STATE OF CONNECTICUT

DEPARTMENT OF PUBLIC UTILITY CONTROL
TEN FRANKLIN SQUARE
NEW BRITAIN, CT 06051

DOCKET NO. 98-01-02 DPUC REVIEW OF THE CONNECTICUT LIGHT AND POWER COMPANY'S RATES AND CHARGES - PHASE II

February 5, 1999

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DECISION

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EXECUTIVE SUMMARY

This full rate setting proceeding pursuant to General Statutes of Connecticut (Conn Gen. Stat.) Section 16-19 and 16-19(g) was ordered by the Department of Public Utility Control to address overearnings identified in the December 31, 1997 Decision in Docket No. 97-05-12, DPUC Financial and Operations Review of The Connecticut Light and Power Company. In this case, the Department undertook a comprehensive review of The Connecticut Light and Power Company's overall expenses and revenue requirements and established the appropriate level and structure of rates to be effective no later than September 28, 1998. Based on this review, the Department finds that the Company's revenue requirements should be reduced by $231,964,000 or 9.68%.

The Department has determined that rates should be reduced by $95,816,000 or 4%. In addition, the Department is assigning $136,148,000 or 5.68% to write down deferred taxes. In so doing, the Department balanced the interest of the Company in having sufficient capital to operate successfully and in a manner that allows it to maintain its financial integrity with that of ratepayers for immediate rate reductions. The Department will apply the rate reductions found herein in an across-the-board manner and makes no changes in rate design.

As indicated in the Decision, the revenue reduction is effective September 28, 1998. The reductions noted above are for the rate year, 1999. The revenue reductions between September 28, 1998, and February 5, 1999, when the Decision is finalized, will be applied against Financial Accounting Standard 109 (deferred taxes) and the Energy Adjustment Clause.

Nuclear regulatory adjustments include a finding that the retirement of Millstone Unit I (12 years prior to its license expiration date of 2010) was for economic reasons, as well as other considerations. The Department found that if Millstone 1 had continued operation, it would have provided ratepayers with approximately $84.5 million in economic value in the years 1999 and 2000 and imputed those ratepayer benefits into rates by way of reducing the rate base and not allowing a return on the unit's current rate base balance. In addition, the Department ordered the Company to continue the non-cash accrual of the Millstone Unit 2 out of rate base disallowance to be used as an offset to the potential ratepayer liability for the accumulated Connecticut Yankee replacement power cost deferrals. The Department also disallowed the Company's claim for approximately $11.8 million in transmission and distribution system improvements incurred in 1996 and 1997 to be included in rate base, finding that they would not have been required absent the Millstone unit outages at that time. For similar reason, the Department denied approximately $11.8 million in Operations and Maintenance expenses for four Devon Station gas turbines installed in 1996 to provide replacement capacity and energy when the Millstone units were out of service and approximately $3.3 million in depreciation expense for those units. Also disallowed were increased financing costs by way of higher interest rates and fees in the Niantic Bay Fuel Trust. In doing so, the Department determined that these expenses were associated with the prolonged nuclear outages and are not to be supported by ratepayers.

Financial adjustments include an approved capital structure consisting of 2.82% in short-term debt; 54.71% in long-term debt; 7.54% in preferred stock, and common equity of 34.93%. The Department allows the Company a rate of return on equity of 10.3% with a weighted cost of capital of 8.12%. Other regulatory adjustments include: reducing payroll expenses by $18.9 million; reduction of proposed depreciation expenses by $12.9 million; reducing the Company's forecasted price of fossil fuels for purposes of setting its base fuel rate, which was the primary factor in reducing the Company's base fuel rate expenses by $78.8 million; reducing the claimed allowance for materials and supplies other than fuel for the 1999 rate year by $3.8 million to $67.2 million; and disallowing industry restructuring advertising costs of $1.4 million. The Department also reduced the rate base for fossil/hydro units by $3.6 million and associated depreciation by $7.2 million.

On the revenue side, the Department found that the Company's sales and revenues forecast was approximately $27 million lower than appropriate and assigned that amount to forecasted Company revenues. The Department also allowed CL&P to transfer its wholesale market-based contracts to an affiliate of its parent, Northeast Utilities, but requires that the future value of these contracts (forecasted to be up to $50 million) be used to offset stranded costs. The assessment of the value of these agreements will be reviewed in a later proceeding, when the Department determines the Company's stranded costs.

Further, the Department is requiring the Company to continue to offer Flex Riders and to continue to honor the terms of all special contracts entered into before April 29, 1998.

DECISION

I. INTRODUCTION

A. BACKGROUND OF THE PROCEEDING

By letter dated January 5, 1998, to CL&P and on its own motion and pursuant to §§ 16-11, 16-19 and 16-19(g) Conn. Gen. Stat., the Department opened the instant docket to address the overearnings of CL&P identified in the Decision dated December 31, 1997, in Docket No. 97-05-12, DPUC Financial and Operations Review of The Connecticut Light and Power Company. The Department advised the Company that it would be conducting this proceeding in two phases: phase one being a Conn. Gen. Stat. § 16-19(g) review to determine if the Company's revenue requirements should be reduced on an interim basis and phase two being a complete rate review pursuant to Conn. Gen. Stat. § 16-19. The Department ordered the Company to submit the Standard Filing Requirements for a rate case (SFRs) no later than April 1, 1998.

By letter dated January 27, 1998, CL&P requested a delay until June 1, 1998, to file the SFRs so that the rate case could be based on a calendar year 1997 test year. By letter dated February 2, 1998, the Department granted CL&P's request with the caveat that the Company stipulate that any rate decrease be effective no later than September 28, 1998, which would be the 180 day deadline for a Conn. Gen. Stat. § 16-9 Decision to be rendered. By letter dated February 5, 1998, the Company so stipulated.

The Department issued an Interim Decision in phase one on February 25, 1998, adjusting rates on an interim basis to remove the Millstone Unit 1 nuclear generating unit (MP1) from rate base and to address certain specific non-rate base dollars totaling $110,479,000.

The Company filed its phase two application on June 1, 1998, (Application) seeking Department approval of new and amended rate schedules. By Notice of Technical Meeting dated June 9, 1998, a technical meeting was held in the Department's offices, Ten Franklin Square, New Britain, Connecticut on June 17, 1998, to discuss the Application. At the meeting the Department indicated that the Application did not contain sufficient detail for the Department to conduct a proper review of the Company's revenue requirements. The Company agreed to amend its filing. By letter dated June 18, 1998, the Department formalized the additional data required and ordered the Company to submit it no later than June 30, 1998. The Company made its supplemental filing on June 30, 1998, (Supplemental Filing) and the Department accepted it by letter dated July 2, 1998.

B. CONDUCT OF PROCEEDING

By Notice of Technical Meeting dated June 23, 1998, and Notice of Change of Scope of Technical Meeting dated July 2, 1998, a technical meeting to discuss the

termination of the Northeast Utilities' (NU) Generation and Transmission Agreement (NUG&T Agreement) and the Public Service Company of New Hampshire (PSNH) Sharing Agreement (Sharing Agreement) and its impact on CL&P's base rate fuel revenue factor, as proposed in the Application, was held at the offices of the Department on July 7, 1998.

By Notice of Audit dated July 21, 1998, the Department conducted an audit of the books and records of the Company, at CL&P's offices, 107 Selden Street, Berlin, Connecticut, beginning July 27, 1998.

By Notice of Hearing dated July 23, 1998; Notice of Additional Hearing Session dated September 2, 1998; and Notice of Continued Hearing dated October 2, 1998, a public hearing was held at the offices of the Department on September 10, 11, 14, 15, 16, 17, 18, 22, 23, 24, 25, and 28; and October 8, 13, 15, 16, and 20, 1998. In addition, the following evening sessions were held to receive comments on the Company's proposals from members of the public:

September 3, 1998, Legislative Office Building, Hartford
September 15, 1998, New London City Hall, New London
September 17, 1998, South Windsor Town Hall, South Windsor
September 22, 1998, Windham Town Hall, Willimantic
September 24, 1998, Torrington Town Hall, Torrington
September 28, 1998, Greenwich Town Hall, Greenwich

The October 20, 1998 hearing was continued without date to accommodate questions regarding Late Filed Exhibits. No questions were raised; therefore, the Department issued a Notice of Close of Hearing on November 9, 1998.

By letter dated December 1, 1998, the Company extended the 180 day deadline for rendering a final Decision by 30 business days. The Department issued a draft Decision in this matter on January 19, 1999. All Parties and Intervenors were provided an opportunity to file written exceptions to and present oral arguments on the draft Decision.

C. PARTIES AND INTERVENORS

The following were recognized as Parties to this proceeding: The Connecticut Light and Power Company, P.O. Box 270, Hartford, CT 06141-0270; Office of Consumer Counsel (OCC), Ten Franklin Square, New Britain, CT 06051; Prosecutorial Division of the Department (PRO), Ten Franklin Square, New Britain, CT 06051; and Connecticut Siting Council, Ten Franklin Square, New Britain, CT 06051.

The Connecticut Conference of Municipalities (CCM), Connecticut Industrial Energy Consumers (CIEC), and the State of Connecticut Office of the Attorney General (AG) requested and were granted intervenor status.

II. DEPARTMENT ANALYSIS

A. CONTINUED UNIT OPERATIONS

1. General

By Order No. 4 in the Decision dated December 31, 1996, in Docket No. 96-04-01, DPUC Eleventh Annual Review of The Connecticut Light and Power Company and The United Illuminating Company Integrated Resource Planning, the Department ordered the Company to conduct a revised Continued Unit Operation (CUO) study of MP1 and the Connecticut Yankee (CY) and Millstone Unit 2 (MP2) nuclear generating plants. The Company filed the study on July 1, 1997, in Docket No. 96-10-06, DPUC Investigation into Whether The Connecticut Light and Power Company has Fulfilled Its Public Service Responsibilities with Respect to Its Nuclear Units (1997 Study). The Department then deferred its review of this study to Docket No. 98-03-04, Thirteenth Annual Review of The Connecticut Light and Power Company and The United Illuminating Company Integrated Resource Planning. The Department subsequently deferred its review of this matter to the instant proceeding. On June 1, 1998, the Company re-filed the 1997 Study in the instant proceeding. At that time, the Company notified the Department that it was updating the study and would re-file it when the new analysis was completed. The Company filed the revised study on July 17, 1998 (1998 Study). This Decision addresses the 1998 Study.

The analyses performed by the Company compare the revenue requirements of continued operation between the projected July 1, 1999 restart and the expiration of its operating license in 2010 to the revenue requirements of replacement energy, capacity, and applicable costs in retirement, should these units be prematurely retired from service. Issues such as transmission modifications, environmental impacts, fuel diversity, employment and taxes were not considered in the economic analyses. Tr. 9/25/98, p. 2707. Decommissioning costs have been included in the studies because, even though they would eventually be incurred whether the plant continues to operate or is prematurely shutdown, the costs are different for the two cases.

To assess the economics of these two nuclear units under varying assumptions, each analysis was performed under a reference case that assumed base line Operations and Maintenance (O&M) costs and average annual capacity factors of 79.7% and 79.5% for MP1 and 2, respectively. Further, as the Department requested, +10% and +20% non-fuel O&M cases were analyzed.

2. Millstone Unit 1

The 1998 Study indicates that MP 1 has a positive economic value of $19 million and MP2 has a positive economic value of $433 million on a present value basis. 1998 Study, p. 2. The Company concludes that continued operation of MP2 is economic for NU's customers, but states there is not sufficient value to continue to operate MP1 and therefore it will be retired.

> Although positive, the study results are in no way compelling. While this analysis could conceivably be used to support continued operation of Units 1 and 2, the changing utility structure and electric marketplace lead NU to the harsh reality that there is insufficient value in Unit 1 for NU customers and, therefore, we plan to evaluate alternatives and not bring Unit 1 back on line as an operating nuclear plant. NU will now cease restart activities at Unit 1 in preparation for final decommissioning. 1998 Study, Cover Letter.

The 1997 Study indicated that MP1 had a positive economic value of approximately $68 million on a present value basis. The Company testified that the single biggest variable between the 1998 and 1997 studies is the cost of replacement power. The 1998 Study shows the costs for replacement power as $80 million lower than the previous study. Tr. 9/25/98, p. 2698.

In its Supplemental Testimony the Company discusses several reasons that compelled it to retire MP1. First, the marginally positive economic benefit of $19 million indicated in the 1998 Study was neither substantial nor assured. Minor changes in the variables used could reverse these benefits. Second, new or heightened industry standards create relatively greater challenges for plants of MP1's vintage. Although these standards are faced by all nuclear plants in the United States, the costs of implementing unanticipated changes in standards at MP1 could erode the modest economic benefits shown in the CUO study. Third, competition is imminent. MP1 would have had to operate in a competitive generation market after January 2000, in accordance with Public Act 98-28, An Act Concerning Electric Restructuring (Act). It will likely be more costly to continue to operate and more difficult to maintain sufficient cash flows to assure safe operation for a unit with a thin margin between costs and revenues. Fourth, the Act requires CL&P to auction its nuclear plants by 2004 if it intends to seek stranded cost recovery, and CL&P believes that the sale of an operating MP1 would have produced little added mitigation value as opposed to selling the site. Any attempt to restart the unit to enhance its sale price would only add costs without increasing sale net proceeds. Finally, while the foregoing reasons are a sufficient basis for retiring the unit, bringing the unit back to service would continue to burden CL&P's financial and other resources. Morris Supp. PFT, p. 4.

The projected $19 million of economic value was an estimate derived from the information available and assumptions used when the 1998 Study was performed. Based on events since that time, management concluded that the economic value of MP1 was likely lower than shown in the CUO study. For example, based on the level of new generation that is planned in New England, the new pipelines that are being built and the availability of gas into New England, the Company expects replacement power costs to decline to levels lower than reflected in the CUO studies. Tr. 9/25/98, pp. 2711 and 2712. Replacement power costs have the largest influence on the declining economics of MP1, and the developments after CUO assumptions were set strongly suggest that such costs will be lower than assumed in that study. Id., pp. 2728-30. Other changes in the variables used in the CUO study (such as fuel prices, capacity factor and O&M expenses) could make the restoration of MP1 an even more uneconomic investment. Morris Supp. PFT, p. 5.

The Company requests that the Department find that MP1 was retired for economic reasons. Roman Additional Testimony, p. 5; Tr. 10/16/98, pp. 3877-3880. The Company requests the Department's authority to reflect a regulatory asset representing full recovery of the costs associated with its unrecovered investment in MP1, which will be submitted to the Department as part of the ongoing restructuring proceedings. CL&P is also seeking the Department's authority to defer, in the interim between the shutdown and January 1, 2000, all costs related to post-retirement safe shutdown and site protection, and costs incurred for work being done in preparation for the decommissioning of the unit. The amortization of this deferral would be reflected in the Company's proposed Systems Benefits Charge (SBC) calculation to be filed April 1, 1999. Roman Supp. PFT, pp. 9 and 10.

No parties or intervenors in this proceeding support CL&P's proposal. AG, OCC and PRO all recommend that the recovery of remaining costs associated with MP1 be denied.

In its Brief, the AG states that the Department should flatly refuse to adopt CL&P's requested treatment of MP1.

> MP1 was shut down as a result of the Company's imprudence and is not allowed to restart without specific permission of the NRC. There has been no finding in this or any previous docket that MP1 was shut down for economic reasons and CL&P has failed to present any credible evidence to support such a finding in this case. The DPUC should not permit the Company to establish a regulatory asset for MP1 when the Company has shown absolutely no assurance that it will be allowed any recovery under P.A. 98-28. In fact, since the Company has failed to show that the recovery of MP1 is assured, the DPUC should force CL&P to write this asset off its books pursuant to the mitigation provisions of P.A. 98-28. AG Brief, p. 23.

OCC states the Department should reject this CL&P proposal with respect to MP1 at this time. Acceptance of this proposal would amount to a DPUC allowance for CL&P to write itself a blank check with respect to this asset, which would eventually be payable by the Company's ratepayers. This resolution of MP1's regulatory status is singularly inappropriate, particularly in light of this unit's current out-of-rate-base. . . status. OCC Brief, p. VI-3.

PRO also recommends that the Department make a finding that MP1 was not retired for economic reasons and not allow recovery of carrying charges. "It would be wholly improper for the Department to make the requested finding that MP1 was retired for economic, not prudence-related reasons." PRO Brief, p. 5.

The Department must evaluate recovery of MP1 costs based on current law and regulatory case history. Section 8(j)(1) of the Act denies recovery of stranded costs for nuclear generation assets or for any generation related regulatory asset that is not operating as a result of an order by the Nuclear Regulatory Commission (NRC). Section 8(j)(2) however contains an exception for a plant meeting the description of

MP1. The Act allows the owner of such a plant to apply to the Department for approval of early retirement for economic reasons under the general ratemaking statutes.

The Company states it is also significant that the Act reflects a policy that MP1 costs should be recovered by the Company in the event of early retirement of the unit for economic reasons. In effect, the Legislature has expressed the policy that, if MP1 should be retired for economic reasons, the Company should go ahead and do so with the knowledge that its right to recover its costs will be protected. Morris Supp. PFT, pp. 9 and 10.

The Department strongly disagrees with CL&P's interpretation of the Act, which clearly allows the Company to apply for recovery of costs if the plant is retired for economic reasons, but does not guarantee that recovery will be granted.

The Company has conducted what it refers to as a "first level" economic analysis that compares the revenue requirements of continued operation to the revenue requirements of replacement energy, capacity, and applicable costs in retirement, should these units be prematurely retired from service. Issues such as transmission modifications, environmental impacts, fuel diversity, employment and taxes were not considered. Based on its analysis, the Company concludes that there is insufficient value to justify the continued operation of MP1.

The Company implies that the economics of the continued operation of MP1 is marginal. However, it is not just a break-even proposition as the Company suggests. The economics of MP1 are not overwhelming as is the case for MP2; however, they are positive. The Company's own analysis indicates that the continued operation of MP1 would produce $19 million in benefits over the 12 remaining years of its license period, on a present value basis. Since present value analysis is positive, it provides the Company a return slightly higher than 9.2%, the discount rate used by the Company in its analysis. 1998 Study, Exhibit II. The positive value of $19 million on a present value basis is in addition to a return of 9.2%, which is higher than the return of 8.05% being allowed in this rate case.

Perhaps even more important than the overall economic benefits is the distribution of annual economic benefits or penalties of operating MP1. Exhibit 1 of the 1998 Study indicates that the unit provides $64.3 million (nominal dollars) of positive benefits in 1999 and another $45.1 million in 2000 or $109.4 million over the first two years. Over the next 6 years from 2001-2006, the plant is estimated to break even with alternating years of positive and negative benefits. At the end of 2006 the economic benefits total $110.7 million. The remaining four years of the license period are projected to be the worst economically. In those years, the plant's annual economics are negative, $198 million. These penalties outweigh the positive benefits of the first eight years, resulting in a penalty of $87.1 million in nominal dollars over the remaining license period. This equates to a positive $19 of benefits on a present value basis because the benefits in the early years are discounted less than the penalties in the later years. On a present value basis, the economics would increase to approximately $105 million if the plant were retired for purposes of the analysis in 2007 rather than 2010. 1998 Study, Exhibit 1.

The economic assumptions chosen for the 1998 Study are key to understanding its results. On one side of the equation is the cost to operate the plant. Developing the estimated cost to operate MP1 over its remaining life involves a number of assumptions such as O&M costs, capital additions, nuclear fuel and the capacity factor. The cost to operate the plant is compared to the cost of providing power under alternative options. In this case, CL&P has used purchased power. Changes to these assumptions can have a significant impact on the final results and therefore the decision to operate or retire MP1.

A recurring theme in the Company's testimony is that costs other than purchased power, may be higher than expected, which would reduce any benefits from the continued operation of MP1. Tr. 9/25/98, pp. 2711 and 2712. Morris Supp. PFT, p. 5. In general, the Department does not believe the assumptions used by the Company are overly optimistic. While actual costs may be higher than expected, they could also be lower than presented in the base case scenario.

The 1998 Study includes projections of O&M and capital expenditures through the end of each unit's licensed life. The O&M amounts for the years 1998 - 2003 are consistent with amounts the Company has represented elsewhere in this proceeding, (see Dente Testimony, Exhibit TJD-2; Responses to Interrogatories OCC-99 and OCC-172, and the June 30, 1998, Supplemental Filing, Nuclear Business Group). The basis for these projections is discussed in Section II.F.7. For the years 2000 through 2002, the Company's forecast presumes the Millstone units are in the third quartile in comparison to their sister units. Beyond 2002, the forecast presumes that the units improve to the second quartile, due to the impact of the Company's nuclear performance improvement program. Response to Interrogatory EL-389. Historically, the units have generally been in the third quartile prior to the NRC Watch List outages. Response to Interrogatories EL-6 and EL-161; Tr. 9/17/98, pp. 1614-1616.

Since these amounts are consistent throughout the proceeding, and with recent expenditures[1] their inclusion in the 1998 Study is appropriate. Beyond 2003, the Company escalated O&M at 3% annually for the continued operation case. This appears to be a moderate and reasonable expectation. However, it is contrary to assumptions used in the 1997 Study in which the Company ramped down O&M over the final two years of operation, to about 60% of its maximum amount. The Company's justification for ramping down O&M at that time was "[a]s the unit approached the end of its license life, various staffing and or other resource requirements were adjusted accordingly during the final 18-24 months of service."

The Company states that it did not ramp down O&M because it now believes that the NRC will require a nuclear unit to be maintained at the same level throughout its life. Tr. 9/25/98, p. 2715. The Department believes this is reasonable, since the unit must still be operated and maintained in accordance with its license requirements. There may be some areas where O&M will be curtailed toward the end of life, particularly in non-safety related areas of the plant where preventive maintenance activities and engineering support functions can be reduced. However, since a high proportion of non-fuel nuclear O&M expense is driven by regulatory requirements, the impact of such

[1] See Section II.F.7.

reduction in non-safety related O&M is probably minimal. Additionally, there are no case histories where a nuclear plant has operated to the end of its licensed life, therefore the magnitude of any such ramp down effect is a matter of conjecture. Since the Company's overall O&M escalation appears moderate, the Department will accept the absence of a ramp down in O&M at end of life, and approve the projected O&M expense as filed.

The 1997 Study included a ramp down of capital expenditures over the final five years of operation of MP1, from $19,400,000 in 2005 to $0 in 2010, the final year of operation. 1997 Study, p. 20. Similar to O&M, the 1998 Study escalated capital expenditures annually through 2010. The Company's justification was the same as with O&M; the NRC will require the unit to be maintained in good condition throughout its license life. Tr. 9/25/98, p. 2715. However, in the case of capital expenditures, the Department does not believe this argument holds merit. Many capital expenditures are made for the purpose of significantly extending the life of equipment, and may be unnecessary when the equipment only needs to operate for the next few years. This is particularly true of equipment in the secondary side of the plant, where no extensive NRC license requirements apply. Other capital expenditures are desirable only to improve efficiencies and would likely be unnecessary as the unit approaches its license expiration date. Therefore, the Department finds that the assumptions regarding capital expenditures in the 1997 Study were more reasonable. By applying the 1997 rampdown schedule to the 1998 Study, the Department estimates that capital expenditures are reduced by a total of $72,200,000 over the last five years of MP1's original license life.

The Company has included $8.4 million associated with Nuclear Regulatory Commission (NRC) Watch List items as a cost of continued operation in its CUO analysis. Response to Interrogatory OCC-322. Since the Department has ruled that it is not appropriate to recover these costs, they should be removed. This improves the economics of continuing to operate MP1.

The Company uses a capacity factor of 79.7% for MP1 in its economic analysis and assumes that the unit will operate at an 86% capacity factor between refueling outages. Refueling outages are planned to last 49 days and generally occur every 24 months. 1998 Study, p. 14. The Company's assumption is aggressive but not unrealistic. MP1 operated at a capacity factor of 69.6% from 1970 to 1995. The NRC, Information Digest, 1997 Edition indicates that the average capacity factor for the industry over the five year period from 1992-1996 is 75%. Digest, p. 24. The capacity factor usually increases several percentage points when a unit returns to service after being on the Watch List. Response to Interrogatory EL-5.

The Company has included the cost of decommissioning in its analysis, estimating $642 million in its shutdown scenario and $482 million if the plant continues to operate. 1998 Study, Appendix A, pp. 4 and 5. These estimates are preliminary and have not been accepted by the Department for ratemaking purposes; however, there is no basis for any adjustment at this time and therefore they are acceptable for the CUO analysis.

The single most important assumption in the CUO analysis is the cost of replacement power. CL&P states that " . . . replacement power costs are clearly the most important driver in the economics." Tr. 9/25/98, p. 2732. CL&P's assumption in its CUO analysis is that replacement power (energy and capacity) is purchased in the New England market. 1998 Study, p. 6. The Company has forecasted replacement power costs to be $38.10/MWh in 1998 which increases to $44.80/MWh in 2007, a compound annual increase of approximately 1.8%. Response to Interrogatory OCC-323. The Company's response to Interrogatory EL-391 indicates that a 10% increase in the cost of replacement power would increase the present value benefits associated with continued operation of MP1 from $19 million to $122 million. Benefits would jump to $225 million, on a present value basis, if replacement power costs were 20% higher than CL&P's estimates. On the other hand, a decline in purchase power costs would reduce the economic value of continuing to operate MP1 by a similar magnitude.

The Company's forecast of replacement power was developed in-house. Tr. 9/25/98, p. 2700. These purchased power estimates were first used by the Company in its stranded cost testimony for PSNH before the Public Utilities Commission of New Hampshire in November 1997. Response to Interrogatory OCC-323. The Company's study did not provide any alternative supply options, purchased power forecasts, or scenario analyses to evaluate the sensitivity of the study results to changes in replacement power costs.

Although the Department asked several interrogatories and questioned the Company's CUO witness at the hearing to examine this issue further, the Company provided very little evidence to verify and support its purchased power cost estimates. The Company could not provide any recent replacement power price forecasts from independent organizations or other utilities in New England. The only replacement power costs the Company could submit were done in 1996 by the joint owners of Connecticut Yankee. These estimates were lower than those forecasted by the Company. The Company states that these projections were developed with what is an obsolete methodology today. Late Filed Exhibit No. 120. In addition, the Company's Response to Interrogatory OCC-323 included a replacement power forecast that was also used in PSNH's 1997 stranded cost proceeding. Overall, that projection was about 10 percent higher in the 1998-2000 time period and approximately 20 percent higher beginning in 2002. Response to Interrogatory, OCC-323.

Replacement power costs are very difficult to predict with a strong degree of accuracy. Replacement power is made up of the forecasted cost of capacity and energy. The capacity value is estimated based on the balance between the supply of generation resources and the demand for electricity in the region. Changes to supply or demand can change the value of capacity in the market. Energy costs are based on fuels forecasts for oil and gas, which are extremely difficult to predict. For example, over the past two years the price of oil at the Company's Norwalk Harbor Station increased from $15.97/bbl in March 1997 to a high of $21.75/bbl in October 1997 then dropped to approximately $12.00/bbl in October 1998.

The Company and most others who have attempted to forecast fuel prices have done a poor job over the past 20 years. One of the primary reasons Connecticut has high cost nuclear power plants (Seabrook and Millstone Unit III (MP3) and purchased

power contracts is fuel forecasting errors. These plants and contracts were all projected to be cost effective based on oil price forecasts made at the time the units were built or the contracts were negotiated.

The Company, as well as most experts, has overestimated future fuel prices in the past. For example, in its Integrated Resource Plan, 5th Annual Filing, Docket No. 90-04-01, April 1, 1990, the Company forecasted avoided costs to be $.056/kWh in 1998 and $.153/kWh in 2008. In its 12th annual filing, Docket No. 97-04-01, dated April 1, 1997, the Company's forecast for 1998 had dropped by almost 50% to $.03/kWh and its projection for 2008 was $.042/kWh. In its original filing in the instant proceeding, CL&P based its 1999 oil and gas price projections on February 1998 Cambridge Energy Research Associates (CERA) forecasts. Schedule C-3. The Company forecasted oil prices to range between $16 and $18 per barrel for the rate year. Tr. 9/11/98, p. 662; Late Filed Exhibit No. 57. In contrast, oil prices are at or below $12 per barrel today. CL&P's forecast is off by 25% to 30% in less than nine months.

Fuel prices have declined since the Company made its replacement price estimates and could decline further. A number of new generation units are now planned that were not included when the Company made its replacement power forecast. Fuel prices are at their lowest levels since 1973 and could increase from these levels. Oil and gas prices remain tied to international events that are beyond the Company's control. Difficulty projecting fuel prices, combined with changes due to electric restructuring create considerable uncertainty about future replacement power costs. When asked about the Company's ability to forecast replacement power costs, its CUO witness said: "Clearly, it is a daunting task." Tr. 9/25/98, p. 2733.

The Company has not provided adequate evidence to support its purchased power forecast. The decision to shut down MP1 would not need to be made based on such a speculative forecast if it were operating today.

A decision to retire or to continue to operate a nuclear power plant requires more than just a first level economic analysis. One of the most important factors facing the Company was that MP1 was not in operation. If it were, there would not be a compelling reason to retire the plant simply based on a forecast, given the inherent uncertainty and economics at the time. In fact, Exhibit 1 of the 1998 Study indicates that there was positive economic value of $109.4 million in 1999 and 2000 if the plant continued to operated. As discussed above, the economics do not turn negative until 2007. But the plant had been out of service for approximately 56 months and was unable to restart without NRC approval. Its costs remained in rates for approximately 51 months of the shutdown. In the February 25, 1998 Interim Decision in Phase 1 of the instant docket, the Department removed MP1 from rate base. It was officially retired five months later, effective July 24, 1998. Roman Supp. PFT, p. 1. At that time, all work to bring MP1 back on line had been suspended, as all efforts were concentrated on the restart of MP3 and then MP2. The Company did not expect that MP1 would be brought back on line until July 1, 1999, the Company testified that the cost to restart it was estimated to be $112 million. Tr. 9/12/98, p. 2714.

Restart costs must be born by the Company and therefore are not relevant for ratepayers in considering whether MP1 should continue operating. The Company

appropriately excluded most restart costs from its economic analysis but not from its decision to retire MP1. It is clear that cost of restart, its effect on the Company's financial situation, and the time and effort required of employees were important factors in the Company's decision. As Mr. Morris testified ". . . bringing the unit back to service would continue to burden CL&P's financial and other resources. . . ." Morris Supp. PFT, p. 4.

Restructuring of the electric industry is another reason the Company uses to justify its decision to retire MP1. In a competitive generation market, nuclear plants will no longer recover their costs on the basis of full cost of service ratemaking. Instead, they will have to recover their costs from the revenues they derive from selling their output. For units like MP1, the revenue margin above costs will be relatively thin and could get thinner if there were unscheduled outages or the capacity factor were lower. These events would put pressure on cash flow. Morris Supp. PFT, pp. 4, 6 and 7.

The restructuring of the electric industry will not change the cost of operating the plant. It could lower the cost of competitive alternatives thereby reducing the economics of MP1 relative to other sources. More importantly, restructuring will shift the risk of cost recovery from ratepayers to generation companies. In the past, if a generation plant was less economic than other facilities, ratepayers paid the difference and the Company recovered all costs. In the future, as the Company states, recovery will be less certain. Any under recovery will be borne by the generation company, but it will also benefit from higher profits if it is a low cost producer.

At this point, the overall level of risk the Company will face is not known. The market price for power, competition in the generation sector, and stranded costs are speculative. The Department's determination of stranded costs will establish the costs these units must recover in the future to be economically viable. After further questioning as to the impacts of restructuring on the CUO study results, the Company stated: ". . . without an understanding of how the relevant markets will evolve, it is impossible to speculate what the impact on the CUO studies may be." Response to Interrogatory EL-384.

By shutting down the plant, the Company believes it should receive the full return of and on its unrecovered rate base balance at the time of retirement of $229 million. A ruling by the Department that retirement of MP1 is appropriate would eliminate the need to spend $112 million in restart costs and reduce the risk of recovery of O&M costs for the 12 remaining years of its license period. In addition, retiring the plant would essentially end the out of rate base treatment set by the Department. The Department had disallowed the recovery of MP1 costs by removing them from rates and this would continue until the unit returned to service, which was not expected until July 1999. The Company is now requesting to defer for future recovery all costs as of the retirement date of July 1998.

The Company's logic creates perverse incentives that are contrary to those faced by competitive businesses. Businesses in the competitive world lose money if economics sour and even more if they must shut down or go bankrupt. This creates a strong incentive to cut costs and operate more efficiently. CL&P, on the other hand, has quickly retired a generation plant that was not operating and for which it was receiving

no return in the hopes of guaranteeing recovery of its past investments. Under competition or under regulation, such an outcome is not appropriate.

The Company did not consider transmission impacts in its CUO study. When asked if there were any associated with the retirement of MP1, the Company testified that the improvements made over the past two years to bring Millstone Station on line eliminate the need for additional ones. Tr. 9/25/98, p. 2744. The Company did not consider required transmission impacts in the 1997 Study even though upgrades would have been needed if MP1 were retired. 1997 Study, p. 2. While the Company has attempted to rationalize its results in the 1998 CUO Study, it should have specifically examined the impacts of transmission when the study was conducted. The Department is not convinced that there will be no impact to ratepayers for the replacement of MP1 with new generating facilities in Connecticut or out of state; however, there is not sufficient evidence to support any adjustment to the 1998 Study at this time.

The Company also did not consider environmental impacts and fuel diversity in its economic analysis. Tr. 9/25/98, p. 2707. The environmental impacts of nuclear power are significant. An important justification for its use has been the environmental benefit of replacing fossil fuel generation, which emits air pollutants. In the Company's justification of cost recovery, Mr. Morris testified that MP1:

> has been a good performer. It has also made substantial contributions to cleaner air in Connecticut by eliminating the need to burn fossil fuels, thereby avoiding the emissions of millions of tons of air pollutants and has been important to the economy of the region by providing jobs and property tax revenue. Morris Supp. PFT, pp. 9 and 10.

However, the Company did not attempt to quantify or value these benefits or consider them in its analysis to retire the unit.

Fuel diversity has been a cornerstone of energy policy for the Company, the Department and the State since the oil embargo of 1973. Reducing price volatility and potential disruptions was always a justification for nuclear power plants when they were being built and licensed. The associated effects on national security and the balance of payments from reducing the use of imported oil were also considered benefits.

Fuel diversity remains relevant today, since units run by oil and gas will likely make up for the generation lost by the retirement of MP1. Imports of oil have increased as older plants have had to operate to replace the production from retired nuclear units or those out of service. In the future, gas will be the fuel of choice and many developers are rushing to build new generation units that will use gas supplied primarily from Canada.

Environmental impacts and other issues such as fuel diversity and employment are difficult to quantify, but they are important and should be considered in a continued operation study. It would be irresponsible to follow "first level" economics blindly, as the Company's analysis and conclusions imply. If decisions were based solely on the economics, there would be no diversification. This is not a sound risk management approach for a generation company given the ever changing prices for fuels.

In support of its request to recover the remaining costs for MP1, the Company states that the plant: ". . . has generated a great deal of energy for CL&P customers and created a great deal of value to the State of Connecticut during its operating life." Morris Supp. PFT, p. 8.

The facts speak for themselves. MP1 operated at a capacity factor of 69.6% from 1970 to 1995. This is generally consistent with industry averages and expectations when the plant was being constructed. The last two years prior to its retirement it did not operate. In addition, the unit was retired 12 years earlier than its license expiration date of 2010, thereby reducing its useful life by approximately 30%.

In its rush to retire the plant, the Company has precluded options that may have increased value to ratepayers and/or provided an opportunity for the facility to operate at a future date. It does not appear that the Company attempted to sell the facility or develop a strategy to bring it back at a later date if the economics prove more favorable than now forecasted. Mr. Morris testified that:

> Based upon our current expectations concerning the market for nuclear power plants, we do not believe that the potential proceeds from the sale of MP1 would significantly offset CL&P's stranded costs. Two ownership interests in nuclear plants have recently sold in the northeast. The units involved, Three Mile Island Unit I and Seabrook, are both operating very well, and in both cases the sellers received very little for their interests. Any value from the sale of MP1 is expected to be derived from its site value, not from the fact that it is operating. Morris Supp. PFT, p. 7.

The Company has not provided any estimates of sales value with MP1 in operation or if the plant is retired. The value will certainly be less if the facility is not operating. Although CL&P stated that sellers received very little for their interest, the difference could still be tens of millions of dollars. Ratepayers are entitled to this money to offset stranded costs.

The Company's economic study is too simplistic and speculative to justify the retirement of MP1. The Company did not comprehensively examine alternative economic scenarios and failed to consider important factors such as environmental impacts and fuel diversity. Based on the economic analysis the Company provided, the Department must conclude that the Company would not have retired MP1 if it had been operating, particularly given the positive economic benefits in the early years and the uncertainty of the forecasted assumptions later on. There would be no compelling reason to retire the plant in 1998 if it were still operating. A more appropriate response, had the plant been operating, would be to continue to operate the plant, attempt to improve efficiency and periodically reevaluate its economic viability. The Company's analysis shows that it is economic to continue to operate the unit. There is risk that the economic viability can decline but it could also improve if the operating conditions are better than those forecasted.

The Department concludes that MP1 was retired for economic reasons, but other factors related to the outage were considerations in the decision. By retiring the plant

the Company can avoid an estimated cost of $112 million to bring the unit back to service. In addition, the Company hoped to end the out of rate base treatment and reduce operational risks it would face with electric restructuring by requesting full recovery of its unamortized rate base balance with a return from the date the plant was retired.

The Department has discussed the shortcomings in the Company's analyses and changes that could increase the benefits of continued operation; however, other factors particularly lower purchased power costs, could offset the benefits. The Department will therefore accept the Company's reference case forecast of benefits/penalties as filed for ratemaking purposes.

The Department believes that some sharing of the remaining costs between ratepayers and shareholders is appropriate because the study indicates that it may be economic to retire MP1 in the future for economic reasons. Further, the Department believes that ratepayers are entitled to the benefits from 1999 and 2000 that they would have received if the unit had not been retired prematurely. In addition, the Company should not benefit from retiring MP1 before its expected return to service date of July 1, 1999.

In its written exceptions, the Company urges the Department to adjust the $109 million in economic benefits to reflect the following: (1) CL&P's 81% ownership of MP 1; (2) the present value of the economic benefits; (3) lower energy and capacity costs approved elsewhere in the Decision; and (4) lower decommissioning costs consistent with decommissioning costs allowed in the Decision. CL&P Written Exceptions, p. 8.

The Department agrees that the economic benefits should be adjusted to reflect CL&P's ownership share of MP 1 and will do so. In addition, the Department agrees that the economic benefits should be calculated on a present value basis since they are presented in the CUO study in nominal dollars. However, the Department does not agree with the Company's calculation or the present value adjustment. Since the rate year is 1999, 1999 benefits are on a present value basis and no adjustment is necessary. The Department will discount 2000 economic benefits by one year at a discount rate of 9.2%, as used in the CUO study. The revised economic benefit ratepayers will forgo due to the early retirement of MP 1 is $84.5 million.

The Department does not agree that the economic benefits should be adjusted to reflect lower fuel prices or decommissioning costs. It is unclear how the Company calculated their adjustments for energy and decommissioning. These adjustments are not supported by the record and therefore inappropriate at this time. While adjusting these components in the CUO study might seem consistent with the Department's ratemaking in this Decision, it would be inconsistent with the other components of the CUO study. Many of the assumptions in the CUO study have changed since the Company conducted its analysis. It is not appropriate to selectively adjust assumptions that benefit the Company. Updating or quantifying other factors could increase the economic benefits of the continued operation of MP 1, which would offset the adjustments proposed by the Company. The Department notes that it did not increase the economic benefits for the $8.4 million associated with the Watch List items identified above that should be removed for the costs of continued operation. In addition, CL&P

did not request that the Department update the CUO results to reflect reduced nuclear employee levels approved in the Decision. Doing so would reduce O&M costs and increase the economic benefits of continued operation. Finally, the Department has not attempted to quantify benefits such as fuel diversity, employment and environmental impacts, which the Company did not include in its analysis. For these reasons, the Department will not adjust the economic benefits for changes in fuel prices and decommissioning as requested by the Company.

a. Treatment of Millstone Unit 1 in the Application

The Company originally forecast MP1 to restart on July 1, 1999. Consequently, the 1999 forecast contains incremental restart costs for the first six months and normal operating costs for the last six months of the year. Response to Interrogatory EL-152. As of March 1, 1998, ratepayers have not been supporting MP1 and have received a 1.39% credit on their monthly bills to reflect removal of MP1 costs. The total credit for MP1 was dependent upon actual sales and the time before rates are adjusted. If MP1 remained out of service at the conclusion of phase two of this docket, the Department would determine the appropriate rate treatment for crediting customers in the phase two Decision. This credit was not subject to true-up, as waived by the Company in Docket No. 97-05-12. Interim Decision, pp. 3 and 4. The total credit was not dependent on the retirement of MP1.

The Company reflected the MP1 credit in revenues for the first six months of 1999, effectively eliminating MP1 costs for that period. The Company then adjusted the forecast to reflect the continuation of the credit for the last six months. The Company also removed all MP1 costs from the Application. The end result is that revenue requirements and proposed rates for 1999 do not include MP1 costs; they do, however, include MP1 RPC. Tr. 9/17/98, pp. 1401-1415.

The Department notes and the Company agrees, that the costs in the 1999 forecast do not equate to the current MP1 credit, which was based on an estimate of 1998 costs. Tr. 9/17/98, pp. 1411 and 1412. However, because the Company proposes to roll the credit into base rates and the expenses have been removed, any difference from the credit that would be calculated based on estimated 1999 expenses is captured in the calculation of revenue requirements and ultimately in the revenue sufficiency. The Department concludes that CL&P's treatment of MP1 costs in the Application is appropriate.

b. Retirement of Millstone Unit 1 Pursuant to the Act

The Company retired MP1 on July 24, 1998. Roman Supp. PFT, p. 1. Therefore, its next set of financial statements must reflect this change in plant status. Section 8(j)(2) of the Act contains specific provisions for regulatory treatment for MP1 should it be prematurely retired. The Company may not receive stranded costs for MP1 if the Department determines that it was not retired for economic reasons. The treatment differs if the Department should find that the retirement was due solely for economic reasons. The Company claims the retirement decision was made solely based on economic reasons. Consequently, the Company asks the Department to rule

that CL&P's decision to retire MP1 was prudent. Morris Supplemental PFT, pp. 3-7; Tr. 10/16/98, p. 3880.

The Company continued to depreciate the MP1 plant asset while it was out of rate base before it was retired. In effect, that expense flowed directly to the bottom line because the Company was not receiving revenues from ratepayers in support of the expense. Tr. 9/17/98, pp. 1517-1520. The Company ceased recording depreciation when the unit was retired. Any future recovery of the plant (i.e., depreciation) from the date of retirement will depend on future regulatory decisions. CL&P requests approval to reclassify the undepreciated plant balance at retirement along with its associated construction work in progress (CWIP), deferred taxes, nuclear fuel and materials and supplies, net of CMEEC costs, as a regulatory asset for a total of $228.7 million. Roman Supplemental PFT, p. 2; Tr. 10/8/98, pp. 3239-3242; Tr. 10/16/98, pp. 3860 and 3861; Late Filed Exhibit Nos. 15 and 165.

MP1 was placed in extended maintenance mode prior to 1998. The Company decided that it did not have sufficient funds to restart the three Millstone units and it was going to concentrate on MP2 and 3. Tr. 9/10/98, pp. 353 and 354. CL&P has incurred about $5.5 million ($6.8 million x 81% ownership) per month to keep MP1 in extended maintenance mode and expects that level to continue through 1998. The Company would not seek recovery of costs incurred to keep MP1 in extended maintenance mode. Response to Interrogatory OCC-169; Tr. 9/11/98, p. 565. The Company did not make many capital expenditures for MP1 while it was in extended maintenance mode. Tr. 9/11/98, p. 567. The Company reclassified the extended maintenance mode costs as post shutdown, pre-decommissioning costs when MP1 was retired. These costs contain expenditures for certain activities that were performed prior to retirement and will continue to be performed after retirement. The Company requests explicit Department approval to create a new regulatory asset for these expenditures. CL&P believes the post shutdown, pre-decommissioning costs it has incurred prior to new rates being effective are different from regular operating costs and the requested deferral is consistent with the treatment contemplated by the Act. The Company has not requested that the Department come to a conclusion on the level of recovery. The Company believes that the primary vehicle for reviewing the appropriateness of these costs is the proceeding to begin in 1999 for the calculation of the SBC. Roman Supp. PFT, p. 5; Tr. 10/8/98, pp. 3212-3218 and 3247; Late Filed Exhibit No. 166.

The Company has not requested to receive a return on its investment during 1999, the rate year in this docket; however, it has requested that the Department allow it to create a regulatory asset for the return on the investment (i.e., carrying costs) from retirement to January 1, 2000, and defer discussions on the amount recoverable. The Company would file for recovery of deferred balances when it begins collecting the Competitive Transition Assessment permitted in the Act. The proposal to defer the carrying costs is a reversal from the current out of rate base treatment and the Company's original filing, where it removed MP1 rate base effectively eliminating recovery of carrying costs. The Company also has created a regulatory asset for the unrecovered decommissioning liability that it must now recognize. The Company will only have to write off the components of the regulatory assets that the Department explicitly or Department precedent says are not likely to be recovered. Right now CL&P believes there is no reason to write off any assets. Roman Supp. PFT, p. 4; Tr. 9/11/98,

pp. 599, 600, 611 and 612; Tr. 10/8/98, pp. 3236 and 3254. If the Department denies the deferral of the carrying costs, the Company would not be able to recognize those carrying costs. If the Department concludes that the Company would never be allowed to receive carrying costs on the remaining investment, SFAS 90 requires the Company to recognize a level of return on the unrecovered balance that is at least equal to its incremental cost of borrowing. The Company would have to discount the cash flows associated with recovering the balance at its incremental borrowing rate and compare that discounted amount to the amount on the Company's books. The difference, which CL&P estimates to be $40 million, would have to be written off. Tr. 10/8/98, pp. 3255-3259; Tr. 10/16/98, p. 3879.

SFAS 71 and SFAS 121 give guidance as to when a regulated entity can record an item as an asset on its books and when it must write off that asset if the future revenue stream is not sufficient to recover all costs. On each balance sheet date, the Company must determine that recovery of its assets, including regulatory assets associated with MP1, is likely. If it determines that recovery has been impaired, then it must write off the amount it is not likely to recover. The Company believes that based upon Department precedent, the Act and a Department ruling in this proceeding that the retirement of MP1 was made for prudent reasons, it can create all regulatory assets it believes are required and will not need to write off any costs. The Company has not asked the Department to make a finding on the amount of the regulatory assets the Company will be allowed to recover. The Company has asked that the Department agree that the appropriate proceeding to determine the amounts to be recovered is in a restructuring proceeding. As a result of that proceeding, the Company would true-up the initial entries for any changes that occur. Tr. 9/11/98, pp. 564, 583-587; Tr. 10/8/98, pp. 3252 and 3253. The Company believes it would have to take a write down if the Department said that a certain amount of the unrecovered plant will never be recovered. That would be a clear signal that an asset has been impaired. Tr. 10/8/98, p. 3238. CL&P has requested the Department be very careful with its language regarding creating a regulatory asset for carrying costs and future recovery of the asset. Without any specific denials, the Company believes it can record all the regulatory assets it needs and not incur any write-offs at this time. Tr. 10/16/98, pp. 3878 and 3879.

The Department has set September 28, 1998, as the effective date of new rates in phase two. By reclassifying MP1 costs as regulatory assets as of the retirement date, the Company is seeking not to be denied recovery of MP1 costs from the retirement date until the conclusion of phase two. The Department concludes that it is not appropriate for CL&P to recover any MP1 costs from July 24, 1998, to September 28, 1998, the time period for which the Department, in the Interim Decision, ordered the Company to credit ratepayers for MP1 costs.

MP1 was not expected to restart until July 1, 1999. Response to Interrogatory EL-152. The Company did not expect to recover the costs of restarting MP1. Morris Supp. PFT, p. 8. If CL&P had not decided to retire MP1, it would have continued to depreciate the plant, would not have been earning a return on its investment, and would have been expensing extended maintenance mode and restart costs as they were incurred. Therefore, the Department concludes that CL&P is not entitled to recover any MP1 costs through July 1999.

The Department will include in rates the recovery of rate base as of July 1, 1999, based on the projected unamortized balance at that time, which includes amortization of $18.1 million minus $84.5 million associated with the benefits if the unit had continued to operate though 2000. The amortization is equal to the depreciation contained in Schedule C-2. Therefore, the total regulatory asset to be recovered, net of CMEEC, is $126.1 million, as shown on the following table:

Millstone Unit 1 Regulatory Asset ($ Millions)

	CL&P Estimate	DPUC Allowed
Net Unrecovered Plant In-Service	$196.2	$196.2
CWIP	21.1	21.1
Nuclear Fuel	50.0	50.0
Materials and Supplies	14.2	14.2
Sub-total Unrecovered Assets	281.5	281.5
Accumulated Deferred Income Taxes	-43.4	-43.4
Net Unrecovered Balance	238.1	238.1
Less: Benefits Through 2000		-84.5
Amortization of Unrecovered Plant		-18.1
CMEEC 4.3% of Unrecovered Plant & CWIP	-9.4	-9.4
Total Net Unrecovered Millstone Unit 1 Balance	228.7	126.1

The Department will not allow a return on the Company's remaining investment since the plant is not operating. The Department believes it is crucial to strike a balance between the Company and ratepayers on recovery of MP1 costs. Since CL&P will be allowed to recover some MP1 costs, which are now reclassified as a regulatory asset, and the Act contemplates mitigation and recovery of regulatory assets, the MP1 regulatory asset should not be subject to further analysis in the future. The Department also believes it is not appropriate to have that regulatory asset remain long into the future and determines that recovery over three years is appropriate. Therefore, the Department allows amortization of the regulatory asset in the amount of $42.033 million for the rate year.

The Department does find that it is appropriate to establish regulatory assets for the post shutdown, predecommissioning costs CL&P will incur subsequent to July 1, 1999, and the decommissioning costs. The Department will examine the appropriate amount of recovery in an upcoming restructuring docket.

3. Millstone Unit 2

The 1998 Study indicates net benefits of $669 million or $433 million on a present value basis with the continued operation of MP2 over the remaining years of its license. 1998 Study, Exhibit 2. The Company concludes that MP2 is economic for ratepayers. Id., p. 1. The Company indicated that the continued operation of MP2 was significantly more cost effective than MP1 primarily due to its longer remaining life. MP2

has an additional five years to generate power and since it is more economic on a yearly basis, the benefits are additive. The differential in O&M costs between nuclear plants are nearly the same regardless of the size of the plant. Since MP2 is about a third larger than MP1, it produces more kilowatt-hours over which to spread the costs. Tr. 9/25/98, pp. 2703-2705.

The Department examined the Company's assumptions and asked it to provide a sensitivity analysis. The Company's analysis of MP2 continued operation assumes that MP1 is also operating. Response to Interrogatory EL-386. Given the decision to shut down MP1 the economic value to operate MP2 should be adjusted by $71 million to about $362 million. Response to Interrogatory EL-386.

Like MP1, the 1998 Study of MP2 is limited to a "first level" economic analysis and does not consider other important impacts. However, the Department believes that the assumptions are generally reasonable. The savings are sufficiently robust to enable the facility to remain economic under other possible operating scenarios. The Department finds that MP2 is economic and its continued operation is in the best interest of the ratepayers of Connecticut.

B. MILLSTONE UNIT 2 RESTART

In the Application, CL&P had projected to restart MP2 on July 1, 1998. Schedule C-3, p. 2. The Company later revised the restart date to December 1, 1998. Schedule C-3.11 (Revised). The Company later indicated that MP2 may not return to service until early 1999. The most current anticipated restart date is April 1, 1999. CL&P believes that updating the Application to reflect a date certain would not resolve the dilemma of accommodating subsequent shifts in the restart schedule. Roman Supp. PFT, p. 5. There was discussion throughout the hearings on what CL&P would do should the Department order further rate reductions than those it proposed. CL&P gave conflicting testimony on whether or not further rate reductions would affect the restart effort for MP2. Mr. Morris stated that CL&P will not slow down the restart effort of MP2 if the Department orders further rate reductions. It will find a way to go forward with the restart efforts. Tr. 9/10/98, p. 341. Mr. Forsgren testified that the Company would not let financial pressures affect the restart effort of MP2 if it could possibly avoid it. However, Mr. Morris also testified that some things the Company intended to get done might not get done. According to Mr. Morris, money only comes from the customers; something has to give. However, the Company would realign where it would spend its money in 1999 and try to protect as much as it could the restart effort of MP2. Tr. 9/10/98, pp. 409-411.

In accordance with the Decision dated April 29, 1998, in Docket No. 92-11-11, on May 1, 1998, CL&P began recording an out-of-rate-base (ORB) non-cash accrual for MP2 of $3.14 million per month, which offsets the CY deferral. With interest, this accrual totals $16.018 million through September 30, 1998. Response to Interrogatory OCC-97-SP01. On September 16, 1998, the Company requested revised treatment of MP2 for the rate year. The Company proposes to replace the current ORB non-cash accrual with a cash credit on customers' bills for MP2 costs contained in the rate year effective September 28, 1998, for the period MP2 is shutdown. In addition, for the period September 28, 1998, until new rates are implemented, the Company would

accrue the credit to customers, plus interest, and include the accrued credit in base rates in the rate year. The Department could then decide to apply the accumulated MP2 non-cash accrual against the CY deferral or use it for something else. Roman Supp. PFT, pp. 1-3; Tr. 10/13/98, pp. 3455-3461.

In Exhibit 1-SP01, the Company filed an ORB calculation based on the revised Application. It was similar in format to the current ORB calculation. The rate base data were also contained in the response to Interrogatory OCC-98. The Company annualized first quarter 1999 revised simulated replacement energy and capacity costs (RPC) as a proxy for 1999 RPC. The annualized RPC was used to match the annualized numbers used in the rest of the ORB calculation. The Company believes the credit is most likely to be in effect only for the first quarter of 1999, and, therefore, wanted the RPC and the credit to reflect what it projects the actual costs will be. The RPC would continue to be subject to true-up in the Energy Adjustment Clause (EAC), as is done currently. Tr. 10/13/98, pp. 3464-3466.

OCC believes that MP2 should continue its ORB status, although on a cash reduction basis. However, OCC believes the proper MP2 ORB calculation should remove property taxes and not allow recovery of replacement capacity costs. OCC believes that ratepayers should not be required to fund property taxes for a generation plant that is not used and useful. OCC Brief, pp. VI-8 and 9. OCC did not identify any record evidence in support of its belief that CL&P does not need to buy capacity. OCC also would like to change the terms under which the MP2 surcredit would end. OCC believes the unit should run at 95% power for 200 hours and that specific Department approval should be required. OCC Brief, pp. VI-9 and 10. The Decision dated April 29, 1998, in Docket No. 92-11-11 states that upon notification to the Department that MP2 or Millstone Unit 3 (MP3) has operated at no less than 95% power for 100 continuous hours, the corresponding accrual would end without further Department action. Decision, pp. 7 and 9.

