatures. They are considered contributors to acid rain and ground-level ozone (or smog). Sulfur Dioxide (SO_2) is formed when fuels containing sulfur are burned. Major health effects associated with SO_2 include asthma, respiratory illness and aggravation of existing cardiovascular disease. The production of electricity can produce other harmful emissions and have other environmental impacts. Environmental impacts differ among individual power plants.

If you have questions or need further explanation, please contact Constellation Energy Commodities Group Maine, LLC toll-free at 1-888-808-3826 or the Maine Public Utilities Commission, toll-free, at 1-877-782-3228. Additional information can also be found at http:www.maine.gov/mpuc.