CP&L

Carolina Power & Light Company
PO Box 1551
411 Fayetteville Street Mall
Raleigh NC 27602

May 7, 1996

Ms. Kate Billing
State Energy Office
1201 Main Street
Suite 820
Columbia, SC 29201

Dear Ms. Billing:

Enclosed is a copy of Carolina Power & Light Company's Integrated Resource Plan which was filed with the South Carolina Public Service Commission on June 30, 1995. We are sending the IRP to you at the request of Jim Spearman of the Commission Staff.

If you have questions or comments, please call me at (919) 546-7911.

Yours truly,

B Mitchell Williams

B. Mitchell Williams
Director - Regulatory Policy & Analysis

BMW/sbc
Enclosure
c: Jim Spearman

Integrated Resource Plan

CP&L
Carolina Power & Light

South Carolina Public Service Commission
June 30, 1995

CP&L Exhibit No. 1

Carolina Power & Light Company

1995 Integrated Resource Plan Report

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Carolina Power & Light Company (CP&L) provides electric power to approximately one million customers in a 30,000 square mile service area that covers eastern and central North Carolina, the Asheville area in western North Carolina, and the northeastern quadrant of South Carolina. Continuing growth of the CP&L service area has created a steady demand for increasing amounts of electric power. The electric utility industry has experienced, and continues to experience, significant changes that challenge the planning process for providing the resources needed to meet growing electricity demand. Industry regulation, increasing competition in the wholesale power market, and environmental regulations are among the key issues which currently face the industry and Carolina Power & Light Company. The uncertainties surrounding these key issues demand a responsive and flexible resource plan. CP&L incorporates flexibility as a key principle in developing its Integrated Resource Plan (IRP). The IRP process utilizes both the management of energy growth through demand-side management (DSM) programs and the addition of supply-side alternatives as resource options, and includes an extensive risk assessment of key uncertainties to produce a flexible resource plan which will provide a reliable and cost-effective power supply to customers.

While the demand for electricity in the CP&L service territory continues to increase, the need to produce electricity in an environmentally sound manner also continues to increase. The Clean Air Act Amendments (CAAA) of 1990 have resulted in significant changes in environmental regulations. Since compliance with CAAA regulations impacts the utilization of existing coal units and increases the cost of new generation facilities, the Company's resource planning analysis includes not only the integration of demand and supply resources for satisfying future load growth, but also the integration of strategies for compliance with the 1990 CAAA.

Objectives of the IRP

The overall objective of CP&L's integrated resource planning process is the development of a flexible resource plan which will provide an adequate and reliable supply of electric power to customers at the lowest reasonable cost and in an environmentally conscious manner. CP&L's integrated resource plan achieves this objective by incorporating a cost-effective mix of demand-side and supply-side resources which will increase the utilization of existing facilities, will encourage customers to be energy efficient, will minimize the cost of providing electricity, and will comply with applicable environmental laws and regulations.

Overview of Integrated Resource Plan

Carolina Power & Light Company provides reliable and cost-effective electric power for its customers from a well-balanced mix of demand-side and supply-side resources. Table I presents planned additions and changes to the Company's Integrated Resource Plan. The table shows the forecasted system energy and peak load, the demand-side and supply-side resources planned, the projected year the resources will be needed, and the resulting annual capacity margins. The Company continues to experience high levels of growth in peak demand for electricity even with its aggressive DSM efforts. The current forecast projects peak load to grow approximately 2.1% annually through 2009. This level of growth corresponds to approximately 228 MW of additional peak load each year. All generation additions scheduled through 2004 are relatively low cost combustion turbines needed for peaking capacity. The plan also calls for the addition of combined cycle capacity in the 2005 through 2007 timeframe and the first coal unit is added in 2008. This plan is subject to continuing review and change as needed.