The Department finds no basis to use OCC's recommended terms to end the ORB treatment. When MP3 returned from the 10CFR50.54(f) outage, the unit required an extensive power escalation and testing program prior to returning to full power. This program required a slow, deliberate escalation in reactor power and long hold points at pre-defined power levels for testing purposes. This program required several weeks to complete. Given that MP2 will require a similar power escalation program, the unit will have operated for a long period of time prior to exceeding 95% power. The Department believes that this requirement should therefore be relaxed for MP2, and deems that MP2 will be returned to service when it has operated at no less than 75% power for 100 continuous hours. Once MP2 meets that standard, it will be returned to rate base without further Department action.

While the Department finds CL&P's method of calculating MP2 costs for 1999 reasonable, it disagrees with the amounts used and the final ORB estimate. The rate base calculation filed in response to Interrogatory OCC-98 did not contain a materials and supplies (M&S) component. The M&S component of the prior ORB calculation was $13,248,000. Docket No. 97-05-12, Response to Interrogatory EL-95. Consistent with the discussion in Section II.F.6, the Department increases the M&S component to calculate an average M&S for 1999 and includes it in the ORB calculation. The

Department has not removed the MP2 refueling outage accrual, as calculated in Section II.F.23, in the O&M to assure the Company that it will continue to collect the accrual while MP2 is out of rate base. The Department also adjusts MP2 working capital to reflect changes made to total allowed working capital in Section II.E.6.e. The Department also adjusts rate base and O&M by the MP2 adjustments made in Sections II.E.2 and II.F.7.c and f of this Decision. The Department's adjustments result in a rate base reduction of $325,136,000 and O&M removal of $114,534,000 as compared to CL&P's proposed rate base reduction of $333,061,000 and O&M removal of $115,696,000.

The Department calculates replacement energy costs based on production and costs contained in this Decision less direct nuclear fuel. The Final Fuel Simulation, as discussed in Section II.G.1, demonstrates total production for MP2 for 1999 to be 5,257,000 MWhs and direct nuclear fuel cost of $24,466,800. Revise WPC-3.1. This total includes an adjustment to the production for January through June to reduce production to a CL&P basis. The adjusted marginal cost as calculated by the Department is $19.46/MWh. Total estimated replacement energy for MP2 is $77,834,420 [(5,257,000 MWhs x $19.46) - $24,466,800]. Consistent with the discussion in Section II.G.1.k, the Department has not removed nuclear fuel indirect costs to assure the Company that it will continue to collect D&D while MP2 is out of rate base. The Department finds CL&P's method of calculating replacement capacity costs of $19,164,000, using an annualized estimate of first quarter 1999 for MP2, reasonable and accepts that number. Late Filed Exhibit No. 167. The Department finds no basis for OCC's statement that CL&P need not buy replacement capacity for MP2; therefore, net RPC for MP2 is $96,998,420. This compares to CL&P's estimate of $150,824,000. The primary difference is the estimate for the marginal cost of energy due to the fact that oil prices have dropped significantly and were not reflected in CL&P's estimate. The final ORB change to CL&P's retail revenues is $79,032,000 as can be seen on the following table. The RPC will continue to be subject to true-up in the energy adjustment clause, as is done currently.

Millstone Unit 2 ORB Calculation

Rate Base Changes		($000's)
Rate Base Reduction		(325,136)
Return on Rate Base		8.05%
Reduction in Operating Income		(26,173)
Revenue Conversion Factor		1.758
Revenue Reduction - re Rate Base & Capitalization		(46,013)
Interest Synchronization		9,474
Operating Expenses		
O&M	(114,534)	
Depreciation	(26,500)	
Replacement Power: 1999	96,998	
	(44,036)	
Gross Receipts & Bad Debts Factor	1.0456	(46,044)
Total Change in Revenues		(82,583)
Less: CMEEC Ownership Entitlement		3,551
TOTAL CHANGE IN CL&P RETAIL REVENUES		**(79,032)**

The Department believes it is most appropriate to continue the non-cash accrual for the MP2 disallowance to be used as an offset to the potential ratepayer liability for the accumulated Connecticut Yankee RPC deferral (CY Deferral). As of September 28, 1998, the monthly accrual will be $6,586,000 ($79,032,000 / 12) and will earn interest at the Company's weighted cost of capital approved in Section II.M.6. As the Company has already recorded a monthly accrual of $3.1 million per month plus interest for the period from September 28, 1998, through February 5, 1999, the Company should record an additional monthly accrual from February to May 1999 to account for the additional $3,486,000 monthly accrual plus interest for the previous period. Once the accrual exceeds the deferred balance, CL&P shall return the excess MP2 accrual to ratepayers through the EAC. If it is determined that ratepayers are not responsible for CY RPC the Department will determine the ratemaking treatment in a future EAC proceeding.

However, if it is determined that ratepayers are responsible for CY RPC and the MP2 accrual plus interest is less than the deferral at that time, the MP2 accrual will be applied in its entirety against the CY Deferral. Thereafter, the remaining CY Deferral will be amortized at the rate of the monthly revenue reduction associated with MP2 being removed from rate base until the deferral is eliminated or MP2 returns to service. If the deferral is not eliminated before MP2 returns to service, the balance will be recovered through the EAC.

C. ISSUES FROM DOCKET NO. 97-05-12

In the Decision dated December 31, 1997, in Docket No. 97-05-12, the Department concluded that CL&P could potentially overearn during 1998 by approximately $261 million. Decision, Table III. The Department opened this docket to

continue its review undertaken in Docket No. 97-05-12 and to conduct a full rate review. In phase one of this docket, the Department concluded that $110.479 million in overearnings should be used for additional amortizations of regulatory assets subject to true up in the phase two Decision. Interim Decision, pp. 1 and 4.

The Application prescribes rate reductions of $21 million representing 1999 forecasted current outage costs for MP2 and 3 and applies $19 million in revenue sufficiency overearnings to amortization of the deferred balance of Financial Accounting Standard (SFAS) 109. Morris PFT, pp. 3 - 5.

The Company filed an exhibit that addressed $150 million in potential overearnings identified in Docket No. 97-05-12 that were not addressed in phase one, summarized them and indicated how the Company treated them in the Application. The Company removed some costs from the rate year, adjusted the amounts of others, and left some in 1999, as it believed was appropriate. The Company believes it addressed all issues from Docket No. 97-05-12; therefore, the rate year is clean. Late Filed Exhibit No. 9; Tr. 9/11/98, pp. 495-506; Tr. 10/16/98, pp. 3797-3808.

The Company's efforts to exclude some of the Docket No. 97-05-12 Decision items from the rate year should have lead to a greater rate decrease than proposed. However, the Company contends that other items contained in the Application, such as depreciation, fuel costs and cost of capital, have increased since the Department's review in Docket No. 97-05-12. In the September 30, 1998, revised schedules, the Company recommended adjustments to the Application that it deemed necessary to arrive at appropriate rates that it should be allowed to charge customers. OCC, AG, PRO, CIEC and CCM also recommended adjustments in their briefs.

The Department has reviewed the rate base, expenses, revenues and the cost of capital contained in the Application and has taken into consideration recommended adjustments. Based on that comprehensive review, the Department has made appropriate adjustments to the Application and orders additional reductions and amortizations for the rate year. When the Orders are implemented, the Company will have the opportunity to earn the allowed return on equity set in Section II.M**,** below, and will no longer be collecting revenues in excess of its needs. Therefore, the potential overearnings that were identified in Docket No. 97-05-12 and partially addressed in the phase one Decision are moot.

D. TEST YEAR / RATE YEAR

It is the practice of this Department in utility rate cases to establish rates prospectively upon the basis of a historical test year, adjusted for pro forma purposes. In this case, the Company has used the operating results for the 12 months ended December 31, 1997, as its test year. The Department will accept this time period as the test year. Historically, the Company has adjusted its test year to reflect its rate base and capital structure to the midpoint of the rate year (i.e., the year that rates will be in effect). Additionally, revenues were adjusted for weather normalization and forecasted year customers and certain expenses were adjusted for known changes. The Company also applied an inflation factor to those expenses that were not specifically adjusted elsewhere.

The Department believes it is appropriate to begin with the 1997 budget upon which the 1998 forecast was based and then the 1999 rate year projected. In developing the 1999 forecast, the Company has not reflected any MP1 capital and operating costs in the calculation of revenue requirements but has included a full year of replacement power costs. Although MP2 and 3 are forecasted to be operating in 1999, the Company removed from its revenue requirements $21 million of its budgeted operation and maintenance expense levels. Mahoney PFT, pp. 3 and 4. Other costs with known changes, such as fossil outages and amortizations, also were adjusted discretely. The remaining costs were escalated using factors of 1.8% for materials and 3.6% for labor.

E. RATE BASE

1. Fossil/Hydroelectric Plant Additions

a. Bulls Bridge Hydroelectric Station

The Company's initial filing included additions totaling $2,370,600 related to "automation of station/units" at the Bulls Bridge hydroelectric station. Supplemental Filing dated June 30, 1998, FHEO Capital, p. 4. The Company has since indicated that this project will be canceled. Response to Interrogatory EL-75, Supplement 1. The Company also revised its plant additions by $1,307,600 to reflect cancellations or postponements of miscellaneous projects at its fossil units. Late Filed Exhibit No. 6; AR-OCC-67. The Company states that plant additions should not be reduced by these amounts, since it has determined that new additions have been identified that will be required to comply with Phase II of the Clean Air Act. However, the Company did not provide justifications of these projects or any further detail on them. Id.

The Department cannot consider the Phase II Clean Air Act additions without supporting evidence. Additionally, the Company did not quantify these expenditures. Therefore, there is insufficient justification to include them in rate base. The Department reduces average rate base by $1,839,100 [($2,370,600 + $1,307,600)/2].

b. Middletown 1

The Company reactivated Middletown 1 due to the need for increased capacity and predicted it would make capital additions to that plant in 1998. The Company does not anticipate making the capital additions; therefore, $285,000 in rate base should be removed for the rate year. Response to Interrogatory EL-287; Tr. 9/15/98, pp. 1059-1061. The Department concurs and reduces rate base by $285,000.

c. Devon Station Gas Turbines

CL&P installed four gas turbines at Devon Station in 1996 to provide replacement capacity and energy while the Millstone units were out of service. The installation of the leased turbines was directly related to the Millstone outages. The units were procured under a five-year lease, and it is presently planned to release the units upon termination of the lease, or sooner. Response to Interrogatory EL-219. The Company spent $13.7 million in 1996 and $.5 million in 1997 to install the units. Late Filed Exhibit No. 130. The Company forecasts to spend an additional $1.4 million in capital additions on the units. Late Filed Exhibit No. 168, Read-In YY.

As with the T&D reliability additions related to the Millstone outages, see Section II.E.3, the Department concludes that the Devon Station gas turbines were added solely due to the Millstone outages, and therefore all costs associated with these units should be disallowed. The Department assumes the capital installation costs are depreciated over the life of the lease and calculates rate base for the leased units as total capital expenditures less accumulated depreciation and reduces rate base by $6.688 million. In its written exceptions, CL&P sought clarification that the net proceeds from the eventual divestiture of the Devon units will be allocated to shareholders. Written Exceptions, p. 4. The Department is only engaged with the current ratemaking aspects of the Devon units in this case. The Department does not make any ruling as to the assignment of proceeds from divestiture of the Devon units in this case, but will review the assignment of proceeds in other proceedings relating to the implementation of the Act.

The Department makes an out-of-rate-base calculation for MP2 due to the continued outage, which allows CL&P to recover replacement power costs, including replacement capacity costs. See Section II.A.3, above. The cost of capacity related to the Devon leased units is significantly higher than the market price of capacity today. The Department will allow CL&P to use the Devon leased units as replacement capacity, but only at the market price of capacity. Consequently, even though CL&P will not earn a return on the capital costs or receive operating costs through base rates, when the units are used to serve retail load, ratepayers will be partially responsible for the costs of the units in the EAC.

2. Nuclear Plant Additions

The Company included in its filing the expansion of the Four Mile River Road building in East Lyme at a cost of $1.12 million. However, Company documents reveal that this expansion was necessary to accommodate personnel working on the Millstone outages. Late Filed Exhibit No. 6, AR-OCC-35. OCC states that this expenditure

should be disallowed. Schlissel Testimony, p. 67. Since the expenditure is directly related to the Millstone outages, the Department will remove the cost from rate base. However, the Department will reconsider this issue in a future rate proceeding if the Company provides evidence that the addition has value apart from the Millstone outage.

The Company's plant additions also include $4 million for underground oil tanks installed at MP1. Response to Interrogatory EL-163. However, the tanks were installed on the premise that MP1 would restart from the current outage, which is no longer the case. The Company did not seek to include this amount in rates, since all MP1 costs are excluded from rates. However, the Company is considering modifying the tanks and associated piping for use at MP2. The Company has not finalized these plans. Late Filed Exhibit No. 71. Therefore, the Department will not allow this addition in rate base at this time. However, the Department will reconsider this issue in a future rate proceeding if the Company provides evidence that the fuel tanks are being used at MP2.

The Company's filing originally included $29,004,000 in plant additions for MP2 in 1999. Schedule H-1.2. This amount includes projects to be done during the next refueling outage, which was scheduled to occur in 1999 at the time the initial filing was made. Since then, the Company postponed the refueling outage to 2000. Late Filed Exhibit No. 172. The plant additions associated with that outage are therefore not appropriate for inclusion in rate base, because they fall outside the rate year.[2] The actual amount of plant additions at MP2 is $5,081,000, reflecting only those projects still scheduled for 1999 that do not require a refueling outage. Late Filed Exhibit No. 165, Supplement 1. Therefore, the Department reduces rate base for MP2 by $11,961,500 [$29,004,000 - $5,081,000) x (50%)].

3. Transmission and Distribution Additions

The Company's request includes plant additions for T&D system improvements incurred in 1996 and 1997 at a cost of $16,066,474 to increase transmission import capacity during the Millstone outages. Response to Interrogatory EL-219. The improvements were located in the Enfield and Suffield areas. The Company states that these additions should be allowed, regardless of their origin, since they will allow customers access to a wider array of power sources after the industry is opened to competition in 1999. Louth Testimony, p. 10. The Company states that these upgrades will improve the flexibility and security of the system even after the nuclear plants are returned to service. Id., p. 11. The Company also states that many of these upgrades would have been necessary in the next 10 years regardless of the loss of the Millstone units and that many had been previously contemplated as system improvements. Response to Interrogatory EL-219, p . 3.

The Department sought information from the 1995 time frame that indicated whether any of these projects were planned at that time to determine whether any of the subject improvements would have been implemented regardless of the Millstone outages. Tr. 9/28/98, pp. 2807-2809. The Company was unable to provide any such

[2] Rate base is limited to 50% of 1999 plant additions, since the Department uses the average rate base for the rate year.

information. Instead, it provided documentation on the projects that dated to the 1996 (post Millstone outage) time frame. The Company also provided information from a study concerning T&D improvements in the western and southern portions of the state. Late Filed Exhibit No. 129, Attachments A and B. However, there is no mention of pending improvements to the T&D system in the Enfield and Suffield areas in these documents. The Company was therefore unable to support its claim that some of these projects were planned prior to the Millstone outages.

The Company states that the projects that involve installation of capacitors would not appear in the 1995 documentation, since capacitors are installed on an ongoing basis as part of good utility practice. Tr. 9/28/98, p. 2808. The Department agrees that this is the case, since installation of capacitors does not involve significant preplanning/engineering work, in relation to other system improvements. Capacitors are installed in utility distribution systems to counteract inductive loading, or leading power factor, in a portion of the system. Inductive loading tends to increase over time as system loads increase, therefore, a utility system installs capacitors as a normal course of business. Installation of these devices is therefore part of ongoing system maintenance. The Department requested data on system inductive loading or power factor in the subject portions of the T&D system from the 1995 time frame. Id. The Company provided power factor data by district from 1995. Late Filed Exhibit No. 129, Attachment C.

When the electric system contains only resistance, the current (amperes) and voltage remain in step (rise and fall in value together and reverse in direction at the same instant - referred to as “in-phase”). In this case, the product of volts times amperes (“volt-amperes”) equal watts, which, when measured over time, equal watt-hours. When the system contains inductance equipment, such as transformers and, to a lesser extent, the power lines themselves, the current is shifted “out-of-phase” with the voltage causing the current to lag the voltage. The amount of shift depends on the relative amounts of resistance and inductance. When the current is out-of-phase with the voltage, the power in watts is no longer equal to the volt-amperes (apparent power) but rather is equal to the product of volt-amperes times the “power factor.” The power factor can be defined as the ratio of actual power (in watts) to volt-amperes or the ratio of actual power to apparent power. When the current and voltage are in-phase, the power factor is unity (1.00), the largest value possible, and as current lag increases the power factor decreases. The power factor represents the portion of electric energy supplied that is converted into useful work or heat and lighting (“actual power” or “active power”). The remainder of the electric energy supplied is required to produce or sustain the magnetic fields necessary for the operation of induction devices and performs no work. This is the “reactive power.” In practice, a “perfect” power factor of 1.0 is almost never achieved.

The data the Company provided on power factor indicate that the system power factor in 1995 in the Enfield district was not materially in need of capacitance. The Enfield district power factor under maximum load was 0.9788, and under average load was 0.9865. Late Filed Exhibit No. 129, Attachment C. Both of these values are relatively high. In fact, they were higher than any of the other three districts that comprise the Eastern Region. Of the 11 other districts in the CL&P system, the Enfield district was in better condition from a power factor standpoint than eight of them.

Although this simple comparison does not conclusively demonstrate that no capacitors would have been required at any point in the system at that time, there are no data that indicate that additional capacitors were necessary in the Enfield district. Therefore, the Company has not demonstrated that the capacitors would have been required absent the Millstone outages. However, this evidence also demonstrates that capacitor additions were required in substantially all the other districts. The Department believes that a sharing of the capacitor costs is therefore appropriate and will allow the Company to include 50% of these costs in rate base, or $3,540,569.

The Company also states that the T&D additions may have value after the Millstone units have returned to service and the industry is opened to competition in 1999. However, the extent to which this is true will depend heavily on how the market evolves, and the emergence of new generation resources within Connecticut. The impact of these T&D resources on the market is therefore uncertain at this time. In addition, it is not clear at this time as to who would be responsible for the costs of transmission system upgrades under competition. It is possible that they would be the responsibility of the electric suppliers who want to move power over the transmission lines to serve end-use customers. Thus, they would not be recovered through transmission charges.

The Department concludes that the there is no substantial evidence that the T&D additions related to the Millstone outages, other than the capacitors discussed above, provide any benefit to the Company's T&D system, other than importing power while the units are shut down. The future value of these additions is uncertain. Therefore, the Department will not allow these additions in rate base. The majority of these additions are recorded in accounts 353 and 356. Late Filed Exhibit No. 177. Therefore, the Department will assume an average service life of 42 years and reduce rate base, net of accumulated depreciation by $11,880,092. However, the Department will reconsider this issue in a future rate proceeding if the Company provides evidence that the additions have value apart from the Millstone outages.

4. Construction Program

The Company's proposal for construction in 1999 totals approximately $312,250,000 and for the five-year period 1999 through 2003 totals approximately $1,663,630,000, which equates to an average expenditure of $332,726,000 per year. The breakdown of these amounts is as follows:

Construction Program Forecast ($000)

	1999	1999-2003 Total	1999-2003 Average
Production	80,245	294,783	58,957
Transmission	4,582	51,262	10,252
Distribution	195,879	1,202,122	240,424
General	8,655	22,229	4,446
Removal	20,301	97,039	19,407
Total	309,662	1,663,630	332,726

Schedule F-7.0.

The Company's average capital expenditures for the years 1993 through 1997 were $148,690,000. Response to Interrogatory EL-365.

In general, the forecast of capital expenditures is consistent with the past, with the exception of distribution. Distribution expenditures increased from $75,476,000 in 1993 to $88,756,000 in 1997. Id. Distribution expenditures are expected to increase to a maximum of $263,846,000 in 2001. Schedule F-7.0. The primary reason this increases is a greater focus on improving reliability. Louth Testimony, p. 3. Capital intensive components of the Company's reliability improvement program include:

CL&P Reliability Expenditures Forecast, 1999

Program	Funding Forecast
Replace Obsolete Overhead	$17M in 1999, escalating to $60M in 2003
Replace Direct Buried Cable	$7M
Replace Transmission/Substation Equip.	$11M
Bare Wire Upgrade to Covered Wire	$11M

Louth Testimony, pp. 20-23.

The Company's line maintenance program describes how the Company maintains and improves its distribution plant. The Department last reviewed the Company's line maintenance program in Docket No. 86-12-03, Long Range Investigation to Examine the Adequacy of the Transmission and Distribution Systems of The Connecticut Light and Power Company and The United Illuminating Company, and Docket No. 97-11-10, DPUC Review of Electric Utility Line Maintenance Plans - 1998. In the joint Decision in those dockets, the Department stated that it "expects significant improvements in CL&P's system reliability . . ." and found that the Company's new policies for replacement of failure prone equipment, including direct buried cable and overhead equipment, were necessary and should improve system reliability. Decision dated August 21, 1998, pp. 9 and 11. The Department also found that the Company did not have a systematic program for replacing bare wire with covered wire, but that such a program was necessary to improve reliability, given the conclusive data on the effectiveness of covered wire in preventing tree-caused outages. Id., p. 11.

The proposed amounts for funding improvements to the distribution system represent a major commitment on the part of the Company to enhance system reliability. Replacement of old or faulty overhead, underground, and substation equipment is necessary to improve the reliability of the distribution system. The Company's plans for bare wire conversion to covered wire will increase the proportion of covered wire from 34% to 50% by 2003. Louth Testimony, p. 23. The Department believes this is a reasonably aggressive effort to improve the resistance of the system to tree contacts and will therefore improve reliability substantially. The proposed capital expenditures for distribution improvements are therefore reasonable and necessary to serve the public. The Department concludes that the construction program appears reasonable for planning purposes; however, all proposed items are subject to review when the Company seeks their inclusion in rate base.

5. Accumulated Depreciation

The Department reduces CL&P's proposed depreciation expense by $13,280,827 ($7,210,587 + $2,238,000 + $3,084,646 + 747,594) in Sections F.1, below. Since the Department uses the average rate base for the rate year, the accumulated depreciation must be adjusted by one half of the adjustment to depreciation expense. Consequently, the Department reduces accumulated depreciation by $6,640,414, thereby increasing rate base by the same amount.

CL&P correctly stated in its written exceptions that the Department did not adjust accumulated depreciation for the removal of Bulls Bridge Hydroelectric station, Middletown 1 and the Four Mile River Road building. CL&P estimated the adjustments to be $140,870. Written Exceptions, Appendix, p. 8. However, the Department also did not remove the rate year depreciation expense for these items. The adjustment to depreciation expense would offset the accumulated depreciation adjustment resulting in no change to revenue requirements. Therefore, the Department does not make either adjustment.

6. Working Capital

a. Introduction

It is customary regulatory practice to allow an adjustment to rate base in recognition of the timing differences between when revenues are received and when expenses are paid out and to account for the need to have such items as fuel and materials and supplies on hand and available prior to actually being needed. For large utilities, the Department typically requires that timing differences between revenues and expenses be determined by means of a lead/lag study rather than using some rule of thumb approach.

In the Decision dated June 16, 1993, in Docket No. 92-11-11, the Department ordered the Company to conduct a lead/lag study and submit it with its next rate application. The Company has complied with that order and filed the results of its study as Schedule H-1.6 along with supporting work papers. In addition to a request for a working capital allowance based on the results of its lead/lag study (cash working

capital), the Company has requested an allowance for Fuel Reserve, Nuclear Fuel Reserve, and Materials and Supplies, Excluding Fuel.

The Department has reviewed the Company's request for a working capital allowance and finds it acceptable except as noted below.

b. Fuel Reserve

The Company has proposed to include a level of fuel reserve in its working capital based on the average expected fuel inventory for December 31, 1998, and December 31, 1999, and reflecting fuel prices for those two dates as forecasted by CERA. Schedules B-1.0 and B-4.0; Late Filed Exhibit No. 100. As of the date of the Company's filing, CERA was projecting the cost of oil delivered to CL&P generating sites to range from $18.57 to $31.04 per barrel during this time frame depending on the site and fuel grade used. These forecasted oil costs are significantly higher than current costs to the Company and higher than the Department is expecting for the Company during calendar year 1999. See Section II.G.1, below. Consistent with the oil costs the Department is using in this Decision to determine the base fuel rate for the Company, the Department will recalculate the fuel reserve using oil costs to the Company that range from $12.00 to $24.47.

In addition, the Department finds the use of inventory levels as of December 31st for purposes of setting a fuel reserve for ratemaking purposes highly questionable. The level of inventory for generating sites typically varies during the course of a year as the level of production expected/required from the site changes. Since the Company generally attempts to keep a minimum 10-day, full-load supply of inventory at each site, months of higher expected/required production are characterized by higher inventories and vice versa. Late Filed Exhibit No. 100. The months of December, January and February mark that time of the year when oil generation is expected to be its highest and, thus, inventories taken at that time tend to be significantly higher than at other times of the year. Late Filed Exhibit No. 138. In the Decision dated June 16, 1993, in Docket No. 92-11-11, the Department found ". . . it inappropriate to use a December balance . . . because December levels are usually higher." Decision, p. 14. That Decision indicated that inventory levels for April 30th were more than 30% less than the December 31st levels. Id. Late Filed Exhibit No. 138 shows that average monthly expected oil generation production during 1999 is more than 32% less than the production in December. Compared to January, the discrepancy is even greater, with average production more than 50% less. Clearly, an inventory level as of December 31st is likely to be at least 30% higher than average inventory levels for the year; therefore, the Department will reduce the fuel reserve by 30%. The net result of the above adjustments is to reduce fuel reserve from $22,888,000 to $10,734,000.

c. Nuclear Fuel Reserve

The Company's request for nuclear fuel reserve is predicated on decontamination and decommissioning (D&D) costs that were incurred by the Company for 1996 through 1997 and into 1998 but have not been expensed. Tr. 9/22/98, pp. 2039 and 2040. The Company claims that these costs have also not been recovered from ratepayers and, thus, are owing from ratepayers, including rate base treatment

while the costs are recovered. Id.; Brief, pp. 24-28. However, as discussed in Section II.G.1, below, the Department finds that until the units were removed from rate base, these costs were recovered from ratepayers during the period they were incurred. As such, there is no amount due to the Company and no amount that should be included in rate base. Therefore, the Department has reduced the nuclear fuel reserve included in rate base by $11,150,000 (22,300,000 ÷ 2).

d. Materials and Supplies, Excluding Fuel

The Company initially requested an allowance of $70,364,000 for materials and supplies, excluding fuel for the 1999 rate year based on the average of the materials and supplies, excluding fuel balances on December 31, 1998 and December 31, 1999. These balances were calculated using the actual balance as of December 31, 1997, of accounts 154 and 163 escalated at 4% per year plus CL&P's portion of the average materials and supplies balance per the Northeast Nuclear Energy Company Millstone 3 Nuclear Unit funding statement for January 1998. Schedule B-1; WPB-1; Late Filed Exhibit No. 5 AR-DPUC-08, AR-DPUC-028. In its revised filing, the Company used an escalation rate of 3% on account 154 and 163 balances. The 4% and 3% escalation rates used by the Company in its calculations of the average materials and supplies, excluding fuel balance for rate year 1999 are significantly in excess of the escalation rates, as measured by the Producer Price Index, historically achieved in the first two quarters of 1998, and currently projected for 1998 as a whole and 1999. See Section II.F.6, below. The current projections for 1998 and 1999 are negative 0.4% and positive 0.7%, respectively. Id. The Department finds it reasonable and consistent to use these latest projections to escalate the balances of accounts 154 and 163 to calculate the average materials and supplies, excluding fuel balance, for rate year 1999. Using these escalation rates results in a reduction to the 1999 average materials and supplies excluding fuel balance, from $70,364,000 to $67,190,000, a net reduction of $3,174,000.

e. Cash Working Capital

The Company's request for an allowance for cash working capital is based on the average timing difference between when the Company receives its revenues and when it pays out its expenses as measured and weighted by the Company for the 1997 test year. Relative to the Company's prior lead/lag study, the study submitted in this case indicates a number of significant decreases to the leads of several expense categories, including pension costs, nuclear fuel, and local property, federal unemployment, Connecticut unemployment, sales/use, and corporate business taxes. The Company testified that these changes were related to changes in its accounting practice, better tracking of certain transactions, changes in the make up or definition of certain accounts and/or the particulars of the 1997 test year relative to the test year used in the prior study. Response to Interrogatory EL-341; Tr. 9/22/98, pp. 2067 and 2068. Given the Company's testimony regarding the reasons for various expense lead decreases, the Department will accept the leads and lags indicated in the study for purposes of determining a cash working capital allowance in this proceeding.

The study did not look at the lead associated with short-term debt and this item has not been historically considered for purposes of determining the Company's cash working capital allowance. However, in this proceeding, the Department finds it appropriate to include short-term debt in the Company's capital structure as discussed in Section II.M, below. To maintain consistency between the capital structure and the cash working capital allowance, the Department finds it appropriate to include short-term debt in the calculation of the allowance. The Department has done so assuming a short-term interest expense lead of 30 days reflective of monthly interest payments.

In addition to the various leads and lags assigned to expense and revenue categories, a cash working capital allowance is also predicated on the weight accorded each category and the level of total expense that the allowance must accommodate. The Company's proposed allowance is based on a hybrid approach using an average of expected annual total expense for 1998 and 1999, and categories that are weighted based on the percent of total each category achieved during the test year 1997. Tr. 9/22/98, pp. 2045 and 2046. During cross-examination, the Company agreed that the total expense should be based solely on the level for 1999 and not averaged with 1998 as done by the Company. Id. Also, and relative to this proceeding, the Department finds it more appropriate to weight the categories based on revenues and expenses found reasonable for ratemaking purposes, (i.e., based on calendar year 1999 and as adjusted by the Department), as this better matches the allowance with the period for which rates are being set and is consistent with the total expense level that is being accommodated. The Company concedes that such an adjustment is not inappropriate. Id. Making this adjustment and using the total expense level allowed by this Decision reduces the calculated net lag for the Company from 12.71 days to 10.36 days and the requested cash working capital allowance from $79,974,000 to $65,397,000.

7. Conservation and Load Management

The Company forecasts $28.752 million in 1999 conservation and load management (C&LM) expenditures as approved in the Decision dated March 25, 1998, in Docket No. 97-10-23, DPUC Review of The Connecticut Light and Power Company's

1998 and 1999 Conservation and Load Management Program, Budgets and Conservation Adjustment Mechanism. The Company indicated that it deferred the entire amount to the balance sheet and proposes to amortize 1999 deferred expenditures ratably over 1999. The Company expects to amortize and fully recover all current and prior unamortized C&LM costs through 1999. The Company later indicated that the amount deferred was $26.7 million, while $2.1 million related to payroll was expensed. Responses to Interrogatories EL-88 and OCC-255; Tr. 9/14/98, pp. 793-796, 913; Late Filed Exhibit No. 6, AR-OCC-56 and 168, Read-In I.

The Company offsets unamortized C&LM balances by the after tax proceeds received from sales of SO_2 Allowances and NO_X Emission Reduction Credits in accordance with the Decision in Docket No. 93-04-07, DPUC Review of Electric Utilities' Plans Pursuant to Public Act 92-106 Regarding Permit Allowance Revenues from the Federal Clean Air Act Amendments of 1990. The Company confirmed that the revenues from sales of SO_2 Allowances from Environmental Protection Agency (EPA) auction sales reduce unamortized C&LM balances. Tr. 9/14/98, p. 917. The revenues from these sales fluctuate from $30,000 to $60,000 each year. Response to Interrogatory EL-89. The EPA auction sales will continue into 1999; however, the Company did not reflect any offsets to C&LM balances. This is because there are likely to be credits held back and the Company did not model the forecast down to the level of precision that would incorporate the small amount of SO_2 Allowance sales revenues. Tr. 9/14/98, pp. 917-920.

The Company set an objective in Docket No. 96-10-09, DPUC Review of the Conservation and Load Management Programs and Budgets and Conservation Adjustment Mechanism of The Connecticut Light and Power Company for 1997, to reduce the unamortized C&LM balance to zero by 2000. The Department agreed that was an appropriate objective. Decision dated April 16, 1997, p. 6. If the Company's expectation for fully amortizing C&LM balances in 1999 is not met, any small remaining unamortized balance at the end of 1999 would be offset by the revenue the Company will receive from the sales of SO_2 Allowances. Because the amount at issue is likely to be immaterial, the Department will not revise the Company's 1999 unamortized C&LM balance or impute revenues from sales of SO_2 Allowances.

The 1999 detailed forecast used to project the operating expenses in the Application shows 1999 amortization of deferred C&LM expenditures to be $41.779 million. Response to Interrogatory OCC-6, p. 3. The unamortized balance at December 31, 1998, is $13.026 million. Response to Interrogatory OCC-255, p. 5. A simple calculation leads to the conclusion that CL&P amortized $28.753 million ($41.779 million - $13.026 million) of 1999 deferred expenditures in 1999. The Department believes the actual financial data are more persuasive than the Company's later assertion to the contrary. Therefore, the Department finds that CL&P has deferred 100% of 1999 C&LM expenditures.

The Company's methodology of deferring 100% of 1999 C&LM expenditures and fully amortizing them over 1999 leads to a similar ratemaking result as expensing all 1999 expenditures. Therefore, no adjustment to the Company's rate base is necessary.

The Department has reviewed all the issues surrounding recovery of past and current C&LM expenditures and concludes that it is appropriate to expense all 1999 C&LM expenditures. However, amortizations of prior C&LM balances remain unchanged from the Company's filing.

The Company's sales and revenue forecast reflects lost sales and consequently lost fixed costs as a result of C&LM initiatives. The Company recovers the costs of C&LM, including amortization of capitalized expenditures, a return on the unamortized balance of capitalized expenditures, lost fixed costs, and a bonus incentive to encourage C&LM initiatives through base rates and the Conservation Adjustment Mechanism (CAM). The Department now finds that by year end 1999 all past deferred C&LM expenditures, all 1999 C&LM expenditures and lost fixed costs will be recovered. Therefore, the Department eliminates the CAM for 1999. The Department allows the Company to continue to earn a bonus return on its C&LM expenditures for 1999. See discussion in Section II.F.13, below.

8. Gains on Disposition of Property

Schedule G-2.17 lists completed and projected land sales for 1997 - 1999. However, CL&P believes the level of uncertainty that surrounds land sales makes it impossible to predict when each sale will ultimately occur. Therefore, CL&P did not reflect land sales in the rate year forecast. Response to Interrogatory OCC-134; Tr. 9/14/98, p. 935.

The Company espoused this same belief in Docket No. 92-11-11. According to the Company, a major land sale at the time was speculative and other properties registered with the Department of Economic Development would take three to five years to sell. The Department acknowledged that the land sale market was stagnant, but indicated there was extensive potential for sales and recommended that the Company be innovative in marketing its properties. Therefore, the Department increased gains on disposition of property for the rate period. Docket No. 92-11-11 Decision, pp. 27 and 28.

Ultimately, the major land sale transaction did not close. However, the Company has closed an average of 12 real estate transactions per year and achieved annual gains on disposition of property of $157,000; $3,197,638; $1,030,206; $104,000; $243,000; and $695,000 during the years 1992 - 1997, respectively. Late Filed Exhibit Nos. 40 and 168, Read-Ins UU and ZZ. This evidence of actual gains on land sales validated the Decision in Docket No. 92-11-11.

CL&P did not present new evidence in this proceeding that would lead the Department to reverse course from the Decision in Docket No. 92-11-11. Historically, the Department has imputed gains on disposition of property as revenue in a rate year, reducing revenue requirements in setting retail rates. Section 8(h)(3) and (4) of the Act mandates that stranded costs for nuclear generation assets be reduced by the net proceeds that are above book value (i.e., gains) received by an electric company for the sale or lease of any real property after July 1, 1998. The Department has ordered the Company to create a contra asset account to record the gains and offset rate base by such gains. Decisions in Docket No. 98-06-09, dated August 21, 1998, Application of

The Connecticut Light and Power Company for Approval of Land Sale and Grant of Easement, p. 2; and Docket No. 98-05-11, dated August 21, 1998, Application of The Connecticut Light and Power Company for Release of an Easement in Meriden, Connecticut, p. 3. This method of recording gains allows ratepayers to receive the benefit of the carrying costs on the gains until they are used to reduce nuclear stranded costs.

CL&P provided a list of land sale transactions not completed by July 1, 1998, that have been approved by the Department or that CL&P is negotiating with or has contracted with buyers. This list contains CL&P's estimated completion date for each transaction. Response to Interrogatory EL-210; Late Filed Exhibit No. 40. From this evidence, the Department concludes that the Company will have some amount of closed land sales in 1998 and 1999 resulting in gains on disposition of property. CL&P agreed that it is likely some land sales will take place in 1999. Tr. 9/14/98, p. 934.

Consistent with the Act, CL&P will reflect the gain on sale of relevant property as an offset to stranded costs of nuclear generation assets. Response to Interrogatory EL-142. CL&P calculated the impact to rate base and income for 1997 - 1999 from gains for all the land sales listed in Schedule G-2.17 by taking the sales price less expenses associated with the sale less the book value of the property less income taxes. The Company identified one sale in which $2.08 million of the gain related to land that was never included in rate base. The Company did not reflect the gain in the revenue impacts because the gain would historically have been recorded below-the-line. Response to Interrogatory EL-143. The Company revised the exhibit and calculated the impact to rate base and income that results from treating the gains in accordance with the Act. Late Filed Exhibit No. 38. Once again, the Company did not include the gain from the sale of land that was never in rate base in the calculation. Also, the Company added the average gains in 1998 and 1999 in the calculation of the impact to 1999 rate base.

OCC believes the projected gains should be recorded as income in the rate year. Larkin PFT, p. 21 and Exhibit L&A-1. OCC believes this adjustment is appropriate because the Department has referred to this proceeding as a traditional rate case. In this proceeding OCC believes the Department should ignore the requirements of the Act, because those issues will be dealt with in the stranded costs proceeding. OCC does not perceive using the gains to reduce revenue requirements in this proceeding and mitigating stranded costs in a later proceeding as a double hit to the Company. Response to Interrogatory CL&P-8; Tr. 10/13/98, pp. 3389 and 3390.

The Department believes it is appropriate to reflect gains on all land sales expected to occur by December 31, 1999, in setting rates for 1999. However, the Department strongly disagrees with OCC's argument to impute gains in rate year revenues. OCC's argument is contradictory to the Act.

Based on the data contained in Late Filed Exhibit No. 40, the Department forecasts gains on disposition of property from July 1, to December 31, 1998, and all of 1999 of $1.157 million and $7.12 million, respectively. The Department did not include the gains for two sales, one in Lebanon and the other in Cromwell. The buyer of the Lebanon property rescinded his offer to purchase the property and the Company does

not have a new buyer for it at this time. The Company has yet to calculate the book value and consequently the estimated gain on the Cromwell property. Late Filed Exhibit No. 168, Read-In VV; Tr. 10/20/98, pp. 3944 and 3945. By not including the gain on the sale of the Lebanon and Cromwell properties, the Department is allowing the Company some flexibility in achieving the forecasted gains.

The Company is actively marketing its surplus property. However, the Act has not compelled the Company to market surplus properties or seek to identify other properties more aggressively that it might be able to sell and increase the gains available to reduce stranded costs. Tr. 10/15/98, p. 3573. The Department is interested in exploring all land sale opportunities to reduce stranded costs of nuclear generation assets. The Department will order the Company to request a technical meeting to discuss in greater detail the Company's policies and procedures for identifying and marketing all properties that are not needed in the delivery of electric service.

In summary, the Department reduces rate base by $2.558 million, which is the sum of after tax gains from post July 1, 1998, and the average after tax gains for 1999. The Department also reduces rate base by $.248 million, which is the sum of the book value of property expected to be sold in 1998 plus the average book value of property to be sold in 1999. This methodology is consistent with the average rate base methodology for including plant additions. The total decrease to rate base for 1998 and 1999 land sales is $2.806 million ($2.558 million + $.248 million).

9. Nuclear Fuel Final Core and Materials and Supplies

As discussed in Section II.F.10 and II.G.1, below, the Department disallows CL&P's request for amortization of nuclear fuel final core and materials and supplies. The Company reduced rate base by $1.638 million for the reserve amount included in its forecast for the rate year for MP 2 and 3. The reserve for MP1 was removed when the Company removed effects of MP1 from the Application. Schedules B-1 and WPB-1.0; Tr. 9/15/98, p. 1103. The Department increases rate base by $1.638 million.

10. Enhanced Tree Trimming

The Company's view is that the enhanced tree trimming, as described in Section II.J, below, is a one-time improvement to the physical facilities that exist whether or not wire is actually replaced. Therefore, it is appropriate to treat these costs similarly to the costs of tree trimming associated with new line installations or reconductoring. The Company began this program in 1998 and if the Department accepts the Company's proposal, CL&P will capitalize the costs incurred in that year. The Company included these costs as part of the rate base in the Application and is looking for Department concurrence to capitalize them so that it can properly record costs incurred in 1998 when it closes its books. Tr. 9/11/98, pp. 542 - 545. These costs represent a minor item of property that did not previously exist but is now added to plant because a substantial dollar addition to plant results. CL&P believes its view is consistent with FERC's instructions for additions and retirements of electric plant contained in FERC 18 CFR, Item 10. Late Filed Exhibit No. 12; Tr. 10/16/98, p. 3808. The Company identified one other electric company that has a similar program and will be capitalizing the costs.

Tr. 10/16/98, pp. 3809 and 3810. When the initial cycle of enhanced tree trimming is completed, the Company will expense costs to maintain the additional clearance in subsequent years. Tr. 9/11/98, p. 547.

AG believes that enhanced tree trimming is different than tree trimming done in connection with reconductoring or other capital improvements and does not deserve to be capitalized. AG also contends that, overall, CL&P has failed to show that these costs should be capitalized instead of expensed. AG Brief, pp. 15 and 16.

If the Department agrees with the AG's preferred method of accounting for these costs, and requires the Company to record them as expenses, rate year expenses would be higher by $11 million, the amount of enhanced tree trimming expenditures projected for 1999. Response to Interrogatory OCC-154. This would actually increase rates to customers without providing additional benefits. The Department has reviewed the FERC requirements for accounting for tree trimming costs and concurs with CL&P's view with respect to capitalizing the enhanced tree trimming costs. Therefore, the Department does not make an adjustment to rate base or expenses.

11. Deferred Nuclear Refueling Outage Costs

The Company reduced average rate base by $33,500,000 for deferred nuclear refueling outage costs, net of deferred taxes. Schedule B-1. The Company has collected $32,016,000 ($16,464,000 + $15,552,000) from ratepayers for O&M Accruals for MP2 and MP3 through December 31, 1998. During 1999, the O&M Accruals of $4,822,000 for MP2 and $3,423,000 for MP3 will be added to the balance and MP3 outage costs of $15,900,000 will be subtracted. See discussion in Section II.F.23, below. Therefore, at the end of 1999, the accrued balance will be $24,361,000. Using these data, the Department revises the average deferred refueling outage costs, net of deferred taxes, to $17,262,000. Therefore, the Department increases 1999 average rate base by $16,238,000 ($33,500,000 - $17,262,000).

12. Payroll Adjustment

The Department reduces rate base by $1.8 million as a result of the reduction to the employee compensation levels as discussed in Section 11.F.17.c.

13. Niantic Bay Fuel Trust

The Department reduces rate base by $1.3 million as a result of the reduction to the Niantic Bay Fuel Trust levels as discussed in Section 11.F.5.

14. Rate Base Summary

The Company requested a 1999 average rate base of $3,040,778,000. Schedule B-1. As a result of the rate base adjustments discussed above, the Department sets the 1999 average rate base at $2,876,802.

F. EXPENSES

1. Depreciation Expense

The Company's last depreciation study was reviewed and approved, with modifications, in the Decision dated August 1, 1991, in Docket No. 90-12-03, Application of The Connecticut Light and Power Company to Amend Rate Schedules. The Company presented a new depreciation study in this case (Study). As in previous cases, the Company used the straight line method, remaining life technique and vintage/broad group method, or average life group, for compiling depreciation of each type of plant.

The Study results indicate a very small change in the depreciation expense compared to the results based on the study approved in Docket No. 90-12-03 (Schedule A-1.7, p. I-7). However, this is not the proper comparison. In the Decision dated July 1, 1996, in Docket No. 92-11-11, Application of The Connecticut Light and Power Company to Amend Its Rate Schedules, the Department approved a settlement agreement (Settlement Agreement) that allowed the Company to increase the depreciable lives of T&D assets by 10 years. This resulted in a reduction to the Company's depreciation expense of approximately $25 million. Subsequent cross-examination and interrogatory responses indicate that the Company's proposal would increase depreciation expenses by $20,521,565 when compared to current rates approved in the Settlement Agreement. Of the total increase, $347,988 is primarily due to modifications to generation facilities. The remaining $20,173,577 increase is due to modifications to the average service lives for transmission, distribution and general plant. Late File Exhibit No. 68.

a. Fossil/Hydroelectric Generating Facilities

The Company's Study, as prior ones, includes a negative net salvage amount for the projected dismantling cost of the fossil and hydroelectric units. In this case, the Company submitted site specific demolition studies for the Devon Station Power Plant, the Norwalk Harbor Station Power Plant, the Montville Station Power Plant, and the Middletown Station Power Plant. The following table shows the proposed negative net salvage amounts and the amounts proposed in Docket No. 90-12-03.

Fossil/Hydro Negative Net Salvage (in $million)

Unit(s)	Proposed	Prior	Increase
Montville	$14.1	$12.6	$1.5
Norwalk Harbor	$12.2	$10.9	$1.3
Devon	$28.5	$24.8	$3.7
Middletown	$15.3	$13.6	$1.7
Hydro (all)	$19.2	$16.7	$2.5

1995 Depreciation Study, Schedule II, pp. 1-11.

The total annual amount of depreciation expense associated with negative net salvage is $7,210,587. Response to Interrogatory EL-13. PRO states that the Department should not allow negative net salvage, since any remediation costs

rightfully belong to the buyer of the units after they are sold. Also, because any proceeds from the sale of the plants in excess of their book value will serve to offset stranded costs, requiring ratepayers to reduce the book value of the assets now to claim the stranded cost reduction in the future unnecessarily forces them to bear the time value of money. PRO Brief, p. 8.

Section 5 of the Act requires each electric company to divest non-nuclear generation by January 1, 2000. The Company has indicated that it does not plan to shut down any of its fossil or hydroelectric units permanently before that date. Late Filed Exhibit No. 6, AR-OCC-58. Such future resource decisions will be highly dependent on future development of other generation resources, among other factors. The life of the fossil units, or at least portions thereof, could also be prolonged indefinitely by repowering options that would increase their thermal efficiency. The life of the hydroelectric units could be prolonged indefinitely in response to the Act's incentives to operate such renewable generation, through the renewable portfolio requirements. Given the uncertainty inherent in the development of electric markets after deregulation, the nature and timing of dismantling of the fossil/hydro units is impossible to predict. Therefore, the actual costs of dismantling are also subject to uncertainty. For example, in the Company's fossil demolition studies, 10 factors are listed that are variable over time, such as labor and material. Response to Interrogatory EL-10.

In prior rate cases, the Department has traditionally allowed net negative salvage to be included in the Company's decommissioning accruals. The Department believes that, given that the fossil and hydroelectric units will not be dismantled while the units are subject to cost of service regulation, the cost of dismantling these units should rightfully be borne by the new owners of the units, as would be the case in other competitive industries. This conclusion is reinforced by the uncertainty regarding future operation and the dismantling cost inherent in the Company's estimates. Also, there is no reason to speculate regarding the cost of removal, since this cost will be reflected in the price paid for the units when they are sold, and thus ultimately included in the calculation of stranded costs. Therefore, the Department will order the Company to reduce depreciation expense by the $7,210,587 associated with the fossil/hydro negative net salvage.

b. Long Island Submarine Cable

The Company has included a negative net salvage value of $15 million with an annual accrual rate of 16.8% for removal of a submarine cable from Norwalk Harbor to Northport, Long Island in Account 358, Underground Conductors and Devices. The high cost of removal is the result of significant environmental considerations involved with its removal. The accrual rate is high because the Company plans to retire the cable in 2004; therefore, the accrual rate corresponds to a six-year amortization. Study, p. III-11. The net impact of this change is $2.238 million. Late Filed Exhibit No. 68. PRO states that this proposed change should not be allowed, since the Company has not met its burden of proof. PRO Brief, p. 8.

The Department requested further information from the Company regarding the basis for the submarine cable removal estimate and the environmental issues involved.

The Company did not provide the requested information. Late Filed Exhibit No. 21. Therefore, the change to depreciation in Account 358 is not sufficiently supported to justify it, and the Department will reduce depreciation expense by $2.238 million. However, the Department will reconsider this issue in future rate proceedings, if the Company provides additional information on the cost and necessity of removing this cable.

c. Transmission, Distribution and General Plant

The Department is concerned that the Company may be manipulating its depreciation expense. First, it increased the lives of T&D assets in the Settlement Agreement to lower its costs and provide capital while the Company was in financial difficulty due to the Millstone outages. Now the Company proposes to increase the expense by shortening the lives of T&D assets to reduce its "revenue sufficiency."

The Department believes it would be equitable and justifiable to leave the depreciation rates for T&D assets as approved in the Settlement Agreement. These rates are generally a bit long but within the range of industry practice. The Department, however, does believe that the study prepared by the Company's consultant is generally fair and more in line with industry averages.

The OCC states that ". . . the Company's requested average lives are not entirely unreasonable." However, due to the increased expense, the OCC recommends phasing-in the change in service lives. OCC Brief, p. IV-65. Due to the modifications to the depreciation study and the overall revenue and expense adjustments ordered in this case, the Department does not believe a phase-in of depreciation rates is needed at this time.

The Company's consultant often used several different techniques to evaluate the service lives of assets. The consultant also interviewed Company engineers and considered their professional opinions when developing his recommendations. Different analyses result in quite different estimates, so that considerable judgment is necessary when determining the service lives of particular assets. While the Department generally agrees with the consultant's proposals, several modifications are appropriate. Therefore, to avoid the potential for T&D rate increases in the future, the Department will approve the T&D lives subject to the modifications discussed below.

i. Transmission Account 354 - Towers and Fixtures

Account 354 is segregated into two groups; 345 kV and All Other. The Company proposes 45 years as the average service life for both accounts. Currently the average life is 45 years for 345 kV and 55 years for All Other. The Study indicates that the industry average life is 50 years and the Company engineers are of the opinion that 50 to 60 years might be appropriate for steel towers. Study, p. III-9. The Department therefore will order the Company to keep All Other at 55 years. This results in an overall average of approximately 51 years, consistent with the industry average.

ii. Distribution Account 362 - Station Equipment

Account 362 is segregated into System Control and Data Acquisition (SCADA) Equipment and All Other. The Company proposes to decrease the average service lives for All Other from 45 to 40 years. The Company's analysis does not support this conclusion. The Study states that the Balances Method indicates lives in the order of 40 to 45 years, while the Period Retirement Method indicates even higher average lives. Study, p. III-12. Further, the Company's engineers indicate that lives of distribution station equipment would be comparable to those of smaller equipment in Account 353 - Transmission Station Equipment, which has a proposed life of 47 years. Study, p. III-13. For these reasons, the Department will not approve the proposed change to 40 years. The Department will order the Company to use an average life of 45 years for Account 362, All Other.

iii. Distribution Account 367 - Underground Conductors and Devices

The underground conductor account is also segregated into two sub-accounts, the direct burial system and duct system. The Company proposes to decrease the life for the duct system from 45 to 35 years and the direct burial system from 35 to 25 years. Study, p. III-16. The Study states:

> Company engineers have noted some significant developments that will affect average service lives in the future. Some Direct Buried conductor has continued in service longer than was originally anticipated and may continue in service for as long as 30 years. More significantly the Company has been gradually replacing its paper and lead insulated cables with modern solid dielectric cable which has a manufacturer's guaranteed life of 40 or more years. As a result of these factors the average service life of Accounts 367.50 and 367.60 may both be increasing. Id.

Given this uncertainty, the Department does not believe the Company's proposal for a major change to the average service life of this account is appropriate at this time. Late Filed Exhibit No. 140 indicates that the industry average is 34 years and the industry mean is 35 years for this account. The Department will therefore approve a life of 40 years for the duct system and 30 years for direct burial.

iv. General Plant

The Company has also proposed to decrease the average service lives for six general plant accounts. The Company has provided no evidence to support its proposal for Account 394 Tools, Shop & Garage Tools or Account 395 Laboratory Equipment. In both cases the Company proposes to decrease the average service lives from 25 to 15 years. Study, pp. III-20-23. These proposals are not consistent with industry averages of 24 years for Account 394 and 28 years for Account 395. Late Filed Exhibit No. 140. The Department therefore rejects the Company's proposal and requires 25 years for both accounts.

v. Summary

The Department will reduce depreciation by $3,084,646 for transmission, distribution and general plant accounts. The table below provides a summary of the Department's adjustments to depreciation expense for transmission, distribution and general plant accounts.

Summary of Depreciation Adjustments

Average Service Lives				
	Current	**Proposed**	**Approved**	**Adjustments***
Transmission Acct. 354-Towers and Fixtures System—All Other	55	45	55	$ 166,724
Distribution Acct. 362-Station Equipment System—All Other	45	40	45	1,182,668
Acct. 367-Underground Conductors & Devices				
Duct System	45	35	40	584,205
Direct Burial	35	25	30	900,377
Acct. 394-Tools Shop & Garage Tools	25	15	25	155,572
Acct. 395-Laboratory Equipment	25	15	25	95,100
	TOTAL			$3,084,646

*Adjustments are based on information in Late Filed Exhibit No. 68

d. Devon Station Gas Turbines

As discussed in Section II.E.1.c, above, the Department removed the capital costs related to the Devon station gas turbines from rate base. Consequently, the Department must also adjust depreciation expense for the capital costs. Assuming the capital costs would be fully depreciated at the end of the lease, the Department removes depreciation expense of $3,332,000 from the rate year. The Company discussed this adjustment in its written exceptions. However, it did not dispute the underlying assumption that the capital costs would be fully depreciated at the end of the lease. Written Exceptions, Appendix, p. 4. Therefore, the Department does not change the amount of the adjustment.

e. Transmission and Distribution Reliability Improvements

As discussed in Section II.E.3, above, the Department removed $11,880,092, net of accumulated depreciation, in T&D reliability improvements from rate base. Consequently, the Department must also adjust depreciation expense for the improvements. Therefore, the Department removes annual depreciation expense of $298,236.

f. Millstone Unit 2 Plant Additions

As discussed in Section II.E.2, above, the Department removed $11,961,500 for MP2 plant additions that will not be incurred in 1999. Consequently, the Department must also adjust depreciation expense for the plant additions. Therefore, the Department assumes CL&P would have recovered this investment over the remaining life of the unit, 16 years, and removes depreciation expense of $747,594 ($11,961,500 / 16 years).

2. Potential Employee Settlements

The Company included $970,000 for potential settlements of employee lawsuits based on the 1998 employee settlement budget. Response to Interrogatory OCC-71. However, the Company could not supply information about the claims, on the basis that the personnel information is subject to statutory nondisclosure obligations and that litigation information is protected by attorney-client privilege. CL&P Brief, p. 33. According to the Company, it did not budget for this item prior to 1998. Late Filed Exhibit No. 168, Read-In F.

OCC states that the projected employee settlement expenses of $970,000 should be removed from the rate year. OCC believes that in Docket No. 92-11-11 CL&P's employee settlement and related legal expenses were recorded below the line. OCC also states the Company did not provide any information concerning the specific types of employee settlements that were included in the test year. OCC Brief, p. 37. The Company states that its inability to provide the details of these matters does not render the settlement costs unrecoverable or improper. CL&P Brief, p. 33.

The Department disagrees. The Department cannot blindly accept costs and allow ratepayers to pay for ones that have not been justified. As the presiding Commissioner stated during the hearings, ". . . the burden of proof is on the Company to show that it acted in a reasonable manner . . . and to demonstrate that each of the cost-of-service components underlying a proposed rate is reasonable." Tr. 9/10/98, p. 269. The Company has failed to do so in this case, therefore, the Department will disallow the $970,000 for potential employee settlements.

3. Employee Relocation Expenses

The Company projected relocation expenses of $1.1 million for 1999. This is a 160% increase over the year-to-date actual of $426,000. The Company explained that the 1999 level was predicated on known relocation costs for specific individuals that were identified by cost control managers. The Human Resources Department calculated the budget based upon the recognition that there are generally some level of internal staff and new hires that will be relocated. Tr. 9/18/98, p. 1878. According to the Company, the increase from 1998 to 1999 is due to the movement of the nuclear employees at Millstone Station. Tr. 10/15/98, p. 3543.

OCC believes that the past two years have seen an unusually high level of relocation expenses because of the large turnover of senior management. OCC attributes this turnover to CL&P's financial problems resulting from imprudent operations

of it's nuclear plants. Hiring new senior management has led to a high level of travel, moving, housing and real estate expenses. OCC proposes the use of a five-year average for the calculation of the appropriate rate year expense level. OCC recommends utilizing actual annual expenses for the years 1994-1997 and the annualization of actual 1998 expenses through August. As can be seen in the table below, this results in an annual expense allowance of $456,000. OCC Brief, pp. 17 and 18.

Relocation Expense

1994	1995	1996	1997	YTD* 1998	1999
$ 317,000	$ 255,000	$ 118,000	$ 951,000	$ 426,000	$ 1,100,000

The Department concurs with OCC and reduces employee relocation expenses by $644,000.

4. Advertising Expense

a. Grassroots Program

The Company has included $550,000 in its advertising expense for the grassroots program, which it describes as a voluntary program for NU employees, retirees and shareholders that seeks to educate its participants on state and federal public policy issues, provide them with the tools to get involved in the political process and to mobilize them to take action to affect the outcome of public policy issues. Response to Interrogatory OCC-46. OCC states that the $550,000 cost clearly falls under those specifically disallowed in §16-19d of the Conn. Gen. Stat. and should be disallowed. OCC Brief, pp. 39 and 40. Conn. Gen. Stat. §16-19d, (2) states that:

> 'Political advertising' means any advertising for the purpose of influencing public opinion with respect to any legislative, administrative or electoral decision or with respect to any controversial issue of public importance.

The grassroots program is clearly political in nature, as defined in §16-19d; therefore, the Department reduces advertising expense by $550,000.

b. Industry Restructuring

The Company also has included $1.4 million in its advertising expense for industry restructuring. This includes $773,000 in Account 930 that relates to bill inserts and other educational communications designed to increase customer awareness on topics such as electric industry restructuring and customer choice and $626,000 in Account 909 that relates to general restructuring. Response to Interrogatory EL 406; Late Filed Exhibit No. 6, AR-OCC-32.

OCC believes that the entire restructuring advertising costs of $1.4 million should be disallowed. It is the OCC's position that any advertising regarding restructuring to be recovered from ratepayers should be done through the joint effort under the restructuring legislation not base rates. OCC cites Section 17 of the Act, which states that restructuring-related advertising costs will be recovered through the SBC. OCC Brief, pp. IV-40 and 41. The Company believes that the program described in Section 17 is not exclusive of all other customer education efforts regarding restructuring. CL&P seeks to recover these costs on a current basis in 1999; but will entertain their deferral should the Department determine that these costs belong in the SBC. CL&P Reply Brief, p. 36.

Section 17 of the Act specifically states that it is the Department's responsibility to develop a public outreach program that will educate consumers on the issue of restructuring. If the Department determines that it needs the assistance of the electric companies in its educational campaign, any costs they incur will be recoverable through the SBC. The Department disallows the $1.4 million of advertising costs related to restructuring activities.

5. Niantic Bay Fuel Trust Expenses

In the case of the Niantic Bay Fuel Trust (Trust), the Company has incurred additional financing costs that have resulted from higher interest rates and fees associated with the prolonged nuclear outages at the Millstone plants. On June 2, 1998, CL&P, in conjunction with Western Massachusetts Electric Company (WMECO), issued the Series G Intermediate Term Notes (Series G IT Notes) at an average aggregate principal amount of $180 million, of which CL&P has a pro rata share of 74.5%. The Series G IT Notes have a five-year maturity and a coupon rate of 8.59%, or 300 basis points over a five-year US Treasury note of 5.59%.

The Company testified that if it were rated BBB+ rather than BB, the coupon rate would have been approximately 150 basis points over the five-year US Treasury note, or 7.09%. Docket No. 91-06-04, Application of The Connecticut Light and Power Company and Western Massachusetts Electric Company with respect to Nuclear Fuel Financing Arrangements, Decision dated May 27, 1998, p. 6. The Company further testified that due to its financial difficulties associated with the Millstone plant outages, the Trust banks were unwilling to extend the lower cost short-term revolving credit financing in the Trust beyond July 31, 1998. Prior to the Company's nuclear problems, it had received short-term financing in the Trust at London Interbank Offered Rate (LIBOR) plus 50 basis points. Response to Interrogatory EL-50 in Docket No. 91-06-04, Decision dated May 27, 1998, p. 5. To issue the Series G IT Notes, CL&P incurred a placement fee of 2.0% of the $180 million gross proceeds, or $3.6 million. This is a higher fee than the 0.88% fee that was estimated to have applied had the Company been rated BBB+. Id., p. 6.

The Department will allow the expenses and capitalized costs associated with CL&P's pro rata share of $180 million in the Trust assumed to have been financed in the following manner: $90 million Series G IT notes at 7.09% at a placement fee of

0.88%, and $90 million in short-term financing at a rate of LIBOR plus 50 basis points.[3] These allowed financing costs result in a reduction in the Company's expenses of $3,870,000 in Account 518, and a decrease in the allowed capitalized amount of $1,325,000 in the Company's Account 120. Late Filed Exhibit No. 25.

CL&P's revised fuel simulations reflect an adjustment to the Trust expense, reducing it by $2,601,000. Schedule C-3.6 Revised; Late Filed Exhibit No. 138 SP 1; Response to Interrogatory OCC-254. Therefore, based on the foregoing, the Department further reduces this expense by $1,269,000 ($3,870,000 - $2,601,000). The Department will include all adjustments in the calculation of the final base fuel rate. See Section II.G.1.s.

6. Other O&M Costs Escalation Rate

The Company has used an inflation adjustment of 1.8% for Other O&M costs in its forecasted 1999 budget. This represents a slight adjustment from the escalation rate of 1.6% for Other O&M costs used in the 1998 budget year. Supplemental Filing, June 30, 1998, p. 38. The Company's escalation factor for Other O&M costs is obtained directly from Data Resources, Inc. (DRI) forecasts of the Producer Price Index (PPI) finished goods, capital equipment. Response to Interrogatories EL-133 and 134. Mr. Wiater testified that the forecasted 1999 escalation rates are considered upper bounds for planning purposes; individual departments are expected to have cost increases below those targets. Tr. 9/18/98, p. 1847.

An examination of recent annual rates of increase of producer prices shows minimal and occasionally negative inflation rates. For the years 1992 though 1996, the average annual rate of change for the PPI was 1.86%; during 1997 and the first two quarters of 1998, the PPI averaged a slight negative rate of change. Response to Interrogatory EL-138. In the case of the PPI finished goods capital equipment index, the years 1992 though 1997 showed an average annual rate of change of 1.47%. During 1997, the index had virtually no annual increase, and the first two quarters of 1998 showed an annual rate of change of approximately -0.6%. Late Filed Exhibit No. 91, p. 2. In a publication prepared by NU's economic and load forecasting department, the Company stated that, "for now, inflation is low," and that "problems in Asia will help keep prices low." Federal Reserve Board Chairman Greenspan characterized the current economy as expansionary ". . . with the price level, inflation rate, staying down, and by some measures even continuing to fall." Late Filed Exhibit No. 175, pp. 7 and 20.

DRI's May 1998 update of its 1999 forecast of the PPI finished goods, capital equipment for 1999 shows a downward revision to 0.7%. For 1998, the index is projected to fall 0.4%. CL&P argued that the PPI finished goods capital equipment has been heavily influenced by price weakness in vehicles, aircraft and other goods that are

[3] None of the seven Decisions issued in Docket No. 91-06-04 specify the maturity length of the LIBOR rate used in computing the interest rate for the short-term financing in the Niantic Bay Fuel Trust Facility. To obtain a LIBOR rate, the Department averaged LIBOR rates for maturity lengths of one month to one year. As of the closing date of the hearing, November 9, 1998, LIBOR rates averaged 5.263%.

a relatively small portion of CL&P O&M expenditures. Tr. 10/20/98, pp. 3975 - 3980. The Company pointed out that the DRI Total Utility O&M index is projected to rise 1.9% in 1999, and is "more representative of likely price changes that CL&P will encounter in 1999." Late Filed Exhibit No. 90. However, the Company's 1999 Other O&M costs escalation rate is taken directly from the May 1997 DRI forecast of the PPI finished goods, capital equipment index.

The Department concludes that it is appropriate to use an escalation rate of 0.7% for Other O&M costs for ratemaking purposes, based on the updated 1999 DRI forecasted PPI finished goods, capital equipment index. This lower rate is also supported by recent minimal to negative rates of change in producer prices. OCC also supports an escalation rate of 0.7% based on the revised DRI forecast. OCC Brief, p. IV-43. The adjustment to a 0.7% escalation factor for O&M costs results in an expense adjustment of $1.9 million. OCC Brief, pp. 56-59. Therefore, the Department reduces expenses by $1.9 million.

7. Nuclear O&M Expense

The Company's filing includes higher than historical O&M expense at MP2 and MP3. The Company analyzed the differential expense based on comparison to the historical average for the years 1990 through 1995. The expense for MP2 is $34.5 million higher than the 1990-1995 average; for MP3 this differential is $11.8 million. Kenyon Testimony, p. 6. The following table shows the 1990-1995 historical amounts and the 1999 budgeted amount for each unit, on a CL&P basis.

Projected vs. Historical Nuclear O&M Amount (In $million)

	MP2	MP3	Total
1990-1995 Average	72.6	53.2	125.8
1999	107.1	65	172.1
Difference	34.5	11.8	46.3

Response to Interrogatory OCC-172.

The Company analyzed the O&M differential by identifying those costs that account for the differential and segregated them into costs related to the current outage and costs related to new or heightened industry standards. The following table shows these amounts, on a CL&P basis:

MP2 and MP3 Differential O&M vs. Historical (in $million)

	MP2	MP3	Total
Costs Related to Current Outage	15.0	5.5	20.5
Costs Related to Industry Standards	19.5	6.3	25.8
Total	34.5	11.8	46.3

Dente Testimony, Exhibit TJD-1.

The Company is not seeking to recover those costs related to the Millstone outages that began in 1996.

AG and OCC state that the Company's base 1990 - 1995 period should be adjusted downward by the cost of the nuclear Performance Enhancement Program (PEP). According to AG and OCC, this program was intended to address deficiencies in the Company's nuclear program, and, since the program did not prevent the Millstone outages, it was ineffective and should not be included in the base O&M comparisons. AG Brief, p. 5; Schlissel Testimony, pp. 7-10. The Company states that the base years should not be adjusted for PEP, since the Department previously approved most of the PEP expenses, and that historical nuclear costs are similar to other nuclear units, including PEP. CL&P Brief, pp. 21 and 22.

The Department ruled on the recovery of PEP costs in the Decision dated June 16, 1993, in Docket No. 92-11-11. In that proceeding, the Department examined the history of PEP and the objectives of the PEP action plans. The Department concluded the following:

> When analyzing the background and merit of PEP, the Authority believes that it is inappropriate to view PEP as one program with one goal. The Action Plans which comprise PEP have their own degree of merit. Some Action Plans are associated with regulatory requirements unrelated to the prior performance of NU's nuclear power plants. Some Action Plans have a direct impact on plant operation and maintenance (although they may not be cost-beneficial), while the impact of others is more subtle. Some Action Plans represent programs that were under evaluation by the Company prior to formulation of PEP and some represent initiatives that have already been implemented throughout a large segment of the nuclear industry. Other Action Plans represent programs that directly result from lack of timely management attention to certain issues. These programs have all been placed under the umbrella of PEP. The Authority believes that a reasonable decision on this issue is possible only by analyzing the constituent Action Plans. Decision, p. 52.

Based on its review, the Department determined that 65% of the costs of PEP should be allowed, while the remainder was deferred to Docket No. 93-09-28, DPUC Review of The Connecticut Light and Power Company Nuclear Performance Enhancement Program, for further review. The remaining 35% was dispositioned by the July 1, 1996 Settlement Agreement in Docket No. 92-11-11.

By requesting exclusion, AG and OCC are requesting the Department to rule that PEP was an imprudently incurred expense. As outlined above, the Department has already ruled on the necessity and propriety of most of PEP, and noted that many of the expenses of PEP were irrelevant to the performance of the Company's nuclear program. It would be inappropriate to reverse a prior Decision by judging it from the ultimate fate of the Company's nuclear program. If PEP costs are excluded from the comparison, there would presumably be other expenses that would account for the differential from the historical comparisons. Additionally, the Company has formally requested O&M based on projections for 1999, and the base period was used for

comparison purposes only. The Department views the position of OCC and AG on this matter as supporting retroactive ratemaking and will not reduce nuclear O&M as these parties have requested.

The Company identified the costs related to industry standards by function. OCC states that costs associated with a number of these functions should be disallowed. The following sections address each of these functions.

a. Work Planning and Control

The Company's improvements to its work planning and control program include establishing a full time outage management staff, and ancillary costs associated with maintaining this staff. Response to OCC-177, Bulk, p. 1. OCC states that costs associated with the Work Planning and Control function should be disallowed since the Company did not identify any new or heightened industry standard requiring it, and these activities are necessary to raise the Company's standards. Schlissel Testimony, p. 40. The Company states that the costs of this program are driven by the Maintenance Rule, which was an NRC regulation established in 1991 that became effective in 1996. The objective of the Maintenance Rule is to establish a performance-based maintenance system at each nuclear power plant that would result in performance of maintenance based on an assessment of risk. Response to Interrogatory OCC-182, Supplement 1, Bulk, Letter dated March 4, 1997, to NRC Commissioners from Joseph Callan, p. 2.

The Company's documentation on the Work Planning function indicates that implementation of the Maintenance Rule has increased quality requirements, resulting in increased training requirements and more work while the unit is on line. Response to Interrogatory OCC-177. Documentation submitted by the Company to support this function was largely linked to the Maintenance Rule. Response to Interrogatory OCC-182. The justification submitted consists largely of NRC documentation regarding Maintenance Rule inspections at other nuclear units. The documentation contains numerous references to Maintenance Rule requirements regarding safety risk assessments prior to removing equipment from service while the unit is on line. The NRC found this to be a common weakness at several plants. Id., NRC Information Notice 97-18, Problems Identified During Maintenance Rule Baseline Inspections, pp. 2 and 3. The NRC documentation includes references to utility programs that were implemented to comply with the Maintenance Rule, shows how these programs have evolved over time beyond the scope of the initial Maintenance Rule, and contains statements showing that the NRC endorsed these efforts. Id., Letter dated March 4, 1997, from Joseph Callan to NRC Commissioners, p. 5. The Maintenance Rule has been amended twice since it was issued, last in 1996. Id., p. 7. The picture that develops from this documentation is of an industry struggling to comply with a complex regulation, whose implications were not fully foreseen when initially promulgated. However, it is clear that the Maintenance Rule requires daily vigilance on the part of Company personnel who are familiar with the complex requirements of that rule. This is consistent with the Company's establishment of a full-time outage management staff.

Regardless of the existence of any standard for such a group, this function is clearly not related to the outages at Millstone nor does any party make such a claim.

Also, the Department does not believe that the Company should be held to making only those expenditures necessary for minimal compliance with standards. In fact, the Department has found that a culture of minimal compliance was one of the root causes of the decline of Millstone station performance, resulting in the current outages. Tr. 6/27/97 in Docket No. 96-10-06 (Oral Decision), DPUC Investigation into Whether The Connecticut Light and Power Company Fulfilled Its Obligations with Regard to its Nuclear Operations, p. 847. As stated by the Department at that time, "the public and the citizens of Connecticut have a right to expect that the management of a nuclear power plant will always strive for excellence." Id., p. 856. The Company should certainly not be held to a standard where any expenses beyond those necessary to comply with minimal regulatory standards should be viewed as wasteful, as OCC implies. Also, "industry standards" are sometimes inherently difficult to establish, since they may be set by a common approach to problems that is not codified in any documentation. Often, standards are established and understood by interaction among staff assigned to different nuclear plants. Since the cost associated with Work Planning and Control is not a consequence of the current outage, the Department will allow its inclusion in rates.

b. Material Condition Improvement Program

The Company is establishing a program that consolidates all painting and coating work into one organization. OCC states that the costs of this program should be disallowed, since they cannot be linked to new or heightened industry standards. Schlissel Testimony, p. 42. Also, the Company had painting and coating programs during the reference 1990-1995 time period, therefore OCC believes the additional cost cannot be justified. Id., p. 43. The Company states that the proposed costs incorporate recent industry experience with coatings at other nuclear power plants and the program achieves greater accountability by consolidating all similar work in one department. Response to Interrogatory OCC-177.

The Company provided supporting documentation from the NRC that describes significant deficiencies in the application of coatings at other nuclear power plants. Response to Interrogatory OCC-182. The reported events, from as recently as 1997, highlight the importance of coatings in certain applications, where defects in coatings could have major safety implications. The record shows that industry experience with protective coatings is continually evolving. This is supportive of the Company's efforts to focus more attention on this area of its nuclear operations.

No party claims that the expenses associated with this function are the result of the current outages. As in Section II.F.7.a, above, the Department believes the Company should have the flexibility to operate and maintain its nuclear plants beyond minimal industry standards, and that it is not appropriate to include in rates only those costs required for minimal compliance with industry standards or NRC regulations. Therefore, the Department will allow this program's costs to be included in rates.

c. Commitment Tracking System

The Commitment Tracking System function includes expenses for creating a centralized tracking system for all commitments made to the NRC by the Company. Response to Interrogatory OCC-177, p. 3. OCC states that the costs associated with

this function should not be allowed, since the system was developed in response to the NRC 10CFR50.54(f) demand for information. Schlissel Testimony, p. 45.

The Company provided documents from the NRC and the Nuclear Energy Institute that describe industry standards and NRC expectations for managing NRC Commitments. Response to Interrogatory OCC-182. The documents describe the importance of establishing processes and procedures for controlling commitments made to the NRC. The changes to the Commitment Tracking System improves the Company's ability to track and maintain future commitments as well as presently existing ones. However, documentation provided by the Company states "The RCD [Regulatory Commitment Database] was developed as part of the response to the 10CFR50.54(f) letter to (1) ensure compliance with the Licensing Basis and (2) establish programs to ensure continued compliance." Response to Interrogatory OCC-182, Letter dated 5/28/98 from Mario Robles to Walkesl. Since this program was necessitated by the 10CFR50.54(f) demand for information, the program is related to the Millstone outages and the Department will remove its costs from rates. The CL&P portion of the expense for this program is (0.81 * $500,000) [MP2] + (0.53 * $500,000) [MP3] = $670,000. Dente Testimony, Exhibit TJD-1.

d. Personal Computer Leasing Program

The Company has instituted a program to lease personal computers for employees, instead of buying them. OCC states that the costs associated with this program should not be allowed, since they are not associated with a new or heightened industry standard. Schlissel Testimony, p. 47. The Company states that it is leasing personal computers because it has found it to be more cost effective than purchasing them. Tr. 9/25/98, pp. 2606 and 2607.

There has been no claim by any party that leasing personal computers is a result of the Millstone outages. There is no evidence that suggests leasing personal computers is a wasteful use of ratepayer funds, particularly when the alternative to leasing computers is buying them. Similar to Section II.F.7.a, above, the Department will not disallow expenses for the sole reason that they are not necessary to meet industry standards. Therefore, the Department will allow these expenses to be included in rates.

e. Consolidation of Information Technology and Support

The Company has instituted a program to consolidate all information technology and support functions in one department, to improve administration of these functions and achieve synergies. OCC states that the costs associated with this program should be disallowed, since it is not related to a new or heightened industry standard. Schlissel Testimony, p. 47.

There has been no claim by any party that the consolidation of information technology functions is a result of the Millstone outages. Consolidation of these similar functions should result in long-term cost savings. Again, the Department will not disallow expenses for the sole reason that they are not necessary to meet industry standards. Therefore, the Department will allow these expenses to be included in rates.

f. Non-capital Plant Modifications

Non-capital modifications (NCMs) are low-cost changes to plant that are treated as expense items. The Company's initial filing included $11,800,000 for NCMs at MP2 and $930,000 at MP3, on a whole-unit basis. Dente Testimony, Exhibit TJD-1. The CL&P portions of these amounts are $9,558,000 and $493,000, respectively. The Company stated that these amounts were based on historical experience adjusted for known commitments to the NRC. Response to Interrogatory EL-1.

The Company subsequently revised its expectations for 1999 NCMs when the projects were identified and submitted a list of the projects on October 29, 1998. The NCM amounts on a total unit basis are $2,720,000 for MP2 and $8,850,000 for MP3. Response to Interrogatory EL-1, Supplement 1. The CL&P portions of these amounts are $2,203,000 and $4,691,000, respectively. NCM expenses for the three years prior to the Millstone outages, 1993-1995, averaged $3,200,000 for MP2 and $9,700,000 for MP3. Response to Interrogatory EL-354. The proposed NCM amounts are consistent with historical expenses. The expense items are typical of small modifications that occur throughout the life of a nuclear plant. Therefore, the Department accepts the revised amounts and decreases the original MP2 amount by $7,355,000 and increases the original MP3 amount by $4,198,000, for a net reduction of $3,157,000.

g. Calculation Tracking System

The Company's filing includes expenses for a new system for tracking calculations, which eases the retrieval of the calculations when a future need arises to access them. Previously, calculations were not comprehensively tracked on a centralized computer system. Response to Interrogatory OCC-177, Supplement 1, Bulk p. 5. OCC states that the costs associated with this program should not be allowed, since the program is not related to industry standards and is a result of the NRC 10CFR50.54(f) order that resulted in the Millstone outages. Schlissel Testimony, pp. 55 and 56. However, OCC did not cite any evidence supporting this position.

The system is intended to be used on a going-forward basis to ensure future calculations are properly tracked. This should result in improved efficiencies by reducing the administrative burden of retrieving calculations from diverse locations. Tr. 9/25/98, pp. 2623-2625. Again, the Department will not disallow expenses for the sole reason that they are not necessary to meet industry standards. Therefore, the Department will allow these expenses to be included in rates.

h. Material Equipment Parts List

The Material Equipment Parts List (MEPL) is a database of plant components that contains information important to the maintenance of that equipment. Response to Interrogatory OCC-177, Supplement 1, p. 7. The Company's filing includes incremental expenses for completing the MEPL. The changes to the MEPL include adding components and increasing efficiencies in the procurement and storage of replacement parts. Response to Interrogatory OCC-182, Supplement 2, Maintenance of Material Equipment Parts List. OCC states that expenses associated with this program should

not be allowed, since the Company has not identified new or heightened industry standards associated with this program; rather, it is necessary to remedy "deficiencies." Schlissel Testimony, p. 58.

There is no evidence that the MEPL improvements are related to the Millstone outages. They are enhancements to an existing program. Since safety grade components cost considerably more than non-safety grade ones, the enhancements should result in long-run savings by elimination of the practice of procuring non-safety grade components that were previously classified as safety grade. Again, the Department will not disallow expenses for the sole reason that they are not necessary to meet industry standards. Therefore, the Department will allow these expenses to be included in rates.

i. Implementation of Condition Based Maintenance

The Company's filing includes expenses for the addition of an Integrated Preventive Maintenance Program (IPMP) and an Equipment Effectiveness Training Program (EETP). These programs were implemented to develop methods for trending and monitoring performance for common component failures. The Company states that these programs will improve equipment reliability over time. Response to Interrogatory OCC-177, Supplement 1, p. 8. OCC states that the costs associated with the IPMP and EETP should not be allowed, since the Company has not identified new or heightened industry standards associated with them. Schlissel Testimony, p. 59.

Documentation provided by the Company states that these programs were designed by consultation with other nuclear industry participants to identify characteristics of successful programs in this area. Response to Interrogatory OCC-178, Supplement 2, Equipment Effectiveness Trending - Best Practices Initiative, p. 3. Therefore, evidence supports the claim that these programs were implemented to meet industry standards. There is no evidence that the IPMP and EETP are related to the Millstone outages. They are improvements of an existing program. Therefore, the Department will allow these expenses to be included in rates.

8. Devon Station Gas Turbines

The Devon Station O&M costs are $11.823 million, including lease payments of $9.6 million, for the rate year. June 30, 1998, Supplemental Filing, Devon Station O&M; Tr. 9/15/98, pp. 1055 and 1056; Late Filed Exhibit No. 92. As concluded in Section II.E.1.c, above, the gas turbines were added solely due to the Millstone outages. Therefore, the Department reduces expenses by $11.823 million.

9. Decommissioning

The Company filed the latest decommissioning studies for MP1, 2, and 3. The proposed method of decommissioning is immediate dismantlement (single unit DECON) for each unit. The estimated cost of decommissioning in 1997 dollars is $481,800,000 for MP1; $430,900,000 for MP2; and $519,400,000 for MP3. By comparison, the DECON cost estimates the Company submitted in Docket No. 92-11-11 were $350,864,000 for MP1; $281,798,000 for MP2; and $383,175,000 for MP3.

The NRC requires each nuclear plant owner to calculate a minimum decommissioning cost per Title 10 of the federal Code of Regulations,10CFR50.75(c). The NRC also requires the owner to fund decommissioning for at least this amount, regardless of the amount determined by the site specific study. The amount is determined by a prescribed formula in 10CFR50.75(c) and adjusted by escalation factors for labor, energy, and radioactive waste burial charges. The labor and escalation factors are required to be derived from U.S. Department of Labor Statistics data, and the radioactive waste burial factor must be derived from NUREG-1307, "Report on Waste Burial Charges." 10CFR50.65(c)(2). These amounts in 1997 dollars are calculated as $512,000,000 for MP1; $460,000,000 for MP2; and $488,000,000 for MP3. Levy Testimony, p. 21.

The following chart shows the decommissioning amounts for each unit.

Decommissioning Amounts (in $thousands)

	92-11-11 DECON	98-01-02 DECON	NRC Minimum	Proposed
MP1	350,864	481,800	512,000	512,000
MP2	281,798	430,900	460,000	460,000
MP3	383,175	519,400	488,000	519,400

The DECON cost estimates were developed by TLG Engineering, Inc. using the latest cost estimating methodologies and are based on site-specific studies for each unit. Each estimate reflects the present cost of decommissioning under current requirements using available technology. Levy Testimony, pp. 11 and 12.

The DECON estimates also include a contingency factor to reflect possible schedule delays due to unforeseeable events such as equipment breakdowns. The contingency factors are assigned to individual activities based on the uncertainty associated with that activity. The overall contingency factors for each unit are 19.7% for MP1, 18.6% for MP2, and 19.0% for MP3. By comparison, in Docket No. 92-11-11 the DECON estimates included contingency factors of 15.95% for MP1, 16.18% for MP2, and 16.00% for MP3. The Company states that the changes in contingency factors are based on industry experience with decommissioning and related issues such as radioactive waste disposal costs. Tr. 9/25/98, p. 2670.

The Company proposes to base the decommissioning collections on the NRC minimum amounts for MP1 and 2, and the site-specific amount for MP3. For each unit, the amount requested is the greater of the NRC minimum or the site amount. In the

case of MP1 and 2, the amount requested is based on regulatory requirements and is not subject to potential inaccuracies in assumptions such as contingency or future radioactive waste disposal costs. Therefore, the Department concludes that the proposed amounts for MP1 and 2 are reasonable and approves them as filed.

The Company proposes to base its decommissioning collection for MP3 on the site-specific DECON study amount of $519,400,000, which is $31,400,000 more than the NRC minimum amount. The Company states that the site-specific cost estimate is greater than the NRC minimum due to features peculiar to MP3 that differ from the unit on which the minimum calculation is based. Levy Testimony, p. 21. The cited differences include design, siting, and access to radioactive waste disposal sites. Response to Interrogatory EL-27. In its decommissioning estimates, the Company includes the cost of removing non-radioactive structures and components. However, the NRC does not require the costs of removing this material to be included in decommissioning cost estimates, and, in fact, specifically excludes them from its regulations regarding decommissioning. Response to Interrogatory EL-16. The Company states these costs should be included in the cost estimates, since they are legitimate business costs that will be incurred in the future. Tr. 9/25/98, pp. 2655 and 2656.

The total estimated cost of non-radioactive material removal at MP3 is $71,189,000. Response to Interrogatory EL-18. This amount includes removal of a technical building, and the training/simulator building. Tr. 9/25/98, p. 2673. Both these buildings could have value after the units are decommissioned, since they do not contain any radioactive contamination and could be used for another purpose. This is particularly true of the technical building, which was constructed in 1994. Decision dated May 5, 1994, in Docket No. 93-09-04, Application of Northeast Nuclear Energy Company, The Connecticut Light and Power Company and Western Massachusetts Electric Company for Approval to Finance the Construction of a Technical Building at the Millstone Nuclear Generating Units, p. 9.

Including the cost of removing non-radioactive material in decommissioning cost estimates involves issues of equity between nuclear and non-nuclear generating facilities, since non-nuclear facilities do not benefit from prefunding of dismantling costs. This is not equitable to those facilities since, given pending deregulation of electric generation, those facilities will not have a mechanism to recover these costs, but nuclear facilities would. The Department therefore believes the decommissioning cost estimates should only reflect those costs that the NRC requires to be prefunded. Since the NRC only requires radioactive material removal costs to be prefunded, the Department will not consider the cost of removing non-radioactive material in the decommissioning cost estimates. In the case of radioactive materials, there are clear regulatory and public safety issues that mandate funding of these costs.

Subtracting the non-radioactive material removal cost from the total MP3 decommissioning cost yields a total radioactive material remediation cost of $448,211,000. This is below the NRC minimum decommissioning amount of $488,000,000. Since the NRC requires this amount to be prefunded, the Department will allow decommissioning collections to be based on this amount. The Department will therefore order the Company to reduce MP3 decommissioning collections to reflect the

NRC minimum, reducing revenue requirements from $9.35 million to $8.42 million, a reduction of $930,000.

a. Nuclear Decommissioning Financing

The calculation of nuclear decommissioning funding requirements for 1999 and over the life of the nuclear decommissioning trusts requires assumptions about the earnings, schedule of contribution levels, tax rates, cost escalation rates, as well as estimates of the current cost of decommissioning. Each Millstone plant has two decommissioning trust funds, a "qualified" (tax-deductible) and a "non-qualified" (non-tax deductible), to finance its nuclear decommissioning. CL&P contributes its pro rata share of funds, which are deposited into each trust fund on a monthly basis. MP2 and 3 trust funds have investment allocations of 40% equity and 60% fixed income securities, while the MP1 trust fund, with a shorter decommissioning time horizon, has asset allocations of 30% equity and 70% fixed income securities. At the end of the time horizon for each of the trusts, the time period when the majority of the funds will be spent, the percentage of assets invested in equity will be reduced by 5% per year until all of the equity investments have been phased out. Response to Interrogatory EL-395. The assumed rates of return for the trusts' assets are as follows:

Equity:	9.5%
Fixed income:	
Taxable	6.0%
Tax exempt `	4.5%

Source: Response to Interrogatory EL-395

The expected return of 9.5% on equity was developed using information on current returns and expected long-term returns on stocks. The 6.0% expected return on bonds is the average yield on the bond market as a whole, as measured by the Lehman Aggregate Index. The tax exempt rate of 4.5% was obtained by taking 75% of the average yield on taxable bonds, which reflects the ratio of the returns of tax-exempt compared to taxable fixed securities. Response to Interrogatory EL-399. These rates of return would result in a weighted average before-tax assumed return on assets of approximately 6.53% for the MP1 trust and 6.95% for the MP2 and 3 trusts. Response to Interrogatory EL-395; Tr. 9/25/98, pp. 2689-2691. Recent returns on assets of the trusts for MP1, 2 and 3, 1992 through 1997, have averaged a before tax return of approximately 10.2%.[4]

The Company also submitted escalation rates for materials, labor and energy, which have average long-term growth rates of 2.1%, 4.1%, and 3.6%, respectively. Response to Interrogatory EL-393, p. 2. The Department finds these escalation rates to be reasonable.

The Company has used assumed rates of return on equity and fixed assets that are less than the actual earned rates for the years 1992 through 1997; however, the Department finds the assumed rates to be reasonable for the long term. Although the

[4] Averages for the Millstone Units trusts are unweighted.

Department reduces the 1999 decommissioning collections for MP3 by $930,000, as described in Section II.F.9, above, the magnitude of this change in 1999 costs does not warrant a revision in the assumed earnings and future collections in the MP3 trust to reflect this cost reduction.

10. Nuclear Final Materials and Supplies Expense

The Company requests that the Department approve $1.428 million for amortization of final M&S. Response to Interrogatory OCC-232, p. 2. The final M&S value is based on the M&S on hand on 12/31/97. Tr. 9/15/98, p. 1111. This is the first time the Company has sought inclusion of this item in rates.

Pursuant to the Act, nuclear units will not be subject to rate regulation after January 1, 2004. The Company's operational nuclear units are expected to continue running until at least the year 2015, the license expiration date for MP2. Response to Interrogatory OCC-86, p. 4. Therefore, at the time the M&S expenses are incurred, the units will not be subject to rate regulation. The Company is requesting that the Department allow an expense in regulated rates that will be incurred in a deregulated market. It is not appropriate to recover these costs through rates, absent a significant public policy determination to do so. Also, there is no reason to speculate as to the value of the final core and M&S since this amount will be reflected in the price paid for the units when they are sold, and ultimately included in the calculation of stranded cost. Therefore, the Department will disallow this expense, reducing expense by $1.428 million.

11. MP Unit 1 Administrative and General Expenses

Due to the early retirement of MP1, CL&P forecasts O&M expense savings of $111.4 million in 1999. Late Filed Exhibit No. 6, AR-OCC-34. The Company did not include $5.6 million of administrative and general (A&G) expense savings associated with the MP1 retirement in the O&M expense savings. Tr. 9/17/98, pp. 1427-1429; Late Filed Exhibit No. 168, Read-In W. PRO and OCC believe that the Department should remove $5.6 million from the rate year. PRO Brief, p. 9; OCC Brief, p. IV-30.

The Department does not agree with PRO and OCC that it is appropriate to remove the A&G expense savings from the rate year. The Company cleansed the rate year of MP1 expenses in Schedule C-2. Therefore, any savings the Company may realize from the retirement do not affect the rate year.

12. Maine Yankee

The Company has included expenses in the rate year for its contractual payments to Maine Yankee (MY) based on its ownership percentage. The components of the payments are O&M, Department of Energy Decontamination and Decommissioning (DOE D&D) costs, amortization of nuclear fuel final core and M&S, depreciation, taxes, decommissioning, and a return on the unrecovered investment balance. Response to Interrogatory EL-211. MY currently has a proceeding before the Federal Energy Regulatory Commission (FERC) to determine the rates it may charge its

owners, including CL&P. Response to Interrogatory OCC-189. FERC precedent is to establish rates subject to refund. Tr. 9/14/98, p. 950.

In the event FERC decides the rates charged by MY are too high or if any components of the rates are denied because of imprudence, CL&P would receive credits or refunds, which it would apply to the account where the costs were initially recorded. Because the Application does not contain any credits, they will flow directly to the financial statements and the bottom line, not to ratepayers. However, the Company could defer the refunds for future disposition to ratepayers. Response to Interrogatory OCC-335; Tr. 9/14/98, pp. 951, 952 and 957.

Because FERC has jurisdiction to set the rates CL&P must pay MY, the Department will allow the MY costs to be passed on to ratepayers. However, the Department leaves open the possibility of refunding MY costs to ratepayers that are disallowed by FERC. The Department will order CL&P to create an account to record refunds or credits it receives from MY. The Department will consider the disposition of refunds or credits by reopening this docket or in a future rate proceeding.

13. C&LM Bonus Incentive

As discussed in Section II.E.7, above, the Department eliminates the CAM for 1999. Traditionally, CL&P is awarded a bonus incentive of up to 3% of average rate base, based on the cost effectiveness of its C&LM programs, as a means of promoting C&LM. A target incentive is calculated each year and then trued up in following years based upon the actual cost effectiveness of the C&LM programs. The Company is concerned that there could be some true-ups from prior years that might not have been taken care of without the CAM. Tr. 9/14/98, p. 922. However, the Company is never guaranteed it will receive a bonus because the cost effectiveness of the C&LM programs could fall below expectations.

The Department allows a 2% bonus incentive for 1999 applied to 1999 C&LM expenditures instead of rate base, because the 1999 rate base will be extremely small. This equals $575,000 ($28.752 million x .02). This gives the Company a reasonable incentive to pursue C&LM for 1999 and should allay the Company's concerns about prior years true-ups as well as the true-up for 1999.

14. Electric Power Research Institute

The Electric Power Research Institute (EPRI) provides extensive research and development (R&D) services to the electric utility industry. In recent years it has expanded membership eligibility to all organizations in the evolving energy field, including the generation, delivery and sale of electricity, related services and other energy suppliers. EPRI also has taxable subsidiaries, EPRICSG, Inc. and EPRIGEN, Inc., which were created to meet new and emerging needs of an increasingly competitive energy industry, while maintaining EPRI's historical, tax-exempt mission to perform R&D in the public interest. Late Filed Exhibit No. 6, AR-OCC 55.

At the present time, many technological changes are being introduced in the electric industry and many more are in the developmental stages. EPRI's R&D results

take the form of products, services, and information that can be applied for the benefit of the members, their customers, and the energy community at large. Any entity eligible to join EPRI may fund projects in the taxable subsidiaries, and, in so doing, will be considered a member of EPRI. This means that contributors to the taxable subsidiary will have rights of EPRI membership even if they only fund taxable subsidiary projects and do not fund any EPRI projects in the non-profit parent. Id.

The Company's proposed EPRI dues for the 1999 rate year are approximately $1.5 million: direct CL&P allocation of $853,965; CL&P's share of NNECO dues (approximately 72%) of $644,799; and CL&P's share of Seabrook dues (approximately 4%) of $12,180. In 1997 and 1998, the total amounts allocated to CL&P were $810,000 and $897,513 respectively. Response to Interrogatory OCC-51. This equates to an increase of 86% over 1997 and 68% over 1998 with 95% of the increase in the direct CL&P allocation.

CL&P states that the substantial increase in the 1999 rate year is due to its budget constraints in 1998. Late Filed Exhibit No. 7, AR-PRO 7. These budget constraints were primarily in the non-nuclear areas. The level of project funding was reduced to five environmental programs in 1998. For the 1999 rate year, the Company has increased the project funding to all of the 22 environmental programs offered by EPRI. The Company believes with all of its nuclear units running in 1999, and the benefits it will be deriving from the current EPRI projects, its involvement in the 22 projects from EPRI will be beneficial in the long run. Tr. 10/16/98, p. 3753.

OCC believes that the 1999 rate proceeding does not give CL&P the right to abandon cost containment efforts. OCC states that the Company found that it did not need to fund the extra EPRI programs in 1997 and 1998; therefore, it should not be the responsibility of ratepayers to fund all of the 22 EPRI projects in 1999. OCC suggests an adjustment of approximately $543,000 to reflect the 1997 EPRI dues cost level of $311,000 (direct CL&P allocation), which is higher than the projected 1998 level of $270,000. OCC Brief, p. IV-41.

The Department believes that ratepayers should bear their appropriate share of research expenses, where the cost of such research is reasonable and the benefits equitable. The Department is unconvinced, however, that CL&P has provided evidence in this case to warrant cost recovery associated with the substantial increase in dues to fund all 22 of the EPRI environmental projects. Further, the Department concurs with OCC that CL&P should not abandon its cost containment efforts. The Department is concerned that the Company is reverting to a "business as usual" approach now that MP3 is running and MP2 should be in the near future. The Company will need to incorporate the cost containment approaches used in the last few years to succeed in the upcoming restructured environment.

The Department is also concerned that EPRI appears to be expanding its membership to the point that regulated entities may be directly or indirectly subsidizing unregulated entities. Although the Company has assured the Department that its own unregulated subsidiary (Select Energy) does not use EPRI, there are other non-regulated entities that do. Late Filed Exhibit No. 27.

The following chart shows the increase or decrease in the EPRI funding levels for the years 1997 to 1999.

	EPRI					
	1997	1998	Percentage Inc./(Dec)	1998	1999	Percentage Inc./(Dec)
CL&P	310,801	270,102	(15%)	270,102	853,965	216%
NNECO	490,121	615,783	20%	615,783	644,799	5%
Seabrook	9,127	11,628	22%	11,628	12,180	5%
Total	810,049	897,513		897,513	742,374	

The Northeast Nuclear Energy Company (NNECO) and Seabrook levels appear to be within reason. CL&P's do not. Although the Company explained the benefits, it did not submit a cost/benefit analysis to substantiate the increased funding. Late Filed Exhibit No. 6 AR-OCC-13, p. 2. The Department believes that the increase of funding in the CL&P level is inappropriate. The Department will cap the CL&P level to 25% over the 1997 level. This brings the CL&P expense to $388,501, which is a reduction of $465,464.

15. Consulting Fees

In 1997, CL&P entered into a Transition and Retirement Agreement with its then Chief Executive Officer (CEO) to reflect his election to retire. Under the Transition Agreement, CL&P was required to engage him as a consultant for two years, with annual fees of $500,000 and $300,000 for the first and second years. Late Filed Exhibit No. 5, ADR-DPUC No. 22, Proxy Statement. CL&P's portion of the consulting costs that will be applicable in the 1999 rate year is approximately $84,000. Tr. 10/16/98, p. 832.

OCC states that this is a non-reoccurring consultant fee and should be removed from the rate year. OCC Brief, p. 35.

According to the Company, the former CEO is carrying out work as a consultant in support of litigation that pertains to outage related issues, such as joint owner litigation. Tr. 9/14/98, p. 831. Because these are clearly outage-related costs that are a result of mismanagement of the plants, the Department reduces the 1999 rate year consultant expense by $84,000.

16. Telephone Expense

The 1999 telephone expense proposed by the Company is $5.3 million, which includes approximately $3.3 million billed from Northeast Utilities Service Company (NUSCO). The telephone expense budgeted in 1998 was $5.2 million, which includes approximately $3.2 million billed from NUSCO. The actual 1998 telephone expense through August is $2.9 million, of which approximately $2.1 million is billed from

NUSCO. This compares to the budgeted $3.5 million telephone expense through the same period for CL&P, which includes $2.1 million billed from NUSCO. Response to Interrogatory EL-316.

Within the last few years, the Company has been reviewing the rates paid for telephone services. By negotiating with AT&T, CL&P was able to cut long distance rates in half, resulting in savings of approximately $80,000 per month (NU level). Consultants were utilized to validate the rates of the Company's local service carrier, SNET. The existing SNET contract was restructured, resulting in total savings of approximately $300,000 (CL&P level) over the next two years (1999 and 2000). Late Filed Exhibit No. 149.

OCC recommends an adjustment of $900,000 to the projected 1999 telephone expense, which is equal to the annualized amount CL&P was under budget as of August 1998. OCC believes that after making this adjustment, the projected telephone expense will be more in line with 1997 actual. OCC Brief, p. IV-36.

The Department recognizes the Company's efforts to reduce the cost of its telephone rates. However, there is no evidence to indicate that the AT&T or the SNET savings were in the 1998 budget or reflected in the 1999 projections. When comparing actual to budget through August 1998, there is a difference of approximately $600,000 in the total telephone expense. This equates to a reduction of approximately $75,000 per month. An adjustment of this magnitude is appropriate given the savings that resulted from the renegotiation of the AT&T and SNET contracts that approximate $76,500[5] on a CL&P level. The Company did not offer any explanation as to why there was this large discrepancy between actual and budget. Therefore, the Department concludes that the savings discussed in Late Filed Exhibit No. 149 were not reflected in 1998 or 1999. The Department therefore will reduce the 1999 telephone expense by $900,000 ($75,000 x 12).

17. Payroll Adjustments

a. Labor Escalation

The Company reflects a 1999 labor escalation rate of 3.6%, derived from the DRI review of the U. S. Economy, May 1997. Schedule F, CL&P Summary of Assumptions, p.1. The Company made the assumption that all areas, union/non-union, exempt/non-exempt, would be escalated at 3.6% due to the ongoing union contract negotiations. Response to Interrogatory OCC-105; Tr. 10/14/98, p. 810. The contract negotiations had ceased with the contract rates, effective June 1, 1997, but were extended until September 25, 1998. Late Filed Exhibit No. 29. The negotiation process had not been completed as of the end of hearings in this docket.

[5] The savings associated with the AT&T renegotiations are approximately $80,000 a month at a NU level. The Department approximates CL&P's portion to be 80%. That results in savings to CL&P of $64,000 per month. The savings associated with the SNET negotiations was $150,000 per year. That is about $12,500 per month. Thus, the total CL&P savings are approximately $76,500.

According to the Company, the actual 1996, 1997 and estimated 1998 labor escalation rates were 3.8%, 3.9% and 3.9%, respectively. Late Filed Exhibit No. 5, AR-DPUC-9. The Company presented local market surveys that indicated that the 1998 level was consistent with other area businesses. Late Filed Exhibit No. 5, AR-DPUC-7. In addition, the Company presented the projected budget increase and structure adjustment survey results for 1998. This survey included data on a national level, regional and utility levels. Id. The Company uses a different market depending on the type of employee for which it is structuring a pay level. The Company states that it attempts to determine the pay levels based upon the markets from which it hires people and to which it loses people. As an example, an accountant may be an exempt employee whose work is not utility specific, therefore, the Company would use general industry as a comparison for growth in the exempt pay. The actual increase for employees in 1998 was 4% versus the budget of 3.9%. The 1998 salary program was determined by comparing actual base salaries to the market. Tr. 9/18/98, pp. 1656 and 1663-1665.

In the past, the Company has used DRI for its projected escalations and they have been reasonable. Therefore, the Department will accept the Company's projected labor escalation rate of 3.6% for 1999.

b. Employee Levels

Northeast Utilities has several subsidiaries that provide support services for its system companies and, in some cases, for other New England utilities. NUSCO provides centralized accounting, administrative, information resources, engineering, financial, legal, operational, planning, purchasing and other services to the system companies. NNECO acts as agent for the system companies and other New England utilities in operating the Millstone nuclear generating facilities. Form 10K, p. 1.

The total payroll for CL&P is a combination of direct labor CL&P charges and allocations from NUSCO and NNECO. To the extent NUSCO and NNECO can identify labor charges that pertain specifically to CL&P, the charges are direct. To the extent the support work cannot be identified, allocations are used.

Overall, the Company is proposing employee levels of 6,870 for 1999. This is an increase of 619 positions, which is approximately 10% over the 1997 actual level of 6,251. The Company submitted the actual number of employees for 1997, budgeted levels for 1998 and projected for 1999 for CL&P, NUSCO and NNECO. Responses to Interrogatories OCC-28 and OCC-310.

Employee Levels

		1997	1998	1999
CL&P				
	Budget	2,232	2,456	2,589
	Actual	2,161	2,368	
Difference		71	88	
NUSCO				
	Budget	2,730	2,447	2,467
	Actual	2,453	2,234	
Difference		277	213	
NNECO				
	Budget	1,820	1,775	1,814
	Actual	1,637	1,659	
Difference		183	116	
TOTAL				
	Budget	6,782	6,678	6,870
	Actual	6,251	6,261	

The Company had two explanations for the discrepancies between the budget and actual levels. The first is the static unemployment level and the second is the Company's effort to conserve money, given its financial condition. Tr. 10/15/98, p. 1034. Traditionally, a turnover rate is used to project employee levels; however, the Company budgeted for expected actual employees for 1999. Tr. 10/18/98, p. 1872. The Company explained that, in general, because of its financial condition, there were strict budget constraints and management was held accountable for keeping staffing levels down. On a NNECO level, the Company indicated that it probably used more contractors than employees in its nuclear restart efforts. Tr. 10/15/98, p. 1033.

OCC recommends that the employee levels be based on the September 1998 actual levels. OCC Brief, p. IV-21. OCC believes that the 1999 levels are inflated and that the Company has not provided any justification for the majority of its increases. Id., p. IV-19.

i. NNECO

In Docket No. 97-05-12, NNECO levels were budgeted at 1,820 for 1997. This was an increase of 548 employees from the 1996 actual level of 1,272, and 275 over the June 1997 actual of 1,545. Docket No. 97-05-12, Response to Interrogatory PRO-54. According to the Company, the increase was due to the staffing levels of the recovery organizations and to replace contractors. In addition, NNECO was able to absorb some employees from CY. Docket No. 97-05-12, Tr. 10/21/98, p. 921. The Decision dated December 31, 1997, in Docket No. 97-05-12, stated that ". . . the Department will assume that the 275 positions budgeted in 1997 for NNECO will be filled." Decision, p. 30 Those levels were not reached in 1997 or in 1998. NNECO ended the year at 1,637 employees, which is 183 short of its budget.

The 1998 budget contains 1,775 NNECO positions for 1998 and as of September 1998 the actual level was 1,659. That equates to 116 open positions that would have to be filled by year end. The Department is skeptical that this will be accomplished, particularly because the Company has stated that the current staffing levels at Millstone are high for a two operating unit site. Late Filed Exhibit No. 170.

The Company proposes 1,814 positions for 1999, an increase of approximately 40 employees over the 1998 budget. Response to Interrogatory OCC-28-RV1. This was updated to show a decrease of approximately 40 positions in 1999 due to the cessation of operations at MP1. Response to Interrogatory EL-296. According to the Company, as the plants come on line, the number of employees needed for continuous operation will increase, replacing contractors that were working on the restart. Tr. 10/15/98, pp. 1036 and 1037. According to Mr. Kenyon, CL&P has reduced the number of contractors at Millstone in the range of 500 to 600 to date. Tr. 9/10/98, p. 356.

The Department is very concerned about the safe operation of the nuclear units and recognizes the importance of adequate staffing. On average, for the last two years, the Company has been 150 positions short of budget projections and is currently 116 shy of the 1998 budget. In addition, the Company itself has admitted that the current level of positions is too high. Late Filed Exhibit No. 170. The Department has therefore determined that the projected 1999 level should be 1,698. This should allow the Company some flexibility over the next year to finalize the MP2 restart and allow for a smooth transition from its use of contractors.

ii. CL&P

CL&P budgeted 2,232 employees for 1997. This is an increase of 40 employees from the 1996 levels of 2,192 and 84 over the June 1997 actual level of 2,148. Docket No. 97-05-12, Response to Interrogatory PRO-54. In analyzing employee levels in Docket No. 97-05-12, the Department indicated that the Company provided no support for the increases and determined that the 1996 actual level was sufficient. Docket No. 97-05-12, Decision dated 12/31/97, p. 30. The actual 1997 year end level of employees was 2,161. This was 13 positions higher than the June 1997 actual of 2,148 but 71 positions lower than the 1997 budget of 2,232 submitted by the Company. Docket No. 97-05-12, Response to Interrogatories PRO-54 and OCC-28-RV1.

The Company has budgeted a CL&P employee level of 2,456 for 1998, an increase of 295 positions between the December 1997 actual and the 1998 budget. The Company explains that there were employee transfers that occurred in December 1997 that were reflected in 1998. Of the 295 employee increase in the 1997 to 1998 period, 175 are customer service positions, 57 are district administration positions, and 14 are conservation and load management positions that were transferred from NUSCO to CL&P. Supplemental Filing, Section II-4. The actual through September 1998 is 2,368. Id.; Late Filed Exhibit No. 145. There are 88 positions that will need to be filled to attain the 1998 budget level of 2,456 when compared to the September level of 2,368.

The Company maintains that it will fill the 88 positions for 1998 by year end. Response to Interrogatory OCC-308. This is possible, but not probable. The Full Time Employee (FTE) level has decreased every month in 1998, and for 1997 and 1998 has averaged approximately 80 positions lower than budgeted. Response to Interrogatory OCC-26; Late Filed Exhibits Nos. 145 and 168, Read In HH.

The Company has projected employee levels to be 2,589 for 1999, which is 133 over the 1998 budget and 221 over the actual September 1998 levels. Late Filed Exhibit No. 145. The increase is primarily in the energy delivery area, where the responsibilities include:

- ⇒ Studying T & D systems and authorizing modifications
- ⇒ Developing strategic guidelines for T & D
- ⇒ Maintaining and Operating the T & D systems
- ⇒ Performing all work associated with adding load to the system
- ⇒ Streetlight and area light installations
- ⇒ Some customer service
- ⇒ Designing and constructing all T & D

Response to Interrogatory OCC-24.

The Company states that there is much work to be done in 1999 including reliability initiatives and restructuring activities. CL&P Brief, p. 75.

The Department is concerned that only financial constraints would evoke accountability by management to contain staffing levels. This should be a normal business practice benefiting the Company as well as ratepayers. The Department believes that the projected 1999 CL&P employee level should be 2479. This should be sufficient for the Company to complete the 1999 workload.

iii. NUSCO

During Docket No. 97-05-12, the Company's 1997 budget contained 2,730 NUSCO positions. This was an increase of 204 employees over the 1996 actual level of 2,526, and 223 over the June 1997 actual of 2,507. Docket No. 97-05-12, Response to Interrogatory PRO-54. According to CL&P, the primary reasons for the increase are: retail and wholesale marketing; Information Technology (IT) millennium project; and replacement of outside contractors. Docket 97-05-12, Tr. 10/21/98, p. 922. The Decision in Docket No. 97-05-12, stated that ". . . the Department believes that the Company can provide reasonable services at these levels [1996 actual] for CL&P and NUSCO." Decision, p. 30. The 1997 year end actual was 2,453, which is 54 positions lower than the June 1997 actual of 2,507 and 277 positions lower than the 1997 budget of 2,730. Response to Interrogatory OCC-28-RV1.

NUSCO's budget level is 2,447 for 1998, which is essentially unchanged from the 1997 level of 2,453. The Company explained why the 1998 budget did not decline despite a transfer of employees to the operating companies. Two hundred and fifteen positions left the Customer Service Center, 100 left Marketing and 14 left conservation

and load management. Response to Interrogatory EL-293. This decrease appears to be offset by an increase in FTE's resulting from: personnel added to the Employee Concerns Department; the filling of vacancies from 1997; additions in the Information Technology area; staffing of the Environmental Management System Area; and staffing the Bidding and Scheduling functions as a result of NEPOOL restructuring. The actual through September is 2,234. Id. This means that 213 positions will need to be filled by year end 1998. The Department does not believe this can be accomplished or is needed for efficient Company operations.