Demand-side management resources

Through the end of 1994, CP&L has implemented 1,076 MW of demand-side resources, offsetting the need for a significant amount of new supply-side generating capacity. Demand-side management will continue to play an important role in CP&L's future integrated resource plans. Expressed as a percentage of peak load, the projected cumulative DSM load reduction capability in 1995 is approximately 12%. Over the 15-year planning horizon the Company's plan calls for the addition of approximately 835 megawatts of DSM peak load reduction capability. CP&L's mix of DSM programs includes programs which impact the timing and magnitude of electric demands on our generating facilities. This "management" of load can produce improvements in load factor, increase utilization of existing capacity, reduce the need for additional peaking capacity, reduce the level and frequency of future rate increases, increase customer satisfaction, and encourage economic growth. Table II lists the programs currently implemented and potential programs under study.

Table I
Resource Plan Summary

	Annual Energy (GWH)	Peak Load (MW)	Demand-Side Management (MW)	Supply-Side Resources (MW)	Capacity Margin (%)
1995	52,312	9,690	1,151	-	13.6
1996	51,794	9,698	1,210	15 NUG	13.6
1997	53,295	9,986	1,268	225 Darl. County CT	12.8
1998	54,815	10,272	1,331	500 Wayne County CT* -50 PA/SCPSA 200 PA CT	15.1
1999	56,224	10,549	1,398	700 Wayne County CT* -400 Duke -50 PA/SCPSA	14.6
2000	57,612	10,802	1,465	300 CT**	14.6
2001	58,902	11,034	1,532	300 CT**	14.8
2002	60,229	11,269	1,600	300 CT**	14.9
2003	61,571	11,509	1,665	300 CT**	15.1
2004	62,845	11,740	1,728	200 CT**	14.6
2005	64,099	11,968	1,787	300 CC**	14.8
2006	65,356	12,197	1,842	300 CC**	15.0
2007	66,632	12,428	1,894	300 CC**	15.1
2008	67,912	12,661	1,941	500 Coal**	16.4
2009	69,148	12,888	1,986	-	14.9

* The Company has not committed to a particular design or unit size for the capacity.
** The Company has not committed to a particular design, unit size, or location for the capacity.

Negative numbers indicate the expiration of purchase contracts.

NUG = Non-Utility Generation
CT = Combustion Turbine
CC = Combined Cycle
PA CT = Power Agency CTs

Table II
Demand-Side Management Programs

Current Programs

Residential
- Common Sense Home (Thermal Efficiency -New Homes)
- Thermal Efficiency-Existing Homes
  - Homeowner's Energy Loan Program
  - Residential Energy Conservation Discount
- EZ-$64
- High Efficiency Heat Pump
- Time-Of-Use Rates

Commercial
- Energy Efficient Design
- Energy Analysis (Audit)
- Time-Of-Use Rates
- Thermal Energy Storage

Industrial
- Audit/Energy Efficient Plants
- Time-Of-Use Rates
- Large Load Curtailment

Potential Programs

Residential
- High Efficiency Water Heater
- Heat Pump Water Heater
- Home Comfort Analysis
- Common Sense Manufactured Home
- Common Sense Home Program-Environmental Option