The Company projects the 1999 level to be 2,467, which is 20 more than the 1998 budget and 233 more than the actual September 1998. Id. The Company states that NUSCO levels did not decline in the 1998/1999 time frame because there were changes required to enhance nuclear performance and monitoring and initiatives to position the Company better as it enters a competitive marketplace. In addition, reorganizations and changes in how organizations conduct their business required additional staffing and the filling of positions left vacant during 1997. Response to Interrogatory EL-293, p. 1.

The Department has heard in this proceeding, as well as others, how cuts or reorganizations in one area are continually being absorbed by another. Although the actuals decline, there are no budget reductions in any areas. Late Filed Exhibit No. 170; Docket 97-05-12, Tr. 10/21/97, p. 921. The budgets for 1999, for CL&P, NUSCO and NNECO are higher than the 1997 actuals and actual through September 1998.

The Department is concerned about the levels of NUSCO personnel. It appears that the Company is trying to get back to levels that were in place prior to the Millstone outages, ignoring all the cost containment efforts that were in place and proceeding in a "business as usual" fashion. The Company needs to focus now on the levels needed under deregulation. The Department in its analysis looked not only to the past on this issue, which is speckled with inconsistencies between actual levels and budget levels, but to the future, when competitive forces will require increased efficiencies. Therefore, the Department believes that the appropriate 1999 employee level necessary for NUSCO to attain its projected work load is 2,259.

c. Compensation

The Company based its 1999 salary program on the expected actual level of FTE's and labor dollars. July 1997 data were used as the starting point for the 1998 budget process. The actual FTEs and the estimated labor costs (using DRI escalation rates) are included. The Company then adjusted for any transfers, new employees and any other known adjustments. The same process was used for 1999 using updated data where possible. Supplemental Filing, Volume 2.

The Company provided the average compensation level for the exempt and non-exempt employees for CL&P, NUSCO and NNECO for 1997 - 1999. Response to Interrogatory EL-294. The 1998 salary increase occurred in September; therefore, the 1998 level presented by the Company was based upon salary annualized using six months' data. The 1999 salary was projected using a 3.4% escalation factor. This is due to the projected salary increase of 3.6% being applied in March 1999.

	1997		1998		1999	
	Base Salary	Benefits	Base Salary	Benefits	Base Salary	Benefits
CL&P	49,414	16,514	49,634	16,587	51,322	17,152
NUSCO	53,948	18,029	58,110	19,420	60,086	20,080
NNECO	56,230	18,792	57,472	19,207	59,426	19,860

The benefits include pension, FAS 106, Life Insurance, Medical Insurance and HMO, Long-term Disability, 401K, and Benefits Consulting.

The Department has determined that compensation will be adjusted as a direct result of the reduction to employee levels. The total adjustment is $20.7 million, of which $18.9 million will be expense and $1.8 million will be capital. The total payroll for CL&P is a combination of direct labor CL&P charges and allocations from NUSCO and NNECO. To the extent NUSCO and NNECO can identify labor charges that pertain specifically to CL&P, the charges are direct. To the extent the support work cannot be identified, allocations are used. Form 10K, p.1. In this filing, the NUSCO allocation percentage was approximately 40%, while the NNECO was 71%. Responses to Interrogatories OCC-366 and OCC-367. The following chart splits the adjustments among capital and expense:

			1999			
		$	$	$		$
		CL&P	NUSCO	NNECO		Total
Capital		1,506,428	266,793	32,650		1,805,871
Expense		6,025,712	6,403,018	6,497,345		18,926,075
Total		7,532,140	6,669,811	6,529,995		20,731,946

The distribution of labor costs involves the assignment of direct costs and allocation of the indirect costs to the proper accounts, work orders and cost centers receiving the benefits of the expended labor. It is extremely important to allocate labor costs accurately among various capital projects or expense accounts due to the impact these categories have on the ratemaking process. The Company uses a payroll allocator, which is based on the level of capital projects being done in a particular year. According to the Company, it will send around a notice to cost control center managers asking them to identify what percentage of their work will be charged to capital. In addition, the Company will use the historical payroll, which shows what ultimately was

charged to capital. Tr. 10/08/98, pp. 3167 and 3168. The Department combined expense and other in its adjustments.

Using an average salary of $68,474 including benefits, the reduction to the CL&P projected employee levels results in a $7.5 million decrease (68,474 x 110) from projected salaries of approximately $152 million. Response to Interrogatory 104-RV2, p. 3. Thus, the CL&P direct payroll would be approximately $145 million. The Department has allocated this 20% to capital and 80% to expense based upon the ratio of each component to the total of the base payroll. Id. The impact to payroll taxes as a result of this adjustment is a reduction of $345,500 ($51,322 average base salary x 110 employees x 80% expense x 7.65% tax rate).

The reduction to the NNECO projected employee levels using an average salary of $79,286 including benefits results in a $9.2 million decrease (79,286 x 116) of which $6.5 million will be allocated to CL&P, based on an average allocator of 71%. Response to Interrogatory OCC-366. This reduces the projected NNECO salaries from $134 million to $127 million. Id. This was then allocated .5% to capital and 99.5% to expense based upon the ratio of each component to the total of the base payroll. Response to Interrogatory OCC-104-RV, p. 3. The impact to payroll taxes as a result of this adjustment is a reduction of $372,544 ($59,426 average base salary x 116 employees x 71% allocation factor x 99.5% expense x 7.65% tax rate).

Using an average salary of $80,166 including benefits, the reduction to the NUSCO projected employee levels results in a total decrease of $16.7 million (80,166 x 208), of which $6.7 million will be allocated to CL&P using a 40% allocator. Responses to Interrogatories OCC-366 and 367. This then reduces the projected NUSCO payroll from $69 million to $62 million. Id. The Department then allocated 4% to capital and 96% to expense based upon the ratio of each component to the total of the base payroll. Response to Interrogatory OCC-104-RV, p. 3. The impact to payroll taxes as a result of this adjustment is a reduction of $367,138 ($60,086 average base salary x 208 employees x 40% allocation factor x 96% expense x 7.65% tax rate).

d. Executive Compensation - Other

Other Compensation comprises special payments such as hiring inducements, expense reimbursements, special payments for continuing employment, and termination payments for executive officers. Response to Interrogatory OCC-34. According to the Company, any compensation would be part of the compensation/benefit package, and those types of expenses would be considered above the line costs charged to ratepayers. Tr. 9/18/98, p. 1647. The estimated other category for 1998 is a $100,000 retention payment for one of the five officers. In the 1999 estimate of $674,950, $520,000 is for four top officers relating to retention payments or incentives for achieving specific goals such as Millstone Station being removed from the Watch List. Late Filed Exhibit No. 28.

The Department believes that the retention payments and incentives of $520,000 that relate to removing Millstone from the watch list are clearly outage-related and are a result of mismanagement of the plants. The balance of approximately $155,000 was never explained by the Company. Without justification, the Department cannot allow

the costs to be passed on to ratepayers. Therefore, the Department will disallow the entire Other Compensation of $675,000.

e. Supplemental Executive Retirement Program

The Supplemental Executive Retirement Program (SERP) is a ratepayer supported, non-qualified pension plan providing supplemental retirement income to system officers. Under this plan, executives receive supplemental benefits in two forms. The first is a make whole benefit that provides for the makeup of the benefits lost because of Internal Revenue Code limits. The second allows any awards paid to executives under the executive incentive compensation program, executive incentive plan and the deferred compensation (as earned) to be included in the calculation of their pensions. 1998 Proxy Statement, p. 12. According to the Company, the supplemental benefits and perquisites provided are consistent with practices in other utilities. Tr. 10/13/98, pp. 3374-3377.

OCC believes that the SERP costs of $1.3 million should be disallowed because the plans are excessive and not required for the provision of safe and reliable service. In addition, OCC states that shareholders should provide for this discriminatory extra benefit. OCC Brief, p. IV-24.

The Department believes that the make whole benefit puts executives on an even footing with other employees. In as much as the incentive payments for NU are counted toward pensions for executives, in 1996 it was also included for the other staff. Response to Interrogatory OCC-362(e)-Bulk. The SERP cost (expense and capital) was $2.9 million in 1996, $3.6 million in 1997, estimated at $1.7 million in 1998, and projected at $1.7 million for 1999. Response to Interrogatory OCC-349.

Because the SERP is a common practice among utilities and the Company has made efforts to reduce the costs associated with this program, the Department will allow these costs to remain in the 1999 rate year.

f. Executive Incentives

Consistent with its goal to recognize the importance of retaining key executive talent and to help assure officers' dedication to their duties to the Company and its shareholders, a stock price recovery program was implemented in 1996; as were a one-year, short-term incentive program and a three-year, long-term incentive program in 1997. During 1997, the Committee began restructuring compensation plans to align them more closely with the changing electric utility industry. A new Incentive Plan was approved in 1998. The new plan provides: annual incentive awards to officers of the Company at vice president level or above; grants of incentive stock options; non-qualified stock options, restricted stock, stock appreciation rights and performance units to selected employees of the Company; and grants of non-qualified stock options to non-employee trustees and Company contractors. The new plan also includes a Deferred Compensation plan that allows deferral of some portion of compensation that officers are prevented by federal tax rules from taking under the Company's 401K plan with matching contributions and an employee share purchase plan. Id. The Company believes that the compensation of its senior officers is reasonable, as any incentive

compensation that is charged to CL&P is not supported by ratepayers. CL&P Brief, pp. 37and 38; Response to Interrogatory EL-112.

Because CL&P states that the 1999 Bonus/Incentive and other amounts for the officers charged to CL&P are not readily identifiable, OCC questions how the Company can say with certainty that the incentive costs are paid by shareholders. OCC, therefore, recommends a disallowance of $1.8 million. OCC Brief, p. 28.

The Department believes that shareholders should pay the executive incentive plan costs because the benefit to shareholders far outweighs the benefit to ratepayers. The Company states that a detailed itemization of the executive compensation for 1998 and 1999 that are charged to CL&P are unidentifiable, but the Company can look at the budget for the incentive and verify that it is charged to activities that would be allocated below the line to shareholders. Tr. 10/18/98, pp. 1876 and 1877. The Department agrees and makes no adjustment to executive incentives.

18. Pension Expenses

The Company submitted forecasted 1999 total pension expenses of ($28,880,000), which, net of SERP expenses, are ($30,580,000). Supplemental Filing, Vol. 1, Workpaper A-14; Response to Interrogatory OCC-349. The negative pension expense is due to the fact that over the last several years actual pension returns have exceeded long-term projected returns and historical averages. Tr. 9/24/98, p. 2324. The NUSCO retirement plan asset portfolio consists of approximately 67% equity, 25% fixed income, and the remainder in real estate and other investments. Late Filed Exhibit No. 112. The pension credit is an increase from the $25,438,000 credit for budget year 1998. To analyze pension expenses properly, it is necessary to examine the reasonableness of the key actuarial assumptions that affect pension expenses, namely the discount rate, the long-term rate of return on plan assets, and the expected rate of increase in salaries. Another important determinant of pension expenses is the accounting treatment of any gains or losses in pension assets.

The forecasted 1999 pension expenses are based on the following long-term actuarial assumptions: 7.5% discount rate, 8.75% rate of return on assets, and 4.75% salary growth rate. These are updates of the 1998 actuarial assumptions of 7.25% discount rate, 9.50% rate of return, and 4.25% salary growth rate. Responses to Interrogatories EL-432 and PRO-55.

The assumed 8.75% return on plan assets for 1999 is a downward revision from the 1998 assumed rate of 9.50% to the 8.5% to 8.75% range that the Company has assumed since 1993. From 1993 to 1997, the Company's pension fund has significantly outperformed the assumed earnings rates in every year except 1994; actual earnings have averaged 15.44%, while earnings were assumed to grow at an annual average rate of 8.6%. Response to Interrogatory PRO-52. On the one hand, the recent high earnings rates in CL&P's pension assets and equity markets generally suggest that retaining a rate of 9.50% for long-term earned returns is warranted. However, the recent volatility in financial and equity markets casts doubt as to whether a return of 9.50% could be maintained in 1999 or over the long-term. In light of the many

uncertainties in projecting long-term earnings, the Department finds the Company's assumed rate of return on assets of 8.75% to be reasonable.

CL&P 1999 forecasted salary assumptions represent the middle range of the 1997 assumed salary growth rates for the Fortune 500 survey group of electric and gas companies. Of the 70 companies in the survey group, 27% of the companies assumed salary per annum growth rates in the 4.5% to 4.99% range, with an average growth rate of 4.5% for all companies. Thirty-six percent of companies had salary growth rate assumptions below 4.5% and 37% had salary growth rates exceeding 5.0%. Response to Interrogatory EL-431, p. 2. In recent years, CL&P has consistently forecasted a salary growth rate in excess of actual growth. Between 1993 and 1997, the Company's assumed salary growth rates averaged 4.85% while actual salaries grew at an average of 3.82%. Response to Interrogatory PRO-54. According to the Company, factors that influence the salary rate assumption are base rate salary increases, promotions, employee turnover, and the underlying inflation rate. The Company's witness, Mr. DeAngelo, testified that short-term labor market shortages were a factor in the upward revision of the salary growth rate assumption. However, he also testified that inflation rates are historically low, which has the effect of lowering the salary growth rate assumption, as well as other actuarial assumptions. Tr. 9/24/98, pp. 2353 and 2358.

The Department revises the 1999 forecasted 4.75% salary growth assumption to 4.5%. The Company provided no convincing rationale for the 50 basis point increase in assumed salary increases. The revised salary growth assumption is more reflective of the recent salary growth rates experienced by the Company as well as the expected low inflation rates projected in the near-term. An assumed 4.50% salary growth rate places CL&P at the average salary growth rate for the Fortune 500 utilities and maintains the 300 basis point differential between the discount rate and the salary growth rate that the Company used in its 1998 actuarial assumptions.

With regard to the accounting treatment of the pensions, the Company did not make use of the "10 percent corridor" in amortizing its pension gains. The Company argued that it was able to amortize a greater amount of its pension gains, and lower its pension costs by not using the corridor, i.e., not excluding a portion of pension gains equal to 10% of the pension assets from amortization over the expected service period of the plan participant,. Tr. 9/24/98, pp. 2328 and 2329. The Company amortized its pension asset gains over the service period of the active plan participant, which, for CL&P, is 16.26 years. Tr. 9/24/98, p. 2330. An amortization period at least as long as the expected service period of the plan participant conforms to the guidelines set forth in the FAS87 accounting standards. Tr. 9/24/98, p. 2327. Although it is possible to amortize the pension gains over a shorter time period, the Company pointed out that using a shorter amortization period would not be in conformance with FAS87 accounting standards and would lead to greater year-to-year volatility in pension expenses. CL&P Brief, pp. 78 and 79. The Department concurs that using a shorter amortization period for ratemaking purposes would create greater volatility in pension expenses and accepts the 16.26 year amortization period.

The Department finds the Company's pension expenses reasonable, with the downward adjustment of the 1999 assumed salary growth rate from 4.75% to 4.5% for ratemaking purposes. This results in a decrease of $1,365,000 in the Company's

pension costs, a reduction from ($30,580,000) to ($31,945,000). Response to Interrogatory PRO-55.

19. Post-Retirement Benefits Other Than Pensions (FAS 106) Expenses

The Company proposed post-retirement benefits other than pension expenses of $18,377,000 for forecasted year 1999. Supplemental Filing, June 30, 1998, Workpaper A-14, p. 1. The forecasted 1999 FAS 106 expenses are based on the following 1998 long-term actuarial assumptions: 7.75% discount rate, 9.25% return on plan assets, and 4.75% salary growth rate. The 1999 FAS 106 expenses were developed by escalating the budget 1998 expenses by 3.6%. Response to Interrogatory EL-438; Supplemental Filing, June 30, 1998, Workpaper A-14, p. 2. The Company's forecasted actuarial assumptions for 1998 use a higher discount rate and long-term rate of return than the forecasted rates for 1999. The Company assumed a discount rate of 7.50%, a long-term rate of return of 8.75% and a salary growth rate of 4.75% in its 1999 forecasted pension expenses. See Section II.F.18. FAS 106 assets are invested in approximately 55% equity and 45% fixed income securities. Late Filed Exhibit No. 112.

Between 1993 and 1997, actual returns have exceeded forecasted returns in the health insurance and life insurance Voluntary Employee Benefit Association (VEBA) trusts that fund post-retirement benefits other than pensions. Response to Interrogatory PRO-49. The Company has amortized the difference between actual and projected earnings over four years, which is the maximum recommended amortization time period under the FAS 106 rules. Tr. 9/24/98, pp. 2279 and 2280. In 1998, this amortization resulted in a reduction of FAS 106 expenses by $2.9 million. In setting 1999 forecast FAS 106 expenses, the 3.6% escalation factor was applied to 1998 FAS 106 expenses that were reduced by the $2.9 million amortization. Late Filed Exhibit No. 108.

The Company testified that it is approximately at the median of the value of its post-retirement benefit package, compared to a peer group of utility and nonutility companies. Tr. 9/24/98, pp. 2267 and 2268. The Company indicated that it had taken several steps to limit post-retirement benefits to its pension recipients. These included implementing managed care, eliminating its vision care program, increasing its prescription drug copayments, and updating its actuarial assumptions to reflect its retiree profile. Response to Interrogatory PRO-27; Tr. 9/24/98, pp. 2259-2272. The Department finds the Company has exercised due diligence in balancing cost containment goals with an effort to retain an attractive benefit package for its retirees.

The Company used somewhat higher actuarial assumptions than in the 1999 pension forecast, as discussed in Section II.F.18; however, when considered together, these assumptions are acceptable for setting 1999 FAS 106 expenses. The Department finds that use of the 1998 actuarial and amortization assumptions, together with the escalation rate of 3.6%, produces a reasonable estimate of 1999 FAS 106 expenses.

OCC recommended that the FAS 106 expenses be reduced by $1,354,000. OCC noted that CL&P's 1998 budget FAS 106 costs, used as a basis for 1999 FAS 106 costs, assumed that 75.2% of the FAS 106 costs were expensed, in excess of the actual 67.4% of FAS 106 costs that were expensed as of June 1998. OCC Brief, pp. IV-

25 and IV-26. The Department finds that the change in the percentage of FAS 106 that is expensed rather than capitalized is insufficiently large to warrant a change in the projected 1999 FAS 106 expensed and capitalized allocations as filed by the Company.

20. Outside Services

The Company included approximately $5.1 million in outside services related to the restart efforts at the Millstone units. Response to Interrogatory OCC-49-RV1. This includes $2.9 million of legal expense and $2.2 million of consultant costs associated with nuclear organization activities. The Company filed an update to its June 1st filing on September 30, 1998, in which it removed $5 million from Account 923 and $100,000 from Account 920. Late Filed Exhibit No. 6, AR-24-RV1. The Department agrees with the reduction in the updated filing.

21. Millennium Project

The Company included $2.2 million of costs related to the millennium project in the 1999 rate year. Response to Interrogatory EL-194. The millennium project refers to the need to reprogram all of the Company's microprocessors or devices that are time dependent so that they will operate in the proper manner after December 31, 1999. At present they are not yet year 2000 (Y2K) compliant. Tr. 9/25/98, p. 2572. After further analysis, the Company realized that an error had been made and the total 1999 Millennium projected costs should be $10.6 million. This is an increase of $2.4 million over the 1998 budget amount of $8.2 million.

The project is laborious and time consuming because it is difficult to locate problems and fix and test systems adequately. Changes will be needed to the infrastructure (operating systems, database managers, security systems), to the applications that run on it, and to data stored in systems. In its updated filing, the Company made the increased adjustment of $8.4 million. Due to the scope of the problems that could exist absent this project, the Department allows the additional $8.4 million into the rate year for the millennium project. The Department notes that it is hiring a consultant to assess the major utilities Y2K efforts. CL&P's millennium project will be part of this review.

22. Connecticut Municipal Electric Energy Cooperative

In rate filings, the Company allocates revenues and expenses for the Connecticut Municipal Electric Energy Cooperative's (CMEEC) life-of-unit contracts, including the contracts for MP1 and 2, to the wholesale business, thereby eliminating them from the determination of retail revenue requirements. The CMEEC contracts have been terminated; however, the Company has decided not to ask retail ratepayers to pick up the costs that were paid by CMEEC. Thus, they were not included in the Application. Responses to Interrogatories EL-72 and 249; Tr. 9/12/98, pp. 892, 893, 901 and 907.

CL&P retired MP1 and because it will not seek recovery of CMEEC's investment in that plant, it wrote off the costs associated with the investment in the third quarter of 1998. On the other hand, CL&P considers MP2 an economic operating plant. The Company intends to market CMEEC's portion of MP2 and generate revenues to recover

the associated costs. Therefore, the Company did not write off the costs associated with CMEEC's investment in MP2. Tr. 10/16/98, pp. 3817 - 3819; Late Filed Exhibit No. 173.

The Department determines that no adjustments to the rate year are necessary to reflect CL&P's treatment of MP1 and 2 costs previously paid for by CMEEC because the Company did not originally include them in the calculation of retail revenue requirements.

23. Nuclear Refueling Outage O&M Accruals

Outage accruals are used to normalize the impact of refueling outage O&M costs on rates. The Company is allowed to collect outage costs during the rate year even though the actual outage expenditures will not occur until sometime in the future. Tr. 9/17/98, pp. 1433 and 1434.

Prior to the Settlement Agreement, the actual amount of O&M accrual for the next refueling outage (O&M Accrual) collected from ratepayers would be trued up to actual O&M expenditures after the nuclear refueling outage. Any difference between the amount collected and the amount spent would be deferred for future collection or refunded to ratepayers in the Company's next general rate case. Tr. 9/17/98, p. 1449. The Settlement Agreement ceased this deferral. Decision dated July 1, 1996, in Docket No. 92-11-11, Attachment A. As of January 1, 1997, CL&P had a deferred credit balance of $45.3 million for the accumulated O&M deferrals from prior refueling outages and accruals for the next nuclear refueling outages. The Company wrote off this balance to earnings over 1997 in accordance with the Settlement Agreement. This write off was made for the purpose of affecting earnings under the Settlement Agreement for 1997, which resulted in the 1997 ROE being 2.34% higher than it otherwise would have been. The Settlement Agreement then assumed, beginning January 1, 1997, that all of the Millstone units would be back on line from their current outages and a new O&M Accrual would begin. Those assumptions did not end on December 31, 1997, but became the recoveries of the O&M Accrual from ratepayers until the next rate case when the Company would look to set a new level of O&M Accrual. Responses to Interrogatories EL-164 and 419; Tr. 9/17/98, pp. 1435-1443. The Company is seeking to reset the O&M Accrual for the rate year. Tr. 9/17/98, p. 1447.

The Company contends that the annual O&M Accruals built into the Settlement Agreement were $8 million for MP2 and $16.5 million for MP3, which were derived from the 1995 budget with outages for each unit occurring in 1997. Late Filed Exhibit No. 168, Read-In X-SP01. However, the Company began to record different O&M Accruals on its books in the first quarter of 1997, $686,000 monthly for MP2 and $648,000 monthly for MP3. The new book accruals assumed the next refueling outages would begin April 1998 for MP2 and November 1997 for MP3. Response to Interrogatory EL-420. The Company periodically adjusts its book accruals to true up on a prospective basis to revised O&M estimates or the number of months until the refueling outages. Tr. 10/16/98, p. 3770.

The Company contends that it filed the O&M Accruals in this docket in accordance with what it believes is the appropriate Settlement Agreement methodology for collecting outage costs. Tr. 9/17/98, p. 1254. The Company argues that it has only collected from ratepayers the O&M Accrual recorded on its books. The Company seems to believe that adjusting or levelizing the accrual on its books on a going forward basis levelizes the costs to ratepayers. Tr. 9/17/98, p. 1450.

The Company has missed the mark on what costs ratepayers are paying. Rates do not change when the Company adjusts its book accrual. Tr. 9/17/98, p. 1447. Therefore, the amount ratepayers have paid for the next refueling outages also has not changed. The Company agreed that the revisions it made to its book accruals had no effect on the recoveries from the Settlement Agreement for future outage costs. Tr. 9/17/98, p. 1445.

Ratepayers are indifferent to the book accrual recorded by the Company. If rates are not reset before the next refueling outage to reflect the Company's revised estimates of outage dates and O&M, then the amount ratepayers are paying in rates might not equal the actual outage O&M. Ratepayers are not entitled to a true-up of amounts paid to actual costs. The Department still believes that ratepayers should prepay outage O&M to eliminate large variances in rates between years. Therefore, it is imperative that the Department adjust the amount ratepayers are paying in rates to lessen the possibility of over or under payment. The Department believes that the correct analysis to use in determining a new O&M Accrual is to compare the total of all payments made by customers and the new estimated O&M costs. The difference is divided by the number of calendar months until the end of the next refueling outage. This amount will then be the monthly O&M Accrual included in new rates and will be collected by the Company until its next rate case regardless of actual book entries or operation of the plants.

The Company conceded that the methodology to determine a new O&M Accrual favored by the Department may not be contrary to the Settlement Agreement methodology. Further, the Company agrees that the Department has the ability in this proceeding to take into consideration the different methodologies and make an adjustment as it sees fit relative to this particular situation. Tr. 9/17/98, pp. 1452-1454. However, CL&P objected to this methodology in its written exceptions. Written Exceptions, p. 20. The Department notes that the methodology it uses is identical to the one the Company uses each time it recalculates the book accrual except that the Department correctly acknowledges the amounts already funded by ratepayers.

The Department finds that the Company's contention that the O&M Accruals contained in the Settlement Agreement for 1997 were based on the 1995 budget is unsupported. The Settlement Agreement clearly recognized that the Millstone units were not operating for some time in 1995 and 1996 and that all accruals as of January 1, 1997, were returned to ratepayers. Therefore, it is illogical that the Settlement Agreement did not contemplate new O&M Accruals for 1997.

The Company's latest estimated next refueling outage O&M costs are $24.5 million for MP2 with the outage occurring February - April of 2000 based upon a December 1, 1998 restart date and $15.9 million for MP3 for the outage occurring May -

July 1999 and $14.9 million for the outage occurring from May - July 2001. Responses to Interrogatories EL-164, EL-165 and OCC-99-SP01; Late Filed Exhibit No. 6, AR-OCC-23. However, CL&P has since stated that it believes MP2 will not restart until the first quarter of 1999. Late Filed Exhibit No. 172. The delay in the restart will delay the next refueling outage. For the purposes of this analysis, the Department will assume the refueling outage will not begin until June of 2000. As of January 1, 1999, the Company has collected from ratepayers the O&M Accrual set in the Settlement Agreement for two years. The Department calculates the total collected to be $16.464 million ($686,000 x 24 months) for MP2 and $15.552 million ($648,000 x 24 months) for MP3.

Therefore, the Department allows a 1999 O&M accrual using the correct analysis as discussed above of $4.822 million for MP2 [($24.5 million - $16.464 million) / 20 months x 12]. The Department also sets the 1999 O&M accrual for the 1999 MP3 outage at $348,000 ($15.9 million - $15.552 million), which will be collected from January to July 1999, the end of the outage. The Company provided the monthly O&M Accrual of $615,000 for the 2001 outage for MP3. Response to Interrogatory EL-165. The 2001 outage accrual begins in August 1999; therefore, the 1999 O&M Accrual for the 2001 outage is $3.075 million ($615,000 x five months). Based on the Department's analysis, the 2001 outage estimated monthly O&M Accrual is $620,000 ($14.9 million / 24 months). The Company's proposal for the 2001 monthly O&M Accrual is reasonable, and the Department accepts it. The total allowed MP3 1999 outage accrual is $3.423 million ($348,000 + $3.075 million).

The Application contained 1999 MP2 and MP3 annual O&M Accruals of $8.5 million and $7.2 million, respectively. Response to Interrogatory OCC-99-SP01. Therefore, the Department reduces expenses by $3.678 million for MP2 ($8.5 million - $4.822 million) and $3.777 million for MP3 ($7.2 million - $3.423 million).

The Company originally forecasted an MP1 O&M Accrual of $5.668 million for July to December 1999 and stated that it had removed the accrual from the Application. Tr. 9/14/98, p. 971; Response to Interrogatory OCC-89-SP01. In later testimony, a Company witness admitted that subsequent to filing the Application, the Company discovered that it did not remove the accrual. The MP1 O&M Accrual should be removed from the rate year. Response to Interrogatory EL-214; Tr. 9/17/98, pp. 1406-1409 and 1457. Therefore, the Department reduces expenses by $5.668 million.

The total reduction to expenses for 1999 O&M Accruals for all three Millstone units is $13.123 million ($3.678 million + $3.777 million + $5.668 million).

24. Property Taxes

The Company's June 1st filing included property taxes of approximately $65.8 million. Property tax expense is based on the latest estimated mill rates and assessments. The Company discovered an error on one of the supporting worksheets for the 1999 property tax calculation resulting in a reduction of the projected 1999 property taxes of $213,000. This adjustment was included in its September 30, 1998 updated filing. The Department agrees with this reduction.

25. Executive Compensation - Base Salary

Base salary is the amount of executive compensation that has traditionally been allowed for ratemaking purposes. The chart below represents the officers salaries at the NU level. CL&P would be allocated its percentage of those salaries. The Company maintains time records for each executive for activities related to CL&P, utilities regulated in other jurisdictions and non-regulated businesses. Base salaries are then apportioned based on the time records. Where time records are impractical, an allocation is made. For example, if Mr. Morris, the Chief Executive Officer, spent 30% of his time specifically on CL&P and 10% on activities that encompass the whole Company, approximately $295,000 [($775,000 x 30%) + ((775,000 x 10%) x 80%)] would be CL&P ratepayers obligation.

Compensation of NU's Top 4 Executives

		1998 (1) Estimated	1999 (1) Estimated
Chairman, Pres. & CEO	M. G. Morris	776,300	804,200
President & CEO-	B. D. Kenyon	517,500	536,100
EVP & CFO	J. H. Forsgren	362,300	375,300
President, RBG	H. C. Mackenzie	279,500	289,500
Total		$ 1,935,600	$ 2,005,100

Source is Late Filed Exhibit No. 28-SP1

In 1998, the Company budgeted a 3.9% increase for its top executives as well as other staff, but implemented a 4% increase in September. For 1999, the Company has projected a 3.6% increase for executives and other staff.

Comparison of NU'S Top 4 Executives

	(1) Base Salary	Other Utilities	General Industry		(3) Updated Utilities
Chairman, President, & CEO	$ 775,000	$ 671,834	$ 753,527		$ 760,256
President -Nuclear	500,000	257,753	322,020		455,104
Executive Vice President & CFO	425,000	278,990	343,488		347,181
President-Retail Business Group	270,000	246,943	270,000	(2)	302,853
Total	$ 1,970,000	$ 1,455,520	$ 1,689,035		$ 1,865,394

(1) This is actual salary after the September 1998 raise of 4%.

(2) There was no match available so NU's salary was imputed.

Source is Late Filed Exhibit No. 79 and 79-SP1.

The above chart reflects two comparisons. The first is NU's top four executives base salaries with those of other utilities and the general industry. Late Filed Exhibit No. 79. According to the Company, this comparison is based on averages, with NU executives being compared to a mix of company sizes with a variety of generation mixes. It does not take into account issues such as restructuring and the additional amount of compensation needed because NU is primarily a nuclear generation company. Tr. 10/20/98, p. 4018. CL&P executives' base salaries are approximately 35% higher than the other utilities and approximately 17% higher than the general industry. The Company witness, Mr. Coakley, explained that the disparities exist due to: the need to recruit top leadership at this difficult time for NU; the Company's extraordinary need to recruit and retain top talent for its nuclear organization; and the highly competitive nature of the nuclear market. In addition, one of the executives, Mr. Forsgren, has been give extra responsibilities and therefore it was difficult to find an accurate comparison. Tr. 10/20/98, p. 3997.

The second compares NU's top four executives base salaries against the those of nine companies that, according to the Company, closely reflect NU's nuclear generation and size. In this comparison, NU executives were still 6% higher. It appears that the peer group used may not be totally reflective of NU's status in that these companies' nuclear plants are currently running.

AG believes that the base salaries paid to NU's executives are significantly higher than those paid to executives of other comparable utilities. Further, AG states that the Company failed to show that these increased costs are not outage related. AG Brief, p. 14.

Executive Salaries Over Time

	1995	1996	1997	Estimated 1998	Estimated 1999
Total of NU's top 4 executives	1,167,692	1,514,870	1,825,498	1,935,600	2,005,100

Source is the 1997 and 1998 Proxy Statements

From 1995 to 1998 executive base salaries have increased approximately 70%. According to the Company, executive salaries are expected to increase in the future at a rate that is consistent with increases in industries and at companies with which CL&P competes for its executive talent. Late Filed Exhibit No. 5, AR-DPUC-8; 1997 NU Proxy Statement, p. 8. NU's prior Chairman, President and CEO had base salaries of $544,459, $551,300 and $551,300 for 1994, 1995 and 1996, respectively. 1997 NU Proxy Statement, p. 8. In 1996, the former CEO did not receive an increase because of Company performance. Id., p. 14. Mr. Morris was hired at a base salary of $750,000. Id., p. 8. The Company states that, in general, the higher salaries for the executives are due to the leadership needs of the Company in its most difficult time. Tr. 10/20/98, p. 3997.

The Department believes that the executive salaries need to be adjusted downward to reflect market. The Department is concerned that the Company is looking to other companies' increases in salaries to justify its own. The Company needs to look to the market as a benchmark for its salaries not just to replicate the dollars spent. Many factors, such as company performance and the economy, must be considered in determining not only executive, but all, salaries.

Although the Company believes that the updated utility comparison better reflects its position in increasing the executive salaries, the Department does not. The Department believes that between the two comparisons there is a fair overall base salary compensation level. The Department will reduce the 1999 executive base salaries by 8.5%. This takes into account the 6% that the current 1998 salaries are over the updated comparison and reflects a 2.5% adjustment to account for status differences in the comparison such as size and energy mix. This results in a total reduction of approximately $171,000 at the NU level and $88,500 at the CL&P level.

26. Storm Expense

The Company calculated rate year storm expense of $11.652 million by averaging storm costs for the six-year period 1992 - 1997 and escalating the result 3% per year to the rate year. Response to Interrogatory EL-190; Tr. 9/15/98, p. 1122. CL&P believes all six years, including years when the expense was lower or much higher, should be used to forecast rate year expense because they show the uncertainty related to these costs. Tr. 9/15/98, p. 1124.

PRO and OCC believe that 1996 was an abnormal year and the storm expense for 1999 should be the average of 1992 - 1997 excluding 1996 costs. This results in a rate year expense of $7.866 million, a reduction of $3.786 million from the requested

amount. OCC analyzed the storm expense data and found that there is no relationship between total storm expense and inflation. For example, storm expenses were higher in 1992 and 1993 compared to 1994 and expenses in 1995 and 1996 were higher compared to 1997. Therefore, OCC also believes that there is no justification for an escalation factor in the storm budget. PRO Brief, pp. 9 and 10; OCC Brief, pp. IV-52 and 53.

The Department often uses a historical average, excluding the highest and lowest years' costs, to calculate a rate year expense and believes that is the appropriate method for storm expense. The Department agrees with OCC's analysis on the escalation factor. The Department calculates 1999 storm expense to be $8.483 million by averaging storm costs for 1992 - 1997, excluding the lowest and highest costs in 1994 and 1996. Therefore, the Department reduces expenses by $3.169 million ($11.652 million - $8.483 million).

27. Directors' and Officers' Insurance

CL&P has requested $1.391 million in directors' and officers' (D&O) liability insurance premiums for the rate year. Response to Interrogatory OCC-70. D&O insurance expenses for the years 1994 - 1997 were $497,000, $456,000, $630,000 and $1,022,000, respectively. Expenses increased due to claims paid and higher liability limits. CL&P projects 1999 expenses will be higher for the same reasons. Responses to Interrogatories OCC-312 and PRO-6; Late Filed Exhibit No. 5, AR-DPUC-14. The Company indicated that the two reasons were actually one and the same. As claims are paid, the insurance available in the future is reduced by that amount. Because of the claims already paid and potential claims, the Company purchased higher limits to restore its liability coverage to previous amounts. This would give the Company enough coverage for potential future claims. Tr. 10/20/98, pp. 4005 and 4006; Late Filed Exhibit No. 162. A Company witness testified that all of the shareholder lawsuits are well known to CL&P and the Department and any damage claims would be borne by shareholders. Tr. 9/10/98, pp. 430-432.

PRO, AG and OCC argue that D&O costs have increased from 1995 to 1997 as a direct result of management imprudence and the nuclear outages. The claims paid and pending relate to the nuclear outages. OCC and PRO believe the expense should be reduced to the 1996 level. Even though the outages occurred during 1996, PRO believes this would allow for some increase due to inflation. OCC Brief, p. IV-39; PRO Brief, p. 12; AG Brief, p. 15.

Ratepayers should not have to fund higher liability limits for directors and officers when it is those directors and officers who failed to ensure that the Company operated prudently and reasonably. The Department reduces D&O liability insurance premiums to a level that does not reflect the nuclear outages. The Department agrees that the 1999 expense should be based on the 1996 level. However, the Department also believes that this is an expense that is typically influenced by inflation and sets the 1999 allowed expense at $.65 million, which is the 1996 actual expense adjusted for inflation. Therefore, 1999 expenses are reduced by $.741 million ($1.391 million - $.65 million).

28. Employee Benefits

The Company included $87,550 for performance awards in its 1999 filing, of which $83,313 relates to SPOT recognition and employee service programs and $4,237 is for the Chairman's award. Responses to Interrogatories OCC-31 and 104-RV-2. The Company testified that the SPOT performance awards consist of small awards that every department is eligible to make to its employees. According to the Company, the awards are limited to $200 per person out of a pool of $25 per person in the department. These types of awards are given by supervisors, managers and directors to recognize a job well done and to improve morale. Tr. 10/20/98, pp. 3993 and 3994. The Company's proposal for these three specific items is a $14,308 increase over the 1997 level.

Service and recognition awards are morale boosters for employees and the Department supports them. However, good morale and the productivity it engenders are beneficial to shareholders as well as ratepayers. If costs for these programs continue to rise, shareholders may be asked to share them. This said, the Department will allow the SPOT recognition program, employee service awards and the Chairman's award at the levels proposed.

29. Employee Incentive Compensation

The Company included $13.1 million for its non-management bonus/incentive program. Response to Interrogatory OCC-104-RV2. The dollars used for the incentive program in 1999 are primarily the escalation of the 1998 targets caused by the 3.6% escalation of payroll plus or minus any full time employee adjustments because the 1999 goals were not available. Response to Interrogatory OCC-362. The bonus/incentive was $11.1 million in 1995, $13.9 million in 1996, and $15.5 million in 1997. Approximately 75 to 80 percent was expensed and the rest capitalized. Response to Interrogatory OCC-104-RV2.

Historically, goals are established by a business unit at the beginning of the year. Based on the achievement of those goals, the payout will be a percentage of the employee's pay. Tr. 9/18/98, pp. 1643 and 1644; Response to Interrogatory OCC-362. However, beginning in March 1998, the Company announced that there was a change in the determination of the employee incentive compensation program. This change is the Company's way to get in step with other companies in competitive industries where employees share in the earnings of their company through their incentive programs. Response to Interrogatory OCC-362 (e) Bulk. The new program will now be based on two factors: how well the departments perform against their own incentive goals; and the financial health of the company, which will be determined by the earnings per share (EPS) at year end. Response to Interrogatory OCC-362 (e) Bulk. In addition, a minimum level of earnings must be achieved before incentives are paid. In March 1998, the minimum earnings level for the incentive plan was $0.20 EPS. This means that the first $0.20 of earnings per share would be retained for the benefit of shareholders. A portion of earnings above $0.20 per share would be used to fund employee incentive

plans. Due to an unanticipated accounting change, the Company revised its EPS goal of $0.20 per share to $0.05 per share.[6] Id

Employee Incentive Compensation

EPS Performance	$0.20/share	$0.35/share	$0.45/share	$ 0.55/share
Adjusted EPS Performance		$ 0.10/share	$ 0.20/share	$ 0.30/share
Incentive Plan Fund	4% of Target Payout	25% of Target Payout	Target Payout	Maximium Payout

Generally, nonexempt employees have a target incentive payout of 2% with a maximum payout of 3.25%; exempt employees have a target payout of 6% with a maximum payout of 12%; and at higher manager and director levels, the target level payout is 10% with a maximum payout of 20%. Response to Interrogatory OCC-362. According to the Company, the goals and targets for the incentive plans are raised each year, making it more difficult to achieve the targets; therefore, the incentive payouts are not guaranteed. Id. The Company stated that since their inception, the majority of the incentive awards have been paid at or above target levels. Response to Interrogatory OCC-362 (e) Bulk.

OCC does not believe that the Company, as a whole, has attained any right to any incentives that are based upon performance. OCC attempted to gain a breakout of the components of the incentive plans. It states it was able to identify $4.2 million for non-officers (CL&P basis) and $5.9 million for the nuclear plan and believes that $1.8 million is for the officers' incentive plan. OCC claims that there is a million dollar plus difference that has not been identified by the Company to come up to the $13.1 million presented. In essence, OCC does not believe that an incentive plan should be collected through rates, because it could provide a windfall to shareholders if incentive payments were not made. Therefore, OCC believes that the entire $13.1 million included in the Company's 1999 projections should be disallowed. OCC Brief, pp. 27-30.

The Department was not able to review the 1999 goals because they were not available. As a proxy, the Department has reviewed the historical goals of the program to determine their validity and the distribution of risk. The Department is concerned that the 1998 program may improperly transfer risks of operation from shareholders to ratepayers and Company employees. This transfer of risk results from the new program making incentive payments based upon the Company meeting a specified earnings per share threshold. Such thresholds can jeopardize a utility's commitment to providing safe, reliable, economical service over the long-term by over-emphasizing short-term performance. Another concern of the new plan is that the Company retains the right not to make incentive payments earned under the plan unless a minimum level of earnings

[6] The Securities and Exchange Commission (SEC) required the Company to reverse its nuclear reserves for 1996 and 1997. This requires the Company to transfer the reserve funds to earnings for those years. Response to Interrogatory OCC-362 BULK.

is achieved. This again transfers risk from shareholders to ratepayers and totally ignores the attainment of the individual and departmental goals. If expenses are unexpectedly high or revenues unexpectedly low, shareholders can offset these losses with funds provided by ratepayers for the incentive compensation program. Finally, the Company has failed to show the incentive program is necessary for dependable operations or that it would produce tangible benefits for ratepayers.

In general, the stated goals of the program, better customer service, greater safety and higher productivity, are all appropriate but in some instances are clearly core values each employee's performance is already expected to reflect. The Department looks to the customer satisfaction goal, where a specific department measures its customer service to its internal customers. There are 5 service rating categories: (1) well below expectations; (2) below expectations; (3) meets expectations; (4) exceeds expectations; and (5) greatly exceeds expectations. The incentive goal is based on an average of the service area rating. An employee is allowed a minimum payout if he meets expectations; receives the target level if he is between meets and exceeds expectations and the maximum if he exceeds expectations. The Department believes that incentive compensation should be based upon stretch goals, not simply by meeting expectations. Specific 1998 goals, such as those in the Nuclear area, reflect approximately 25% that are directly related to the restart of MP2 and 3. Although an appropriate goal, the Department will not allow ratepayers to be charged with any restart related costs, including any percentage of an incentive program. In Fossil Hydro, the environmental goal consists of four criteria that, when combined, equate to the total goal weight of 15%. One of the four is weighted 25% and consists of having the station operate in accordance with laws and regulations, which is clearly a core requirement.

In the Department's opinion, the trigger concept makes an assessment of the reasons for payouts and the amounts difficult by comingling goals. The trigger will have the effect of motivating employees toward increasing shareholder value first, and ratepayer satisfaction second. The Department, therefore, does not approve of an incentive compensation plan that conditions compensation for attainment of the goals that are clearly weighted more heavily toward shareholder interest.

While the Department does not want to discourage at-risk compensation plans, it also does not want to build into expenses a level that will not be incurred or that has the possibility of being manipulated. In addition, the Department does not believe ratepayers should be required to pay rates that compensate the Company for pursuing goals that may not be beneficial to them. The Department believes that incentive compensation is a reasonable and proper way to motivate and reward Company employees for superior performance and to promote Company efficiencies. Penalizing the Company for implementing incentive compensation imperfectly could discourage the kind of innovative management necessary to control costs in an increasingly competitive environment. Therefore, rather than a total disallowance as recommended by OCC, the Department will allow recovery of incentive compensation costs as outlined below.

a. Core Requirement Goals versus Stretch Goals

The Department believes that, historically, some of the incentive goal criteria have reflected normal achievements. Incentive-based compensation should be predicated on stretch goals. Although the Company stated it raises the bar each year, it is not reflected in the goals. The Company should reevaluate its goals and require a higher level of achievement. The Department therefore reduces CL&P, NUSCO and NNECO incentive compensation levels by 5% each. This equates to a total reduction to CL&P of $600,000, of which $200,000 is related directly to CL&P; $100,000 to NUSCO; and $300,000 to NNECO.

b. Employee Reductions

Employee incentive compensation must be reduced to reflect 434 fewer employees (see Section II.F.17, above). This equates to a total reduction to CL&P of $800,000, of which $200,000 is related directly to CL&P; $200,000 to NUSCO; and $400,000 to NNECO.

The Department will direct the Company to file a report on the operation and performance of its incentive compensation program with its next rate case application. The report will include an accounting of all amounts paid under the plan since inception, by area; all amounts recorded as earned but not paid; and an evaluation of the program's success in meeting its stated goals, including controlling overall employee compensation costs.

30. Financial Accounting Standard 109 Amortizations

The Company proposes to use the "revenue sufficiency" contained in the Application to accelerate the amortization of the regulatory asset balance related to FAS 109 deferrals by $19 million. Roman PFT, pp. 9 and 10. The Company claims that accelerating these amortizations will benefit both customers and shareholders and is consistent with Section 8(c) of the Act, where mitigation of strandable costs is encouraged. Response to Interrogatory OCC-256; Tr. 9/11/98, pp. 576-578.

The Department has made a number of adjustments to the Application. The result is a revenue requirements reduction for 1999 that far exceeds the Company's estimate. The Department believes CL&P's proposal to accelerate FAS 109 amortizations is appropriate. However, based upon the conclusions reached in Section IV, the Department believes $136,148,000 of the revenue requirements reduction should be used to accelerate the nuclear portion of FAS 109 amortizations for 1999. Consistent with the interim Decision, when the Company is able to breakout the FAS 109 asset in sufficient detail to identify the portions related to MP1 and 2, the Company shall not apply the accelerated amortizations to the MP1 component at all or the MP2 component for as long as MP2 remains out of rate base.

31. Interest Synchronization

The Department has made adjustments to CL&P's requested rate base and capital structure. Therefore, an interest synchronization adjustment must be made to

coordinate the allowed rate base and cost of capital with the income tax calculation. The Department's adjustments cause CL&P's interest deduction to be lower for tax purposes and, consequently, causes an increase in income tax expense. This effect is taken into account in the Tables attached to the Decision.

32. Millstone Unit 3 Out of Rate Base Accrual

In accordance with the Decision dated April 29, 1996, in Docket No. 92-11-11, CL&P recorded an out of rate base accrual from MP3 from July 1, 1998, to July 18, 1998. With interest, this accrual was $7.382 million. Response to Interrogatory OCC-97-SP01. The Department finds that CL&P recorded the accrual appropriately.

G. Revenues and Revenue Adjustments

1. Base Rate Fuel Revenue

a. General

CL&P's fuel costs are recovered through base rates and the Energy Adjustment Clause (EAC). Fuel costs included in base rates are expressed in cents per kWh and are commonly referred to as the base rate fuel recovery rate (BRFR). At the time of a rate case the BRFR is established based on assumptions regarding costs and generating plant performance. Significant among the assumptions is the performance of nuclear generating units (i.e., capacity factor), fossil fuel prices, wholesale purchases and the cost of purchases under cogeneration contracts. The EAC then reconciles the total actual fuel cost incurred by CL&P to the revenue collected through the BRFR.

The Company's current BRFR (Current BRFR) is $.02185/kWh and was established pursuant to the Settlement Agreement approved in the Decision dated July 6, 1996, in Docket No. 92-11-11. Response to Interrogatory EL-42; Tr. 9/16/98, p. 1275. The Company proposes to increase the BRFR to $.03089/kWh (Proposed BRFR), an increase of $.00904/kWh. The Proposed BRFR is based on a forecast of total fuel costs of $734,248,000 and net fuel costs of $646,061,000. Schedule C-3.1, Fuel Simulation B; Tr. 9/16/98, p. 1276. A discussion of each component of the Proposed BRFR follows.

The Company was directed to submit a revised fuel cost simulation (Final Fuel Simulation) and BRFR (Final BRFR) to incorporate the adjustments discussed below. Tr. 10/20/98, pp. 4098-4121; Late Filed Exhibit No. 138 SP 1. The following also addresses the Final Fuel Simulation.

b. Nuclear Capacity Factors

The table below demonstrates the nuclear capacity factors assumed in the Company's original fuel cost simulation (Fuel Simulation).

Proposed Capacity Factors

	As Filed
Millstone Unit 1	-
Millstone Unit 2	72.8%
Millstone Unit 3	70.7%
Conn. Yankee	-
Maine Yankee	-
Vermont Yankee	78.9%
Seabrook	76.6%

*Source: Schedule WP C-3.1, p. 6.

Traditionally, the Company established the BRFR using the forecasted rate year capacity factor for each nuclear power plant. The forecasted capacity factor established production from each nuclear unit based on the rate year refueling outage schedule and an estimated level of forced outages. For example, for MP2, a two-year refueling cycle with an assumed operating performance of 86% between outages and a refueling outage of 56 days, the resulting capacity factors will be 72.8% for the year in which the refueling outage is scheduled and 86% for the year without the scheduled outage. This results in an average fuel cycle capacity factor of 79.5%. Late Filed Exhibit No. 56; Tr. 9/16/98, pp. 1290-1300. Similar assumptions were used to determine the rate year capacity factors in the Fuel Simulation. Id.

The Company states that it does not rely on historical operating performance of nuclear plants when forecasting rate year capacity factors because historical values have proven to be poor indicators in short-term forecasting. Instead, the Company believes it is appropriate to rely on the latest forecasted data for determining nuclear performance. Id. Further, the Company states that it is inappropriate to ignore planned refueling outages when setting the BRFR. To do so would understate fuel cost recovery associated with known and measurable events that occur in the course of operating these units. In addition, the use of the rate year capacity factor provides proper timing of fuel cost recovery. Tr. 9/16/98, pp. 1324-1327. In addition, CL&P states that the use of higher capacity factors would understate base recoveries resulting in a built-in regulatory lag for recovery of fuel costs. Also, if the capacity factor used is unrealistically high, the incentive collar provision of the EAC would react negatively, forcing the Company to write-off the full value of the collar. Response to Interrogatory EL-48.

The following demonstrates the historical performance of the Seabrook (SB) and Vermont Yankee (VY) nuclear power plants.

Historical Capacity Factors for Vermont Yankee and Seabrook

	1993	1994	1995	1996	1997	1999 Proposed	5-Year Average	4-Year Average	3-Year Average
Seabrook	90.0%	61.7%	83.3%	97.6%	79.0%	78.9%	82.3%	80.4%	86.6%
Vermont Yankee	74.9%	95.8%	84.8%	82.8%	93.3%	76.6%	86.3%	89.2%	87.0%

Source: Resonse to Interrogatory EL-160.

As the table demonstrates, since 1995, annual and average performance at these plants has exceeded the proposed capacity factors in four out of the last five years for both plants. These data reflect five years of operation and capture multiple refueling outages. Therefore, these capacity factors reflect fuel cycle averages for these plants. Absent evidence to the contrary, it is reasonable to expect these units to continue to operate at historical levels. The Department concludes that the evidence does not support the Company's assertion that historical operating performance is a poor indicator of short-term performance. The Department concludes that where relevant historical data are available, they should be considered when establishing rates.

The use of either the three, four or five-year average results in a capacity factor that exceeds CL&P's proposal for these units. However, the use of a five-year average captures multiple refueling outages and therefore better reflects fuel cycle averages than does the use of the other averages. As directed by the Department, CL&P used a capacity factor of 82.3% for VY and 86.3% for SB in the Final Fuel Simulation.[7]

Recent historical capacity factors for MP2 and 3 are unavailable because these units have not operated during the past two years; therefore, an alternative forecasting method must be used. In the past, the Department relied on rate year capacity factors to establish the BRFR because refueling outages were known, measurable events, generally occurring when scheduled. However, based on the recent problems experienced at CL&P's nuclear plants, and nuclear plants in which CL&P has contractual obligations, refueling outages cannot be viewed as known, measurable or predictable. This has affected the BRFR. For example, the current BRFR assumed that MP2 and MP3 would be refueled in 1997. As a result, the rate year capacity factors embedded in base rates for these units were set at 73% and 71%, respectively. Late Filed Exhibit No. 2, Docket No. 92-11-11, Summary of Assumptions, Schedule SE-3, 1997 Fuel Schedules, p. 7. However, neither refueling outage occurred in 1997 and the BRFR has not changed since that time. Because the BRFR can only be adjusted in a rate proceeding, the replacement power costs (RPC) embedded in base rates for MP2 and 3 continue to reflect the capacity factors assumed for the 1997 rate year.

[7] The Department notes that it inadvertently directed CL&P to use the wrong five-year average capacity factors for SB and VY in the Final Fuel Simulation. The correct capacity factors should have been 82.3% for SB and 86.3% for VY. As discussed herein, the Department accepts the capacity factors as proposed by CL&P for these units; therefore the capacity factors as directed by the Department in the Final Fuel Simulation have no bearing on the approved BRFR.

As further evidence of the difficulty in predicting refueling outages at the Millstone units, the Proposed BRFR assumed that MP2 would be refueled in 1999, resulting in an forecasted capacity factor of 72.8% for this unit. Schedule WPC-3.1, pp. 6 and 13. However, subsequent to the initial filing, CL&P modified the refueling schedule for MP2, moving the outage to 2000. As a result, CL&P modified its Fuel Simulation and Proposed BRFR to reflect a rate year capacity factor of 86% for MP2. Revised WPC-3.8, dated September 30, 1998, pp. 4-13. As detailed below, this adjustment increased the forecasted production from MP2 by approximately 950 Gigawatt-hours (GWh). Nuclear Production Table below.

CL&P states that the use of rate year capacity factors provides for timely recovery of its costs. The Department disagrees. Although this may have been true when refueling outages occurred as planned, as noted above, they have not in the recent past. In addition, as with SB and VY, the use of a fuel cycle average capacity factor and/or recent historical operating performance levelizes base recovery of the Company's total fuel costs. The change in the MP2 capacity factor noted above provides an example of this. Had the Department relied on CL&P's initial filing to determine fuel costs, the BRFR would have reflected the lower capacity factor for MP2 and the BRFR would have overstated costs for this unit.

Absent historical operating data for MP2 and 3, the use of a fuel cycle average levelizes fuel cost recovery, provides less volatility in relation to the predictability of refueling outages and is consistent with the method used to determine capacity factors for SB and VY. In addition, the use of a fuel cycle average is consistent with the analysis provided in the MP2 CUO Study. Response to Interrogatory EL-8; Tr. 9/16/98, pp. 1286-1290. The use of a fuel cycle average for MP2 would reduce the Company's revised capacity factor from 86% to 79.5%. The Department directed CL&P to use a capacity factor of 79.5% for MP2 and 78.9% for MP3 reflecting fuel cycle averages of 86% between refuelings in the Final Fuel Simulation.

c. Millstone Unit 1

CL&P was directed to embed MP1 RPC in the Final Fuel Simulation. Tr. 10/20/98, p. 4120. CL&P included RPC for this unit in its Final Fuel Simulation. Schedule C-3.1, Fuel Simulation B.

d. Maine Yankee

The MY nuclear power facility was retired on August 6, 1997. Pursuant to the Decision dated December 31, 1997, in Docket No. 97-06-01, DPUC Periodic Review of The Connecticut Light and Power Company's Energy Adjustment Clause and The United Illuminating Company's Fuel Adjustment Clause, CL&P was allowed current recovery of MY RPC through the EAC. However, recovery of these costs was subject to refund pending a final decision by the FERC in Docket No. ER98-570-000, In the matter of Maine Yankee Atomic Power Company. Decision in Docket No. 97-06-01, pp. 5 and 6.

The FERC investigation is ongoing and a decision is not anticipated in the near term. Therefore, it is appropriate to maintain the current status for recovery of these

costs and allow CL&P recovery of MY RPC subject to refund. CL&P has embedded MY RPC in the Fuel Simulation. The Department agrees that this is appropriate but directed the Company to identify these costs separately in the Final Fuel Simulation. Tr. 10/20/98, p. 4098. CL&P will be required to track MY RPC and to report these monthly costs in its EAC filings.

e. Connecticut Yankee

The CY nuclear power facility was retired on December 4, 1996. Pursuant to the Procedural Order dated June 6, 1997, in Docket No. 97-06-01 (CY Procedural Order), the Department suspended current recovery of CY RPC incurred subsequent to the plant's retirement until a final decision is issued by FERC in Docket No. ER97-913-000, In the matter of Connecticut Yankee Atomic Power Company.[8] As a result, CL&P has deferred CY RPC since the plant was retired. FERC issued an Initial Decision on August 31, 1998, but a final decision had not been issued as of the close of the evidentiary portion of this proceeding.[9]

Pursuant to the Decision dated April 29, 1998, in Docket No. 92-11-11, the Department found that the deferral of CY RPC could total in excess of $80 million by December 1998. Decision, p. 18. To avoid the rate impact of this potentially large deferral, the Department required CL&P to accrue the revenue reduction associated with the removal of MP2 and 3 from rate base (MP Accrual) as an offset to the deferral. Id. As of June 30, 1998, the deferral totaled approximately $67 million, while the MP Accrual totaled approximately $6.3 million. Response to OCC-97 SP 1; Response to Interrogatory EL-1, Docket No. 98-06-01, DPUC Periodic Review of The Connecticut Light and Power Company's Energy Adjustment Clause and The United Illuminating Company's Fuel Adjustment Clause.

Because a FERC final decision is imminent, the Department believes it is appropriate to rescind the CY Procedural Order at this time and allow CL&P to recover CY RPC incurred after September 28, 1998, on a current basis. However, consistent with the CY Procedural Order and the treatment of MY RPC, recovery of these costs remains subject to refund pending Department review of the final FERC decision in this matter. CL&P was directed to embed CY RPC in the Final Fuel Simulation and to identify these costs separately. Tr. 10/20/98, p. 4098. CY RPC deferred as of September 28, 1998, shall remain on CL&P's books until the final FERC decision. CL&P will be required to track CY RPC and to report the monthly costs in its EAC filing.

f. Effect of Modifying Nuclear Capacity Factors

CL&P submitted a revised Fuel Simulation (Revised Fuel Simulation) on September 30, 1998. The following demonstrates how the change in capacity factors affects total nuclear production.

[8] The Department is an admitted party to this proceeding.
[9] The Initial Decision is a draft. A final decision requires the vote of the full Commission at FERC.

Fuel Simulation Nuclear Production

	As Filed Schedule WPC-3.1		Revised Fuel Simulation Revised WPC-3.1		Final Simulation Late Filed Exhibit No. 138-SP-1	
	Capacity Factor	Production GWh	Capacity Factor	Production GWh	Capacity Factor	Production GWh
MP1	-	-	-	-	-	-
MP2	72.8%	4,326	86.0%	5,257	79.5%	4,857
MP3	70.7%	3,725	74.5%	4,053	78.9%	4,292
VY	78.9%	303	78.9%	317	82.3%	329
SB	76.6%	315	75.7%	393	86.3%	445
Total		8,669		10,020		9,923

As the table demonstrates, the Revised Fuel Simulation increased total nuclear production by 1,351 GWhs (10,020 - 8,669) above the level included in the original Fuel Simulation. The majority of the increase is attributed to the revised refueling schedule for MP2 and increased capacity associated with the reduced duration of the refueling at MP3. Revised Schedule WPC-3.8, p. 4. Based on the difference between an approximate average cost of fossil production, $25/MWh, and nuclear production, $5/MWh, CL&P's Revised Fuel Simulation reduced total fuel cost by approximately $27 million ($20/MWh x 1,351 GWhs). Noteworthy is the fact that the combined production from MP2, and 3, as well as VY and SB, are virtually identical under CL&P's Revised Fuel Simulation and the Department's revised capacity factors. Further, total nuclear production under the Revised Fuel Simulation exceeds the total nuclear production under the Department's simulation, albeit by a relatively small amount.

As discussed above, where historical data are available they should be considered when developing rates. The Department considered using historical capacity factors to forecast rate year production for SB and VY. However, since the Company's forecast results in essentially the same output from these plants as that demonstrated by historical performance, the Department accepts CL&P's revised forecast. In addition, since there is essentially no difference in the combined nuclear production for MP2 and 3 using fuel cycle averages or the Company's revised capacity factors, the Department will accept the Company's assumptions for these plants at this time.

The difference between the combined production at these plants under the Revised and Final Fuel Simulations is 97,000 MWhs (10,020 - 9,923). Therefore, nuclear production is increased by 97,000 MWhs. This adjustment reduces production/purchases from non-nuclear sources by an equal amount. The expense adjustment associated with this change equals $1,651,167, calculated as the difference in production times the difference between the Company's marginal cost as calculated in the Final Fuel Simulation and the average cost of nuclear fuel. This adjustment reduces fuel cost by $1,651,167, [97,000 x ($21.56-$4.54)].

g. Fossil Fuel Costs

CL&P's Fuel Simulation relied on a forecasted price of oil that ranged between $16-$18 per barrel. Tr. 9/11/98, p. 662; Late Filed Exhibit No. 57. Although the Company used forecasted prices, it believes that the use of current fossil fuel prices in

the Fuel Simulation is reasonable because the EAC will capture changes in the price of fuel. Tr. 9/16/98, p. 1318.

The following demonstrates the price of oil used in the Fuel Simulation and prices during 1998.

Price of Oil at CL&P Fossil Fuel Plants

Oil Type/Station	Cost Per Barrel		
No. 6 Oil	Fuel Simulation	As of June 1998	As of August 1998
	(1)	(2)	(3)
Devon	$16.70	$14.87	$11.92
Middletown .5%	$17.90	$15.97	$13.36
Middletown .3%	$18.20	$16.82	$13.93
Montville	$16.70	$14.94	$11.94
Norwalk Harbor	$16.70	$14.73	$11.65
No. 2 Oil			
All Stations	$24.90	$21.38	not provided

Source:
(1) Late Filed Exhibit No. 57.
(2) Response to Interrogatory OCC-155
(3) Response to Interrogatory EL-428

As the table demonstrates, the price of oil has declined during 1998. As of the conclusion of the hearing, the price was at or slightly above August prices. Tr. 10/20/98, p. 4108. The Department believes that it is reasonable to use current prices in the Fuel Simulation. Therefore, the Department requested the Company to use the current price of oil, adjusted for seasonal changes, in the Final Fuel Simulation.

Norwalk Harbor Station demonstrates the lowest price of oil among CL&P's generating plants and the price at the remaining plants can be estimated based on the Norwalk price. The Norwalk Harbor price was approximately $12 per barrel at the close of hearing. Tr. 10/20/98, pp. 4108-4110. Based on a review of CL&P's historical fuel prices, $12 per barrel represents the lowest price for oil in over a decade. As a result, the Department adjusted the Norwalk Harbor price for purposes of the Final Fuel Simulation because it appeared unlikely that $12 per barrel would be sustained and because prices generally rise seasonally as demand for oil increases during the winter months. Therefore, the Department directed CL&P to use a Norwalk Harbor 'base price' of $13.50 per barrel in the Final Fuel Simulation and to adjust the price of oil for its other fossil plants. Id.

The price of natural gas trends with oil. Id.; Late Filed Exhibit No. 88. Therefore, the Department directed CL&P to adjust the price of natural gas used in the Fuel Simulation to trend with the base price of oil used at Norwalk Harbor. The Company included this adjustment in the Final Fuel Simulation.

h. Cogeneration Costs

The BRFR reflects the total cost for purchases under CL&P's cogeneration contracts. A breakdown of the forecasted total cogeneration cost was provided in response to Interrogatory EL-59. Upon review of these data, the Company discovered that the Fuel Simulation incorrectly priced the purchases from the Citizen's and Self-Generation contracts, overstating total cogeneration costs. Late Filed Exhibit No. 60. The Citizen's contract was overstated by $5,023,000 while Self-Generation costs were overstated by $106,000. The Company indicated that it was appropriate to reduce its forecast of fuel costs by $5,129,000, the total of these amounts. Id. The Company was directed to include these adjustments in its Final Fuel Simulation. Tr. 10/20/98, pp. 4098, 4121 and 4122.

i. Nuclear Decontamination and Decommissioning Assessments

The Energy Policy Act of 1992 requires electric utilities to fund the decontamination and decommissioning (D&D) of the Department of Energy's (DOE) uranium enrichment plants through 15 annual assessments running through October 2006. In Docket No. 92-11-11, the Department approved estimated D&D assessments for the period July 1, 1993, through June 30, 1996. The assessments were added to the cost of the Millstone units' fuel and amortized as the fuel was burned (Fuel Burn Method). Mahoney PFT, p. 8.

CL&P contends that since 1996 it has continued to make payments to the DOE for D&D, but because the Millstone units have not been operating, and therefore not burning nuclear fuel, CL&P has not recovered its DOE payments from ratepayers since that time. Consequently, CL&P is proposing to amortize in 1999 an accumulated $22.3 million unrecovered balance as of December 31, 1998 (Unrecovered D&D) and collect it through the BRFR. Id.; Schedule WPC-3.1, pp. 12-15. In addition, the Company is proposing to change the recovery method for D&D expense to collect the annual assessments on a more current basis consistent with the current FERC method of recovery. The Fuel Burn Method adds D&D to the cost of each fuel load and amortizes the cost as the fuel is burned. Mahoney PFT, p. 8. The FERC method amortizes actual amounts paid to the DOE over the 12 months subsequent to each payment period. This latter change would become effective with the October 1998 assessment. Together, the proposed changes represent an increase of $22.9 million to 1999 forecast fuel costs over levels produced by the current recovery method. Id.; Response to Interrogatory OCC-267.

j. Unrecovered D&D

In support of its proposal regarding Unrecovered D&D, the Company claims that while the Millstone units were off line and not burning fuel, it did not recover D&D from ratepayers under the Fuel Burn Method. The Company states that fossil generation and its concomitant costs replaced unavailable nuclear production and its concomitant costs; therefore, D&D that is embedded in the cost of nuclear fuel was not recovered from ratepayers. Tr. 10/20/98, pp. 4074-4081; Read-In RR. In addition, the Company states that the 1992 Energy Policy Act deems D&D costs as a reasonable cost of fuel recoverable in rates. Id.; Late Filed Exhibit No. 138 SP1.

The U.S. Congress deems D&D cost ". . . a necessary and reasonable current cost of fuel [that] shall be fully recoverable in rates in all jurisdictions in the same manner as the utility's other fuel cost." Pub. L. 102-486 § 28 Sec. 1802 (g). In light of Congress' treatment of D&D costs, the Department concurs with CL&P that they are recoverable in rates. Therefore, the analysis regarding Unrecovered D&D does not address the appropriateness of cost recovery, but whether these costs have been recovered from ratepayers since 1996.

The Company's claim that it has not recovered D&D from ratepayers under the Fuel Burn Method is false. In fact, D&D costs are embedded in CL&P's current BRFR. Current rates were approved pursuant to the Settlement Agreement in the Decision dated June 13, 1998, in Docket No. 92-11-11, and include recovery of D&D costs under the Fuel Burn Method. Id.; Tr. 9/16/98, p. 1380; Response to Interrogatory OCC-265. Put simply, D&D costs are an integral element of the nuclear base fuel rate established in a rate proceeding. Consequently, these costs were recovered from ratepayers while the nuclear units were in rate base. Schedule H-1.1, CL&P's FERC Form 1, p. 123.9. The Department concludes that CL&P recovered D&D from ratepayers during the outages at Millstone Station while the units remained in rate base; therefore, CL&P's proposal to collect $22.3 million of Unrecovered D&D is denied.

The Company did not recover D&D costs during periods in which its nuclear units were out of rate base, because virtually all costs related to a nuclear unit (except property taxes and replacement power) were disallowed through base rates once the unit was taken out of rate base. It is appropriate to allow recovery of D&D while the nuclear units were excluded from rate base for two reasons: (1) D&D costs are government-imposed and incurred regardless of a unit's operational status; and (2) according to the language in the Energy Policy Act of 1992, electric utilities' D&D costs are fully recoverable. Consequently, the Department authorizes recovery of D&D costs incurred during periods of time in which the Company's nuclear units were not in rate base.

To determine the amount of allowed D&D costs, it is necessary to delineate the status of each of the Millstone units in CL&P's rate base over the period of time the Company claims that D&D was not recovered (1996 through October 1998). The Decision dated February 25, 1998, in the instant docket, established March 1, 1998, as the effective date for removal of MP1 from CL&P's rate base. Decision, p. 5. Pursuant to the Decision dated April 29, 1998, in Docket No. 92-11-11, MP2 was removed from CL&P's rate base effective May 1, 1998. Decision, p. 9. In addition, the Decision in Docket No. 92-11-11 concluded that if MP3 did not return to service by July 1, 1998, it would be considered not used and useful and automatically removed from CL&P's rate base effective on that date. Decision, p. 7. MP3 did not return to service by July 1, 1998; consequently, it was taken out of CL&P's rate base effective July 1, 1998. Since the Millstone units' removal from rate base, only MP3 has returned to service (on July 18, 1998). Upon its return to service, MP3 was immediately reincorporated into rate base.

While the Department rejects the Company's request to collect $22.3 million, it approves collection of D&D costs in an amount that reflects the total number of days

that each Millstone unit was out of rate base. Based on the evidence presented, the Department is unable to determine that amount but will do so in a subsequent EAC proceeding.

CL&P was directed to exclude Unrecovered D&D from the Final BRFR and to identify the effect on the BRFR. Tr. 10/20/98, p. 4110. However, the Company did not remove the Unrecovered D&D from its Final Fuel Simulation. Instead, it included four options for recovery of these costs. Late Filed Exhibit No. 138-SP-1, pp. 3 and 4. Based on the above, the Department reduces CL&P's net forecasted fuel expense by the amount of the Unrecovered D&D, $22.3 million. As discussed below, the Department approves CL&P proposal to modify the recovery method for current D&D costs. Therefore, it is reasonable to remove the full amount of the Unrecovered D&D because the Final BRFR embeds current recovery of D&D under the proposed FERC method effective October 1998.

k. D&D Recovery Methodology

CL&P also requested a change in the method of recovery for current D&D costs. The requested method would expense each of the remaining D&D annual assessments over a 12-month period in line with FERC guidelines. As noted above, the Fuel Burn Method could result in the build-up of a regulatory deferral should the Company experience an extended outage under normal, prudent operations. The Department believes that the use of the FERC method will levelize recovery of D&D costs and avoid the potential for deferring these costs. Therefore, the Company's proposal is approved. The FERC method was assumed in the original Fuel Simulation and was carried forward to the Revised Fuel Simulation and Final BRFR. Therefore, no further adjustment to the Final Fuel Simulation is required.

l. Delivery Efficiency

Delivery efficiency (DE) represents the difference between retail sales and retail requirements (i.e., generation) needed to serve those sales. The value is expressed as a percentage and can be accounted for primarily by line losses, company use and billing lag. Losses are primarily incurred on the transmission and distribution systems as the result of transmitting power from generation sources to the ultimate users. According to CL&P, billing lag can be affected by "drastic temperature changes at year end, and to a smaller degree by estimating customers usage." Late Filed Exhibit No. 62. DE can also fluctuate due to changes in the mix of sales among major classes of service as well as the gain or loss of large customer loads. Id. The DE percentage approved in Docket No. 92-11-11 is .92225. CL&P proposes to reduce it to .92040 in this proceeding. Schedule WPC-3.1, p. 16; Response to Interrogatory EL-288.

Historical Delivery Efficency Percentages

	Actual	Five-Year Average	Four-Year Average	Three-Year Average
1993	91.63%			
1994	93.26%			
1995	92.11%			92.33%
1996	92.77%		92.56%	
1997	92.11%	92.38%		
Proposed	92.04%			

Source: Late Filed Exhibit No. 62

CL&P states that the DE percentage does not 'drive' the determination of generation requirements from forecasted sales. Instead, CL&P forecasts its energy requirements and retail sales separately, then determines its DE percentage based on these forecasted values (sales divided by requirements). Therefore, the proposed DE percentage 'falls out' of these separate forecasts. Tr. 9/16/98, pp. 1361-1367; Tr. 10/20/98, pp. 1362 and 4091-4098. The Company's method of deriving DE appears to be reasonable, but the result should be compared to actual. It was not. According to the Company the proposed percentage reflects "an increase in unaccounted for losses," an undesirable trend. Id.

The DE percentage provides a link between sales and generation; the lower the DE percentage, the more electricity that must be generated and the greater the total fuel cost needed to serve the forecasted load. As such, the DE percentage should drive the determination of requirements or at least be used as a check against the reasonableness of forecasted generation and fuel cost. The table above demonstrates that DE has improved in the recent past; therefore, the Department finds CL&P's proposed DE percentage unsupported. The three, four and five-year averages are higher that the DE proposed by CL&P and the five-year average provides a reasonable, long-term DE. Therefore the Department approves it. CL&P was directed to use 92.38%, the five-year average, in its Final Fuel Simulation. Tr. 10/20/98, p. 4099.

m. Sharing Agreement and NUG&T

The 1992 merger of NU and PSNH resulted in a sharing agreement designed to allocate the energy cost savings resulting from the economic dispatch of the combined NU and PSNH systems (Sharing Agreement). In addition, the Sharing Agreement includes a mechanism for allocating capacity and related costs between PSNH and NU to share the surplus capacity of the combined systems (Capacity Transfer) when one of the systems is capacity deficient. According to CL&P, the Sharing Agreement "defines the mechanical process" regarding energy cost savings and the transfer of surplus capacity. Tr. 9/16/98, pp. 1194-1286.

The Northeast Utilities Generation and Transmission Agreement (NUG&T) came about following the creation of NU, which essentially consolidated the Western Massachusetts Electric Company (WMECO), Holyoke Water and Power (HWP) and

CL&P (combined, NU Initial System Companies).[10] The NUG&T allows NU Initial System Companies to plan and dispatch for system need based on the operation of the combined companies instead of on a stand-alone basis. The savings that result from this single system approach are shared among the companies. Roman PFT, pp. 2-7; Id.

Restructuring activities are underway in New Hampshire and Massachusetts and those activities require PSNH, WMECO and HWP to sell their generation and generation-related assets. Based on the timetable for restructuring in those states, CL&P anticipated that the sale of PSNH, WMECO and HWP generation assets would be completed prior to 1999.[11] The sale of those assets would render the Sharing Agreement and NUG&T unworkable because the companies would no longer control generation. The Fuel Simulation submitted with the original filing assumed that the Sharing Agreement and NUG&T were not in effect throughout 1999. Therefore, the Proposed BRFR was based on a Fuel Simulation in which CL&P assumed operation of its generation system on a stand-alone basis for the rate year. Id.; Tr. 9/16/98, pp. 1202 and 1237; Shuckerow PFT, pp. 3-8.

Implementation of retail choice in New Hampshire and Massachusetts has been delayed. As a result, CL&P states that the Sharing Agreement and NUG&T will remain in effect through the first half of 1999. The Revised Fuel Simulation assumes operation of the NUG&T through June 1999 and continuation of the Sharing Agreement through April 1999. Id.; Filing dated September 30, 1999, Revised Schedule C-3.8 and WPC-3.8.

CL&P states that including the NUG&T in the revised filing for the first half of 1999 increases capacity costs but reduces energy costs. Essentially, "CL&P incurs capacity charges for being a member of the NUG&T and receives energy benefits for being a member." Tr. 9/16/98, p. 1242. The Company estimates the annual net effect of these two items as an increase to costs of approximately $8 million, or $4 million for the half year assumed in the revised filing. Tr. 9/16/98, p. 1244.

The Sharing Agreement provides energy cost benefits to CL&P through the pooled dispatch of PSNH resources. However, the NU Initial System Companies are capacity deficient as a result of the extended outages at Millstone Station and the retirement of MP1, CY and MY. Under the Capacity Transfer provisions of the Sharing Agreement, the NU Initial Companies must take surplus capacity from PSNH at formula-based rates. The cost of capacity under the 'must take' provision of the Sharing Agreement is in excess of current market rates and, although there are energy cost benefits included with these transfers, there is a net increase to expenses associated with the transfer. Therefore, the revised filing reflects increased capacity costs and reduced energy costs associated with the Sharing Agreement through April 1999. Id.; Tr. 9/16/98, 1234-1258.

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[10] The NU Operating Companies are referred to as the NU Initial System, whereas the operation of NU including PSNH, is referred to as the Combined System.

[11] For example, Massachusetts legislation provided for implementation of retail choice by March 1998.

The Capacity Transfer provision requires CL&P to take PSNH surplus capacity for six-month periods (Capability Period) that run from November through April and May through October. For 1999, CL&P included a forecast of capacity costs reflecting four months of PSNH capacity in its revised filing. The four-month period, January through April, represents the final months of the November 1998 through April 1999 Capability Period. CL&P states that the capacity costs reflect the transfer of 270 MWs of capacity for this Capability Period at a forecasted average monthly cost of $2.5 million. Id.; Tr. 9/16/98, pp. 1204-1215.

At the time CL&P prepared its rate filing, it appeared that restructuring activities in Massachusetts and New Hampshire would render the Sharing Agreement and NUG&T unworkable for the rate year. As a result, CL&P submitted its original filing based on the assumption that these agreements would not be in effect throughout 1999. However, restructuring is a complex task and although delays were not expected, it is not unreasonable for them to occur, as they have.

The Department believes that the Company acted reasonably in assuming that the Sharing Agreement and NUG&T would terminate prior to the rate year, given the information available to it at the time. Once CL&P became aware that the agreements would go forward into 1999, it was reasonable for the Company to amend its filing and include continued operation of the agreements for the first half of 1999. Therefore, the Department accepts continued operation of these agreements for the first half of 1999.

The combined PSNH and NUG&T capacity costs are forecasted to total $46.8 million for January through June 1998. Late Filed Exhibit No. 151; Revised Schedule C-3.8; Late Filed Exhibit No. 138 SP 1. These costs reflect the operation of the NUG&T for the full six-month period and the operation of the Sharing Agreement through April 1999. The four-month recovery of PSNH capacity costs assumes approval of CL&P's proposal to transfer its wholesale contracts to an unregulated subsidiary. See Section II.G.5. Therefore, the Final Fuel Simulation did not demonstrate PSNH capacity costs for May and June, nor did it include the energy benefits associated with the transfer for these months.

CL&P embedded $46.8 million in capacity costs in the non-fuel component of base rates in its revised filing. At the Department's request, CL&P isolated NUG&T and PSNH capacity costs in the BRFR under the Final Fuel Simulation. Tr. 10/20/98, p. 4103; Late Filed Exhibit No. 138 SP 1. The Company states that reflecting NUG&T and PSNH capacity costs in the calculation of the BRFR will not change the overall revenue requirement but will assure tracking of these costs through the EAC. Id. However, the Company believes that capacity costs are not permitted in the EAC; therefore, it is inappropriate to include these costs in the BRFR.

The Department disagrees. At present, the EAC is truing-up the capacity costs associated with the MP2 out-of-rate-base disallowance. Docket No. 98-06-01, EAC filing, p. 79. In addition, CL&P recovers the full cost of PPP contracts through the BRFR and these costs are trued-up in the EAC. Although CL&P books all PPP purchases as energy, it is clear that these costs reflect both energy and capacity. See Section II.I.10.

Traditionally, the BRFR has excluded recovery of non-PPP capacity costs. However, the capacity costs associated with the NUG&T and Sharing Agreement will end at the mid-point of the rate year. If these costs are embedded in non-fuel rates, there is no adjustment mechanism should actual costs deviate from forecasted levels. The Company would continue to recover at the level embedded in rates beyond 1999 unless base rates are reset at that time. If these cost are included in the BRFR, the Department can true them up with a simple adjustment through the EAC. Therefore, the Department will include $46.8 million in the BRFR. These costs will be trued-up to actual through the EAC. The Department notes that embedding these costs in the BRFR increases that rate by approximately 2 mills while reducing non-fuel base rates by an equal amount.

CL&P has proposed to transfer its wholesale contracts to an NU subsidiary to avoid PSNH capacity payments for May and June 1999, the first two months of the next Capability Period. Consistent with this proposal, CL&P has excluded a forecast of PSNH capacity costs for May and June 1999, therefore, the Final BRFR does not reflect recovery of these costs. Late Filed Exhibit No. 138 SP 1; Late Filed Exhibit No. 151.

As discussed in Section II.G.5., the Department approves CL&P's proposal to transfer its wholesale contracts to an unregulated subsidiary. Therefore, it appears that CL&P will not incur PSNH capacity costs for May and June 1999. However, the Department notes that if MP2 does not returned to service by April 1999, CL&P will remain capacity deficient and may require PSNH capacity in May and June. If this occurs, the Department will address the matter in the appropriate EAC proceeding.

n. Price of No. 6 oil

As noted above, the price of oil at CL&P's oil-fired plants can be estimated based on the price of oil at the Norwalk Harbor Station. Therefore, the system average production cost of oil-fired generation can also be determined based on the price of oil at this facility. The Company's original Fuel Simulation assumed the price of oil at Norwalk Harbor Station to be $16.70/bbl.[12] That Fuel Simulation demonstrated an average production cost of $27.70/MWh from oil-fired generation based on production of 4,208,000 MWhs and total cost of $116,552,000. Late Filed Exhibit No. 57; Schedule WPC-3.1 The Final Fuel Simulation used $13.50/bbl as the price of oil at Norwalk Harbor Station. Tr. 10/20/98, p. 4108; Late Filed Exhibit No. 138 SP 1. The Final Fuel Simulation demonstrated an average production cost of $22.46/MWh from oil-fired generation based on production of 6,582,000 MWhs and total cost of $147,816,000. Based on these costs, the average production cost per dollar price is $1.66/MWh ($27.70 ÷ $16.70) and ($22.46 ÷ $13.50). See table below.

As discussed above, the Department directed the Company to use $13.50/bbl in the Final Fuel Simulation, because it was unlikely that the $12/bbl price would be sustained. However, oil prices have not increased; therefore it is reasonable to adjust the Company's forecasted total fuel cost to reflect the price as of the last day of the

[12] Norwalk Harbor Station demonstrates the lowest price of oil among CL&P's generating plants, approximately $12/bbl at the close of hearing. Tr. 10/20/98, pp. 4108-4110. The cost of oil at CL&P's remaining plants was based on the Norwalk Harbor price. Id.

hearing. Therefore, the Department reduces the price of oil at Norwalk Harbor Station to $12/bbl.

The Department examined the forecasted production cost and price of oil demonstrated in WPC-3.1 and Late Filed Exhibit No. 138 SP 1. The following table demonstrates these values.

Fuel Cost Adjustment
Change In Oil Price

	(1) Price/bbl	(2) Production (Mwhs)	(3) Total Cost	(4) Cost per MWh (3/2)	(5) Production Cost* (Per MWh) (4/1)
Original Fuel Simulation	$16.70	4,208,000	$116,552,000	$27.70	$1.66
Final Fuel Simulation**	$13.50	5,964,000	$133,946,000	$22.46	$1.66
			(2x4)	(1x5)	(5)
DPUC Adjustment**	$12.00	5,964,000	$118,802,880	$19.92	$1.66
Difference/Adjustment			$15,143,120		

Source: Schedule WP C-3.1; Late Filed Exhibit No. 138 SP 1.

* Price is per MWh per dollar a barrel cost.

** January through June production and cost are adjusted to a CL&P basis using .85 as a multiplier.

A review of these data finds that a relationship exists between the price of oil and the forecasted cost of production. Each dollar of cost reflects a production cost of approximately $1.66/MWh. See table above, column 5. Therefore, reducing the base price of oil to $12/bbl reduces total fuel cost for oil-fired generation by approximately $15.1 million. This value was determined by subtracting the total fuel cost for oil-fired production at $12/bbl, $19.92/MWh ($1.66 x $12/bbl) times total production of 5,964,000 MWhs, from the total fuel cost for oil-fired production reflected in the Final Fuel Simulation, $133,946,000. Although a change in the price of oil drives changes to production from oil and gas-fired facilities as well as market purchases, the Department has not attempted to capture these changes in this adjustment. The adjustment herein reflects the approximate effect of the change in oil prices and all other changes will be captured through the EAC. The table above demonstrates this adjustment.

o. Marginal Cost

A change in the price of oil drives a change in the forecasted marginal cost, which in turn drives a change in expense associated with an adjustment to sales. The Department did not request a Fuel Simulation using $12/bbl as the base price. Therefore, the Department has calculated an estimated marginal cost based on a $12/bbl base price of oil.

The Department examined the forecasted marginal cost and price of oil demonstrated in WPC-3.1, Late Filed Exhibit No. 138 and Late Filed Exhibit No. 138 SP 1. The following table demonstrates the price of oil and resulting marginal cost.

Comparison of Oil Prices and Marginal Cost

Exhibit	Price $/bbl	Percentage Change	Marginal Cost	Change In Marginal Cost
WPC-3.1	$16.70		$25.40	
LFE 138	$15.00	10.18%	$23.45	$1.95
LFE 138 SP 1	$13.50	10.00%	$21.56	$1.89
DPUC Adjusted	$12.00	11.11%	$19.46	$2.10

A review of these data finds that a relationship exists between the price of oil and the forecasted marginal cost. For each 10% decline in the price of oil, the marginal cost declines by approximately $1.90, or $0.19 for each percent decline in price ($1.90/10). The use of $12/bbl reduces the price of oil by $1.50 or 11.1% from $13.50/bbl used in the Final Fuel Simulation. Applying the average percentage and dollar changes noted in the table results in a forecasted marginal cost of $19.46 [$21.56-($.19x11.1)]. The Department used $19.46 as the marginal cost in its expense adjustment for increased sales discussed in Section II.G.1.q, below.

p. Nuclear Fuel Final Core Amortization

The Company's filing includes $1.845 million for amortization of unburned fuel that will exist at the end of the life of the nuclear units. Response to Interrogatory OCC-86, p. 4. The intent of this item is to avoid placing high nuclear fuel costs on ratepayers over the final two or three fuel cycles, due to the need to recover the cost of unburned fuel that will exist when the unit is retired. Response to Interrogatory EL-367. The Company based the unburned fuel amount on the value of the unburned fuel at the end of the most recent fuel cycle for each unit. Response to Interrogatory EL-159. The discussion in Section II.F.10, above, regarding final M&S expense also applies to the final core fuel amortization. Therefore, the Department will disallow this expense, reducing fuel expense by $1.845 million.

q. Expense Adjustments Associated with Sales Adjustments

In Section G.2, below, the Department has made certain adjustments to Company sales. Fuel and taxes are the only expenses that will increase significantly as the result of an increase in the sales forecast. Response to Interrogatory EL-247; Schedule F-6.2; Schedule WPF-6.2. CL&P determined the cost associated with increased sales based on its forecasted marginal cost of fuel as calculated in Schedule C-3.1. Id.

It is reasonable to increase expenses based on the sales adjustments made herein and to use a forecast of CL&P's marginal cost as the basis for the adjustment. As a result of adjustments made to CL&P's base rate fuel revenue assumptions, the original forecast of marginal cost has changed. Therefore, the Department will use the updated marginal cost, $19.46/MWh, discussed above, as the basis for this expense adjustment. The following table summarizes the adjustment.

Sales Related Expense Adjustment

Item	kWhs	Marginal Cost/kWh	Expense
Residential Sales	(34,421,000)	$0.01946	($669,833)
Commercial Sales	249,427,000	$0.01946	$4,853,849
Industrial Sales	53,659,000	$0.01946	$1,044,204
Reliability Improvements	1,931,643	$0.01946	$37,590
Total Expense Adjustment	270,596,643		$5,265,811

Therefore, based on the sales adjustments made herein the Department increases expenses by $5,265,811.

r. Niantic Bay Fuel Trust Expense

As discussed in Section II.F.5, above, the Department reduces the Trust expense by $1,269,000.

s. Summary of Adjustments

The Company was directed to incorporate the adjustments discussed above in the Final BRFR and Final Fuel Simulation. Tr. 10/20/98, pp. 4098-4121; Late Filed Exhibit No. 138-SP-1. Based on the Final Fuel Simulation, adjustments made herein and the sales adjustments discussed in Section II.G.2, the Final BRFR equals $.02697/kWh, reflecting approved total fuel costs of $637,888,000. This reduces forecasted total fuel costs by $96,360,000 ($734,248,000 - $637,888,000) and forecasted net fuel costs by $74,807,000 ($646,061,000 - $571,254,000). The following table compares the Proposed and Final BRFRs.

Final Base Rate Fuel Revenue

		As Filed Schedule C-3.1	As Revised LFE 138 SP-1	Approved BRFR
	CL&P forecasted fuel expense	$734,248	$637,888	$637,888
Less:	Fuel cost: Market Based Contracts	$66,766	$58,363	$58,363
	Net CL&P forecasted fuel expense	$667,482	$579,525	$579,525
	NUG&T and Sharing Agreement Capacity	$0	$46,788	$46,788
		$667,482	$626,313	$626,313
Less:	Int., Econ. Development and Sp. Contract Costs	$21,421	$18,117	$18,117
Plus:	Fuel expense associated with sales adjustment			$5,266
	CL&P net forecasted fuel expense	$646,061	$608,196	$613,462
Less:	DPUC Adjustments			
	Capacity Factor Adjustment			(1,651)
	Unrecovered D&D			(22,300)
	Reduced cost, No. 6 oil			(15,143)
	Nuclear Fuel Final Core Amortization			(1,845)
	Niantic Bay Fuel Trust			(1,269)
	Adjusted net fuel expense			$571,254
	CL&P forecasted firm retail sales	20,914,110	20,914,110	20,914,110
	DPUC sales adjusment			270,597
	Allowed sales			21,184,707
	CL&P base fuel recovery rate	$0.03089	$0.02908	$0.02697

2. Retail Sales and Revenue

a. General

The Company forecasts pro forma revenues at present rates of $2,368,187,000 for 1999. These revenues are based on forecasted sales of 24,281,328 MWhs. Response to Interrogatory EL-258; Late Filed Exhibit No. 139; Tr. 10/8/98, p. 3059. The following table provides a breakdown of forecasted sales and revenues.

1999 Forecast of Sales and Revenue

	Sales (MWhs)	Revenue ($000)
Retail		
Residential	8,745,306	$1,012,159
Commercial	8,742,722	$856,161
Industrial	3,862,933	$297,140
Streetlighting	117,032	$25,385
Railroad	213,335	$15,389
Total Retail	21,681,328	$2,206,234
Wholesale	2,600,000	$110,069
Other	n/a	$51,884
Total	24,281,328	$2,368,187

Source: Responses to Interrogatories EL-257 and 258 and OCC-125.

Sales and revenues for 1998 are forecasted and form the basis for the 1999 sales and revenue projections. Tr. 9/28/98, p. 2931. Therefore, it is necessary to examine the accuracy of the 1998 forecast to determine the reasonableness of the 1999 forecast. The Company submitted its 1998 Monthly Sales and Revenue Reports for January through September (Monthly Sales Report). Late Filed Exhibit No. 139 SP 2. The Monthly Sales Report provides actual sales and revenues by class. The Department relied on the 1998 Monthly Sales Report to determine the reasonableness of the 1998 forecast for each customer class.

The Company also provided a breakdown of revenues by class for 1997-1999. Revenues were identified as total (Total Revenues), fuel (Fuel Revenues) and base (Base Revenues). Base Revenues equal Total Revenues minus Fuel Revenues. Response to Interrogatory EL-258.

Fuel Revenues, that is, those recovered through the EAC or its predecessor clauses, the Fuel Adjustment Clause (FAC) and Generation Utilization Adjustment Clause (GUAC), vary annually. Therefore, Total Revenues do not provide a basis for comparing historical and forecasted revenues per customer, per class or average revenues per kWh. However, CL&P's tariff rates have not changed since 1996. As a result, a comparison of annual and average historical Base Revenues, which are essentially 'tariff revenues,' and exclude fuel adjustment revenues, provides a reasonable basis for analyzing forecasted revenues. Therefore, the Department examined the reasonableness of the 1998 and 1999 revenue forecasts based on a comparison of forecasted average Base Revenues per kWh as demonstrated in the response to Interrogatory EL-258, and actual average Base Revenues per kWh, as developed from the 1998 Monthly Sales and Revenue Report. Sales and revenue adjustments are detailed below.

b. Residential Sales and Revenues

The Company forecasts 1999 residential sales of 8,745,306 MWhs, resulting in approximately 1% growth above 1998 sales. This equates to pro forma revenues at

present rates of $1,012,159,000, and an average Base Revenue rate of $.1157 per kWh for this class of customers. Response to Interrogatory EL-258. The Company updated its 1999 forecast of residential sales (Revised Residential Forecast), increasing rate year sales by 83,000 MWhs (8,828,000 – 8,745,000). The Revised Residential Forecast demonstrates growth above 1998 sales of approximately 2%. Late Filed Exhibit No. 139 SP 3. The following table demonstrates historical and forecasted residential sales and growth as originally filed.

Historical and Forecasted Residential Sales

	1993	1994	1995	1996	1997	1998*	1999*
Sales (Mwhs)	8,296,454	8,536,314	8,404,752	8,573,444	8,487,115	8,652,351	8,745,306
Annual Change (Mwhs)		239,860	(131,562)	168,692	(86,329)	165,236	92,955
Percentage Change		2.89%	(1.54%)	2.01%	(1.01%)	1.95%	1.07%

Source: Response to Interrogatory EL-258.

* Forecasted

CL&P's original sales forecast reflected 1998 residential growth of approximately 1.9% (8,652,351 - 8,487,115). Response to Interrogatory EL-258. However, based on the 1998 Monthly Sales Report, CL&P's residential sales for the year-to-date period ending September 1998 have increased by approximately 1.55% above sales for the same period in 1997. Therefore, based on actual sales data, residential growth in 1998 has lagged behind CL&P's forecast. Based on the above table, although the growth associated with CL&P's original forecast or its Revised Residential Forecast can be viewed as consistent with historical trends, it is inconsistent with year-to-date 1998 sales. Therefore, the use of either forecast would overstate revenues from this class in 1999. Therefore, the Department rejects the original and Revised Residential Forecast.

As noted above, year-to-date 1998 residential sales have lagged behind the Company's forecast. As a result, the Company's 1998 and 1999 sales forecasts are overstated as originally filed and must be adjusted. Consistent with the adjustment to commercial sales below, 1998 residential sales will be based on annualized year-to-date data.

Year-to-date residential sales through September 1998 total 6,379,537 MWhs, an increase of 97,253 MWhs or 1.55% above 1997 sales for the same period. Late Filed Exhibit No. 139 SP 2. Residential sales for 1997 total 8,487,115 MWhs. Response to Interrogatory EL-258. Based on a growth rate of 1.55%, annualized 1998 sales total approximately 8,618,665 MWhs (8,487,115 x 1.0155%). Therefore, the Department adjusts 1998 sales to 8,618,665 MWhs.

The Company's projected 1999 residential growth rate is 1.07% and is consistent with historical trends for this class. Therefore, the Department will apply this growth rate to the adjusted 1998 sales to determine 1999 sales. As a result, projected 1999 residential sales total 8,710,885 MWhs, (8,618,665 x 1.0107%) a reduction of 34,421 MWhs from the Company's forecast as filed (8,745,306 - 8,710,885).

The Company calculated residential average Base Revenues of $.1162/kWh and $.1157/kWh for 1998 and 1999, respectively. Department review of this calculation

finds residential average Base Revenues per kWh to be reasonable. The Department used 1999 average residential Base Revenues in its revenue adjustment for this class. The decrease associated with the Department's adjusted residential sales results in a decrease to pro forma revenues of $3,982,510 ($.1157/kWh x 34,421 MWhs). Therefore, the Department adjusts pro forma revenues at present rates by this amount. The decrease to expenses associated with this adjustment is discussed in Section II.G.1.q, above. The following summarizes the residential sales adjustment.

Residential Sales Adjustment
(Mwhs)

	1997	1998	1999
Sales as filed	8,487,115	8,652,351	8,745,306
Sales as adjusted		8,618,665	8,710,885
Adjustment*		(33,686)	(34,421)
Growth Percentage		1.55%	1.07%

Source: Response to Interrogatory EL-258.
*Adjusted sales less sales as filed.

c. Commercial Sales and Revenues

The Company forecasts 1999 commercial sales of 8,742,722 MWhs. This level of sales results in pro forma revenues at present rates of $856,161,000, and an average rate per kWh of $.0979/kWh for this class of customers. Response to Interrogatory EL-258. The following table demonstrates historical and forecasted commercial sales and growth.

Historical and Forecasted Commercial Sales

	1993	1994	1995	1996	1997	1998*	1999*
Sales (Mwhs)	7,899,077	8,143,891	8,233,196	8,468,757	8,567,369	8,665,104	8,742,722
Annual Change (Mwhs)		244,814	89,305	235,561	98,612	97,735	77,618
Percentage Change		3.10%	1.10%	2.86%	1.16%	1.14%	0.90%

Source: Response to Interrogatory EL-258.
* Forecasted

The Company updated its 1999 forecast of commercial sales (Revised Commercial Forecast) in Late Filed Exhibit No. 139 SP 3. Sales under the Revised Commercial Forecast equal 8,896,000 MWhs, increasing rate year sales by 153,000 MWhs above the original forecast [8,896,000 – 8,743,000 (rounded)]. Based on the Revised Commercial Forecast, 1999 sales would increase by 328,000 MWhs above 1997 levels, or approximately 3.8% over this two-year period [8,896,000 - 8,567,000 (rounded)]. Late Filed Exhibit No. 139 SP 3.

The Company states that its Revised Commercial Forecast reflects a slowing in the rate of growth in 1999. Tr. 10/8/98, p. 3088; Tr. 10/20/98, pp. 3945-3957. In addition, the Company states that 1998 commercial sales will exceed its original forecast by approximately 2%, but notes that commercial sales should be adjusted to account for Company use at Millstone Station and other CL&P facilities (Company Use). Tr. 10/8/98, pp. 3078-3090. In addition, the Company cautions that current, tenuous

global economic conditions should be considered when adjusting 1999 sales for the commercial and industrial classes. CL&P believes that a forecast that simply applies historical growth trends to actual 1998 sales could overstate rate year sales and revenues for these classes. Tr. 10/8/98, pp. 3090-3097. However, the Company's witness stated that forecasting is not science and that they "had a very difficult time trying to figure out . . . a good outlook for 1999 . . . because things have been changing so rapidly and erratically that frankly no one knows . . . what is likely to happen in 1999." Tr. 10/20/98, p. 3955.

Based on the 1998 Monthly Sales Report, commercial sales for the year-to-date period ending September 1998 have increased by 4% above sales for the same period in 1997. Late Filed Exhibit No. 139 SP 3. As the above table demonstrates, CL&P forecasts commercial sales to increase by 1.14% and .9% in 1998 and 1999, respectively. Based on actual data, 1998 year-to-date commercial sales through September have increased by 259,598 MWhs (6,707,169 – 6,447,571) over the same year-to-date period ending September 1997. Id. Through September 1998, monthly commercial sales have exceeded 1997 actual sales and the Company's 1998 forecast in seven of the nine months reviewed. Based on these data, it appears likely that commercial sales will continue at levels that exceed 1997 sales for the remainder of 1998. As a result, the Department believes that 1998 commercial sales will exceed the 1999 Revised Commercial Forecast of 8,896,000 MWhs. Even if commercial sales for October through December 1998 slowed, only equaling 1997 levels for the remainder of 1998, the year-to-date increase to commercial sales has nearly equaled the increase to 1997 sales forecasted under the Company's Revised Commercial Forecast for 1999 (259,598 vs. 328,631).

For the most part, the Company has experienced annual growth in commercial sales since 1974 and forecasts annual growth in commercial sales through 2017 with a compound growth rate of 1.9% for this class through the forecast period.[13] Response to Interrogatory OCC-229, NU 1998 Forecast of Loads and Resources for 1998-2017, Table II-1; OCC Brief, p. IV-9. Therefore, the use of CL&P's 1999 Revised Commercial Forecast would require that 1999 commercial sales stall at, or decline from, anticipated 1998 levels. This is inconsistent with the historical and forecasted growth trends for this class. Based on the foregoing, the Department rejects CL&P's 1999 Revised Commercial Forecast.

The Company states that because Millstone Station has not been supplying its own generation, the Station is supplied energy off the grid and that this consumption has been treated as a commercial sale. Tr. 10/8/98, p. 3079. As a result, CL&P believes that Company Use should be removed from commercial sales when calculating 1998 sales. Id.; Late Filed Exhibit No. 139 SP 3. According to the Company, September 1998 year-to-date Company Use totaled approximately 160,000 MWhs (6,707,169 - 6,546,605). Id. Actual 1997 and year-to-date 1998 commercial sales include Company Use. Tr. 10/8/98, p. 3082. Although the Company demonstrated an adjustment based on Company Use, it did not adjust revenues. Id.

[13] In 1989 commercial sales declined by 9,000 MWhs or less than 1/10th of one percent.

Company Use is not unique to 1998 and is included in all commercial sales data presented in this case. Total annual commercial sales are used in the calculation of average revenues (i.e., total class revenues divided by total class sales). Therefore, if the Department removes Company Use from 1998 sales, this same adjustment would need to be made to 1997 and 1999 data. Company Use does not generate revenue; therefore, the effect of removing it from sales, the denominator in the calculation of average revenues, with no reduction to revenue, would be an increase to the average commercial Base Revenue per kWh.

Based on CL&P's adjustment, the removal of Company Use reduced September year-to-date 1998 growth from 4% to 3.3%. As noted, if Company Use is removed from 1998 sales, a like adjustment must be made to 1997 sales, which CL&P did not do. Year-to-date September 1998 commercial sales are 4% greater than sales for the same 1997 year-to-date period. Because CL&P did not remove Company Use from 1997 sales, its adjusted growth rate of 3.3% understates the actual 1998 commercial growth percentage. Therefore, the Department rejects the proposed Company Use adjustment.

Year-to-date 1998 commercial sales through September total 6,707,169 MWhs, an increase of 259,598 MWhs or 4% above 1997 sales for the same period. Late Filed Exhibit No. 139 SP 3. Commercial sales for 1997 total 8,567,369 MWhs. Response to Interrogatory EL-258. Based on year-to-date growth, annualized 1998 sales total 8,912,316 MWhs. Id. Therefore, the Department adjusts 1998 commercial sales to 8,912,316.

The Company's projected 1999 commercial growth rate is .9% and is consistent with historical trends for this class. Therefore, the Department will apply this growth rate to the revised annualized 1998 sales to determine 1999 sales. As a result, 1999 commercial sales total 8,992,149 MWhs, an increase of 249,427 MWhs above the Company's 1999 forecast as filed (8,992,149 - 8,742,722). Based on the above, the Department establishes 1999 commercial sales at 8,992,149 MWhs reflecting annualized September 1998 year-to-date sales escalated by .9%, the growth factor for the commercial class assumed in the original filing. Late Filed Exhibit No. 139 SP 3, p. 2. The following summarizes the commercial sales adjustment.

Commercial Sales Adjustment
(Mwhs)

	1997	1998	1999
Sales as filed	8,567,369	8,665,104	8,742,722
Sales as adjusted		8,912,316	8,992,149
Adjustment*		247,212	249,427
Growth Percentage		4.03%	0.90%

Source: Response to Interrogatory EL-258.
*Adjusted sales less sales as filed.

The Company calculated commercial average Base Revenues of $.0985/kWh and $.0979/kWh for 1998 and 1999, respectively, which the Department finds reasonable. The Department used 1999 average commercial Base Revenues in its

revenue adjustment for this class. The increase associated with the Department's adjusted commercial sales results in an increase to pro forma revenues of $24,418,903 ($.0979/kWh x 249,427 MWhs). Therefore, the Department adjusts pro forma revenues at present rates by this amount. The increase to expenses associated with this adjustment is discussed in Section II.G.1.q.

d. Industrial Sales

The Company forecasts 1999 industrial sales of 3,862,933 MWhs. This level of sales results in pro forma revenues at present rates of $297,140,000, and an average rate of $.0769/kWh for this class. Response to Interrogatory EL-258. The following table demonstrates historical and forecasted industrial sales.

Historical and Forecasted Industrial Sales

	1993	1994	1995	1996	1997	1998*	1999*
Sales (Mwhs)	3,855,113	3,965,945	3,949,756	3,910,022	3,900,077	3,886,423	3,862,933
Annual Change (Mwhs)		110,832	(16,189)	(39,734)	(9,945)	(13,654)	(23,490)
Percentage Change		2.87%	(0.41%)	(1.01%)	(0.25%)	(0.35%)	(0.60%)

Source: Response to Interrogatory EL-258.
* Forecasted

As the table demonstrates, CL&P forecasts industrial sales to decline by .35% in 1998 and by .6% in 1999. Based on the 1998 Monthly Sales Report, industrial sales for the year-to-date period ending September 1998 have increased by .8% above sales for the same period in 1997. Late Filed Exhibit No. 139 SP 3. The Company updated its 1999 forecast of industrial sales (Revised Industrial Forecast) in Late Filed Exhibit No. 139 SP 3. Sales under the Revised Industrial Forecast equal 3,842,000 MWhs, reducing rate year industrial sales by 20,933 MWhs from the original forecast (3,862,933 – 3,842,000). Based on the Revised Industrial Sales forecast, 1999 sales to the industrial class would decline by 58,077 MWhs below 1997 levels, or approximately 1.5% over this two-year period (3,900,077 - 3,842,000). Id.

CL&P states that industrial sales have been relatively stable in recent years but declined by approximately 1.7% between 1994 and 1997, a time of economic growth in Connecticut. Late Filed Exhibit No. 139. Further, industrial sales have seen periods of weak growth, which have been negated by recessions and the loss of large customers. The Company's forecast reflects this experience. Id.

Over the long-term, industrial sales have demonstrated the trends noted by CL&P, relative stability broken by periods of growth and decline. For example, industrial sales were 3,902,000 MWhs in 1978, essentially the same as 1997 sales. Id.; Response to Interrogatory OCC-229, NU 1998 Forecast of Loads and Resources for 1998-2017, Table II-1. In addition, with the exception of the 1989-1993 period, a time of unprecedented economic difficulties in Connecticut, during the 28-year period, 1970-1997, annual declines in industrial sales were generally recovered in the following year. Id. CL&P's Forecast of Loads and Resources demonstrates that industrial sales will increase between 1998-2001.

OCC believes that 1999 industrial sales should be based on annualized 1998 data increased by the recent historical five-year composite industrial growth rate of .4%. OCC Brief, p. IV-11. The OCC proposal results in rate year industrial sales of 3,946,069 MWhs, an increase of 83,136 MWhs above CL&P's forecasted sales (3,946,069 - 3,862,933). Id.

Although OCC recommends increasing annualized 1998 industrial sales based on an average five-year composite growth rate, based on historical trends and the Company's long-term forecast for this class, establishing 1999 sales based on the Department's adjusted growth rate appears reasonable. As the above table demonstrates, the recent five-year composite growth rate is heavily influenced by the growth experienced in 1994, 2.87%. Elimination of the 1994 data would result in a negative growth rate. Therefore, the use of the five-year average growth rate is unreasonable.

Year-to-date 1998 industrial sales through September total 2,953,824 MWhs, an increase of 22,751 MWhs or .8% above 1997 sales for the same period (2,953,824 - 2,931,073). Late Filed Exhibit No. 139 SP 3. Industrial sales for 1997 total 3,900,077 MWhs. Response to Interrogatory EL-258. Based on year-to-date sales, annualized 1998 sales total 3,930,348 MWhs. Id. Consistent with historical trends, 1998 appears to be a year in which industrial sales are rebounding from previous declines. However, despite the increase demonstrated in the 1998 year-to-date sales data, the Revised Industrial Forecast predicts further reductions in sales to this class in 1999. The Revised Industrial Forecast is inconsistent with 1998 year-to-date experience, historical trends for this class and estimates contained in the NU Forecast of Loads and Resources. Therefore, the Department rejects it and establishes 1998 industrial sales at 3,930,348 MWhs.

The Company projects a decline of .6% for 1999 industrial sales. Although a decline in sales can be anticipated, a negative growth rate of this magnitude is inconsistent with the 1998 year-to-date experience and estimates contained in the NU Forecast of Loads and Resources. Therefore, the Department adjusts the rate to a decline of .35%.

The Department applies this growth rate to the revised annualized 1998 sales to determine 1999 sales. As a result, 1999 industrial sales total 3,916,592 MWhs, an increase of 53,659 MWhs above the Company's 1999 forecast as filed (3,916,592 - 3,862,933). Based on the foregoing, the Department establishes 1999 industrial sales at 3,916,592 MWhs reflecting annualized September 1998 year-to-date sales reduced by .35%, the Department's adjusted 1999 growth factor. The following summarizes the industrial sales adjustment.

Industrial Sales Adjustment
(Mwhs)

	1997	1998	1999
Sales as filed	3,900,077	3,886,423	3,862,933
Sales as adjusted		3,930,348	3,916,592
Adjustment*		43,925	53,659
Growth Percentage		0.78%	-0.35%

Source: Response to Interrogatory EL-258.
*Adjusted sales less sales as filed.

The Company calculated industrial average Base Revenues of $.0784/kWh and $.0769/kWh for 1998 and 1999, respectively, which the Department finds reasonable. The Department used 1999 average industrial Base Revenues in its revenue adjustment for this class. The increase associated with the Department's adjusted industrial sales results in an increase to pro forma revenues of $4,126,360 ($.0769/kWh x 53,659 MWhs). Therefore, the Department adjusts pro forma revenues at present rates by this amount. The increase to expenses associated with this adjustment is discussed in Section II.G.1.q.

e. Streetlighting

The Company forecasts 1999 streetlighting sales of 117,032 MWhs. This level of sales results in pro forma revenues at present rates of $25,385,000, and an average rate of $.2169/kWh for this class of customers. Response to Interrogatory EL-258.

CL&P notified the Department of its intention to commence a one-year pilot program, in August 1998, for the installation of historical/period decorative outdoor lighting fixtures and poles and specialized spotlighting for buildings (Lighting Pilot). Letter dated July 17, 1998. In addition, the Company has proposed to expand its streetlight offerings. Roncaioli PFT, p. 10. The Company anticipates that 2,000 decorative lights will be installed as a result of the Lighting Pilot and enhanced streetlighting offering but that one half of these lights would replace existing, standard streetlights. The Company did not adjust sales, revenues or expenses based on the Lighting Pilot or the enhanced streetlight offerings. Responses to Interrogatories EL-264 and EL-265.