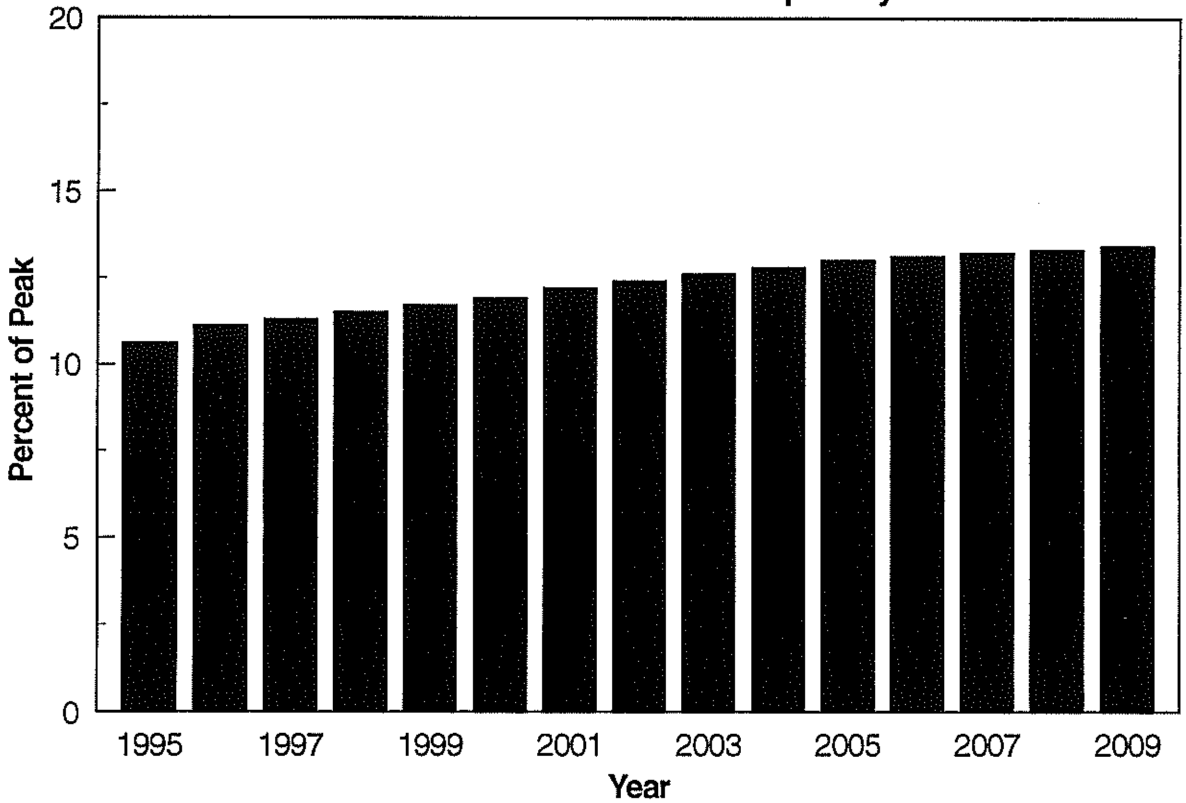
Commercial/Industrial
- Thermal Energy Storage - Schools
- Non-residential Energy Efficient Heat Pump
- Commercial Load Control
- Small Load Curtailment

Through December 1994, residential DSM programs accounted for 410 MW of peak load reduction capability. Commercial programs contributed 149 MW and industrial programs accounted for 517 MW. Figure I displays cumulative DSM peak load reduction capability as a percent of summer system peak. As this figure indicates, CP&L's demand-side management efforts are projected to grow at a faster rate than the Company's summer system peak.

For more than two decades the Company has been promoting successful energy management options for its customers. In the early to mid-1970's, load growth was severely taxing CP&L's ability to build enough capacity to meet need. During this period, CP&L focused primarily on conservation with emphasis on a general reduction in energy usage, increased insulation, and overall improved thermal efficiency. During the mid-to-late 1970s, CP&L's programs expanded to focus not only on conservation but also load management. In the early-to-mid-1980s, in addition to the previous conservation and load management programs, CP&L added peak clipping programs supported by curtailable and other rate structures. From the mid-1980's to the present, CP&L's DSM programs have continued to evolve in response to changing resource and customer needs.

CP&L's current DSM efforts are focused on cost-effective peak load management, strategic conservation, and strategic sales programs which will help reduce peak load, improve the utilization of existing facilities, and defer the need for future rate increases. The comprehensive assessment of future DSM options remains an integral part of the Company's IRP process.