The Company did not initiate the Lighting Pilot as proposed. Tr. 9/22/98, p. 1935. Therefore an adjustment for these sales is unnecessary. As discussed in Section II.I, the Company is expanding its streetlight offerings to include specialty lighting and protective devices for streetlights. The expanded offerings are in response to customer requests and as a strategy against the erosion of streetlighting sales and revenues. Response to Interrogatory CCM-1 SP 1; Tr. 9/28/98, p. 2951. Although the expanded streetlight offerings will begin in 1999, the level of participation is uncertain; therefore, the Department makes no adjustment for these sales.

Department review of CL&P's forecast of 1998 and 1999 streetlighting sales finds the forecast to be consistent with historical sales data for this class. In addition, the Company calculated streetlighting average Base Revenues of $.2151/kWh and

$.2169/kWh for 1998 and 1999, respectively. Department review of this calculation finds streetlighting average Base Revenues per kWh to be reasonable. The Department finds the Company's forecast reasonable and makes no adjustments to streetlighting sales.

f. Wholesale Sales

The Company forecasts 1999 wholesale sales of 2,600,000 MWhs. This level of sales results in pro forma revenues of $110,069,000. Response to Interrogatory EL-258. The forecast reflects CL&P's 1999 wholesale contract sales (Committed Sales) and excludes a forecast of short-term/spot transactions (Daily Sales) and "revenue neutral" transactions such as NEPOOL Interchange service. Tr. 9/28/98, pp. 2954-2956 and 2973-2975; Late Filed Exhibit No. 139. The Company excluded Daily Sales from the forecast because these transactions are difficult to predict and result in little or no margin. The Company states that the margins associated with Daily Sales result from capacity transactions, and, because the Company is capacity deficient, they are limited or non-existent. The Company provided a breakdown of its year-to-date wholesale activity. Id.

The Company's forecast of Committed Sales is based on its contractual obligations for 1999. Response to Interrogatory OCC-236; Tr. 9/28/98, p. 2955. A review of this information finds the forecast to be reasonable. Historical data demonstrate that Daily Sales occur annually. However, the level of these sales has declined recently. The year-to-date wholesale data demonstrate that Daily Sales have occurred in 1998. However, the Company states that these sales reflect a contract that has been included in the 1999 forecast as a Committed Sale. Absent this sale, Daily Sales activity in 1999 is minimal. Late Filed Exhibit No. 139 SP 2. Daily Sales are likely to occur in 1999; however, CL&P is capacity deficient and will remain so into 1999. As a result, the level of sales and associated margin is difficult to predict; therefore, the Department accepts CL&P's forecast of Daily Sales.

The Company states that the shutdown of MP1 and change in the refueling schedule reduces unit contract sales by $3.1 million. Revised Schedule C-3. It is reasonable to expect that the loss of MP1 will affect unit capacity sales. Therefore, the Department accepts the proposed $3.1 million revenue and reflects it herein.

g. Unbilled Sales

OCC believes that CL&P has improperly adjusted the 1999 sales and revenue forecast by removing unbilled sales. Therefore, OCC states that rate year revenues should be increased by $7.2 million to reflect these sales. OCC Brief, p. IV-13.

The Company's sales forecast is based on billed sales while its requirements (i.e., generation) are based on usage. The difference reflects unbilled sales. Tr. 10/20/98, p. 4092. CL&P states that it is appropriate to reflect unbilled sales in its 1999 forecast because it will not recover revenues from these sales in the rate year. For example, 1999 sales include usage from December 1998 that is billed in 1999 (1998 unbilled sales) while 1999 sales exclude usage in December 1999 that will be billed in 2000 (1999 unbilled sales). CL&P Reply Brief, p. 16.

Unbilled sales essentially reflect a lag in revenue recovery created by meter reading cycles. They occur in one period but do not generate revenue until a subsequent one. CL&P submits its annual unbilled sales to the Department in its Annual Report. See, FERC Form 1, p. 304, Sales of Electricity by Rate Schedule. Department review of unbilled sales for the period 1994-1997 finds that the annual level of these sales can vary significantly. For example, for the period ending December 31, 1996, CL&P reported unbilled sales of 119,211 MWhs and associated revenues of $12,725,515, while the period ending December 31, 1997 demonstrates unbilled sales of 11,465 MWhs with associated revenues of $1,203,918. 1996 and 1997 FERC Form 1, p. 304. Based on historical data the Company's forecast of unbilled sales appears to be reasonable, and no adjustment is warranted.

3. Other Operating Revenue

a. Rate 58 Revenues

The Company states that the production, transmission and distribution demand charges for Rate 58, as reflected in the June 1, 1998 filing, were understated; production and transmission demand by $.15/kw and distribution demand by $.11/kw. The Company recalculated Rate 58 revenues based on current rates. As a result, the Company states that total revenues should be increased by $1.1 million to reflect this correction. Schedule C-3 Revised; Schedule E-2.4, p. 14.

Department review of this adjustment finds it to be reasonable. Therefore, the Department increases pro forma revenues at present rates by $1.1 million. This adjustment does not increase sales; therefore, no expense adjustment is necessary.

b. Flexible Rate Rider and Special Contract Discounts

CL&P's original filing demonstrated total revenue discounts of $25.1 million associated with its Flexible Rate Rider and Special Contract (Flex Rider Discounts) customers. Supplemental Filing, Treatment of Four Year Review Issues, Sales - General. Subsequent to the original filing, the Company adjusted its projected 1999 Flex Rider Discounts to $22 million, reducing total discounts by $3.1 million. Late Filed Exhibit No. 95 SP 1. The effect of this adjustment is an increase to 1999 revenues of $3.1 million. Id. OCC believes this adjustment is reasonable and the Department agrees. OCC Brief, p. IV-12. Therefore, the Department increases 1999 revenues by $3.1 million. This adjustment does not increase sales; therefore, no expense adjustment is warranted.

c. Rental Income

CL&P receives annual revenue from Teleport Communication Group, Five-Com NEON/Mode 1 and Metro Access (Cable Fee Revenue) for the rental of utility property. These revenues, which are booked to Account 454, Rent from Electric Utility Property, are projected to total $834,791 in 1998 and $935,000 in 1999. Late Filed Exhibit No. 6, AR-OCC 33; Late Filed Exhibit No. 139. The Company states that although it did not include Cable Fee Revenue in its projection of 1999 revenues, it is appropriate to do so.

Id.; Tr. 9/28/98, pp. 3003-3006. Expenses associated with these revenues are reimbursed to CL&P. Id.

OCC, PRO and AG state that it is appropriate to include Cable Fee Revenue in the forecast of 1999 revenues. OCC Brief, p. IV-16; PRO Brief, p. 12; AG Brief, p. 17. PRO states that the level of revenue being paid may not reflect the value of service being provided by CL&P. Id.

It is appropriate to include Cable Fee Revenue in the projection of 1999 revenues. Therefore, the Department increases 1999 revenues for Cable Fee Revenue by $935,000. As noted, expenses associated with these revenues are reimbursed to CL&P, thus no expense adjustment is necessary.

d. Reliability Improvements

CL&P's enhanced tree trimming efforts are intended to prevent 200-300 interruptions caused by 'hazard trees' and tree limbs falling on backbone sections of primary lines, many of these during major storms, and most affecting large groups of customers. Response to Interrogatory OCC-272. The Company did not adjust revenues based on the improved system reliability anticipated from its enhanced tree trimming efforts. Response to Interrogatory EL-255. The Company estimates the annual revenue lost from these types of outages to be approximately $160,000 for the years 1994-1997. Response to Interrogatory EL-324.

CL&P's enhanced tree trimming efforts are designed to prevent outages. Therefore, it is reasonable to expect that additional sales will be made as power outages are avoided (Outage Sales). However, 1999 sales and revenues were not adjusted to account for these additional sales. Therefore, it is reasonable to increase 1999 sales to reflect the improved reliability associated with CL&P's enhanced tree trimming efforts.

Department review of the calculation of Outage Sales presented by CL&P finds it to be reasonable. The Department will use the four-year Outage Sales average to adjust 1999 sales and revenue. Based on the information submitted in response to Interrogatory EL-324, the Department increases 1999 sales by 1,931,643 kWhs and $160,000. Including Outage Sales in the rate year requires an associated expense adjustment, which is discussed in Section II.G.1.q.

e. Residential Radio Controlled Water Heaters

The Company offers a controlled water heating rate under Residential Rates 1 and 5. The rate is available to customers whose sole source of domestic hot water is a storage-type water heater that meets the Company's specifications or where domestic solar water heating is used in conjunction with a storage unit that meets the Company's specifications (Controlled Heater). These heaters must be installed and wired for control in accordance with CL&P specifications. Tariff, Rates 1 and 5. Current rates provide a credit of approximately $.012/kWh for up to 500 kWhs based on monthly consumption. Id. At present rates, annual credits total $2,204,257 [($.10599 - $.09352)

x 91,844 MWHs] + [($.09648 - $.08365) x 82.538 MWHs].[14] Response to Interrogatory EL-267. The average annual credit is $50 per customer ($2,204,257 ÷ 44,000). However, based on monthly consumption, a Controlled Heater customer can receive a maximum annual credit of $75. Late Filed Exhibit No. 98.

The Company states that when a Controlled Heater fails, there is a real possibility that the control device will not be reinstalled on the replacement heater. In these situations, the customer continues to receive the benefit of the water heater control credit, but the Company forgoes the benefits of reducing the customer's load during peak periods. In addition, CL&P loses the control device. Although there are no hard data to quantify the information, the Company estimates that up to 20% of its 44,000 Controlled Heater customers no longer have the devices but continue to receive the credit. Roncaioli PFT, pp. 15 and 16; Responses to Interrogatories EL-266 and EL-267. Therefore, approximately $440,850 in credits is lost annually ($2,204,257 x .20). Id.

The Company proposes to implement a $10 rebate for returned control devices. In addition to customers who might return the controllers, the Company believes that plumbing contractors, who are responsible for the majority of heater replacements, will take advantage of the rebate. In these situations the customer's account can be determined through an identification number on the control device and the monthly per kWh credit can be removed from the appropriate account. Id.; Late Filed Exhibit No. 98; Tr. 10/20/98, pp. 3932-3939. The Company believes that setting the rebate at $10 is reasonable and although the rebate would apply to past water heater control removals, replacements or conversions, the program is intended to address future change-outs. Id. The Company views the proposed rebate as a starting point that will allow it to determine the success of the program and to make adjustments as needed. Tr. 9/22/98, p. 1985.

Although the Company estimates that 20% of its Controlled Heater customers may be receiving credits inappropriately, it is unaware of the actual number. Absent the rebate proposal mentioned herein, CL&P has not implemented any measures to study or otherwise address this situation. Tr. 9/22/98, p. 1979. It appears that the rebate program will only affect future water heater change-outs because it is unlikely that $10 will induce customers to contact the Company to report the past elimination of a controller. This is reinforced by the fact that the customer would lose the monthly credit. Further, it is also unlikely that plumbing contractors have stockpiled old controllers as these devices have had no value. Therefore, even if the rebate program is successful at identifying future heater change-outs, the Company appears willing to forgo nearly a half a million dollars annually in credits from past, unidentified change-outs. These credits will continue to be paid in the future and CL&P presented nothing in this proceeding to address the losses.

Based on the current average annual credit, the proposed rebate is inadequate. For example, a customer that does not report the elimination of a Controlled Heater costs the Company up to $75 annually in lost revenue. Based on the current situation, this customer can be undetected indefinitely, resulting in potential losses of hundreds of

[14] The Department used the current commodity rates under Rates 1 and 5 in its calculation.

dollars. In addition, the Company's proposal to test the waters with a $10 rebate is shortsighted because if a $10 rebate fails to solve this problem, additional annual credits will be lost.

However, if CL&P offered a $50 rebate, the current average annual credit, the Company loses nothing since it would have lost at least $50 in the year following an unreported water heater change-out. In fact, the Company gains since it will avoid the payment of future annual credits. In addition, an offer of $50 may address past unreported change-outs if the rebate entices customers to report a past event or encourages plumbing contractors or others to 'seek out' disconnected controllers. Therefore, the Department will require CL&P to increase its rebate to $50.

The Department is concerned that despite knowing that it is losing nearly a half a million dollars annually, CL&P has done nothing. This is especially disturbing in light of the Company's pleas in many recent proceedings that its financial situation is tenuous. The Company did not need Department approval to study this situation or to contact its Controlled Heater customers to inquire about the removal of control devices. Further, it appears the Company is indifferent to the level of current, unidentified losses because it includes them in its 1999 revenue requirement. Simply stated, the Company willingly passed these losses onto its ratepayers. The Department will not tolerate such ill management.

Based on the above, the Department adjusts 1999 revenues by $440,850, the Company's estimated annual Controlled Heater credit losses. While there will be some administrative costs associated with this program, they are included in the filing since the Company proposed this program. Therefore, no expense adjustment is warranted.

CL&P will be required to initiate the $50 rebate effective immediately and keep the Department abreast of its efforts. This shall include providing the Department with information regarding implementation of the program and reporting as to the results of its efforts. The Company must track past and current water heater change-outs.

4. Summary of Revenue and Sales Adjustments

The Company states that its proposed base rates produce revenues that are uniformly lower than present base rates by 1.04%. Roncaioli PFT, p. 3. The Company defines current base rates as:

> the rates in effect on July 1, 1996, as reflected in the Settlement Agreement approved by the Department on that date in Docket No. 92-11-11, net of the credit to customer bills ordered by the Department in its February 25, 1998 decision in Phase I of this proceeding, in which the Department removed MP1 from rate base effective March 1, 1998. Mahoney PFT, p. 6.

The Company demonstrated rate year revenues at current rates of $2,337,807,000 and revenues at proposed rates of $2,316,330,000. Schedule C-1.

The Decision dated February 25, 1998, in Phase I of this proceeding, required the Company to apply an across-the-board credit of 1.39% to customer bills to reflect the removal of MP1 from rate base. The Decision states that "in lieu of an adjustment to base rates, the Department will require CL&P to apply a credit to customer bills." Decision, p. 2. Therefore, CL&P's base rates were not adjusted as a result of the MP1 credit and have not been adjusted since approved in the Decision dated July 1, 1996, in Docket No. 92-11-11. Thus, the Department defines current base rates as those approved in that Decision, that is, CL&P's currently approved tariff rates (Current Rates). Based on the foregoing, the Department's rate year revenues at present rates, revenue adjustments, rate reduction and rate design changes discussed herein are based on Current Rates.

Therefore, the Department determines pro forma revenues at present rates to be $2,395,385,000 ($2,368,187,000 + $27,198,604).

The following table summarizes the sales and revenue adjustments made herein.

Sales and Revenue Adjustment Summary

Item	kWhs	Revenue
Residential Sales	(34,421,000)	($3,982,510)
Commercial Sales	249,427,000	24,418,903
Industrial Sales	53,659,000	4,126,360
Wholesale Sales	n/a	(3,100,000)
Rate 58	n/a	1,100,000
Flex Rider Discounts	n/a	3,100,000
Rental Income	n/a	935,000
Reliability Improvements	1,931,643	160,000
Radio Controlled Heaters	0	440,850
Total Revenue Adjustment		**$27,198,604**

5. Reassignment of CL&P's Wholesale Market-Based Contracts

In the past, NU entered into wholesale market-based contracts (MBC) in an effort to market the surplus capacity of its operating companies. Surplus capacity is defined as the amount of capacity not needed to meet the requirements of the companies' franchise customers. NU as a system has been in a capacity surplus position since the mid 1980's and as a result, it has made substantial capacity sales since that time. The economic benefit of these transactions, reduced retail revenue requirements, has flowed to ratepayers in past rate case proceedings. However, strong economic activity within the CL&P service territory has led to higher loads, while the retirement of MP1, Connecticut Yankee and Maine Yankee has reduced NU's total capacity. As a result, CL&P is no longer capacity surplus. In fact, it is capacity deficient when MBCs are factored into its capacity requirements. Shuckerow Supplemental Testimony, pp. 8-11.

The Company states that by retaining its MBCs, it will remain capacity deficient for the Capability Period that begins in May 1999. Therefore, as a result of the continuation of the Sharing Agreement through June 1999, the Company would be required to take PSNH capacity, at above market rates, at that time. However, by

transferring these contracts to NU's unregulated wholesale marketing subsidiary, the capacity position of the NU Initial system would change and the need for a capacity transfer from PSNH to CL&P for May and June 1999 would be avoided. Id.

The contracts permit assignment to an NU affiliate without customer consent while any other assignment requires that consent. The majority of these agreements are priced above current market rates. Therefore, if CL&P were to attempt to transfer the contracts to a non-NU affiliate, customers would likely not grant consent and would instead renegotiate these agreements down to current market rates. By doing so, CL&P would lose the value of these contracts. Transfer to an NU affiliate would preserve the value. Further, CL&P believes that its MBC proposal is consistent with Public Act 98-28, which requires regulated distribution companies to separate their transmission and distribution functions from generation services by October 1, 1999. Therefore, CL&P is requesting that it be authorized to assign its MBC contracts to NU's unregulated wholesale marketing subsidiary. The value of these contracts during 1999 will be passed on to CL&P's customers as a reduction to CL&P's revenue requirements for the rate year. Id.

CL&P's MBC proposal addresses 24 contracts and approximately 450 MW of capacity. The majority of the contracts were entered into in the mid 1990's and the contract rates (i.e., revenue to CL&P) were based on capacity and energy cost assumptions at that time. Most of the agreements end in 2004 and the vast majority of the benefits from these contracts will be realized between 2000-2004. CL&P estimates the future value of these contracts at $65 million, $15 million of which is realized in 1999. Tr. 9/18/98, pp. 1696-1717; Late Filed Exhibit No. 89. Under the Company's proposal, ratepayers would retain the benefit of these contracts in 1999 and would avoid the risk that these agreements would become uneconomic in the future. Id.

CL&P's MBC proposal is intended to avoid PSNH capacity transfer costs for May and June 1999. These costs can range from $2.5 to $5 million per month depending on the amount of capacity transferred. Tr. 9/18/98, p. 1706. To avoid these costs, CL&P must reduce its capacity requirements in those months. The transfer of 450 MW of capacity associated with the MBCs will accomplish this goal.

The estimated future value of these contracts was determined in late 1997, using the cost assumptions relied on in the MP1 CUO study. Current market prices have declined since that time. Therefore, the future, above market value of these contracts is understated. The Company states that the value of these contracts could be reduced to zero if the market price of capacity and energy increases by 20% above the levels assumed in its analysis. Id. As noted, prices have declined since the analysis was done, therefore, current costs would need to increase by greater that 20% to negate all future benefit.

The vast majority of future benefits will be achieved between 2000 and 2004. Tr. 9/18/98, p. 1714. If the MBCs are transferred as proposed, ratepayers lose all benefits beyond 1999. Those benefits would flow to NU's unregulated wholesale marketing group. The Company's proposal does not attempt to capture any of this value for ratepayers.

MBC customers are paying more than they would at today's prices because the cost assumptions that drove the MBC rates have declined since the mid-1990's. Therefore, these contracts are providing benefits in excess of those assumed at the time they were negotiated. The Department believes that these agreements will continue to provide benefits beyond 1999, benefits that may exceed the Company's current estimates.

Under the Company's proposal, ratepayers would forfeit $50 million in potential future benefit to avoid a maximum $10 million cost in 1999. The Department believes CL&P can avoid PSNH capacity costs while retaining future ratepayer benefits from these contracts. Therefore, the Department will allow CL&P to transfer its MBC to an NU affiliate, but will require that the future value of these agreements be used to offset stranded costs. The Department will assess the post December 31, 1999, above market value of the agreements when the Company's stranded costs are determined and will offset such costs by that amount.

H. COST OF SERVICE

The Decision dated June 16, 1993, in Docket No. 92-11-11, required CL&P to make certain changes to its Cost of Service Study (COSS). These included the development of a weighting of residential line transformer costs, the assignment of production and transmission (P&T) costs to interruptible customers, the separation of Rates 116 and 117 and an investigation into the use of marginal cost as the basis for allocating flex rider discounts. Decision, pp. 69-76. The Company states it has complied with these directives. Roncaioli PFT, p. 4.

The Company has proposed to reduce rates across-the-board in this proceeding. The Company states that its rate design proposal is based in part on the requirements of Public Act 98-28. Section 20 of the Act requires that, effective January 1, 2000, the total rate charged to customers must be at least 10% less than the base rates that were effective on December 31, 1996. The Company is concerned that if rate modifications made subsequent to year-end 1996 are not applied equally to all classes, some rate changes would have to be undone to comply with the Act. This could mean that although some customers could see decreases now, these same customers might experience rate increases in 2000, or, that some would see rates reduced in excess of the minimum 10% set by the Act, while others would achieve only the minimum reduction. Tr. 9/22/98, pp. 1902-1905, 1914. Further, the Company states that applying an equal reduction to all customers is consistent with the rate reduction ordered in the Interim Decision dated February 25, 1998, in the instant proceeding. Roncaioli PFT, p. 3.

The OCC argues that the COSS improperly allocates inter-class costs in two ways. First, it allocates demand-related generation and transmission costs by using non-coincident demand as an indicator for coincident demand costs. Second, the COSS allocates distribution costs by classifying too large a portion of distribution costs as customer related and none as energy related. In addition, the OCC states that changes should be made to the COSS to reduce the subsidization among rate classes that currently exists. To accomplish this, OCC believes that the Department should reject CL&P's across-the-board rate decrease proposal and adopt a rate design

strategy that considers the disproportionate rates of return demonstrated in the COSS. OCC Brief, pp. V-5 through V-17.

The Department's review of CL&P's COSS finds that the Company has complied with the directives contained in the Decision dated June 16, 1993, in Docket No. 92-11-11. Individual changes are discussed in Section II.I. Although the Company amended its COSS, it did not propose revenue allocations based on the amended study. Instead, it proposed an across-the-board rate reduction.

Regarding OCC's argument that the COSS inappropriately allocates demand-related generation and transmission costs, a review finds that OCC's arguments are identical to those offered in Docket No. 92-11-11 and addressed by the Department in the Decision in that case. See Decision, pp. 69, 70, 73 and 74. In that case the Department stated that:

> The Company's COSS . . . incorporates the Average and Excess Demand ("AED") methodology using the average of the 12 monthly coincident peaks ("12CP") as the system peak and class non-coincident peaks ("NCP") for class peak responsibilities. Under the AED/12CP-NCP methodology, production capacity is allocated to each rate class on the basis of two demand components. The first component is the class average demand and the second component, excess demand, is a function of the amount by which class peak demand exceeds its average demand. The AED/12CP-NCP has historically been found by the Department to be an acceptable and appropriate COSS methodology for the CL&P system. Decision, p. 69.

In past proceedings the Department has found the Company's application of the AED/12CP-NCP method to be reasonable. The Department also has found the customer component of distribution costs, as developed by the Company, to be reasonable. The Department adopts those finding herein. A review of the COSS finds that CL&P has developed its study using previously approved methods. In addition, the Department accepts the changes to the Company COSS that reflect the directives contained in the Decision in Docket No. 92-11-11. Absent these changes, no new evidence has been presented to convince the Department that it is appropriate to amend the COSS at this time.

Given the 10% rate reduction for each rate class required in 2000, the Department believes that an across-the-board decrease is appropriate for all rate classes except interruptible, special contract and certain Flex Rider rates, as discussed in Section II.I.

CL&P is concerned that if rates are not changed uniformly in this proceeding, the rate reduction provision of the Act may create 'rate design problems' in 2000. As noted above, Section 20 of the Act requires that the total rate charged to customers must be at least 10% less than the base rates that were effective on December 31, 1996. Any change made herein will be considered when setting rates in compliance with Section 20 of the Act.

I. RATE DESIGN

1. Residential Rates

The Decision in Docket No. 92-11-11 required the Company to develop a weighted average for line transformers that is consistent with the actual number of line transformers for each customer class and to incorporate the average in its next COSS. Decision, p. 72. The Company states it has complied with this directive. Roncaioli PFT, p. 4. This change shifts approximately $5 million in costs from the residential class, increasing the rate of return for this class from 7.1% to 7.2%. Although the rate of return increases, the return for the residential class remains below the Company's overall return of 8.9%. Although residential rates could be reduced as a result of this change, the Company believes that rates should not be modified at this time. The Company states that because Public Act 98-28 requires an across-the-board rate reduction in 2000, rate modifications are inappropriate at this time. Schedule E-6.0; Tr. 9/22/98, pp. 1900-1905.

The Department believes that the COSS should be modified as proposed. However, because the rate of return for this class remains below the Company's overall return, except for the across-the-board reduction being applied herein, residential rates should not be modified further at this time.

2. Interruptible Rates

The Company presently offers interruptible service under Rates 19, 20, 21 and 39 and its Demand Reduction Rider. These rates were designed to produce revenue sufficient to cover the Company's short-run cost plus make a small contribution to fixed costs. The contribution is small compared to the cost of production and transmission, which customers on interruptible rates do not pay. Roncaioli PFT, p. 9.

In the Decision in Docket No. 92-11-11, the Department concluded that production and transmission costs (P&T) were not being assigned to interruptible rates at that time and required CL&P to assign a level of P&T to interruptible rates in its next COSS. Decision, pp. 72 and 90. CL&P assigned P&T to interruptible customers in the COSS submitted in this proceeding, but did not propose to modify their rates. The Company believes it is inappropriate to adjust rates at this time because assigning these costs to interruptible rates would materially affect the bills of existing customers. Id. Instead of modifying rates, CL&P proposes to close its interruptible rates to new customers and to continue to provide service to existing customers at current rates. Therefore, under the Company's proposal these rates would not be reduced. Tr. 9/22/98, p. 1911; Schedule E-1.0.

The Company states that under restructuring it will no longer be able to offer discounted transmission or generation service to interruptible customers. Instead, the market will set interruptible rates for generation services and it is not clear how the market will price this service. Rather than increase interruptible rates now, CL&P prefers to address rate structure changes for this class in future unbundling procedures. By closing the rates to new entrants, and not adjusting them, the Company will have time to prepare its interruptible customers for the changes that will occur under

competition. Id.; Tr. 9/22/98, pp. 1908-1914. If interruptible rates are increased, the revenue requirement from all other classes would be reduced. Response to Interrogatory EL-236; Late Filed Exhibit No. 94.

CIEC believes that it is premature to close these rates before competitive generation services are available. In addition, by closing these rates, the Department may be eliminating an opportunity to further economic development in the state. Therefore, interruptible rates should not be closed at this time. CIEC Brief, p. 9.

Interruptible customers are paying distribution and transmission costs but contribute little toward fixed generation costs. The Department agrees that restructuring will change the cost of energy for these customers and that the effect of that change is uncertain at this time. However, given the limited contribution to production costs, it appears likely that their costs will rise.

Based on the assignment of P&T, the revenue requirement from interruptible customers could rise by as much as $3 million. Late Filed Exhibit No. 94. Interruptible customers currently provide approximately $4.2 million in revenues. Schedule E-2.1. Therefore, interruptible rates would rise by 70% if the total increase were applied to them. Rates would rise by 33% or 17%, respectively, if one-half or one-quarter of the total were applied. Although it appears that these rates may rise under restructuring, the effect of restructuring on this class is uncertain.

At this time it is not clear how the rate reduction provision of the Act, Section 20, will be applied to these rates. Further, Section 3 of the Act states that for the period from July 1, 1998, until December 31, 1999, base rates shall not exceed the rates that were in effect on December 31, 1996. Therefore, these rates cannot be increased at this time. Given that these customers demonstrate a negative rate of return, the Department will direct CL&P to maintain interruptible rates at current levels. Further, the negative rate of return and the fact that all customers will be eligible to explore competitive options in the very near future, make it reasonable to close these rates at this time. As discussed below, flexible rate riders will remain in place and are therefore available to further economic development in the state.

3. Flexible Rate Riders

The Company has several flexible rate riders including its Five-Year and Long-Term Economic Development Riders, Business Recovery Rider and Competitive Generation Rider (collectively, Flex Riders). Flex Riders were introduced in the early 1990's when Connecticut was experiencing a significant loss of industry and jobs. Customers can apply for either a rate discount or non-cash assistance and approval is based on CL&P's assessment of each customer's needs. Roncaioli PFT, pp. 7 and 8.

CL&P states that restructuring will provide customers the opportunity to purchase electricity from their supplier of choice at a negotiated price. In addition, the Act mandates a 10% reduction for non-contract (i.e., non Flex Rider) customer bills. These changes will have a major impact on contracting for the price of electricity. In addition, the Connecticut economy and the economy in general are healthier than at the time the Flex Riders were initiated. CL&P believes that the combination of a healthy economy,

future choice of power supplier and the 10% bill reduction will eliminate the need for rate discounting in all but the most extreme cases. As a result, CL&P proposes to eliminate its flexible rate riders at this time. Although existing contracts and those under negotiation will be honored, Flex Riders will not otherwise be available in the future. Id.

The Company states that it:

> effectively ceased entering into new or renegotiated flexible rate rider contracts when Public Act 98-28 became law. The only exceptions, and there were few, were situations where flex rider applications had been filed earlier, had been evaluated and found to qualify and where the Company had made a commitment to the customer. Response to Interrogatory EL-231.

However, the Company clarified its response to that interrogatory stating that "for the short, five-year ED [tariffs] where the company doesn't really have the discretionary powers to say no, those [Riders] are still open." Tr. 9/22/98, p. 1922. Further, the Company states that all contracts entered into after April 29, 1998, the effective date of the Act, will comply with it. Id., p. 1926.

CIEC believes that CL&P's proposal to eliminate Flex Riders should be rejected because the need for these riders continues to exist, the elimination is inconsistent with the Act,and absent these discounts, industrial customers have no other means to lower their electric rates at this time. CIEC Brief, pp. 3-7.

Conn. Gen. Stat. § 16-19hh, as amended by Section 57 of the Act requires the Company to continue to offer Flex Riders. The Act also addresses the treatment of Flex Riders subsequent to the April 29, 1998 passage date. Section 57 requires CL&P to provide for recovery of the competitive assessment charge (CTA) and the SBC in any contract that is renegotiated, extended, renewed or entered into subsequent to passage of the Act. The Act permits CL&P to honor the terms of all contracts that were entered into prior to April 29, 1998, and because these contracts did not address recovery of the CTA or SBC, customers receiving service under said contracts will not be required to pay those charges until their contracts expire or are renegotiated. However, the Legislature intended the CTA and SBC to be non-bypassable. Therefore, the Act requires that the CTA and SBC, charges that will be assessed effective January 1, 2000, be recovered from all other customers. Section 58 of the Act, which becomes effective July 1, 2000, eliminates the requirement that electric companies offer Flex Riders.

Based on the foregoing, CL&P must continue to offer flexible pricing tariffs; therefore, its request to eliminate Flex Riders is denied.

4. Kilovolt Ampere Metering

Customer demand is currently measured in terms of kilowatts (kW). However, CL&P states that a better measure is kilovolt ampere (kVA). Metering kVAs has many benefits over kW metering, but until recently, the high cost of kVA meters precluded their widespread use. Solid state technology and increasing use of these meters has

reduced their cost to the point where they are only slightly more expensive than the kW meters now in use. As a result, CL&P proposes to implement kVA billing. Roncaioli PFT, pp. 12 and 13.

Customers predominantly have a net inductive load, often resulting from running highly inductive loading such as the motors that drive pumps and fans. See Section II.E.3 for a discussion on inductive load. This is particularly the case with commercial and industrial customers. As noted above, an inductive load will drive the customer's power factor further from unity, resulting in greater kVA consumption per kW. This requires CL&P to install necessary power correction devices, such as capacitors, on its system. The cost of this equipment is borne by all customers within a rate class because customers with poor power factors cannot be identified through the use of kW metering. Therefore, because customer demand is currently measured and billed on a kW basis, the customer has no financial incentive to operate its facilities to minimize reactive power.

The Company states that kVA metering is not an issue of revenue recovery because current rates recover CL&P's distribution costs. Instead, it is an issue of fairness between customers because when demand is metered and billed on the basis of kW, customers with higher-than-average power factors are subsidizing those with lower-than-average power factors. Based on the experience with its larger customers, CL&P might extend kVA metering to customers below 1000 kW, although this is not proposed at this time. Id.

Metering kVAs provides a better link between cost causation and the amount each customer pays. The Company proposes to implement kVA billing to allow it to identify poor power factor customers and to provide these customers with an opportunity to improve their power factor. If the customer does not correct its power factor, CL&P would install the appropriate corrective equipment off of the customer's facility and, through rates, hold the customer financially liable. Id.

CL&P is proposing that all services with demands of 1000 kW or more be metered and billed based on kVA. The Company believes it can accomplish the necessary meter conversion for these customers, essentially its Rate 57 and 58 customers, by the end of 2000. The proposal calls for comparative billing at proposed rates (i.e., kW vs. kVA) also for six months after a kVA meter is installed. During this time the customer would continue to pay on the basis of kW demand, but after six months, kVA billing would begin. This initial period is intended to provide the customer time to correct its power factor. If comparative billing data suggest that different kVA charges are appropriate, there would be time for the Department and CL&P to adjust the charges to assure revenue neutrality. Id.

The Company provided comparisons under Rate 57 to demonstrate how kVA billing could affect customer bills. These billing data use an 85% power factor as representing a 'base line' customer under current rates. Under proposed rates, the total charge to a customer with an 85% power factor would not change. Response to Interrogatory EL-241. The following demonstrates potential bill impacts. The actual level of change would depend on each customer's demand, power factor and on/off-peak consumption.

Bill Impacts
Based on Power Factor

Power Factor	Potential Inc./(Dec.)
95%	(4%)
85%	0%
75%	5%
60%	17%

Source: Interrogatory EL-241

Over the long term it is reasonable to expect customers to improve their power factors. This in turn should mitigate the need for CL&P to invest in power factor adjusting equipment. However, initially, CL&P's overall distribution costs will not be reduced. Response to Interrogatory EL-243. Assuming that traditional ratemaking continues, all customers should benefit from reduced distribution costs over the longer term. Response to Interrogatories EL-242 and 243.

Customers can minimize reactive power by installing power factor correction devices and modifying the operation of their equipment. CL&P estimates that a 100 kW demand customer with a power factor of 75% can increase its power factor to 90% with an investment of approximately $3,000. Response to Interrogatory EL-244. Therefore, it is reasonable to expect that a 1000 kW demand customer with a similar power factor will spend no more than $30,000 to achieve similar results.[15] Based on the proposal, customers can achieve a bill reduction by improving their power factor beyond 85% thereby recovering their investment and reducing CL&P's costs.

CIEC supports the installation of kVA meters, but believes that the proposed rates are speculative and should not be approved at this time. CIEC states that kVA billing should be delayed until sufficient data are gathered and evaluated to determine appropriate rates. CIEC Brief, p. 9.

Traditionally, rates have been designed to reflect cost causation and this advance in meter technology provides an opportunity for CL&P to identify and isolate cost causation. As such, CL&P's proposal is consistent with sound ratemaking. However, the Department is concerned about potential bill increases at proposed rates. In addition, absent actual billing data, it is not clear whether the proposed rates will achieve revenue neutrality. Therefore, a comparative billing period must be used to gather the data necessary to set appropriate kVA demand rates. The Company has proposed a six-month comparative billing period. Given that meters will be installed over time, a sufficient number may not be in place in the first six months to gather the data necessary to develop rates for varied demands. A 12-month period would allow for evaluation of seasonal demand data. The information can then be evaluated for purposes of finalizing demand rates and implementation of kVA billing would occur once

[15] Based on economies of scale, the cost of corrective equipment for the 1000 kW customer is likely less than $30,000 (10 times $3,000).

this has been done. CL&P should establish a meter conversion schedule to assure that an adequate sampling of customer demand is available for study.

Based on the foregoing, the Department will allow CL&P to begin installing kVA meters and to issue comparative bills based on the proposed rates. However, customer bills must indicate that the rates are being issued for comparative purposes only and are subject to final review and approval by the Department. Further, the Company must notify its customers of the implementation of this program and the means by which power factors can be corrected. The Company will be required to submit this information to the Department.

In addition, Section 20 of the Act requires that the total rate charged under the standard offer must be at least 10% less than CL&P's base rates that were effective on December 31, 1996.[16] Therefore rates may need to be adjusted to assure compliance with the Act. This matter will be addressed in a subsequent proceeding.

5. Expanded Streetlighting Options

The Company proposes to expand its streetlight offerings in response to customer requests and as a strategy against the erosion of streetlighting sales and revenues. The expanded offering includes a limited number of decorative poles and fixtures, metal halide lamps and bullet resistant shields for the street and security lighting and a spotlight designed to produce narrow beam, specialty lighting. Roncaioli PFT, p. 11; Response to Interrogatory CCM-1 SP 1; Tr. 9/28/98, p. 2951.

The proposed rates for decorative streetlights include the cost of the pole, fixture, maintenance and energy. The rates for fixtures, poles and vandal shields were developed by applying an annual carrying charge rate of 14.75% to the installed cost of these items. The annual rate assumes a cost of capital of 8.5%, a property tax rate of 1.7% and a 5% gross earnings tax rate. The proposed spot lighting rate was set at the Company's existing rate for similar floodlight fixtures. Responses to Interrogatories EL-277 and 278; Schedule E-1.0.

The Company indicates that some municipalities have installed decorative fixtures because CL&P does not offer these services. In these cases, the municipality contracts for the installation of the pole and fixture and then owns and maintains it. The customer generally replaces existing streetlighting with the decorative fixture and then receives service under Rate 117, Partial Street Lighting Service.[17] Responses to Interrogatories EL-271 and 272.

The Company currently offers decorative streetlighting under Rate 116 but the number and types of fixtures are limited. As such, the Company seeks to offer its

[16] The standard offer includes the electric transmission and distribution services, the conservation and load management program change, the renewable energy investment charge, electric generation services, the CTA and the SBC.

[17] Rate 117 is essentially an 'energy only' rate because the customer owns and maintains the fixture. Rate 116 is a full service rate that recovers the cost of installation and maintenance of the fixture and the energy to operate it. Under Rate 116, CL&P owns the fixture.

customers an expanded selection of decorative lighting. Response to Interrogatory CCM-1 SP 1 Bulk. Department review of the proposed rates finds them to be reasonable. However, final rates must reflect the cost of capital approved herein. Therefore, the Department approves CL&P's proposal to offer specialty lighting and protective devices for streetlights subject to the cost of capital approved herein. CL&P will be directed to submit final tariffs for these rates.

6. Streetlighting Rates

The Connecticut Conference of Municipalities (CCM) opposes CL&P's proposal to reduce rates uniformly, stating that because streetlighting Rates 116 and 117 provide a rate of return well in excess of the Company's average rate or return, special consideration must be given to these rates. Further, as historical rates of return demonstrate, this class has paid rates in excess of its cost of service for many years. CCM Brief, pp. 1-8; Response to Interrogatory CCM-5.

Section 20 of the Act requires a 10% reduction to base rates in 2000.[18] In addition, restructuring offers all customers the opportunity to shop for competitive generation rates to achieve further cost savings. Therefore, the Department believes it is appropriate to treat streetlighting rates consistently with other firm rates at this time.

7. New Business Rates

CL&P's customer service policies include its New Business (NB) policies and charges. The charges cover such items as the installation of primary and secondary cable, direct buried service conductors, primary risers, ground level transformer installations, trenching, installation and removal of poles, temporary service connections, three-phase extensions and street and security lighting. The charges, which are effective throughout CL&P's service territory, have been developed to provide uniform rates and standard estimating unit charges for electric supply to all classes of customers. NU Policies NB-1, NB-2, NB-5, NB-10, NB-12, NB-21, and NB-200. These policies and charges were last approved in the Decision dated June 15, 1995, in Docket No. 93-11-13, Application of The Connecticut Light and Power Company to Revise Customer Service Policies. CL&P is uncertain whether it will apply to the Department to amend these charges. Late Filed Exhibit No. 13 and Supplement; Tr. 10/16/98, p. 3813.

The NB rates, which reflect the average installed cost of a wide range of items, are developed using the cost of material, labor, equipment, and 'loaders'. Materials are based on then current costs, while the assignment of labor and equipment is based on average hourly rates multiplied by an estimate of the time required to perform each task. Time studies, adjusted periodically to reflect changes in work methods, provide the time estimates used to develop the rates. 'Loaders' recover costs that are not directly assigned to individual jobs. For example, the total cost to operate CL&P's storage

[18] Section 20 of the Act requires that on January 1, 2000, base rates be 10% less than those that were effective December 31, 1996. The 10% reduction does not apply to customers receiving service under special contract.

facilities is assigned to all work orders through a stores expense loader. Decision, Docket No. 93-11-13, pp. 1-9.

The Company indicated that as part of a reengineering effort that was underway at the time, it would be reviewing the man-hour allocations and its NB management practices in general following the issuance of the Decision in Docket No. 93-11-13. The Decision noted the following:

> in light of the Company's current reengineering efforts and work practices review, requiring the Company to update the time study would not be cost effective. The Department accepts the time estimates assigned to the work task portion of the total man-hours but remains concerned about the use of outdated time study data to support steadily increasing man-hour requirements for these charges. Decision, p. 3.

The Department accepted the time estimates and did not require CL&P to perform a new time study. However, to date the Company has not amended its NB rates nor submitted any information to indicate it has reexamined the basis for these charges. The current NB rates are based on material, labor and loader costs that are nearly four years old, while the time study used to develop the rates is over 20 years old. Therefore, the Department will require the Company to submit these policies and rates for review in a subsequent proceeding.

8. Campground Rates

Public Act 98-149 states:

> each electric company or electric distribution company, as defined by section 16-1, shall allow the installation of submeters at a recreational campground or in any other location as approved by the department and shall provide electricity to such campground at a rate no greater than the residential rate for the service territory in which the campground is located.

The Company proposed to modify its residential Rates 1, 5 and 7 to comply with Public Act 98-149. Roncaioli PFT, p. 7; Schedule E-10. The Company believes that implementation should be consistent with the Legislature's intent, but is uncertain how to implement the Public Act and seeks the Department's assistance in doing so. Further, CL&P believes it is inappropriate to estimate sub-meter usage at these facilities. Tr. 10/20/98, p. 3918-3926.

The Company states that there are many combinations of service provided at campgrounds. These can include service provided through a single meter or multiple meters and can include uses such as camping, convenience store and auto repair facility consumption. Id. Further, in the past, campgrounds were allowed to sub-meter "for their [own] purposes" but that metering was unrelated to CL&P's provision of service. Tr. 10/20/98, p. 3923.

The intent of Public Act 98-149 is found in its legislative history. As stated by Rep. Stratton, "this Amendment . . . is intended to say that . . . when electricity is

charged to residents in campgrounds, that they [campground owners] may not charge more than the residential rate to those individuals [campers]." Further, the amendment "allows the installation of sub-meters at recreational campgrounds. If such meters are in place, the rate that is charged [by the utility] . . . would have to be . . . no greater than the residential rate." 1998 House Proceedings, May 1, 1998, pp. 281-283.

The Department believes that the Legislature intended that campgrounds be allowed to sub-meter 'residential-like' consumption (e. g., lighting, cooking and air conditioning) for purposes of billing individual camp sites. Therefore, the legislation requires the electric utility to provide service for such use at no greater than the utility's residential rate. Although the Company expressed concern regarding implementation of this change, the Department believes that Conn. Agencies Regs. Sections 16-11-236, 116-11-237 and 16-11-238, provide clear direction regarding implementation.

These regulations address the installation, maintenance and testing of the sub-meters as well as the campground's responsibilities as they relate to the billing of individual users. Essentially, sub-meters are owned, installed and maintained by the campground and must be tested in accordance with the most recent American National Standards Institute (ANSI) Code for Electric Meters. Meter testing records must be maintained for at least two years and must be made available to the Department upon request. Further, the campground must read its meters monthly, at regularly scheduled intervals, or, at the time that service is initiated and terminated to a sub-metered service (campsite).

Written bills must be issued to each camper and must include a calculation of the average cost per kWh for all relevant periods, the present and previous meter readings and billing history, if requested. To assure that a campground is not 'reselling electricity for profit,' the regulations require that the campground cannot recover any more than the amount it is being charged by the electric utility for the provision of service. Periodic reconciliation (i.e., audit) of the total revenue recovered from campers and the total electric bill paid by the campground, assures compliance with this requirement. Therefore, the average rate charged to campers cannot exceed the average rate being charged to the campground.

As noted, CL&P believes that it is inappropriate to estimate sub-metered consumption. The Department agrees. Consumption of electricity at these facilities is subject to occupancy and seasonal variations. Given that existing campgrounds are using electricity for multiple uses, including commercial applications, it would be unduly burdensome to require CL&P to attempt to break out the residential portion of that service and then attempt to true up that estimated residential use to the actual readings provided to CL&P by the campground. The Department concludes that compliance with the regulations requires all sub-metered 'residential-like' consumption at campgrounds to be metered separately by the electric company. This will provide accurate consumption data that can be used by the electric company and the campground to reconcile billing data. Therefore, CL&P will be required to modify its Rates 1, 5 and 7 as discussed herein and to submit these rates for approval. Further, CL&P will be directed to notify all campgrounds regarding the requirements of Conn. Agencies Regs. Sections 16-11-236, 116-11-237 and 16-11-238.

The Company is not familiar with every service arrangement at campgrounds; therefore, the Department cannot determine how separate meters in existing facilities might affect current customers. CL&P will be required to examine this issue and submit a report of its findings to the Department. The report should include, but not be limited to, the number of facilities served, the number of meters and types of service being provided, the number of campgrounds that provide sub-metering, whether the sub-metered usage is separately metered and the cost implications of requiring separate metering for residential-type use.

9. Amended Rules and Regulations

Pursuant to Order No. 1 in the Decision dated September 9, 1998, in Docket No. 97-11-14, Application of CareMatrix Corp. for Declaratory Ruling Regarding Metering Requirements for Assisted Living Facilities, CL&P submitted revised Rules and Regulations to address master-metering of Assisted Living Facilities. Letter dated October 23, 1998. Department review of CL&P's revised Rules and Regulations finds that they are in compliance with the Decision in Docket No. 97-11-14. The Company will be required to submit final revisions to its Rules and Regulations.

10. Energy Adjustment Clause

Conn. Gen. Stat. Section 16-19b(f) states:

> the Department shall not suspend or discontinue a purchased gas adjustment clause or an energy adjustment clause which it has approved except (1) after general rate hearings for the companies affected by the clause, and (2) upon a finding by the department of public utility control that the market prices of purchased gas or the costs of energy have stabilized and are likely to remain stable.

The EAC is a formula-based tariff that allows the Company to true-up forecasted and actual fuel costs. The current EAC was approved pursuant to the Decision dated October 8, 1996, in Docket No. 95-07-05, DPUC Investigation of a Fully Tracking Energy Adjustment Clause for Electric Companies. In that Decision the Department concluded that adoption of the EAC would protect the interests of ratepayers better than would the continued operation of CL&P's then current fuel recovery mechanisms, the Fuel Adjustment Clause (FAC) and the Generation Utilization Adjustment Clause (GUAC). The Department found that as the result of changes that had occurred since implementation of the FAC and GUAC, the clauses were not functioning as designed. Significant among the changes that had affected the FAC and GUAC was the increase of nuclear power in the Company's generation mix and the influence of the Company's marginal cost on total fuel cost recovery. Decision, pp. 9-13.

The Decision in Docket No. 97-07-05 modified CL&P's previous energy adjustment clauses in several ways. The EAC merged the FAC and GUAC into a single clause, changed the adjustment period from a monthly to a semi-annual true-up, incorporated an incentive mechanism and eliminated the 'floor' for overall nuclear performance.

CL&P did not propose changing the EAC in the instant docket, stating that it should remain untouched. However, if the EAC is changed, the Company believes that the incentive collar should be eliminated or modified to exclude costs that the Company cannot control, such as the market price of fossil fuels and production from hydro-electric facilities. CL&P Brief, pp. 36-40; CL&P Reply Brief, pp. 47 and 48. In addition, CL&P states that it should be allowed to recover carrying costs if forecasting is removed from the EAC. Response to Interrogatory EL-98.

OCC believes the EAC should be eliminated, citing stability of fuel costs as the basis for suspension. OCC Brief, pp. V-1 - V-5. AG also cites fuel cost stability as the basis for its proposal to eliminate the EAC. AG Brief, p. 20.

At the time the Department approved the EAC, nuclear plants provided approximately 54% of CL&P's generation. Id. The Company acknowledges the significance that CL&P's then current generation mix played in establishing the EAC, stating, "the generation mix issue was a very important issue and finding in that decision as to the potential financial harm to the company and the potential large variation in cost to the supply of generation." Tr. 9/11/98, p. 620.

Since then, MY, CY and MP1 have been retired and CL&P's generation mix has changed. Based on the Company's revised Fuel Simulation, nuclear sources will provide approximately 41% of total production in 1999 (10,019 GWhs ÷ 24,231 GWhs).[19] The current BRFR assumed 17,309 GWhs of nuclear production. Docket No. 92-11-11, 1997 Settlement Fuel Factors, Table OL3-97-1. Nuclear generation is forecasted to provide 10,019 GWhs in 1999, a decline of 7,290 or 42% from the level of nuclear generation embedded in the current BRFR (17,309 – 10,019).[20] Decision, Docket No. 95-07-05, p. 6; Tr. 9/11/98, pp. 654-659; Revised WPC-3.8.

The marginal cost of fuel (i.e., the cost that replaces production when a nuclear plant does not run) was approximately $40/MWh when the EAC was established. FAC filing dated August 26, 1996, Factor FCb, $.03999/kWh.[21] The Company forecasts its marginal cost at approximately $25.60/MWh in 1999. Revised WPC-3.8, p. 1. However, the marginal cost declines to $21.56/MWh under the Final Fuel Simulation. The average cost of nuclear generation is $5/MWh. As a result of the reduction in marginal cost, the net cost to replace nuclear generation has declined from $35/MWh to $16.56/MWh (marginal cost incurred minus the avoided nuclear cost). Combined with the change in CL&P's generation mix, the decline in the marginal cost of replacement energy has reduced the exposure for increased total fuel cost associated with variations in nuclear performance. This has reduced CL&P's financial risk.

The forecasted production and cost from PPP facilities is based on the contract CL&P has with each plant. The majority of these agreements extend beyond 2010 and each is based on essentially a fixed purchase price for production. Historical

[19] Total forecasted nuclear generation divided by system requirements.

[20] Total nuclear generation per the Settlement minus forecasted nuclear generation.

[21] Factor FCb is the CL&P retail average fossil fuel cost approved in Docket No. 92-11-11. This value reflected the cost to replace nuclear generation and was embedded in the FAC and GUAC. The cost per MWh equals the cost per kWh times 1000.

production, adjusted for planned outages, provides the basis for the forecast of output used in the Fuel Simulation. CL&P has contracts with 27 PPP facilities. Of these, five provide in excess of 75% of the total purchases and demonstrate historical capacity factors in excess of 85%. In total, past performance has shown the performance of PPP plants to be predictable and reliable. CL&P's Integrated Resource Plan, dated April 1, 1998, Table II-2; Tr. 9/11/98, pp. 625-627.

The Fuel Simulation embeds the entire costs of each PPP contract in the BRFR at an average rate of $85/MWh. The forecast reflects the maximum contractual purchase obligation (i.e., production and cost) under each agreement. When a facility does not operate, CL&P replaces the 'lost' production at its marginal cost. In addition, if production exceeds the maximum contractual obligation, CL&P purchases the additional energy at its then current marginal cost. Based on the Final Fuel Simulation, PPP costs reflect $296,958,000, or 47% of CL&P's fuel costs ($296,958,000 ÷ $637,888,000). Although CL&P essentially 'purchases the plant' by taking energy and capacity, the Company does not separate PPP costs into capacity and energy, booking all PPP costs as energy. Id.; Tr. 9/11/98, p. 695; Revised WPC-3.1.

Cogeneration costs account for 47% of CL&P's total fuel expense and these costs are fixed by contract. When a cogeneration facility does not operate, the Company's overall fuel costs decline on average by $63/MWh, the difference between the average embedded cost of cogeneration and the Company's marginal cost of fuel ($85/MWh - $21.56/MWh). However, the cost reduction can vary based on the PPP facility. For example, CL&P purchases from the Wallingford Resource Recovery Facility at $245/MWh. Therefore, the Company's costs decline by $224/MWh when this facility does not operate as planned ($245 - $21.56). If a PPP generates more than expected, CL&P purchases the output at its marginal cost. Therefore, forecasted cogeneration costs can only decline based on actual performance of these facilities. Historical data show that these plants have performed reliably and consistently in the past and there is no evidence to suggest performance will decline. Based on the above, the Department concludes that the cost of energy associated with CL&P's cogeneration contracts is stable and likely to remain stable.

The cost of nuclear fuel is determined at the time of each reload (i.e., during a refueling outage). Once the fuel is loaded the cost does not change. CL&P states that nuclear fuel is only expensed as it is burned; therefore, "the mill rate is stable in the simulation because we set one mill rate for a fuel cycle. The mill rate is subject to change, but we set the mill rate so we can take the mill rate times the generation and fully amortize the cost of that fuel load." Tr. 9/11/98, p. 634.

Fuel cycles are either 18 or 24 months depending on the facility. Under the Final Fuel Simulation, nuclear fuel represents 7% of CL&P's total forecasted fuel cost for 1999 ($45,092,000 ÷ $637,888,000). Late Filed Exhibit No. 138 SP 1; Revise Schedule WPC-3.8. The cost of nuclear fuel is fixed at the start of each fuel cycle and because the length of a fuel cycle is known, these costs are stable over that period. Based on the above, the Department concludes that the cost of nuclear fuel is stable and likely to remain stable.

Oil, natural gas and coal-fired generation reflect approximately 33% of the Company's total 1999 fuel cost ($208,634,000 ÷ $637,888,000). Late Filed Exhibit No. 138 SP 1. CL&P states that the price of oil is far less volatile than it has been in the past, but cautions that, despite relative price stability, a $2 or $3 per barrel swing can represent a significant change when applied to current prices. It is the "potential instability" of the price of oil that can dramatically affect the Company's earnings. Tr. 9/11/98, pp. 641-644. The Company indicates that the price of natural gas trends with the price of oil; therefore, the price of gas is also unstable. Id.; Late Filed Exhibit No. 88.

The Company uses financial instruments such as hedges, derivatives and 'swaps' (collectively, Swaps) in its fossil fuel procurement practices. See Decision dated January 25, 1995, in Docket No. 94-05-01, Public Hearing to Investigate Whether Charges or Credits Made under the Purchased Gas and/or Generation Utilization Adjustment Clauses Are Accurate for the Preceding Three Months as Filed by: Bozrah Light and Power Company, et al. An oil swap is a specific type of energy derivative, or financial instrument, whose value is determined in whole or in part by an underlying energy-related commodity, such as oil. Specifically, an oil swap is an agreement between a buyer and seller for a specific volume of oil at a specified price over a specified period of time. In a swap, the seller, generally a financial institution, agrees to pay the buyer of the swap, in this case CL&P, the difference between the actual market price of oil and the agreed upon swap price of oil, if the actual price is higher. If the actual price is lower than the contracted swap price, the buyer pays the seller the difference. The actual market price of oil is based upon a predetermined benchmark, such as No. 6, 1% sulfur fuel oil New York Harbor cargo price. Decision dated January 25, 1995, Docket No. 94-05-01, pp. 2-5. Swaps essentially lock in the cost of a commodity, such as oil, either through delivery of the commodity at a predetermined price or through a 'paper hedge' in which the price is fixed but the commodity is not delivered. Tr. 9/11/98, pp. 645-649.