Figure I
Peak Load Reduction Capability



Supply-side resources

CP&L's existing supply-side resources consist of 5,285 MW of coal, 3,064 MW of nuclear, 1,046 MW of oil/gas, and 218 MW of hydro electric facilities, as well as 1,596 MW of purchases from other utilities and non-utility generators such as cogenerators. Analyses performed in the development of the IRP show that the CP&L system has adequate base load capacity but that additional peaking capacity will be needed to meet the peak load growth projected over the next ten years. The most economical and reliable supply resource available to meet this need is combustion turbine (CT) capacity. Combustion turbines also have short lead times which increase flexibility by allowing more time to determine and verify the need for additional capacity before committing the Company and its customers to significant expenditures.

The resource plan indicates a significant amount of combustion turbine capacity being added in the future. However, only the 225 MW Darlington Addition currently has a certificate of public convenience and necessity. In December 1994, CP&L made a preliminary filing for a proposed new combustion turbine peaking plant in Wayne County, North Carolina, near the existing coal-fired Lee Plant. The proposed plant would contain up to 1,200 MW of capacity, with some of the capacity beginning commercial operation in 1998. Based on the lead-time associated with obtaining necessary permits and to allow time for facility construction, the filing was made in order to maintain the option to construct the plant in time for the 1998 summer peak.

Options other than the construction of new facilities have been and continue to be considered. DSM program enhancements and new DSM programs can potentially satisfy part of CP&L's future capacity needs. In addition, CP&L frequently receives proposals from non-utility generators and from other utilities. All proposals are thoroughly evaluated to determine if our customers and the Company can benefit from the purchase of such power. During the period 1992 through 1994, CP&L received 10 purchased power proposals from eight different sources representing 2,673 MW of capacity. For each proposal, the cost was found to be more expensive than CP&L's alternative.

Overview of CAAA Compliance Plans

One of the most significant changes in environmental regulations which impact electric utilities has been the enactment of the Clean Air Act Amendments of 1990. Title IV of the CAAA has the greatest impact on electric utilities and set three major national goals:

- By the year 2000, reduce the annual level of SO_2 emissions by 10 million tons below the level of emissions in 1980.
- A nationwide cap on SO_2 emissions beginning in the year 2000.
- By the year 2000, reduce the annual level of NO_X emissions by two million tons below the level of emissions in 1980.

As part of the IRP process, CP&L has developed compliance plans to address these regulations.

SO_2 compliance plan

Sulfur dioxide emission regulations are based on the amount of systemwide emissions in tons, and compliance is thus impacted by future generation additions. SO_2 option screening involves a technical and economic review of a number of emission compliance technologies and options. CP&L examined 35 different options for reducing SO_2 emissions from the fossil-fueled generating units. The sulfur dioxide compliance options that passed the screening process are fuel switching to a lower sulfur fuel, sulfur dioxide scrubbing, and emission allowances. Alternative SO_2 compliance plans are developed based on these options and are further evaluated with candidate resource plans.

One of the significant features of the CAAA is the creation of an SO_2 emission allowance allocation and trading mechanism. One "allowance" permits an affected source to emit one ton of SO_2 during or after a specified calendar year. The best overall SO_2 compliance plan was determined based on consideration of risk, diversity, and flexibility. Table III shows the Company's current SO_2 compliance plan. This plan contains a balance of compliance options including the use of emission allowances, fuel switching to burn compliance coal at all coal units by the year 2000, and adding a wet limestone scrubber and burning higher sulfur coal at Mayo Unit 1 beginning in 2007. CP&L continues to evaluate technologies and options and the economics of SO_2 compliance. As technologies evolve and opportunities present themselves, CP&L will examine the costs, benefits, and risks of the compliance plan and make changes as appropriate.