The Company has recently converted Middletown Unit Nos. 2 and 3 to dual-fuel capability, allowing the Company to burn oil or natural gas at this site. Conversion of these units was finalized in 1998. In addition to Middletown Station, Devon Units Nos. 7 and 8 and Montville Unit No. 5 are dual-fueled. CL&P converted these units to control fuel cost, reduce the risk associated with the availability of oil and to address environmental concerns. Tr. 9/11/98, pp. 645-649.

The Final Fuel Simulation assumes market purchases for the second half of 1999. These transactions represent purchases with other energy suppliers and account for approximately 5% of total fuel costs ($30,033,000 ÷ $637,888,000). The Company states that market purchases are driven by the price of oil because fossil-fueled units provide marginal generation throughout New England. Tr. 9/11/98, pp. 639. The Final Fuel Simulation includes production from PSNH and WMECO coal fired plants. Production from these plants is available as the result of the continuation of the NUG&T and Sharing Agreement in 1999. In general, coal is purchased under contracts that range from one to three years. Late Filed Exhibit No. 17.

The Company began limited use of Swaps in 1995 where at that time Swaps was limited. See Decision in Docket No. 94-05-01, p. 3. Since then CL&P has increased the use of Swaps to control fuel costs. Middletown Station was recently converted to dual-fuel capability, adding to the number of CL&P generating units that are dual-fueled. The conversion of Middletown Station provides CL&P with a cost control technique that was not available when the EAC was implemented. A percentage of coal is purchased under contract; therefore, a portion of the cost of this source of energy is stable and likely to remain stable. The Department concludes that the number of fuel cost-control techniques available to CL&P has increased since the implementation of the EAC.

While there are mechanisms available to assist CL&P in controlling the cost of oil and natural gas, they do not stablize market prices for these commodities or for the energy produced from plants that burn these fuels. The cost of oil declined 40% from approximately $20/bbl in November 1997 to the current price of $12/bbl. Natural gas costs trend with oil; therefore, gas prices have also changed. In addition, because market purchase costs are driven by the price of fossil fuels, these costs have also changed.

Oil, natural gas and market purchases represent approximately 38% of the Company's total fuel cost. The price of oil has fluctuated by 40% within the last 11 months and there is no guarantee that the price of this commodity will not experience similar swings in the future. A 40% swing in price cannot be defined as stable and because the price of oil influences gas and market purchases, the fuel cost for these sources of generation is also unstable. Therefore, the Department finds that the cost of oil and natural gas is not stable. The Department notes that the effect of declining fossil fuel prices has been reflected in the EAC, and, as a result of the EAC Collar, has provided benefit to ratepayers and shareholders. Absent the EAC, ratepayers would have lost these benefits.

In the past, the fuel cost associated with variations in nuclear performance was passed along to ratepayers through the GUAC. Historically, 72% was used as the forecasted capacity factor for nuclear plant performance and was embedded in the BRFR. Therefore, under the GUAC, when nuclear performance fell below 72% ratepayers funded the replacement energy costs while performance above 72% reduced fuel costs. Based on historical plant performance, the GUAC resulted in a charge for the operation of MP2 and MP3 for most years between 1991-1996. The following summarizes the historical performance of these units.

Historical Capacity Factors, Millstone Unit Nos. 2 and 3

	1991	1992	1993	1994	1995	1996	1997	1998*
Millstone Unit 2	52.3%	35.6%	82.2%	48.0%	35.8%	13.6%	0.0%	0.0%
Millstone Unit 3	28.7%	65.4%	64.6%	93.7%	79.6%	24.6%	0.0%	0.0%

Source: Response to Interrogatory EL-33.

* Data reflect January through June 1998

Data demonstrate that nuclear plants returning from the Watch List tend to perform above the industry average. Response to Interrogatory EL-5. The Company

did not adjust the forecasted capacity factors for MP2 or MP3 based on improved performance that may result as these plants return to service. In addition, because there is no guarantee that performance will improve, the Department accepted the forecasted capacity factors for these units. However, if the EAC is suspended, ratepayers will lose the benefit of reduced fuel costs should performance at MP2 and 3 improve. The Department believes that ratepayer interests are best served through continued use of the EAC to capture potential improved nuclear performance at MP2 and 3.

Factor FC in the EAC formula allows CL&P to forecast its fuel costs for the upcoming six-month EAC billing period. Forecasting under the EAC was suspended until one or more of CL&P's nuclear units returns to service. Decision, Docket No. 97-07-05, pp. 20 and 21. CL&P's nuclear units have been off-line since the EAC was implemented; therefore, CL&P has not forecasted costs through the EAC. As a result, the EAC has been essentially a prior period adjustment mechanism, truing up base fuel revenue recovery to CL&P's booked fuel costs. This has simplified review and administration of the EAC. The Department believes that elimination of forecasting from the EAC best serves the interests of the Company and its ratepayers. The Department notes that due to a lag in accounting for some costs, the Company has estimated certain values in the EAC (e.g., the marginal cost) requiring a true up in a subsequent EAC filing. The Department intends to eliminate all forecasting and estimating from the clause to have it reflect only actual data. Therefore, CL&P will be required to propose a mechanism to accomplish this goal.

The Company proposes to apply carrying charges to the EAC if forecasting is eliminated. Response to Interrogatory EL-98. The elimination of forecasting creates a lag in fuel cost recovery. Therefore, the proposal to apply carrying costs to the EAC recoveries is reasonable. Carrying costs will be determined in each EAC billing period and calculated with each EAC filing. They will be applied to outstanding EAC balances, plus or minus, so that ratepayers and the Company are treated equally.

As noted in Section II.G.1, above, the Department accepts CL&P's proposed nuclear capacity factors for MP2 and 3.

a. Incentive Collar

The EAC includes a $9 million annual incentive collar Factor IC (Collar). The Collar allows CL&P to retain the first $9 million of savings if actual fuel costs are less than forecasted and does not allow the Company to recover the first $9 million if actual fuel costs exceed the forecast. Decision, Docket No. 97-07-05, p. 25; EAC Factor IC. The Collar was designed to share risk and benefit. Id.

The Company states that setting the BRFR using current, low oil prices, and 'aggressive' nuclear capacity factors assures that the Company's fuel costs will exceed the BRFR, forcing CL&P to absorb the full value of the Collar. CL&P Brief, pp. 36-41. Therefore, the Company believes the Collar should be eliminated. Id.

The Department does not agree that the approved capacity factors are aggressive. In past rate proceedings, the BRFR was generally set using a 72%

composite nuclear factor. Although the approved capacity factors result in an 80.4% composite rate, these values are based on CL&P's forecast and reflect normal and prudent operation of these units. Revised Filing, Schedule WPC-3.8. As such the Department views the forecasted nuclear capacity factors are attainable.

As discussed above, the number of fuel cost control mechanisms available to CL&P has increased since the EAC was implemented. This in turn has reduced the financial risk associated with the Company's overall fuel costs. Also, as discussed above, nuclear plants returning from the Watch List generally tend to perform above the industry average. However, the Department did not adjust forecasted nuclear performance to account for this trend. As such, the Department has provided CL&P an opportunity to reduce its fuel costs through increased nuclear performance. Elimination of the Collar would reduce this incentive. Based on the foregoing the Department concludes that it is appropriate to retain the Collar at this time.

b. Implementation of the EAC

The $46.8 million of capacity costs will be recovered through the BRFR over 12 months or approximately $3.9 million per month. The traditional treatment of expenses through the EAC requires the expense to be recognized in the EAC in the period in which the expense is incurred. Therefore, because these capacity costs will be incurred during the first half of 1999, but recovered through the BRFR over 12 months, a mismatch in the timing of the recovery of this expense will occur.

This unintended result will affect the EAC and the Collar as follows. Because the BRFR assumes an average annual recovery of this expense, base fuel revenues will recover $23.4 million in each six month period (6 months x $3.9 million). However, the Company will book $46.8 million for this expense in the first half of the year and $0 in the second half. As noted, for purposes of the EAC actual fuel costs are based on the costs in a given period. Therefore, as the result of including these capacity costs in the BRFR, the actual average fuel cost per kWh will be greater than the BRFR in the first half of the year and lower in the second half. This could result in a disallowance under the Collar and an EAC charge during the first half of 1999. In the second half of the year the Collar could allow CL&P to retain a portion of its actual fuel cost because its actual fuel cost will appear to be lower than the BRFR and ratepayers could receive a credit through the EAC for the difference.

Recovery of capacity costs will also affect the EAC rate that will be calculated for the retroactive period, September 28, 1998, to the date of this Decision (Retroactive Period). Results similar to those expected for the first half of 1999 appear likely for this period, resulting in a potential disallowance under the Collar and charge to customers through the EAC.

To avoid these outcomes, the Department will require the Company to apply a portion of the revenue reduction from the Retroactive Period to the calculation of the EAC so that the EAC rate, as calculated for the Retroactive Period will be zero. In addition, because the EAC is being calculated in hindsight, for the Retroactive Period, the Department believes it is in the best interest of the Company and its ratepayers to suspend operation of the Collar for the Retroactive Period. Operation of the Collar

would resume effective the date of this Decision. Simply stated, because fuel costs are known, the EAC should not be billing a charge or credit for the Retroactive Period and the Company should be held harmless for costs above or below the BRFR for the Retroactive Period. In addition, for 1999, the Department will require the Company to defer a portion of these costs during the first half of 1999 and amortize the balance in the second half of the year to avoid the over/underrecovery noted above.

J. RELIABILITY OF SERVICE

The Department recently reviewed the reliability of the Company's service in the joint Decision in Docket No. 86-12-03, and Docket No. 97-11-10. The Department found that CL&P's reliability, excluding major storms, generally has been improving since 1992. When the impact of major storms was considered, however, reliability generally was found to be declining. Decision dated August 21, 1998, in Docket Nos. 86-12-03 and 97-11-10, p. 3. The table below summarizes CL&P's system reliability data for the past six years.

CL&P Reliability Indices 1992 - 1997

	WITHOUT MAJOR STORMS			WITH MAJOR STORMS		
YEAR	SAIDI[22]	SAIFI[23]	CAIDI[24]	SAIDI	SAIFI	CAIDI
1992	142	1.35	105	266	1.62	164
1993	136	1.26	108	262	1.68	156
1994	169	1.49	114	288	1.70	169
1995	150	1.32	113	515	2.21	233
1996	130	1.16	112	893	2.54	352
1997	118	1.24	95	321	1.70	*

Note: All of the above reliability indices reflect the new major storm exclusion criterion.
*Not provided

Id.

In Docket No. 97-05-12, the Department found that the changes in SAIDI and SAIFI data are influenced by the frequency and severity of major storms. Decision, p. 47. The Company maintains data to determine outages that qualify for storm exclusion in the calculation of the Company's reliability statistics. Pursuant to the new major storm exclusion criterion, which was approved by the Department by Decision dated March 22, 1995, in Docket No. 86-12-03, it is necessary for CL&P to track, on a daily basis, the number of trouble locations on its system where line crews performed service restoration work. Based on statistical analysis of data from the most recent four calendar years, days in which work locations exceed a predetermined threshold are considered storm periods. Interruptions during these periods, including those extending

[22] SAIDI (System Average Interruption Duration Index): The average interruption duration in minutes per customer served. It is calculated by dividing the sum of all customer interruption duration during a year by the number of customers served.

[23] SAIFI (System Average Interruption Frequency Index): The average number of times that a system customer is interrupted during a year. It is calculated by dividing the total number of customers interrupted in a year by the average number of customers served during the year. A customer interruption is considered to be one interruption to one customer.

[24] CAIDI (Customer Average Interruption Duration Index): The average service restoration time or the average interruption duration for those customers interrupted during a year. It is calculated by dividing the sum of all customer interruption duration by the total number of customers interrupted in a year.

into subsequent days, are classified as storm related. A comparison of the number of trouble locations requiring restoration work for the years 1992 through 1997 shows the following:

Trouble Locations 1992 - 1997

YEAR	STORM RELATED	NON-STORM RELATED	TOTAL
1992	4,329	16,338	20,667
1993	5,185	16,685	21,870
1994	3,270	14,780	18,050
1995	6,482	12,631	19,113
1996	12,094	11,521	23,615
1997	4,429	12,460	16,889

Response to Interrogatory EL-180.

The data clearly correlate changes in storm-related activity to the reliability indices noted above. The total sum of the periods of major storms for the last six years follows:

Total Major Storm Periods 1992 - 1997

Year	Sum of Storm Periods
1992	5 days - 15 hours
1993	9 days - 10 hours
1994	7 days
1995	16 days - 12 hours
1996	21 days
1997	14 days

Response to Interrogatory EL-181.

It can be concluded from the data that major storms affected the Company's distribution system significantly in 1995 and 1996, but less so in 1997. This impact was translated into increased SAIDI and SAIFI values for 1995 and 1996. However, the SAIDI value including major storms was still high in 1997 (321) compared to 1992 - 1994.

In the August 21, 1998, Decision in Docket Nos. 86-12-03 and 97-11-10, the Department indicated its belief that widespread use of covered wire and a well-managed tree trimming program are primary ingredients of a successful reliability improvement program for CL&P. Decision, p. 11. The Department noted that CL&P intended to report to the Department on its future plans in this area by September 30, 1998. The Company submitted this report on September 3, 1998 (Report). The Report compiled extensive data on tree contact outages in the CL&P distribution system, and on the effectiveness of covered wire and enhanced tree trimming (removal of hazard branches and trees outside the normal trim zone) in preventing these outages. The Report reached the following conclusions that, in the Department's opinion, are significant concerning covered wire and enhanced tree trimming.

- The consensus of Senior Circuit Owners, Vegetation Management personnel, and line surveyors is that all three-phase backbones and some major sidetaps should receive both reconductoring with covered wire and enhanced tree trimming (Report, p. 5);

- Circuits with covered wire and spacer cable have significantly lower outage frequency from all causes (approximately 70% lower) than bare wire, since, when a circuit is rebuilt with covered wire, other rebuild improvements are made as well (Report, p. 7);

- The average number of tree caused outages per 100 miles of line in 1996 - 1997 was 5.4 for covered wire vs. 23.4 for bare wire (Report, p. 7);

- Increasing the proportion of covered wire from 37% to 50% should reduce outages by 12% and reduce annual outage-related costs by $11,000,000 (Report, p. 13).

The above conclusions reinforce those of the Department regarding the effectiveness of covered wire and tree trimming in the August 21, 1998, Decision in Docket Nos. 86-12-03 and 97-11-10.

As described in Section II.E.4, the Company plans to expand the proportion of covered wire in its system to 50% by 2003. Given the history of tree contact outages and the effectiveness of covered wire and enhanced tree trimming in preventing these outages, and given other improvements the Company is implementing in its system (see Section II.E.4), the planned reliability improvements are appropriate. Additionally, the Company plans to complete enhanced tree trimming on all three-phase backbones by 2002. Tr. 9/28/98, p. 2816. The Department concludes that the Company's efforts to improve reliability are reasonable.

The Department reaffirms the conclusions it reached in the August 21, 1998 Decision in Docket Nos. 86-12-03 and 97-11-10 that the reliability of CL&P's distribution system should be improved, particularly under major storm conditions. Implementing covered wire and related rebuild work, combined with enhanced tree trimming on three-phase backbones, should provide a major benefit in terms of reducing tree contact outages, under both storm and non-storm conditions. These programs represent a major new commitment on the part of the Company to improve its service reliability following years of neglect. The Department encourages the Company to follow through on these programs as they have been represented in this proceeding. The Department will follow the Company's efforts in this regard in Docket No. 86-12-03 and in future reviews of the Company's Line Maintenance Program.

K. EXCESS CAPACITY

As required by Conn. Gen. Stat. §16-19aa, the Department conducted a review and analysis of CL&P's electric capacity resources and requirements. The Department determines that, under current and near-term conditions, CL&P's total capacity entitlement for the summer of 1999 is 5,283 megawatts (MW). Response to Interrogatory EL-31. This total capacity level represents total reserves of approximately 638 MW or 13.7% above the Company's projected peak load requirement of 4645 MW. Id. Reliability Reserve Requirements and other appropriate adjustments to these total reserves, as provided for under Conn. Gen. Stat. §16-19aa, yield a net reserve capacity projection of -1291 MW.

The Department therefore concludes that under current and projected conditions all of CL&P's capacity is: 1) needed to meet expected loads; 2) needed for reliability reserves; 3) sold through capacity contracts; or 4) appropriately excluded from consideration as excess capacity. Therefore, no generating capacity costs are excluded from the Company's rates under §16-19aa in this case. Further, no transmission capacity costs are excluded from rates as excess at this time.

1. Background

This statute requires that, as part of every rate case under §16-19, the Department:

(1) review the facilities utilized by the company for the generation and transmission of electricity;

(2) determine the level of the company's reserve capacity;

(3) determine the company's net reserve capacity by making such adjustments as the Department deems appropriate;

(4) determine the level of reserve capacity which would provide a net economic benefit to customers of the company (with specific considerations); and

(5) exclude from the company's rates (in a manner which shall provide the optimal short-term and long-term benefits to customers) the costs associated with generating facilities which provide net reserve capacity in excess of the level determined in (4) above.

An "excess capacity exclusion" under (5) above would ultimately result from determinations made in the following sequence:

1. NET CAPACITY (C) - PEAK LOAD (P) = TOTAL RESERVE CAPACITY (T);

2. TOTAL RESERVE CAPACITY (T) - REQUIRED RELIABILITY RESERVE (R) = SURPLUS RESERVE CAPACITY (S)

3. SURPLUS RESERVE CAPACITY (S) - APPROPRIATE ADJUSTMENTS (A) = NET RESERVE (Rn);

4. NET RESERVE (Rn) - ANY Rn of NET ECONOMIC BENEFIT (B) = EXCESS CAPACITY (X); and

5. EXCESS CAPACITY (X) * COST ($) = EXCLUSION (E).

This process produces an excess capacity exclusion (E) only if each of the prior determinations yield positive values. The determination of each of the factors in the sequence may require assumptions, judgments and/or adjustments that influence its

value. The statute's third charge in particular requires that the Department consider specific adjustments in its determination of net reserve capacity.

The Department has completed a number of independent investigations related to the adequacy of electric transmission and distribution systems and overall service reliability to Connecticut electric customers. It remains clear that no excess of transmission capacity exists on the CL&P system.

2. Determination of Net Capacity (factor C)

This analysis focuses on CL&P's mid-year (summer) capacity situation, which represents the annual peak load period for the Company as well as the lowest rating period for seasonably variable capacity. Net capacity available is the total generating capacity owned, adjusted for contract purchases and sales. In the context of a §16-19aa Excess Capacity determination, net capacity can also reflect capacity adjustments for policy considerations or other appropriate reasons as determined by the Department.

CL&P reports total capacity entitlements of 5,283.25 MW for summer 1999. Response to Interrogatory EL-31. The Company proposes to adjust (reduce) this amount for Excess Capacity purposes as follows: Capacity Sales and Exchanges of 682 MW; Conservation and Load Management effects of 493 MW; Contracts with Qualifying Facilities; Resource Recovery Facilities of 417 MW; and Hydro Quebec Interconnection impacts of 337 MW. Id. The Department finds these 1928 MW of capacity adjustments appropriate because they reflect State and Department policy consistent with §16-19aa. Therefore, the Department determines that CL&P's Net Capacity (C) for the summers of 1999 is 3354 MW.

3. Determination of Demand and Total Reserve (factors P and T)

Total Reserve Capacity is defined as the amount of Net Generating Capacity above that required to meet the Peak Load of the given period. This analysis considers the summer peak load forecast as it relates to projected levels of installed and contracted generating capacity for 1999. The Company forecasts a summer peak load of 4,645 MW. Response to Interrogatory EL-31.

Based on the above, CL&P's Total Reserves (T) for Excess Capacity purposes are -1291 MW. Therefore, no generating capacity costs are excluded from the Company's rates under §16-19aa in this case.

Conn. Gen. Stat. §16-19aa,
CL&P Excess Capacity Evaluation for 1999

	MW VALUE
Total Capacity	5283
Adjustments:	
Capacity Sales	682
C&LM Programs	493
QFs & RRs.	417
H.Q.	337
NET CAPACITY (C)	3354
PEAK LOAD (P)	4645
TOTAL RESERVE (T)	-1291

Source: Response to Interrogatory EL-31.

L. ENVIRONMENTAL COMPLIANCE

Generally, under the primary jurisdiction of either the federal Environmental Protection Agency (EPA) or the Connecticut Department of Environmental Protection (DEP), consideration of the environmental consequences and costs (both internal and external) of CL&P's provision of electric services and this Department's Decisions remain an explicit charge of this Department under Conn. Gen. Stat §16-19mm, as well as various State policies. These considerations are also an explicit part of the Department's review of "continued unit operation" studies in this and other proceedings.

The Department has reviewed CL&P's activities related to the purchase and sale of Sulfur Dioxide (SO_2) Allowances under Title IV of the federal Clean Air Act Amendments of 1990 (42 USC 7104, et seq.) and its transactions involving Emission Reduction Credits (ERCs) for Nitrogen Oxide (NO_X) compliance requirements under state and federal requirements. Response to Interrogatory EL-34. The Department finds the overall level of these activities appropriate for environmental compliance purposes and the costs consistent with the markets for these transactions.

The Department applauds CL&P's voluntary efforts to reduce its overall emissions beyond the levels mandated by state or federal requirements as announced in Northeast Utilities' News Release of June 10, 1998. Tr. 9/14/98, pp. 861-866; Late Filed Exhibit No. 34. To the extent that these effects can be accomplished at no incremental cost to ratepayers or to the extent that any direct costs to ratepayers can be sufficiently offset by ERC savings or sales, the Department is fully supportive of such efforts. However, to the extent that the Company determines to reduce pollution below the standards deemed sufficient by the primary environmental regulatory authorities (EPA and DEP) and such activities result in net costs (including the opportunity costs of retired Allowances or ERCs), the Department concludes that the recovery of such costs from customers through rates, absent compelling argument to the contrary, is

inappropriate. The Department further concludes that unquantified general health benefits to the overall population is not such a compelling argument for cost recovery from CL&P ratepayers. Late Filed Exhibit No. 34.

As discussed in the Decision dated July 20, 1994 in Docket No. 93-04-07, the Department believed that the donation of the allowances by CL&P to the American Lung Association (ALA) was a charitable contribution and thus required the Company to reimburse the ratepayers for the full value of the donation of the allowances. Docket No. 93-04-07, Order No. 7. The Department believes that the voluntary emission reduction efforts by the Company are similar to the donation to the ALA in 1993. Since such transactions including emission credits remains very uncertain for 1999, the Department will not impute any revenues at this time. However, the Department will require the Company to credit customers for the value of any future emission credit donations or voluntary retirements in accordance with Order No. 7 in Docket No. 93-04-07.

The Department's treatment of the revenues/costs associated with ongoing environmental compliance can be found in Sections II.E.7 of this Decision. The Department acknowledges that its direct review of many environmental cost issues will diminish as electric restructuring under Public Act 98-28 is implemented.

M. COST OF CAPITAL

1. Introduction

The United States Supreme Court, in Federal Power Commission v. Hope Natural Gas Company, 320 US 591 (1944), established criteria to determine the cost of capital allowances. In its Decision, the Court determined that companies need to be allowed to earn a level of revenues sufficient to enable them to operate successfully, maintain their financial integrity, to attract capital and compensate their investors for their risk.

By law, utilities are entitled to a level of revenues that will allow them " . . . to cover their operating and capital costs, to attract needed capital and to maintain their financial integrity, and yet provide appropriate protection for the relevant public interest both existing and foreseeable." Conn Gen. Stat. §16-19e(a)(4).

To determine a rate of return on rate base that is appropriate for CL&P's overall cost of capital, the Department first identifies the components of the Company's capital structure. The cost of each capital component is then estimated and weighted according to its proportion of total capitalization. These weighted costs are summed to determine the Company's overall cost of capital, which becomes the allowed rate of return on rate base (ROR).

2. CL&P Proposed Capital Structure and Cost of Capital

The Company proposed a weighted cost of capital and capital structure based on the average capitalization for the 1999 forecast year. The Company's proposed weighted cost of capital and associated cost for each class of capital are shown below:

Proposed 1999 Average Capitalization

	1999 Average Capitalization ($000)	Percent of Total	Cost	Weighted Cost
LT Debt	1,735,098	56.30%	6.90%	3.89%
Pfd Stock	239,206	7.76%	6.27%	0.49%
Common Eq.	1,107,842	35.94%	11.40%	4.10%
Total	3,082,146	100.00%		8.48%

Source: Schedule D-1.0 (Revised)

The Company's capital structure, including short-term debt, and the associated cost of each component is shown below:

Proposed 1999 Average Capitalization Including Short-term Debt

	1999 Average Capitalization ($000)	Percent of Total	Cost	Weighted Cost
Short-Term Debt	180,715	5.54%	5.23%	0.29%
Long-term Debt	1,735,098	53.18%	6.90%	3.67%
Preferred Stock	239,206	7.33%	6.27%	0.46%
Common Equity	1,107,842	33.95%	11.40%	3.87%
Total	3,262,861	100.00%		8.29%

Source: Schedule D-1.0, Revised

The Department's allowed cost of debt, preferred stock and common equity are discussed below.

3. Cost of Long-term and Short-term Debt

The Company's average forecasted 1999 long-term embedded cost of debt is estimated at 6.90%. Schedule D-1.0, Revised. Schedule D-1.0, Revised reflects the Company's adjustment of its estimated 1999 annual interest costs that eliminates the higher interest rate impact of two series of bonds for which the Company incurred higher interests costs as a result of its prolonged outages at the Millstone plants. In the case of the 7-3/4% $200 million 1997 Series C Bonds, the Department estimated that the Company had incurred additional annual interest costs of 60 basis points as a result of CL&P financial downgrades due to the Millstone outages. Docket No. 97-03-23,

Application of The Connecticut Light and Power Company to Issue First and Refunding Mortgage Bonds, Decision dated May 14, 1997, p. 11. The Company's revised Schedule D-1.0 also reflected a downward adjustment of 10 basis points in the annual interest cost of the $160 million 7-7/8% Series A Bonds. In the June 12, 1996, Decision in Docket No. 94-07-16, Application of The Connecticut Light and Power Company to Issue First and Refunding Mortgage Bonds and Preferred Stock, p. 6, the Department found that "the recent downgrade of the Company's securities has likely raised the coupon rate of the Bonds by approximately 10 basis points." Id., p. 6. The revised Schedule D-1.0 also reflected adjustments on three series of adjustable rate pollution control notes.

The Company's revised 1999 forecast overstates the amount of long-term pollution control notes held as variable rate securities, and as such, understates the embedded cost of long-term debt. Schedule D-3, p. 1; Tr. 10/8/98, pp. 3208 and 3209. On October 1, 1998, the Company converted $361.9 million principal amount of pollution control notes from an average variable rate of approximately 3.98% to fixed rates ranging from 5.85% to 5.95%. Docket No. 88-09-01, Application of The Connecticut Light and Power Company for Approval to Finance Pollution Control and/or Sewage or Solid Waste Disposal Facilities, Decision dated September 23, 1998.[25] In Docket No. 88-09-01, the Company estimated that the Notes would be priced at 5.7% to 6.0% if the Company were rated BBB+, or approximately 65 basis points less than the estimated interest rate of 6.5%. Id., p. 5. Subtracting the 65 basis points from the actual rates of 5.85% to 5.95% results in an increase in interest rates of $4,139,500, compared to the average 3.98% variable rates submitted by the Company in its 1999 forecast. This results in a rise in the embedded cost of long-term debt from 6.90% to 7.14%.

Two series of long-term debt will have matured during 1998 and 1999. The 7-1/4% Series W, principal amount of $74 million matured on July 1998 and the 5-1/2% 1994 Series A, principal amount $140 million expires in February 1999. The Company testified that it did not anticipate issuing long-term debt holdings during 1999, but instead intended to increase its short-term debt obligations during 1999. Tr. 9/10/98, pp. 377 and 378. For that reason, 1999 forecasted short-term debt rises to $180.7 million, approximately 5.5% of capital structure. Schedule D-1.0, Revised. The Company intends to hold these moneys in short-term debt until some time in 2000 so that it can securitize its debt obligations as allowed in the Act. The Department finds it appropriate to include a portion of short-term debt as a component of the Company's capital structure for the purposes of this rate case, given the Company's plans for increasing short-term debt during 1999. See Decision, Section II,N, pp. 157-158. Only the amount of short-term debt in excess of the 1999 projected average Construction Work in Progress (CWIP) will be included as short-term debt. Schedule F-8, p. 1; CL&P Written Exceptions, pp. 14-16. The Department reduces the $180,715,000 projected average 1999 short-term debt by $91,158,000, the projected average 1999 CWIP, resulting in $89,557,000 to be included in the short-term debt component of the capital

[25] The estimated interest rate in the Decision is 6.5%. In a letter dated October 2, 1998, pursuant to Order No. 3 of the Decision, the Company indicated that the interest rates on the five issues ranged between 5.85% and 5.95%

structure. The Department accepts as the Company's allowed cost of short-term debt. Schedule D-2, Revised.

4. Cost of Preferred Stock

The Company is expected to have $239,206,000 in preferred stock in its capital structure at a cost of 6.27%. The Department accepts the Company's proposed 6.27% cost as submitted in Schedule D-4, Revised.

5. Cost of Equity

a. Introduction

Three witnesses presented testimony recommending a cost of equity for CL&P. The Company's witness, Michael A Wiater, advocated an allowed rate of return on equity (ROE) of 11.4%. Wiater PFT, p. 3. James K. Sutphin, witness for Prosecutorial, recommended an ROE of 9.25%. Sutphin PFT, p. 2. James A. Rothschild, representing OCC, advocated a return on equity of 9.35%. Rothschild PFT, p. 6. Each witness performed a discounted cash flow model (DCF) and risk premium analysis to support his recommendation. These two models are described in the Sections II.M.5.b through II.M.e below.

b. DCF Model

The DCF model assumes that the return received by investors is the sum of the future flow of dividends plus the anticipated growth in the selling price of the stock, discounted to the present. Assuming that the stock price increases consistently with dividend growth, this cash flow of dividends and future selling price equates to the future flow of dividends, and the DCF model takes the basic form:

$$K = D_1/P_0 + g$$

where: K = investors' required return or equity cost of capital
D_1 = next period dividend payment
g = estimated growth rate
P_0 = current market price of common stock

Mr. Wiater developed a proxy group of nine companies with the following characteristics: BBB long-term debt rating, significant nuclear exposure, companies undergoing some degree of industry restructuring, companies not involved in merger activities, and utilities with a Value Line beta of less than 1.0. His proxy group excluded Northeast Utilities (NU), given its suspension of dividends and below investment grade financial rating; however, NU stock performance and growth rates were included for informational purposes. Mr. Wiater justified the use of the BBB rating as the one that CL&P expects to receive when all of the Millstone nuclear units return to service and when regulatory uncertainties are resolved with regard to industry restructuring. Wiater PFT, pp. 3-6.

According to Mr. Wiater, a proxy group of electric utilities may not accurately reflect investors' required return given the industry restructuring toward greater competition. He argued that many electric utilities are reducing the growth rate of their dividends in an effort to strengthen their financial position in response to the onset of competition. Therefore, near-term growth rate may not reflect the earnings and dividend growth rates of the industry in the long run. To model the effect of competition in the electric utility industry, Mr. Wiater used the Value Line Industrial Composite of 785 major industrial companies as the proxy for the "nonregulated sector." Wiater PFT, pp. 16-21.

To calculate the yield for the nine electric utilities, Mr. Wiater used average closing stock prices from 20 consecutive trading days, April 13, 1998, to May 5, 1998. Dividends, D_1, were taken from Value Line's forecasted 1998 yields. This resulted in a yield of 5.24% for the regulated proxy group. Wiater PFT, p. 19; Exhibits MAW-5 and MAW-6. The 1.54% yield for the nonregulated sector was calculated as a composite dividend per share of $0.80 divided by the composite per share price of $52. Exhibit MAW-7.

Growth rates for the proxy group were calculated using the average of the six-year earnings and book value growth rates as projected by Value Line. Mr. Wiater did not use Value Line's projected dividend growth rates "because the electric utility industry as a whole has been holding back dividend growth by reducing dividend payout ratios to prepare for restructuring." The growth rate for the regulated proxy group was calculated at 2.44%. Wiater PFT, p. 19; Exhibit MAW-6. Mr. Wiater averaged Value Line projected growth rates for earnings, dividends and book value to obtain a composite growth rate of 10.33% for the nonregulated sector. Exhibit MAW-7.

Mr. Wiater obtained a DCF estimated cost of equity of 7.68% for the regulated utility proxy group and 11.87% for the non-regulated industrial composite. He combined the nonregulated and regulated DCF results by weighting the two DCF estimates according to the percent of book value corresponding to generation and non-generation (e.g., transmission and distribution) assets of the nine proxy utility companies; generation and non-generation assets accounted for 51.4% and 48.6%, respectively, of the net current book value for the utility proxy group. Using these weighted averages of the regulated and non-regulated proxy groups resulted in an estimated cost of equity of 9.83%. Wiater PFT, p. 21.

Mr. Sutphin chose a proxy group of 10 electric utilities, based on their beta, percentage of nuclear generation, common equity ratio, Standard & Poor's (S&P) bond rating, and financial strength as rated by Value Line. NU was excluded from his proxy group. To calculate the yield, he used an average of stock prices for the proxy group from the period June 1, 1998, to June 30, 1998, then divided the current yield, D_0, by the current price, P_o. He adjusted the current dividend yield by one-half of the average of Value Line's dividend and earnings growth rate to obtain the next period's yield (D_1/P_0) for each of the proxy group utilities. Exhibit JKS-8. This resulted in an average yield of 4.58%. Growth rates were calculated by using Value Line estimates for earnings growth and dividend growth. This resulted in two separate DCF calculations of 8.28% and 6.89%, respectively. Exhibits JKS-8 and JKS-9.

Mr. Rothschild used Moody's 24 electric companies as a proxy group as representative of the industry as a whole. He also used the nine companies selected by Mr. Waiter as a proxy group. Although Mr. Rothschild asserted that NU was excluded from the Moody's 24 electric companies, his exhibits show that NU is among the companies included in the proxy group. Rothschild PFT, p. 13; Schedules JAR 5 through JAR-9. Dividend yields were computed by using a spot price as of July 21, 1998, and an average of the high and low prices during the year ended July 21, 1998. The next period's dividend yield was obtained by adding one-half of the projected growth rate onto the current yield. This resulted in dividend yields between 4.80% and 5.14% for the Moody's 24 companies and between 5.09% and 5.72% for Mr. Wiater's proxy group. Rothschild PFT, p. 16; Schedule JAR-4, p. 1.

Mr. Rothschild employed two variants of the DCF, the simplified model and the two-stage model. In the first model, Mr. Rothschild used forecasted retention growth rates to estimate the growth rate component of the DCF model. He employed the b x r method -- the expected earnings retention rate, b, multiplied by the expected return on book equity, r, allowing for the impact of sales or purchases of new common stock above book value -- for estimating the growth rate. Rothschild PFT, p. 17. Using the forecasted rates of return on equity from Value Line, Zacks Research, and actual equity earned returns in 1996, Mr. Rothschild obtained average forecasted ROEs (r) of 12.0% for the Moody's 24 electric companies and Mr. Wiater's BBB proxy group. Schedule JAR-4, pp. 1 and 2. Using this forecasted value for r, the retention growth rate is computed using the dividend yield to book, market-to-book (M/B) ratios, and allowance for dilution of stock prices due to new equity sales. This results in an estimated cost of equity ranging from 7.68% to 8.30% for the Moody's 24 and 7.59% to 8.71% for Mr. Wiater's selected group. Schedule JAR-3; Schedule JAR-4, pp. 1 and 2.

Mr. Rothschild's two-stage DCF was formulated to take into account any perceived differences in expected short-term vs. long-term growth rates. He used Value Line's five-year forecasts of DPS and EPS to incorporate near-term expected growth rates. Long-term expected growth rates were estimated by using the same b x r computations as in his single stage DCF. Estimates for the second stage of the DCF model were projected 40 years into the future. The estimated future stock price assumes that the current market-to-book ratio remains constant and the dividend payout ratio is also assumed constant. An average of the July 21, 1998 spot price and average stock price for the 12 months ended July 21, 1998, is used as the current stock price. Mr. Rothschild's two-stage DCF model, obtained by computing an internal rate of return, results in a cost of equity of between 8.43% and 8.94% for the Moody's 24 electric companies. Schedule JAR-3; Schedule JAR-5, pp. 1 and 2.

c. Department Analysis of DCF Models

The Department assessed the witnesses' proxy groups to determine whether they accurately reflected the risks incurred by CL&P, absent its nuclear problems. The Department also evaluated the growth rates proffered by the witnesses, since much of the disagreement over the DCF results centered on the choice of growth rates.

With regard to the choice of a proxy group, the Department believes that a BBB+ financial rating is an appropriate financial benchmark to evaluate CL&P cost of equity as

if it did not have its nuclear problems. In recent Decisions, the Department has used the BBB+ financial rating as a benchmark for evaluating interest rate costs CL&P would have incurred were it not for its extended nuclear outages.[26] Mr. Wiater agreed that the BBB financial benchmark used for his group was lower than the BBB+ rating the Company held for approximately 10 years prior to the commencement of its nuclear outages in spring of 1996. Tr. 9/23/98, p. 2125. In fact, Mr. Wiater admitted that his proxy group had an average financial rating of slightly below BBB. Tr. 9/23/98, p. 2126. Mr. Wiater's group also included Public Service of New Mexico, which has a long-term debt rating of BB+, below investment grade. The Department accepts Mr. Wiater's proxy group as a group that is financially more risky than CL&P, prior to the onset of its nuclear problems.

Mr. Wiater's averaging of the growth rates of the Value Line Industrial Composite with the nine-company proxy group was the subject of considerable controversy. According to Mr. Wiater, an important variable in choosing the proxy group was that each of the companies had undergone some degree of industry restructuring. The composite DCF estimated cost of equity was a weighted average, according to the average percentage of book value of assets of the proxy group allocated to transmission and distribution vs. generation, i.e., regulated vs. nonregulated assets in a restructured industry. Although this seems at first glance to be a reasonable method for measuring the cost of equity for the regulated and deregulated sectors of a restructured electric utility industry, it overstates the risks faced by investors. Mr. Wiater admitted that among the proxy group companies currently undergoing restructuring, investors would already have taken restructuring into account in terms of the companies' stock prices and growth expectations. Tr. 9/23/98, p. 2141. Mr. Wiater's 48.6% weighting for the "regulated" sector contains investors' expectations of the riskiness of an industry that is becoming deregulated. The Department does not share Mr. Wiater's conclusion that "the risk of a regulated utility [may be] higher, equal, or . . . lower than competitively delivered electric generation." Tr. 9/23/98, p. 2144. The Department believes that a regulated monopolist's risk would more likely viewed as lower than the competitive sector of the electric industry. Mr. Wiater indirectly concurred with this conclusion by asserting that the electric industry "would probably be perceived as slightly less risky than industrials overall if you weight the regulated and nonregulated." Tr. 9/23/98, p. 2145.

In the DCF calculation for the nonregulated industries, Mr. Wiater's model also fails to discern an important difference between the emerging deregulated electric industry and industries in the nonregulated sector of the economy. In weighting the generation or nonregulated sector at book value, Mr. Wiater's model does not take into account investors' expectations that for the electric power industry, assets for which the market value is less than the book value will be recovered as stranded assets. Although the Department shares Mr. Wiater's wishes that, "Hopefully, none of it is stranded," the fact that several states' restructuring statutes have allowed utilities a return on their stranded assets lowers investors' perception of risk for the electric utility industry. Tr. 9/23/98, p. 2164-2169.

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[26] See Docket No. 91-06-04, Application of The Connecticut Light and Power Company and Western Massachusetts Electric Company with Respect to Nuclear Fuel Financing Arrangements, Decision dated May 27, 1998, p. 6.

Finally, Mr. Wiater acknowledged that during 1999, the period for which CL&P's rates will be set in this Decision, electricity will be generated by a regulated monopolist. To the extent that the model has assumed that competition in generation will have already occurred in 1999, the model overstates investor risks. Id., p. 2169.

The Department concludes that the risks of competition in the electric industry, and therefore investors' required returns, have been overstated in Mr. Wiater's composite DCF model. The Department accepts a reweighting of Mr. Wiater's composite DCF estimates to reflect 75% of the weighted average to reflect the proxy group and 25% to represent the nonregulated industrial sector. This results in an estimated cost of equity of 8.73%. The reweighting addresses Mr. Wiater's overstatement of investor risk and the degree of industry restructuring assumed to have taken place.

The companies in Mr. Sutphin's group had financial ratings ranging from BBB- to A; however, seven out of the ten companies had S&P bond ratings of between A and AA-, which are higher ratings than CL&P had prior to the onset of the outages at its nuclear plants. Exhibit JKS-1. Based on these ratings, the Department finds that Mr. Sutphin's proxy group has less financial risk than the BBB+ rating that CL&P maintained prior to its nuclear outages. The Department accepts Mr. Sutphin's proxy group as a group that is financially less risky than CL&P, absent its nuclear problems.

With regard to Mr. Sutphin's DCF testimony, the Department concurs with Mr. Sutphin that investors are fully informed about the prospects of restructuring in the electric utility industry and that investor long-term earnings expectations are captured in the current price of the stock. The question remains whether Value Line's six-year earnings and dividend growth rates provide reasonable estimates of investor long-term expectations. Mr. Sutphin's DCF estimate of 6.89% using dividend growth rates suggests that six-year dividend projections may not fully capture long-term investor expectations; the indicated cost of equity is only 19 basis points in excess of S&P's September 1998 Index long-term BBB-rated electric utility long-term bond yields of 6.70%. S&P's Bond Guide, October 1998. The Department accepts Mr. Sutphin's 8.28% earnings growth rate DCF estimate; however, the Department recognizes that Mr. Sutphin has chosen a proxy group that has a higher financial rating and less financial risk than BBB+ rated utilities. Therefore, the indicated cost of equity for a BBB+ rated utility would be somewhat higher than 8.28%.

Mr. Rothschild used the S&P 24 utilities group not because of its relative risk profile vis-a-vis CL&P but "because it is representative of the electric industry in the United States and all of the companies in the group are widely followed by investors." Rothschild PFT, p. 14. Mr. Rothchild's adjustment of the S&P 24 group to account for CL&P's greater risk is an acceptable methodology; however, the inclusion of NU among the S&P 24 is puzzling, given Mr. Rothschild's assertion that, "Northeast Utilities, the parent of CL&P, is not currently paying a dividend. This makes application of the DCF method problematic, so I did not include a DCF analysis of Northeast Utilities." Rothschild PFT, p. 13. The Department concurs that NU is not representative of the industry, given its nuclear and financial problems and current suspension of dividends. Mr. Rothschild's proxy group is acceptable, with the exclusion of Northeast Utilities.

Mr. Rothschild's b x r DCF model uses substantially the same method for calculating growth as his ROE testimony given in Docket No. 97-05-12. Decision dated December 15, 1997, p. 60. The b x r model relies on the assumption that "regulators should strive to set authorized earnings at the level required to result in a (M/B) ratio averaging approximately 1.0 in the long run." Rothschild PFT, p. iv. However, the Department recognizes that the M/B ratios are greater than 1.0 in the electric industry. Electric utility M/B ratios are in part influenced by the stock market rally in the nonregulated sector, in which firms have M/B ratios substantially greater than 1.0. As the electric utility industry transitions to competition, average M/B ratios can be expected to resemble more closely those of the nonregulated sector. The Department accepts the b x r growth rate model as theoretically sound, and, as such, accepts Mr. Rothschild's (simplified) DCF ROE average estimate of 8.51% and (two-stage) estimate of 8.94%. Schedule JAR-3. However, the Department recognizes that as the electric industry transitions toward competition, the practical value of the bv x r DCF model is diminished.

d. Risk Premium Model

The risk premium methodology estimates the cost of equity by measuring the differential in investors' expected returns between bonds and more risky equity. The risk premium model takes the general form:

$$k = D + R_p$$

where k is the cost of equity, D is the cost of debt (which can be measured as a risk free rate or the rate on a corporate or utility bond), and R_p is the investors' risk premium over a debt instrument.

Mr. Wiater developed a risk premium model by using the average yield-to-maturity of a 20-year BBB-rated utility first mortgage bond, which as of May 1998 was approximately 7.1%. To the cost of debt, he added the historical risk premiums based on data from Ibbotson Associates, averaged over the last 15 years. Wiater PFT, pp. 7-11. Using the arithmetic mean, the risk premium, averaged over 15 years using Ibbotson Associates data, was 5.9 percent. This resulted in a risk premium ROE estimate of 13.0%.

For his risk premium model, Mr. Sutphin used a 30-year time period to measure the risk premium between stocks and bonds. According to Mr. Sutphin, this time period "best displays the variety of economic conditions that investors would anticipate such as inflationary times, capital market changes, and changes in monetary policy." Sutphin PFT, p. 18. Using the Ibbotson Associates 1968-97 data measuring the arithmetic average difference in return between large company stocks vs. Aaa-/Aa bond yields results in a differential of 3.88%. Using A-rated utility debt for the first quarter of 1998, as published in the June 31, 1998 Blue Chip Financial Forecasts, results in a cost of debt of 7.03%. When the equity risk premium is added to the cost of debt, the estimated cost of equity for an A-rated utility is 10.91%.

Mr. Rothschild used regression analysis for the electric industry as a whole to obtain a risk premium estimate of the "average" electric utility cost of equity. In his multiple regression analysis, the estimated cost of equity, the dependent variable, is a function of a constant and two independent variables, the US Treasury bond rate and the external financing rate faced by electric utilities. Using three different Treasury maturities, 1 year, 5-years, and 30 years, he obtained three risk premium ROE estimates, 10.54%, 9.59%, and 7.75%, respectively. Rothschild PFT, pp. 31 and 32. Schedule JAR-10, p. 2.

An alternative risk premium model, the capital asset pricing model (CAPM), calculates the riskiness of an equity investment over a long-term risk free bond, measured by the historical spread of stocks over the risk free rates, multiplied by the stock's beta risk, B, measure:

K_{CAPM} = $R_F + (R_M - R_F)B$
where R_F = long-term US Treasury bond rate
$R_M - R_F$ = difference between large company stocks and long-term government bonds, and
B = Beta, average systematic risk for electric utilities.

Mr. Wiater developed the CAPM risk-free rate by taking the average of 13-week and 26-week Treasury Bill rate during the month of February 1998, which resulted in a risk-free rate of 5.08%. To obtain $R_M - R_F$, he used Ibbotson data to measure the spread between large company stock returns and returns on US Treasury Bills for the years 1983-97. This resulted in a historical spread, $R_M - R_F$, of 12.04%. To obtain Beta, which measures the relationship between the return on a stock and the return on the market as a whole, Mr. Wiater obtained Beta estimates from Value Line. The average Beta for the proxy group was 0.71. Inputting the data, Mr. Wiater obtained a CAPM cost of equity estimate of 13.64%. Wiater PFT, p. 15; Exhibits MAW-3 and MAW-4.

Mr. Sutphin used a similar methodology for the risk premium and CAPM version of the risk premium model. He averaged the yields on 13-week and 26-week US Treasury Bills for the time period June 1, 1998, to June 30, 1998, which resulted in an average risk-free rate, R_F, of 5.05%. Using Value Line Betas for each company in the proxy group produced an average of 0.715. Exhibits JKS-10 through JKS-13. The risk premium was measured as the arithmetic average of the premium of large company stocks over US Treasury Bills, as compiled by Ibbotson Associates. This resulted in a risk premium of 6.52%. Mr. Sutphin's CAPM model estimated a cost of equity of 5.05% + 0.715 x 6.52% = 9.71%.

Mr. Rothschild used a third risk premium method, the inflation risk premium model. According to the source data, as compiled by Jeremy Siegel, "stocks have yielded between 6.6 and 7.2 percent per year after inflation in all major subperiods [from 1802 through 1997]." The historical returns on stocks net of inflation were computed using the geometric mean. Tr. 9/23/98, p. 2311. He points out, however, that, "Ever since World War II, during which all the inflation in the US has experienced over the past two hundred years has occurred, the average real rate of return on stocks has been 7.5

percent per year."[27] Mr. Rothschild supports the inflation risk premium formulation because, unlike volatile equity risk premiums, "the stability of the historic inflation premium makes it a much more reliable historically based measure than an historically based bond interest risk premium." Rothschild PFT, p. 29. Mr. Rothschild calculates the inflation expectation by observing that inflation-indexed Treasury securities maturing on April 2028 were priced to yield 3.68%, compared to non-inflation-indexed Treasury securities maturing in November 2027, which had a yield of 5.67%. According to Mr. Rothschild, the differential, approximately 2.0%, is the long-term inflation expectation of investors. Adding this 2.0% inflation expectation to Mr. Siegel's calculation of historical equity earnings of 6.6% and 7.2%, results in an indicated cost of equity of 8.6% to 9.2% for a "plain vanilla" equity of average risk. Rothschild PFT, pp. 30 and 31; Schedule JAR-10, p. 2. Mr. Rothchild makes no risk adjustment for the electric utility industry or for CL&P's risk, so that this model can be accepted only as a very general guide. Using the more recent post-WWII equity return of 7.5% offered by Mr. Siegel results in a 9.5% ROE estimate for an equity investment of average risk.

e. Department Analysis of Risk Premium

In this proceeding, Mr. Wiater and Mr. Sutphin, who use Ibbotson Associates historical data in their risk premium models, both make use of the arithmetic mean when comparing average returns of stocks and bonds. Mr. Rothschild, while employing alternative risk premium models, is highly critical of using the arithmetic mean. He also opposed Mr. Wiater's use of a 15-year historical time period for evaluating historical stocks and bond returns. Rothschild PFT, pp. 46-50.

The arithmetic vs. geometric mean controversy is a perennial issue in the historical risk premium model as is the number of years to be considered in the equity premium data set. The geometric mean is a suitable measure of actual historical or *ex post* returns on a reinvested security, and in data series with high variances relative to the mean, it provides a more mathematically accurate measure of actual historical earned returns. The arithmetic mean measures the *ex ante* return of a security reevaluated annually. Thus, it was favored by Messrs. Waiter and Sutphin as a superior measure of investors' expected return.

With regard to the length of the historical series, Mr. Wiater chose the 15-year historical period because of the following economic features included in the data series: a period of sustained expansion as well as a short recession, 1990-91; relatively low inflation and weak energy prices; relatively stable financial markets, and a stock market correction. Wiater PFT, p. 8. Mr. Sutphin elected to use the 30-year time frame because it "best displays the variety of economic conditions that investors would anticipate such as inflationary times, capital market changes, and changes in monetary policy." Sutphin PFT, p. 18. Mr. Rothschild took issue with Mr. Wiater's use of 15 years as almost exclusively including those years in the recent bull market. As evidence, Mr. Rothschild cited Jeremy Siegel's book, Stocks for the Long Run:

[27] Jeremy Siegel, Stocks for the Long Run, McGraw Hill, 1998, pp. 11 and 12.

> The bull market from 1982 through 1997 has given investors an after inflation return of 12.8 percent per year, which is nearly six percentage points above the historical average. But the superior equity returns over this period has barely compensated investors for the dreadful stock returns realized in the previous 15 years, from 1966-1981, when the real rate of return was -0.4 percent. In fact, during the 15-year period that preceded the current bull market, stock returns were more below their historic average than they have been above their average during the past 16 years.[28]

Mr. Wiater disagreed with Mr. Sutphin's use of the 30-year time period. Mr. Wiater pointed out that the 30-year data set provided the lowest arithmetic mean of any recent Ibbotson Associates data subset. As such, he viewed the 30-year time horizon as unrepresentative of the long-term equity risk premium faced by investors. Tr. 9/23/98, pp. 2108 and 2109.

The Department views with concern the use of relatively short historical time periods, given the large variability in the Ibbotson Associates data set for large company stocks and bonds. In this proceeding, the Department pointed out that given the large variance in average equity returns, it is impossible to distinguish statistically that a difference exists between the average returns of stocks vs. bonds over a 15-year time period.[29] Mr. Wiater suggested that investors rarely use statistical analysis to form their earnings expectations. Tr. 9/23/98, pp. 2156-2158. While that may be technically correct, the Department believes that predictive models for which the data yield no statistically significant result should be used with extreme caution. In the case of Mr. Sutphin's 30-year data set, there were enough data points to pass the statistical significance test.

Although the Department does not reject Mr. Wiater's version of the risk premium model, it must be considered with extreme caution. Aside from the statistical infirmity described above, it produces an indicated ROE that is in excess of Value Line's 12.0% expected return for the industrial composite. As pointed out earlier, Mr. Wiater testified that a restructured electric industry "would probably be perceived as slightly less risky than industrials overall if you weight the regulated and nonregulated [sectors]." Tr. 9/23/98, p. 2145.

Mr. Wiater's 15-year historical risk premium, with an update of BBB-rated electric utility bond yields produces the following indicated ROE:

6.70% September 1998 BBB-rated Electric Utilities Bond Yield[30]
\+ 5.89% 15-year equity risk premium
12.59%

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[28] Jeremy Siegel, Stocks for the Long Run, McGraw Hill, 1998, p. 14, as cited in Rothschild PFT, p. 45.

[29] A difference of means test yields a T-value of 1.39, which is lower than the critical T-value of 2.131 at the 5% level of significance.

[30] Standard & Poor's Bond Guide, October 1998, p. 3. BBB-rated Electric Bond Yield Index, average 15 year maturities.

The Department also considered Mr. Wiater's charge that Mr. Sutphin's 30-year time horizon was an "anomaly" over the 1926-1997 time horizon. Tr. 9/23/98, p. 2113. Mr. Sutphin's 30-year data series contains the recent bull market as well as the entire decade of the 1970s. The 1970s were characterized by high inflation, high energy prices and low economic growth rates. Of the 15 additional years included in Mr. Sutphin's data set, 7 are years with negative equity premiums. Exhibit JKS-11, p. 2. The Department concurs with Mr. Wiater that a 15-year time horizon more accurately reflects the current economic conditions faced by investors.

In evaluating the arithmetic vs. the geometric mean, The Department favors the risk premium models using the arithmetic mean offered by Messrs. Waiter and Sutphin. However, the Department recognizes the valid criticisms of the arithmetic mean raised by Mr. Rothschild.

Using an update of the 13-week and 26-week Treasury bills (4.22%)[31] and the arithmetic mean of the 15-year time horizon (12.04%) for the CAPM model results in an indicated cost of equity of 12.77% = 4.17% + 0.71 x 12.04%. Mr. Rothschild's inflation risk premium model provides a general insight with regard to investor long-term equity returns, and as such the Department includes it within the risk premium models. However, the Department adjusts the model by using Siegal's estimate of the post-World War II inflation equity premium of 7.5%, rather than the long-term 1802-1997 equity premiums of 6.6% to 7.2%. The Department accepts Mr. Rothschild's adjusted inflation risk premium cost of equity estimate of 7.5% (inflation equity premium) + 2.0% (inflation rate) = 9.5%, as well as the average 9.29% ROE estimate obtained in his regression analysis risk premium models.

f. Other Cost of Equity Estimates

As part of his testimony, Mr. Wiater also submitted cost of equity estimates of his nine-member proxy group by investment analysts at Salomon Smith Barney. The average cost of equity for the proxy group was 11.39%. Exhibit MAW-9. Although the Department has accepted ROE estimates and key financial analyses from outside sources, these have been chiefly from widely published sources (e.g., Value Line), published scholarly journals or forecasting services. In these instances, source material, authorship, and description of methodology were offered as testimony. On other issues in the instant docket, when key information was presented by outside sources, it was accompanied by testimony from identifiable witnesses made available for cross-examination. The Department believes that accepting a set of numerical estimates of unknown analyst(s) at Salomon Smith Barney with unexplained methodology and data sources would set an unwise precedent, and hereby rejects these cost of equity estimates. Tr. 9/23/98, pp. 2193 and 2194; 2231 and 2232.

g. Conclusion on Cost of Equity

In this proceeding, the Department accepted ROE estimates ranging from Mr. Sutphin's 8.28% earnings growth DCF model to Mr. Wiater's (adjusted) 12.77% CAPM estimate. The Department believes that a reasonable range is 8.73% to 12.0%. The

[31] Source: Federal Reserve Economic Data Base.

Department accepted Mr. Sutphin's 8.28% earnings growth DCF model, recognizing that a DCF estimate for a BBB-rated utility group would be somewhat higher than Mr. Sutphin's A-rated proxy group. Mr. Wiater's blended DCF estimate of a BBB-rated proxy group and the Value Line Industrial Composite, as adjusted by the Department, resulted in an ROE estimate of 8.73%. While the Department has already pointed out that Mr. Wiater's proxy group is somewhat riskier than a BBB+ rated utility, the 8.73% indicated ROE serves as a useful low-end estimate. The Department believes that the 12.0% projected equity earnings of the Value Line Industrial Composite provides the maximum for the reasonable cost of equity range. It is not reasonable to assume that the risk of a BBB+ rated electric utility, not yet transitioned to competition, would exceed that of the nonregulated market. The higher equity costs of Mr. Wiater's (Department updated) 12.59% risk premium and 12.77% CAPM models are considered, subject to this 12.0% ceiling. The midpoint of the reasonable range is 10.36%, and the Department concludes that 10.3% is a just and reasonable return on equity that adequately compensates investors for the risks assumed.

Also to be considered in the setting of a 10.3% ROE are the interest rate changes since the Department's financial review of the Company in Docket No. 97-05-12. In that Decision, dated December 15, 1997, the Department deemed an ROE of 10.7% as reasonable and appropriate. An examination of short-term, intermediate and long-term US Treasury bonds, and electric utility bonds during mid-October to mid-November 1997 and mid-October to mid-November 1998 (four weeks preceding the close of hearings in both dockets) show the following:

	1-Year US Treasury	**5-Year US Treasury**	**20-Year US Treasury**	**Standard&Poor's Electric Utility Bond Index (avg. maturity:15 years)**
October 1997	5.44%	5.86%	6.30%	7.23%
October 1998	4.27%	4.38%	5.45%	6.70%
Basis Point Change	-117	-148	-85	-53

Given the significant decline in interest costs over the last 12 months, the Department has made a reasonable adjustment of 40 basis points from the allowed return on equity of 10.7% set in Docket No. 97-05-12.

The Department approved capitalization, below, is based on Schedule D-1.0, Revised. An allowed return on equity of 10.3% enables the Company to earn an overall return on rate base of 8.05%.

For purposes of §16-19(g) of the Conn. Gen. Stat. the Company will be monitored based on actual average equity (cost of capital).

6. Weighted Cost of Capital

The Department finds a weighted cost of capital to CL&P of 8.12% to be reasonable and appropriate for year end 1998 based on the following weighting of component costs.

ALLOWED WEIGHTED COST OF CAPITAL

1998

FINANCIAL INSTRUMENT	PERCENT	COMPONENT COST	WEIGHTED COST
Short-term Debt	2.82%	5.23%	0.15%
Long-term Debt	54.71%	7.14%	3.91%
Preferred Stock	7.54%	6.27%	0.47%
Common Stock	34.93%	10.30%	3.60%
Total	100.00%		8.12%

N. CL&P'S FINANCIAL CONDITION OF FINANCIAL GOALS

Meeting the increased O&M and replacement power expenses associated with the ongoing Millstone outages has had a significant negative effect on the earnings and financial ratings of CL&P. Although MP3 returned to service in July 1998, the effect of the continued outage at MP2 from incremental O&M and ORB customer surcredits is to increase costs by approximately $11 million per month. Notwithstanding the delay in the restart of MP2 from the 4th quarter of 1998 to the 1st quarter of 1999, the return to service of MP3 and the expected return of MP2 have enabled the Company to take the initial steps toward financial recovery. On July 22, 1998, in response to the restart of MP3, Moody's upgraded CL&P's rating from Ba3 to Ba2. Standard & Poor's (S&P's), which had placed the Company on credit watch on April 8, 1996, removed the credit watch status on July 21, 1998. Despite these improved ratings, the Company remains two steps below investment grade at Ba2 (Moody's) and BB (S&P's). Tr. 9/10/98, p. 303.

To address the deteriorated financial circumstances of NU and its subsidiaries, on November 21, 1996, NU, CL&P and WMECO entered into a new revolving credit agreement (New Credit Agreement) and on May 30, 1997, NU entered into a First Amendment and Waiver to the New Credit Agreement. Interest coverage and common equity ratio requirements were revised downward to enable the companies to meet their financial requirements. Under the First Amendment and Waiver, CL&P has been required to maintain a common equity to total capitalization of at least 32% after December 31, 1997. The First Amendment and Waiver has also required the Company to maintain an interest coverage ratio of 1.25 through December 31, 1997; 1.5 from January 1, 1998, through June 30, 1998; 2.0 from July 31, 1998, through September 30, 1998; and 2.5 thereafter.[32] The Company was able to meet its covenant requirements

[32] Docket No. 97-05-12, Decision dated December 15, 1997, p. 54.

for the first and second quarters of 1998; however, CL&P's witness, Mr. Forsgren, predicted that the Company would be unable to meet its requirements for the 3rd and 4th quarters of 1998.[33] Tr. 9/10/98, p. 304. Due to the anticipated inability to meet these requirements, the Company has renegotiated its covenant terms with its banks.[34] The Company believes that renegotiated benchmarks will afford it the financial flexibility during late 1998 and all of 1999, particularly before the restart of MP2. According to Mr. Forsgren, the banks have been willing to renegotiate the terms of the covenant agreements because of their confidence in CL&P's financial recovery due to the restart of MP3. Tr. 9/10/98, p. 309. In summarizing CL&P's financial outlook, Mr. Forsgren concluded that "while the company's financial condition is and will remain stressed, the ongoing recovery of the company's nuclear program will enable the company to continue to improve over the next several quarters." Tr. 9/10/98, p. 305.

In Docket No. 97-05-12, the Company expressed concern over its ability to extend into the future two sources of external capital, the $90 million short-term financing vehicle in the Niantic Bay Fuel Trust and the letters of credit (which expire during the 3rd and 4th quarters of 1998) required to extend $362 million in tax-exempt variable rate pollution control notes. Decision, p. 55. Since the Decision in Docket No. 97-05-12, these uncertainties have been eliminated. With regard to the Niantic Bay Fuel Trust, on June 1, 1998, the Company issued $180 million in Series G notes, the proceeds of which were used to refinance $80 million in Series F Intermediate Term Notes that expired on June 5, 1998, and to refinance $90 million in short-term borrowings held in the Trust. Thus, the short-term borrowing instrument in the Niantic Bay Fuel Trust was effectively eliminated. Docket No. 91-06-04, Application of The Connecticut Light and Power Company and Western Massachusetts Electric Company with Respect to Nuclear Fuel Financing Arrangements, Decision dated May 27, 1998. In the case of the pollution control notes, on October 1, 1998, CL&P converted $361.9

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[33] The Company's 1998 performance with regard to its required financial ratios is as follows:

	Equity Ratio	Coverage Ratio
1998 Q1	32.54%	3.05
1998 Q2	32.66%	1.59

Projected equity and coverage ratio for the 3rd and 4th quarter of 1998 are as follows:

	Equity Ratio	Coverage Ratio
1998 Q3	31.80%	1.47
1998 Q4	31.27%	1.97

Source: Late Filed Exhibit No. 2, pp. 11 and 12.

[34] The Second Amendment and Waiver imposed the following covenant requirements on CL&P:

	Sept. 1998	Dec. 1998	Mar. 1999	Jun. 1999
Interest Coverage Ratio:	1.25	1.35	1.75	2.00
Equity Ratio	31.0	31.0	31.0	31.0

Source: Late Filed Exhibit No. 2, pp. 11 and 12.

million in pollution control notes from variable to fixed rate securities. By issuing fixed rate notes, CL&P eliminated the need for the extensions of the letters of credit. Docket No. 88-09-01, Decision dated September 23, 1998.

The Company's ability to borrow has been limited by its lowered financial ratings. Under the First Amendment and Waiver, CL&P is able to assume up to $225 million in short-term borrowings; however, because the Company risks violation of its covenant restrictions, it has been effectively prohibited from borrowing the full amount. The Company's First Mortgage Bond indenture prohibits CL&P from issuing new money bonds when its interest coverage ratio falls below 2.0. The Accounts Receivable Program enables the Company to draw up to $200 million and is not considered debt for accounting purposes. CL&P is able to draw upon these funds since its financial ratings remain above the BB- (S&P) and Ba3 (Moody's) financial benchmarks.

The Company's forecasted capital structure shows short-term debt rising to approximately $281.3 million by year-end 1999, for an average of $180.7 million during 1999. For the 1999 rate year, short-term debt is projected to average 5.54% of capital structure and to rise to 8.51% of capital structure by year-end 1999. Schedule D-1, Revised; Schedule D-1.1, Revised. Mr. Forsgren explained that the Company plans to use short-term debt as bridge financing until early 2000, when CL&P expects to securitize the proceeds of its sale of non-nuclear assets. Tr. 9/10/98, pp. 377 and 378. The Company plans to finance its rising short-term debt in 1999 through its Revolving Credit Agreement; however, the 1999 projected short-term debt of $253.4 million exceeds the Company's short-term borrowing limit of $225 million under the current terms of the Revolving Credit Agreement. The Company hopes that the restart of MP2 will significantly enhance its borrowing capabilities under the covenant restrictions of the Revolving Credit Agreement. Moreover, the Company intends to negotiate a new revolving credit agreement in 1999, after MP2 returns to service. The Company believes that it would be able to negotiate more favorable terms (e.g., a higher borrowing limit) in a new short-term borrowing agreement. Tr. 9/14/98, pp. 768-770.

The Company's 1999 financial projections show modest progress in earnings recovery during 1999, assuming the first quarter 1999 restart of MP2 and CL&P's proposed rate plan. Late Filed Exhibit No. 2, pp. 11 and 12. In addition to spending on priority O&M and reliability measures, the Company intends to use the additional earnings to pay down long-term debt maturities and eventually to restore dividends on common stock. Tr. 9/10/98, pp. 405 and 406.

O. CUSTOMER SERVICE ISSUES

1. Customer Billing

a. No Bills

The Company does not produce a bill for an account when there is insufficient information on the customer's usage. This practice is known as generating a "no bill." The Company currently tracks only the potential no bills, that is, customer accounts that possibly will not have a bill produced in any given month. The Company manually calculates billing for some of these accounts, using estimates or new meter readings.

However, for the remainder, a bill is not generated for the account. Tr. 10/20/98, p. 3906. The Company's billing system automatically creates a monthly summary report of the potential no bill accounts. The Company stated that "for the vast majority of the accounts on this report an actual reading can be obtained or an estimated reading can be generated, and the Company will then manually intervene to produce a bill for the customer." Late Filed Exhibit No. 174. However, the Company has no internal tracking mechanism that reconciles the number of potential no bills with the number of no bills that were manually worked and the number of accounts for which no billing actually occurred in any given month. Therefore, the Company can only estimate the actual number of no bills for any given month or year. Tr. 10/20/98, pp. 3903 and 3906.

According to Company estimates, the number no bills is well below one percent of the total bills generated. Late Filed Exhibit No. 174. The Department is concerned about the Company's use of no bills on customer accounts and the inadequacy of the Company's system for tracking its no bills to their final conclusion.

Since the actual number of no bills is small, and the Company has the capability to intervene and manually produce a bill, the Company should produce a bill for each customer account. The Department cannot find any justification for the Company's continued use of no bills and concludes that a monthly bill should be produced for each customer account.

The Company shall produce a customer statement for each potential no bill every month, either through the normal billing process or through manual intervention.

b. Prorated Bill Format

The Company recently revised its format for prorated bills to indicate the monthly customer charge as a separate line item. Previously, the Company included the customer charge with the prorated energy charge. Late Filed Exhibit No. 127. The revision has increased the number of computations that appear on the bill. In addition, the Company now normalizes prorated bills. Tr. 10/15/98, pp. 3637-3639. Normalization involves two separate calculations. The first step normalizes the kWh consumption, projecting the kWh consumption on a monthly basis. In the second step, the normalized amount is prorated by using the actual number of days within the billing period. However, CL&P does not explain normalization or why it is used. As the Company stated, customers who have trouble with the normalization formula must call the Company for an explanation. Tr. 10/15/98, pp. 3637-3638.

The Department is concerned about the increased level of detail that the calculation involves and the lack of explanation. The Company initiated this change without prior Department notification or review. The Department believed that chances such as these should be subject to review. Therefore, the Company must submit any future changes in its customer billing policies, practices or forms to the Department for prior approval and will be required to meet with the Department's Consumer and Assistance Unit to develop a prorated bill format that is easier to understand.

2. Customer Service

a. Off-hours

The Company's business offices provide regular hours for customer service either between 7:30 a.m. and 3:30 p.m. or between 8:00 a.m. and 4:30 p.m. In addition, the Company also provides off-hour appointments or meter readings on Saturdays or in the early a.m. The Company submitted a list of its 12 business offices with their normal operating hours for customer appointments. However, the Company's list did not itemize the hours that are available for off-hour customer appointments on Saturdays or in the morning. Late Filed Exhibit No. 131. During the hearing, the Company stated that Saturday hours are generally the same as normal business hours, 7:30 a.m. to 4:00 p.m. Tr. 10/15/98, pp. 3640-3642.

The Department questions whether these off-hours are regularly offered by the individual business offices, because the Company's list indicates that they are available "when required." It is also questionable whether the Company's customer service representatives are aware of the variation in Saturday and morning hours as the Company's list does not itemize the hours. Customers may not be provided with consistent and correct information about the hours that are available. The Department will order the Company to submit a list of its customer service hours that itemizes the actual off-hours available for each business office. The Department also believes that the Company should provide the Department with any changes that it makes to its customer service policies and procedures prior to their implementation.

b. Average Hold-Time for Customer Calls

According to testimony, the Company has stopped setting an Average Speed of Answer (ASA) target for hold-times for answering customer calls. The Company utilizes two separate methods for determining hold-time for calls, one for in-house use and one for reporting to the Department. For in-house use, the Company sets its target for hold-times based on the percentage of calls answered within 60 seconds. The average hold-time is calculated from the time the Company's phone system initially accepts the customer call and begins its recorded message. Two phone numbers are utilized in determining this average hold-time, the number for the customer service call center in Wethersfield and the number for the credit and collections call center in Berlin. The Company continuously monitors hold-times in the call centers using a display board system showing all staff the average hold-time for the last 10 minutes.

The Company sets different targets for the percentage of calls answered in 60 seconds for each center, 68% for Wethersfield and 59% for Berlin. Late Filed Exhibit No. 168, Read-In AAA. However, the Company did not indicate why it has established different targets for these two centers. The Company stated that it sets an official goal for these hold-times once a year, but was not specific on the details of the goal setting process. In addition, the Company did not explain its method for determining the average call hold-times that it reports in seconds of duration to the Department monthly nor did it explain how the percentage targets it uses in-house correlate with the average hold-times reported in seconds. Tr. 10/20/98, pp. 3908-3912. The Company's testimony raised more questions than it answered. Therefore, the Department will

require the Company to submit its criteria and rationale for determining the reported average hold-times for customer calls.

3. Most Beneficial Rate

CL&P's Rules and Regulations state that all customers are entitled to request service under the lowest applicable rate and that the Company will, upon request, assist a customer in choosing the most favorable rate. CL&P Rules and Regulations, Choice of Rate, Section 1.6. Further, CL&P's Commercial/Industrial Rate Assignments & Changes Policy CS-3 (Policy CS-3) states that a reasonable effort will be made to advise and assist a customer in the selection of a proper rate. Policy CS-3, Item III. In addition, the Company uses bill inserts to notify customers of available rate schedules. These bill inserts are distributed annually and include a request for customers to review their billing information. Late Filed Exhibit No. 171. Although there is a "process that should happen," to insure customers are served at the most beneficial rate, there is no formal policy in place to assure that it does. Tr. 10/15/98, p. 3670; Response to Interrogatory EL-350; Late Filed Exhibits No. 126 and 171.

The Company has no formal procedure for assisting residential customers in selecting the best rate. CL&P attempts to satisfy customer requests concerning rate assignments over the phone and if the customer requires additional assistance Company personnel will schedule a site visit. Site visits are not automatic and are done on a case-by-case basis. Appointments are rarely scheduled at a customer's home. Tr. 9/28/98, pp. 2780-2783. The vast majority of residential customers are assigned to Rate 1 or 5. Response to Interrogatory EL-350.

For commercial accounts, the Company generally relies on historical load information from each service location to determine the rate assigned to the new customer and the rate assignment is based on anticipated demand. For example, demands of less than 350 kW are assigned to Rate 30 or 35, while demands in excess of 350 kW are assigned to one of CL&P's Time-Of-Day rates Tr. 10/15/98, p. 3647-3648. For industrial customers, the Company monitors the billing demand of accounts taking service under Rates 55, 56, 57 and 58. If the demand does not exceed 350 kW for 12 consecutive months, the customer has the option to take service on Rate 35. In these situations, service under Rate 35 will generally reduce a customer's bill. Response to Interrogatory EL-350.

Although Policy CS-3 mentions the assignment of a rate, it essentially deals with a follow-up review once a customer has been assigned to a rate. This policy establishes procedures for the review of historical billing data for commercial and industrial customers assigned to Rates 30, 35 and 40. This procedure, commonly referred to as the Most Beneficial Rate Report (MBR), does not require the evaluation of all commercial and industrial accounts or accounts that have less than 6 months' billing history. CS-3 Appendix I. The MBR is generally issued twice annually, although there is no requirement that this occur. Id.

There are no procedures in place to assure that all customers are receiving service under the most beneficial rate. Although CL&P's account representatives query new customers to determine rate assignments, this does not always result in the

provision of service at the most beneficial rate. Late Filed Exhibit No. 171. It is ultimately the customer's responsibility to request additional information or assistance on rate assignment, with the final choice of rate being determined by the customer. Tr. 9/28/98, pp. 2782-2783.

Utility costs for CL&P's largest customers generally represent a significant component of operation and maintenance expense. These customers often possess the expertise to evaluate the assignment to, and ongoing provision of, service under an appropriate rate. However, the majority of customers lack this expertise. In these cases it appears reasonable for the customer to rely on the Company to aid in the selection of the most advantageous rate. However, CL&P's current policies are not set up to assure this result. Instead, current policies place the burden of choosing a rate with the customer. This must change. The Company must be proactive in assuring not only that customers are made aware that there may be more beneficial rates available, but that the best possible rate is selected initially. However, the customer remains responsible for notifying the Company when a change in usage or equipment might result in the provision of service under a more beneficial rate.

Therefore, the Department will require CL&P to develop a policy to address this issue.

4. Emergency Response Procedures

In the recent past, the Company's emergency responses to de-energize power lines were inadequate. The Company established the Emergency Response Task Force (ERTF) to examine issues related to its response time in de-energizing power lines in emergencies. The ERTF was composed of representatives of police and fire departments within the Tolland area, State of Connecticut fire and public safety departments and CL&P personnel. The ERTF's goal was to develop recommendations that would ensure the safety of emergency workers and the public and also protect property by optimizing the Company's response to emergency incidents. Recommendations would be proposed statewide, but implementation in any area was subject to acceptance by local and state emergency personnel. ERFT Final Report, September 1997, p. 1.

In its final report dated September 1997, the ERTF focused on three key areas for improvement: communications, response and training. To improve communications, the Company developed the Priority Level System (PLS) to promote a statewide system for communication between local and state emergency response personnel and Company personnel. PLS categorizes electrical emergencies into three priority levels: Level 1 for a life threatening situation; Level 2 for a situation that hinders operations; and Level 3 for a routine downed wire or other non-emergency situation. In utilizing the PLS, the Company reports to an incident commander for better assessment of the situation, using a common terminology developed to communicate when safety at the scene is secured. The Company has also developed a plan to review and critique all Level 1 Priority Calls, to solicit input from its craft workers for improving responses, and to schedule regular follow-up meetings to monitor the response system. In addition, the Company has offered to make its employees available to town emergency operations

centers to act as liaisons with the Company operations center in the event of major storm emergencies. Id., pp. 2 and 6-8.

Improvements in training for electrical hazard situations is a major component of ERTF's recommendations. Emergency services (fire, police and EMS) and local public works personnel would be offered comprehensive and refresher training on electrical hazards and safe work procedures. An added module to the current training mandated by the Office of Statewide Emergency Telecommunications (OSET) would provide for local emergency telecommunicators to receive recurring in-service training on incidents involving electrical hazards. All state agencies responsible for training would work cooperatively to develop a standardized multidiscipline curriculum for safe response to electrical emergencies. In addition, electrical hazard training props would be installed in statewide training centers and the Company and other electric utilities would provide support for ongoing training efforts for local and state agencies. The Company would also offer an Electrical Safety Program and video for enhanced training on electric distribution systems and hazard responses. Id., pp. 2 and 10-11.

A critical element of the ERTF recommendation is the development of an acceptable range of response times for electrical emergencies. The ERTF reviewed data and recommended an average response time of 23 minutes for Level 1 and Level 2 emergencies with an ultimate time goal of less than 20 minutes. ERTF also recommended that the Company schedule linemen to serve on-call by the zone in which they live and establish the number of personnel to respond to Level 1 and Level 2 emergencies. A minimum of two responders would be dispatched with the closest lineman dispatched first. A back-up coverage system would be developed in the event that all linemen available for emergency call outs were working and unavailable to respond to a new emergency. Id., pp. 2 and 13-14.

The recommendations of the Task Force were subsequently accepted and implemented in the 14 towns in the Company's Enfield/Tolland district. Implementation is currently underway in the remaining 21 in the Capitol Region Council of Governments (CRCOG) that are not part of the Enfield/Tolland District. The schedule for implementation of the remaining 114 towns within the Company's territory is presently being developed with an expected goal for final implementation by the end of 1999. Response to Interrogatory EL-353.

Additional ERTF recommendations for possible future consideration include: the installation of equipment for remotely switching lines to de-energize an area; the installation of external disconnect on residential services, pending the approval of state and local authorities; and the mutual support of adjacent districts for response in Level 1 emergencies. Response to Interrogatory EL-353; Late Filed Exhibits Nos.123 and 123-SP01.

The Department recognizes the potential for improvements to the Company's internal system for response to safety and emergency situations. The Company has identified two key areas that require upgrading to improve the Company's ability to handle public safety situations. The first targeted area for internal improvement is the staffing of the number of emergency response personnel who provide coverage after hours. The Company is devoting more resources to hiring more personnel. The

Company is also increasing the use of cellular phones in its aerial trucks to augment its radio communication. Late Filed Exhibit No. 124. The second area is the advancement of the Company's distribution SCADA program. SCADA has two uses that enhance the ability to monitor the distribution system: one is to provide information about the status of the distribution system; the other is to de-energize lines remotely, actually opening and closing devices. Tr. 9/28/98, p. 2788; Tr. 10/15/98, pp. 3669-3670.

Currently, the Company has installed some SCADA equipment for the purpose of reporting information to dispatch centers. There are two or three substations throughout the distribution system that have some SCADA where the dispatch centers are able to open and close devices as well as receive intelligence from devices. In 1999 and beyond, the Company plans to expand the use of the SCADA system both by developing a front end to be located at the dispatch centers that will interpret data and also by installing remote terminal units at additional devices throughout the system. In the first year of a three-year expansion plan, the Company will install SCADA at site-specific locations where the need to operate the devices is considered critical. In subsequent years, SCADA will be installed at devices where there is a maximum benefit from being able to operate it as a central location open or closed. Five years from now, the Company envisions that it will have installed SCADA as a way of de-energizing down conductors at its remote rural substations. Subsequent to this, the Company will install SCADA on field devices throughout all of its circuits and will have about 70 percent coverage for opening and closing its system. Tr. 9/28/98, pp. 2787-2790; Tr. 10/15/98, pp. 3669 and 3670.

The Company's efforts in implementing the recommendations of the ERTF and its internal improvements are positive steps toward improving the Company's current emergency responses. The continual improvement of the Company's internal emergency response system is an integral component of ensuring public safety. The Department will continue to monitor the statewide implementation of the ERTF recommendations and also recognizes the need to monitor the Company's internal improvements going forward into the future. The Department will require the Company to submit a formal plan for internal improvements that includes details on each area scheduled for improvement, the specific improvements to be made and the target dates for implementation of the improvements.

III. FINDINGS OF FACT

1. The Company's CUO study did not consider fuel diversity, environmental impacts or employment.

2. MP1 was retired 12 years earlier than its license expiration date of 2010.

3. MP1 was retired for economic reasons, but there were other factors taken into consideration.

4. Replacement power cost forecasts are speculative.

5. The continued operation of MP1 would have provided CL&P ratepayers $84.5 million of positive economic value if it operated in 1999 and 2000.

6. The estimated restart date for MP1 was July 1, 1999, at a cost of $112 million.

7. MP2 may not return to service until early 1999.

8. CL&P proposes to replace the current ORB non-cash accrual with a cash credit on customers' bills for MP2 costs contained in the rate year effective September 28, 1998, for the period MP2 is shut down.

9. CL&P filed a MP2 ORB calculation based on the revised Application.

10. CL&P did not include materials and supplies in the MP2 ORB calculation.

11. CL&P calculated MP2 RPC by annualizing first quarter 1999 revised simulated replacement energy and capacity costs.

12. Total production for MP2 is estimated to be 5,527,000 MWhs at a total direct cost of $24,466,800.

13. CL&P did not reflect reduced oil prices in its MP2 ORB calculation.

14. The Company's filing includes MP2 O&M expenses $34.5 million higher than the 1990 - 1995 average, and MP3 expenses $11.8 million higher than this average.

15. The Work Planning and Control changes are intended to facilitate compliance with the NRC's Maintenance Rule.

16. The Material Condition Improvement Program integrates all coating and painting work in one department.

17. The Commitment Tracking Program changes create a centralized tracking system for all NRC commitments.

18. The Personal Computer Leasing Program replaces the previous policy of buying all personal computers.

19. The Consolidation of Information Technology and Support consolidated all information technology functions in one department.

20. The Calculation Tracking System creates a new system for tracking calculations.

21. The Material Equipment Parts List changes allow more detailed tracking of plant components.

22. The Condition Based Maintenance program creates methods to trend equipment performance to identify common component failures.

23. The proposed expense for non-capital modifications are consistent with historical expenses and the projects comprising them are typical of small modifications that occur throughout the life of a nuclear plant.

24. The Company's plant additions includes $1.12 million for the expansion of the Four Mile River Road building in East Lyme.

25. The Company's plant additions include $4 million for installation of underground oil tanks at MP1, that the Company is planning to modify for use at MP2, but the plans have not been finalized.

26. The Company's filing originally included $29,004,000 for plant additions at MP2 in 1999, which was subsequently reduced to $5,081,000.

27. The Company's request includes plant additions for T&D system improvements incurred in 1996 and 1997 at a cost of $16,066,474 to increase transmission import capacity during the Millstone outages.

28. The Company did not provide any information supporting the claim that transmission and distribution system improvements would have been required absent the Millstone outages, other than certain capacitor installations.

29. The Company's proposal for construction in 1999 totals approximately $312,250,000.

30. The forecast of future capital expenditures is consistent with past expenditures with the exception of distribution, which are expected to increase due to reliability improvement projects.

31. The Company's filing includes revenue requirements for four Devon Station gas turbines that were installed in 1996 to provide replacement capacity and energy while the Millstone units were out of service.

32. The Company filed revised decommissioning amounts of $512,000,000 for MP1; $460,000,000 for MP2; and $519,400,000 for MP3. The Company based the MP1 and MP2 amounts on the NRC minimum amount, and the MP3 amount on the site specific study for that unit.

33. The NRC does not consider the cost of non-radioactive waste removal to be a decommissioning cost.

34. The negative net salvage component of depreciation totals $7,210,587 for the fossil and hydroelectric plants.

35. The Company does not plan to shut down any fossil or hydroelectric plant prior to divestiture of those units.

36. Distribution reliability was affected by major storms in 1995 and 1996.

37. CL&P's enhanced tree trimming efforts are designed to prevent service interruptions.

38. Company documents demonstrate the effectiveness of covered wire and enhanced tree trimming in preventing tree contact outages.

39. The Company plans to expand the proportion of covered wire in its distribution system from 37% to 50% by 2003.

40. The nuclear units will be divested by January 1, 2004. The Company has no plans to shut down any nuclear units before MP2's operating license expires in 2015.

41. The Company continues to employ the practice of no bills on customer accounts, the number and potential dollar amount of which it can only estimate.

42. The Company has established extended service hours for off-hour appointments or meter reading. The Company did not provide the actual off-hours available to customers. The Department is not informed of changes to the service hours made available to customers by the Company.

43. The increased calculation on the Company's revised prorated bill format is more confusing than the prior format.

44. The Company did not provide criteria and rationale for determining average hold-times for calls from customers, as reported to the Department monthly.

45. The Company has incurred additional financing costs in the Niantic Bay Fuel Trust that have resulted from higher interest rates and fees associated with the prolonged nuclear outages at the Millstone plants.

46. A pension salary growth rate assumption of 4.5% would place CL&P at the mean of a 1997 Fortune 500 survey group of electric and gas companies for this actuarial assumption.

47. The Company's financial ratings remain two steps below investment grade at Ba2 (Moody's) and BB (S&P's).

48. Since Docket No. 97-05-12, the Company has been able to extend into the future two sources of external capital, $180 million financing in the Niantic Bay Fuel Trust and $362 million in pollution control notes.

49. The Company plans to use short-term debt as bridge financing until early 2000, when CL&P expects to securitize the proceeds of its sale of non-nuclear assets.

50. The Company's revised 1999 forecast overstates the amount of long-term pollution control notes held as variable rate securities, and as such, understates the embedded cost of long-term debt.

51. The Department approved cost of long-term debt is 7.14%.

52. The Company intends to hold approximately 5.5% of its capital structure in short-term debt during 1999 and the early part of 2000.

53. The Department approved capital structure is: short-term debt, 2.82%; long-term debt, 54.71%; preferred stock, 7.54%, and common equity, 34.93%.

54. Based on the evidence available, the Company's rate of return on equity should be 10.3% for ratemaking purposes.

55. Based on the evidence available, the Company's weighted cost of capital should be 8.12% for ratemaking purposes.

56. CL&P removed all MP1 out of rate base costs and revenues from the Application, except for the 1999 O&M Accrual.

57. CL&P retired MP1 on July 24, 1998.

58. MP1 was placed in extended maintenance mode prior to 1998.

59. CL&P ceased recording depreciation for MP1 when the unit was retired.

60. CL&P has not asked the Department to make a finding in this proceeding on the amount of MP1 regulatory assets it will be allowed to recover.

61. CL&P plans to release the Devon leased units at the end of their five-year lease.

62. CL&P's sales and revenues forecast reflects lost fixed costs as a result of C&LM initiatives.

63. CL&P currently recovers the costs of C&LM, including the amortization of capitalized expenditures, lost fixed costs, and a bonus incentive through base rates and the CAM.

64. CL&P achieved gains on sales of property each year from 1992 - 1997.

65. Section 8(h)(3) and (4) of the Act mandates that stranded costs for nuclear generation assets be reduced by the net proceeds that are above book value received by an electric company for the sale or lease of any real property after July 1, 1998.

66. MY currently has a proceeding before FERC to determine the rates it may charge its owners, including CL&P.

67. CL&P did not include CMEEC costs in the Application.

68. A new refueling outage O&M Accrual began on January 1, 1997, as part of the Settlement Agreement.

69. In the Application, CL&P estimated the next refueling outage for MP2 would occur in 1999.

70. CL&P currently estimates that the next refueling outage for MP2 will not occur until 2000.

71. The Application contained 1999 MP2 and MP3 annual O&M Accruals of $8.5 million and $7.2 million, respectively.

72. CL&P projects 1999 D&O insurance expense will be higher than prior years due to claims paid and higher liability limits.

73. CL&P proposes to use the revenue sufficiency contained in the Application to accelerate the amortization of the regulatory asset balance related to SFAS 109 deferrals by $19 million.

74. In accordance with the Decision dated April 29, 1998, in Docket No. 92-11-11, CL&P recorded an out of rate base accrual, with interest, from MP3 of $7.382 million from July 1, to 18, 1998.

75. The Company used the operating results for the 12 months ended December 31, 1997, as its test year.

76. The Company did not budget for potential employee lawsuit settlements prior to 1998.

77. The Company projected $1.1 million for employee relocation expenses for the 1999 rate year.

78. The Company included $550,000 in its advertising expense for the grassroots program.

79. The Company included $1.4 million in its advertising expense for industry restructuring.

80. Section 17 of the Act specifically states that it is the Department's responsibility to develop a public outreach program that will educated consumers on the issue of industry restructuring.

81. The Electric Power Research Institute, which has two taxable subsidiaries-EPRICSG, Inc. and EPRIGEN, Inc. provides extensive research and development services to the electric utility industry.

82. In 1997, the Company entered into a Transition and Retirement Agreement with its former CEO to reflect his election to retire. He is carrying out work as a consultant in support of litigation that pertains to outage related issues.

83. The Company has negotiated with its telephone service carriers to reduce costs.

84. The Company used a 1999 labor escalation rate of 3.6% derived from the Data Resources, Inc. review of the U. S. Economy, May 1997.

85. The actual labor escalation rates for 1996 and 1997 were 3.8% and 3.9%, respectively.

86. The actual salary increase for employees in 1998 was 4% versus the budget of 3.9%.

87. The total payroll for CL&P is a combination of direct labor CL&P charges and allocations from NUSCO and NNECO.

88. The actual NNECO employee level for September 1998 was 1,659.

89. The Company projects NNECO employee levels of 1,814 for 1999.

90. The Company has reduced contractors at Millstone in the range of 500 to 600.

91. The Company budgeted 2,456 CL&P employees for 1998. The actual as of September 1998 is 2,368.

92. The Company projects CL&P employee levels to be 2,589 for 1999.

93. The Company transferred approximately 250 positions from NUSCO to CL&P.

94. The Company budgeted 2,447 NUSCO employees for 1998. The actual as of September 1998 is 2,234.

95. The Company projects NUSCO employee levels to be 2,467 for 1999.

96. The 1999 salary program is based on the expected actual level of FTE's and labor dollars.

97. A new executive incentive plan which includes a deferred compensation plan, was implemented in 1998.

98. Executive incentive plans are paid by shareholders.

99. Executive base salary is the amount of executive compensation that has traditionally been allowed for ratemaking purposes.

100. The Company's top executives received a 4% salary increase in 1998. The Company has projected a 3.6% increase for 1999 for executives and other staff.

101. From 1995 to 1998, executive base salaries have increased approximately 70%.

102. Non-management bonus/incentives were $11.1 million in 1995, $13.9 million in 1996, and $15.5 million in 1997.

103. In 1998, the employee incentive compensation program was based on how well the departments perform against their own incentive goals and the financial health of the Company, which will be determined by the EPS.

104. The Company included $5.1 million in outside services related to the Millstone Units restart efforts.

105. Property tax expense is based on the latest estimated mill rates and assessments.

106. CL&P's fuel costs are recovered through base rates and the EAC.

107. The EAC reconciles CL&P's total actual fuel cost to the revenue collected through the BRFR.

108. The Company's current BRFR is $.02185/kWh.

109. The Company proposes to increase the BRFR to $.03089/kWh.

110. The BRFR has traditionally used a forecasted rate year capacity factor for each nuclear power plant.

111. The Company does not rely on historical operating performance of nuclear plants when forecasting rate year capacity factors.

112. Since 1995, annual and average performance at SB and VY has exceeded CL&P's proposed capacity factors for these units.

113. Recent historical capacity factors for MP2 and MP3 are unavailable because these units have not operated since 1996.

114. MY was retired on August 6, 1997.

115. Recovery of MY RPC is subject to refund pending a final decision by the Federal Energy Regulatory Commission in Docket No. ER98-570-000.

116. CY was retired on December 4, 1996.

117. CL&P has deferred CY RPC since the plant was retired.

118. Recovery of CY RPC is subject to refund pending a final decision by the Federal Energy Regulatory Commission in Docket No. ER97-913-000.

119. CL&P's Fuel Simulation relied on a forecasted price of oil that ranged between $16-$18 per barrel.

120. The price of oil has declined during 1998.

121. Norwalk Harbor Station demonstrates the lowest price of oil among CL&P's generating plants.

122. The price of oil at Norwalk Harbor was approximately $12/bbl at the close of hearing.

123. The price of natural gas trends with oil.

124. The BRFR reflects the total cost for purchases under CL&P's cogeneration contracts.

125. The Energy Policy Act of 1992 requires electric utilities to fund the D&D costs of DOE's uranium enrichment plants.

126. CL&P proposes to amortize an accumulated unrecovered balance of $22.3 million reflecting unrecovered D&D costs.

127. During the outages at CL&P's nuclear units, fossil generation replaced unavailable nuclear production.

128. D&D costs are embedded in CL&P's current BRFR.

129. The Company did not recover D&D costs during periods in which its nuclear units were out of rate base.

130. CL&P proposes to use the FERC Method for recovering D&D costs.

131. CL&P's current delivery efficiency percentage is .92225 and its proposed percentage is .92040.

132. Historical average delivery efficiency percentages are greater than the proposed percentage.

133. The Sharing Agreement allocates the energy cost savings resulting from the economic dispatch of the combined NU and PSNH systems.

134. The NUG&T allows NU to plan and dispatch for system need based on the operation of the combined NU operating subsidiaries.

135. Restructuring activities underway in New Hampshire and Massachusetts will render the NUG&T and Sharing Agreement unworkable.

136. The Capacity Transfer provision of the Sharing Agreement requires CL&P to take PSNH capacity at cost of service rates.

137. CL&P's original application was based on termination of the Sharing Agreement and NUG&T prior to January 1, 1999.

138. CL&P included $46.8 million of PSNH capacity costs in its revised filing.

139. Traditionally the BRFR has excluded non-PPP capacity costs.

140. There is a relationship between the price of oil and the forecasted cost of production.

141. A change in the price of oil changes the marginal cost.

142. There is a relationship between the price of oil and the forecasted marginal cost.

143. The proposed BRFR included $1.845 million for amortization of unburned nuclear fuel.

144. The Company forecasts residential sales of 8,745,306 MWHs and associated revenues of $1,012,159,000.

145. The Company's forecasted residential growth rates for 1998 and 1999 are 1.95% and 1.07%, respectively.

146. The Company forecasts commercial sales of 8,742,722 MWHs and associated revenues of $856,161,000.

147. The Company's forecasted commercial growth rates for 1998 and 1999 are 1.14% and .90%, respectively.

148. Year-to-date 1998 commercial sales exceed the Company's forecast.

149. The Company forecasts industrial sales of 3,862,933 MWHs and associated revenues of $297,140,000.

150. The Company's forecasted industrial growth rates for 1998 and 1999 are (.35%) and (.60%), respectively.

151. Year-to-date 1998 industrial sales exceed the Company's forecast.

152. The Company forecasts wholesale sales of 2,600,000 MWHs and associated revenues of $110,069,000.

153. Wholesale sales exclude a forecast of Daily Sales.

154. The retirement of MP1 reduces capacity sales.

155. CL&P's sales forecast includes Unbilled Sales.

156. Unbilled sales vary annually and reflect a lag in revenue recovery.

157. CL&P did not include Cable Fee Revenue in its forecasted revenues.

158. CL&P offers a discount under its Controlled Heater rates.

159. CL&P proposes to implement a $10 rebate for Controlled Heaters.

160. CL&P is unaware of the number of Controlled Heaters that have been disconnected.

161. CL&P proposes to transfer its MBCs to an NU affiliate.

162. CL&P's MBCs reflect approximately 450 MW of capacity.

163. CL&P estimates the future value of its MBCs to be $50 million.

164. MBC customers are paying in excess of current market rates.

165. The Company has proposed an across-the-board rate reduction.

166. The COSS contains changes as required by the Decision dated June 19, 1993, in Docket No. 92-11-11.

167. The Company's COSS includes a weighted average for residential line transformers.

168. The Company's COSS includes P&T costs for interruptible customers.

169. The Act requires that rates not exceed those that were in effect December 31, 1996.

170. CL&P proposes to eliminate Flex Riders.

171. Conn. Gen. Stat. § 16-19hh, as amended by Section 57 of the Act requires the Company to continue to offer Flex Riders.

172. Customer demand is currently measured in terms of kW.

173. CL&P proposes to implement kVA metering and billing for customers with demands in excess of 1000 kW.

174. Metering kVAs allows CL&P to identify cost causation.

175. The Company proposes to expand its streetlight offerings.

176. The Company currently offers decorative streetlighting under Rate 116.

177. The rate of return for the streetlighting class has remained in excess of CL&P's average for all classes for some time.

178. CL&P's customer service policies include its NB policies and charges.

179. NB policies and charges were last approved in the Decision dated June 15, 1995, in Docket No. 93-11-13.

180. The NB rates reflect the average installed cost of a wide range of items.

181. The Company proposed to modify its residential Rates 1, 5 and 7 to allow submetering at campgrounds.

182. There are many combinations of service provided at campgrounds.

183. Public Act 98-149 allows the installation of sub-meters at recreational campgrounds and that campers are charged no more than the residential rate.

184. Current regulations address the installation of sub-meters at campgrounds.

185. CL&P submitted revised Rules and Regulations to address master-metering of Assisted Living Facilities.

186. The Company is working to improve its emergency response system by implementing the recommendations of the ERTF and its upgrades to its internal emergency response system.

187. The Company assigns rates for new or transferred accounts based on the load history of previous customers.

188. Periodic reviews are used to verify that customers are receiving service at the most beneficial rate.

IV. CONCLUSION AND ORDERS

A. CONCLUSION

Based on the evidence presented, the Department concludes that revenues of $2,288,417,000 will be sufficient to enable the Company to operate successfully, maintain its financial integrity, attract capital and compensate its investors for the use of their money and the risks assumed. Therefore, the Department reduces the Company's revenue requirements by $231,964,000 or 9.68%.

The Department has been reluctant to reduce the Company's cash flow out of concern for its fragile financial condition, particularly while it worked to bring the Millstone plants on line. The Department believes that ratepayers have been patient long enough and deserve some rate relief now that MP3 is running and the return of MP2 is expected shortly. However, the Department must take into consideration the imminent arrival of retail access and the need to foster competition, which can best be done by reducing regulatory assets as quickly as possible. In recognition of these two goals, the Department concludes that rates should be reduced by $95,816,000 or 4% and the remaining $136,148,000 or 5.68% should be applied to write down FAS 109. In so assigning a portion of the revenue reduction to write down this tax obligation, the Department is setting the level of rates in conformance with the statutory principles and guidelines set forth in Conn. Gen. Stat. §16-19(e). In particular, §16-19(e)(a)(4) requires the Department to set rates such that " . . . the level and structure of rates be sufficient, but no more than sufficient, to allow public service companies to cover their operating and capital costs, to attract needed capital and to maintain their financial integrity, and yet provide appropriate protection to the relevant public interests, both now and foreseeable." With the generation component of the electric industry becoming competitive in 2000, the "relevant public interests, both existing and foreseeable" call for regulators to take steps now to put customers in a position to enjoy lower rates. This measure will reduce future ratepayer obligations.

As indicated in Section I.A, the revenue reduction is effective September 28, 1998. The reductions noted above are for the rate year 1999. The revenue reductions of $63,266,000 for the period between September 28, 1998, and February 5, 1999, when the Decision is finalized, will be applied against FAS 109.

The Company shall apply the rate reduction across the board to all rates except interruptible service, special contracts and those Flex Riders that do not qualify for a reduction. The rate reduction shall apply as a line item credit on all affected customer bills in lieu of a change to tariff rates.

Further, based on the economic analysis provided, the Department concludes that the Company would not have retired MP1 if it had been operating. The Department believes that some sharing of the remaining costs between ratepayers and shareholders is appropriate. Further, the Department believes that ratepayers are entitled to the benefits from 1999 and 2000. Therefore, the Department allows the Company to recover its remaining investment in MP1, net of benefits through 2000, in the amount of $126,100,000 over three years.

The Department concludes that the estimated $79,032,000 change to CL&P's retail revenues from removing MP2 from rate base should continue as a non-cash accrual to be used as an offset to the potential ratepayer liability for the accumulated CY RPC deferral. The RPC will continue to be subject to true-up in the EAC. As of September 28, 1998, the monthly accrual is $6,586,000. This accrual shall continue for as long as the unit is out of rate base. The Company shall record an additional monthly accrual from February to May 1999 to account for the incremental monthly accrual of $3,486,000, plus interest, accumulated from September 28, 1998, through February 5, 1999. MP2 will be returned to service when it has operated at no less than 75% power for 100 continuous hours. Once MP2 meets that standard, it will be returned to rate base without further Department action.

If it is determined that ratepayers are not responsible for CY RPC, or the accrual exceeds the deferred balance, CL&P shall return the excess accrual to ratepayers through the EAC. However, if it is determined that ratepayers are responsible for CY RPC and the MP2 accrual plus interest is less than the deferral at that time, the MP2 accrual will be applied in its entirely against the CY RPC Deferral. Thereafter, the remaining CY RPC Deferral will be amortized at the rate of the monthly revenue reduction associated with MP2 being removed from rate base until the deferral is eliminated or MP2 returns to service. If the deferral is not eliminated before MP2 returns to service, the balance will be recovered through the EAC.

B. ORDERS

For the following Orders, please submit an original and 10 copies of any requested material to the executive secretary, identified by Docket Number, Title and Order Number.

1. Effective for service on and after February 5, 1999, the Company shall apply an across the board 4% decrease to customer bills, except those for interruptible service, special contracts and those Flex Riders that do not qualify for a reduction.

2. On or before February 19, 1999, CL&P shall submit tariffs in compliance with directives contained in Sections II, I, 5, 8, 9, and 10.

3. No later than February 19, 1999, the Company shall submit to the Department, a list of the actual extended hours it makes available for off-hour service on Saturdays and early morning for each of its 12 business offices. The Company will also provide a copy of the notification to the business offices and customer service representatives that details the hours to be provided by each office.

4. No later than February 19, 1999, the Company shall submit to the Department the criteria and rationale for the average hold-time for calls from customers that it reports monthly to the Department. The Company will also provide a detailed description of its formula for computing the average hold-time it reports to the Department.

5. No later than February 19, 1999, the Company shall request a meeting with the Department's Consumer Assistance and Information Unit to discuss revising its prorated bill format.

6. No later than March 1, 1999, CL&P shall request a technical meeting to discuss its policies and procedures for identifying and marketing all properties that are not needed in the delivery of electric service.

7. No later than March 15, 1999, the Company shall submit to the Department a formal plan outlining its overall improvements for its internal safety and emergency response system, as discussed in Section II.O.4, above. The Company also shall provide status reports on the statewide implementation of the ERTF's recommendations to the Department no later than May 1, and September 1, 1999, and January 1, 2000.

8. On or before March 15, 1999, CL&P shall submit revised Rules and Regulations that incorporate the changes noted in Section II, above.

9. On or before March 15, 1999, the Company shall submit its plan for addressing disconnected Controlled Heaters as discussed in Section II.G.3. The plan shall include annual reporting to the Department.

10. No later than April 1, 1999, the Company shall eliminate the use of no bills. The Company shall send notification to the Department, no later March 8, 1999, that it has discontinued the use of no bills as described in Section II.O.1.a.

11. No later than April 1, 1999, the Company shall submit a formal, written procedure for analyzing customer usage in determining rate assignment and for monitoring and reviewing the usage at regularly scheduled intervals. The procedure will establish definitive steps that the Company shall initiate with each application for service to ensure all pertinent information is assembled and analyzed to determine and assign the most beneficial rate to the customer account.

12. No later than April 1, 1999, CL&P shall submit sample journal entries to record MP1 regulatory assets for post shutdown, predecommissioning costs subsequent to July 1, 1999, and decommissioning costs

13. On or before June 1, 1999, CL&P shall submit a report regarding sub-metering of campgrounds as discussed in Section II.I.

14. Beginning June 1, 1999, CL&P shall submit annual reports regarding its Controlled Heaters as discussed in Section II.G.3.

15. On or before June 1, 1999, CL&P shall submit its NB policies and charges for review as discussed in Section II.I.

16. On or before June 1, 1999, the Company shall submit a calculation of the D&D associated with the out of rate base treatment of MP1, 2 and 3 as discussed in Section II. The level of D&D recovery is subject to Department approval.

17. On or before June 1, 1999, CL&P shall submit the information being provided to potential kVa customers regarding implementation of kVa metering and means of correcting power factors as discussed in Section II.I.4.

18. On or before January 1, 2000, CL&P shall transfer its MBC to an NU affiliate as discussed in Section II.G.5.

19. Effective with the EAC filing to be submitted in June 1999, for the EAC billing period of July through December 1999, CL&P shall report the monthly RPCs for MY and CY in its filing as discussed in Section II.G.2.d and e.

20. CL&P shall create an account to record refunds or credits it receives from MY due to a FERC final decision from MY's current rate proceeding.

21. The Company shall submit a report on the operation and performance of its incentive program with its next rate case application. The report shall include the accounting of all amounts paid under the incentive plan since inception by area; all amounts recorded as earned but not paid, and an evaluation of the program's success in meeting its stated goals, including controlling overall employee compensation costs.

22. The Company shall submit to the Department, for prior review and approval, any proposed change to its billing format.

23. The Company shall submit to the Department, 10 business days prior to implementation, any changes in its customer service policies and/or procedures.

DOCKET NO. 98-01-02 DPUC REVIEW OF THE CONNECTICUT LIGHT AND POWER COMPANY'S RATES AND CHARGES - PHASE II

This Decision is adopted by the following Commissioners:

Glenn Arthur

Jack R. Goldberg

Linda Kelly Arnold

Donald W. Downes

John W. Betkoski, III

CERTIFICATE OF SERVICE

The foregoing is a true and correct copy of the Decision issued by the Department of Public Utility Control, State of Connecticut, and was forwarded by Certified Mail to all parties of record in this proceeding on the date indicated.

Louise E. Rickard
Acting Executive Secretary
Department of Public Utility Control

Date

	#		#		#			
	#		#		#			
CONN. LIGHT AND POWER - DN 98-01-02	#		#		#			
INCOME STATEMENT	#		#	($000)	#		PER CENT REVENUE	
ELECTRIC - RATE YEAR 1999	#		#		#		INCREASE ALLOWED =	-4.0000%
SCHEDULE C-1, Filed 6/1/98	#		#		#			
	# REVISED		#		#			
	# PRO FORMA		# AUTHORITY		#		FINAL	
	# RATE YEAR		# ADJUSTMENTS		# TABLE II		CHANGES	TABLE III
	#		#		#			
OPERATING REVENUES 1	#	2,258,118	#	30,299	#	2,288,417	0	2,288,417
OPERATING REVENUES 2	#	110,069	#	(3,100)	#	106,969	0	106,969
RATE DECREASE	#	(51,857)	#	0	#	(51,857)	(43,959)	(95,816)
	#		#		#			
TOTAL REVENUES	#	2,316,330	#	27,199	#	2,343,529	(43,959)	2,299,570
	#							
OPERATION EXPENSE	#	1,266,037	#	(94,370)	#	1,171,667	(246)	1,171,421
MAINTENANCE EXPENSE	#	233,672	#	(6,351)	#	227,321	0	227,321
O & M EXPENSES 3	#	0	#	(35,737)	#	(35,737)	0	(35,737)
DEPRECIATION + AMORTIZATION EXPENSE	#	256,070	#	(13,281)	#	242,789	0	242,789
MISC. EXPENSE 1	#	0	#	38,403	#	38,403	0	38,403
ADD'L NET OF TAX FAS 109 AMORT.	#	11,330	#	80,974	#	92,304	0	92,304
TAXES OTHER THAN GET OR INCOME TAXES	#	90,630	#	(1,298)	#	89,332	0	89,332
GROSS EARNINGS TAXES	#	81,858	#	1,033	#	82,891	(1,670)	81,221
INVESTMENT TAX CREDIT ADJUSTMENT	#	(5,414)	#	0	#	(5,414)	0	(5,414)
PROVISION FOR DEF. INCOME TAXES, NET	#	8,620	#	0	#	8,620	0	8,620
STATE TAXES	#	23,944	#	12,229	#	36,173	(3,574)	32,600
FEDERAL TAXES	#	90,214	#	46,076	#	136,290	(13,464)	122,826
LOSS (GAIN) - LAND SALE	#	0	#	0	#	0	0	0
	#		#		#			
TOTAL OPERATING EXPENSES	#	2,056,961	#	27,679	#	2,084,640	(18,954)	2,065,686
	#		#		#			
	#		#					
	#		#					
OPERATING INCOME	#	259,369	#	(480)	#	258,889	(25,005)	233,884
	#				#			

CONN. LIGHT AND POWER - DN 98-01-02
RATE BASE
ELECTRIC - RATE YEAR 1999

TABLE I - ($000)

		COMPANY PRO FORMA	AUTHORITY ADJUSTMENTS		AS ADJUSTED BY AUTHORITY
UTILITY PLANT IN SERVICE	$	6,269,337	0	$	6,269,337
PLANT 2		0	0		0
LESS: CONS. WORK IN PROGRESS		0	0		0
LESS: ACCUM DEP		2,584,303	(6,640)		2,577,663
NET PLANT	$	3,685,034	6,640	$	3,691,674
PLUS:					
MATERIALS AND SUPPLIES	$	70,364	(3,174)	$	67,190
WORKING CAPITAL		79,974	(14,577)		65,397
PREPAYMENTS		13,040	0		13,040
DEFERRED TAXES		36,551	0		36,551
FAS 109		561,326	(174,448)		386,878
UNAMORTIZED DEFERRALS, NET & MISC. ADJ.		7,483	(25,809)		(18,326)
FUEL RESERVE		32,393	(23,304)		9,089
LESS:					
DEFERRED INCOME TAXES	$	558,462	0	$	558,462
CUSTOMER ADVANCES AND DEPOSITS		7,498	0		7,498
OTHER RESERVES		5,792	0		5,792
SPENT NUCLEAR FUEL RESERVE		178,596	0		178,596
SETTLEMENT RESERVES		9,803	0		9,803
DEFERRED NUCLEAR OUTAGE COSTS		33,500	0		33,500
NUCLEAR FINAL CORE & M&S		1,638	0		1,638
FAS 109		650,098	(70,695)		579,403
RATE BASE	$	3,040,778	(163,976)	$	2,876,802