Table III
Summary of SO_2 Compliance Plan

Generating Unit	SO_2 Control Technology	Implementation Year
Asheville 1 & 2	Switch to Compliance Coal	1998
All other coal units[1]	Switch to Compliance Coal	2000
Mayo 1	Install Scrubber & Burn 2.1 lbs. sulfur coal	2007
Emission Allowances	Use existing and EPA-allocated allowances and purchase additional allowances as needed	2000+

[1]Mayo Unit 1 and Roxboro Unit 4 currently burn compliance coal

NO_X compliance plan

Unlike sulfur dioxide emission regulations, nitrogen oxides emission regulations require each unit to meet a specific emission rate or a group average emission rate; therefore, compliance with NO_X regulations is only minimally impacted by future generation additions. NO_X option screening involves a technical and economic review of a number of emission compliance technologies and options. The Company evaluated over 150 different generating unit/NO_X control technology combinations. The preliminary NO_X compliance plan includes configurations of low NO_X burners and selective non-catalytic reduction (SNCR) for the Company's existing coal fired generating units. These modifications will be made over the next few years during regularly scheduled maintenance outages.

Risk assessment

The best overall integrated resource plan is a robust plan that provides the diversity of resources and the flexibility necessary to confront the most critical uncertainties that face the Company. These uncertainties include load growth, fuel prices, and the performance of existing generating facilities. There are many factors that influence these uncertainties. The uncertainty in load growth, for example, is influenced by factors such as the cost-effectiveness of DSM, environmental regulations, competition in the wholesale bulk power market, and any future changes in industry structure. The outcomes of these activities can have significant impact on CP&L's system load growth and the resources needed to serve the demand. Clearly then, the best overall resource plan is a robust plan designed to contend with an uncertain future rather than an optimal plan dependent on the prediction of specific future events.

Decision analysis methodology

In CP&L's IRP process, the uncertainty surrounding key assumptions is taken into consideration using decision analysis techniques where both the value of an assumption used in the analysis and its probability of occurrence are determined. A decision tree is produced which describes all possible outcomes of the uncertainties in combination and the probability of occurrence for each of the resulting scenarios. The results from all of the scenarios are combined to form an expected value result for each alternative plan which is then used in the evaluation process. Sensitivity analysis of the results is also conducted to test the robustness of the best plan to variations in the probabilities assigned to the different outcomes.

Since there is not one plan that is the best for all the possible scenarios in the decision analysis process, the best overall plan is further examined to determine if there are any scenarios where the plan exhibits serious deficiencies. This analysis is conducted to better understand the scenarios under which the plan is not the best plan, the severity of any deficiencies, and to determine if any adjustments to the plan are needed.

Environmental risk assessment

The potential impact of complying with environmental regulations that have not yet been promulgated is also considered in the planning process. For example, potential regulations regarding air toxics (most notable mercury and other metals) and emissions of greenhouse gases such as carbon dioxide (CO_2) and methane were considered. Air toxics regulations could impact decisions on fuel contracts, and investments in electrostatic precipitator (ESP) equipment and flue gas desulfurization (FGD) systems. Greenhouse gas legislation could impact the growth in electricity demand and could impact the choice of future generating technology.

The possibility of new environmental requirements suggests that a flexible strategy that does not make significant, irreversible commitments would moderate the risks posed by future environmental regulations. The Company's CAAA compliance plans provide the diversity of options necessary to reduce the risks posed by potential environmental regulations. The plans also provide flexibility that will allow the Company to observe the emission allowance market relative to the other compliance options.

Summary risk assessment

The uncertainty and risk analysis techniques used in the development of the IRP are extensive. While the final plan may not result in the lowest cost or provide the most reliable service under all circumstances, it is the most cost effective and reliable under the broadest range of circumstances. The final plan should result in the best overall plan when all the different planning criteria are accounted for and the appropriate risks are considered and factored into the decision. The Company's IRP possesses the flexibility to respond to changing conditions while providing clear economic benefits over a wide range of possible outcomes.

Summary and conclusions

History has shown that the only thing certain about the future is that it is uncertain. Uncertainty surrounds fuel supply, economic growth, industry regulation, and environmental legislation, to name only a few of the current issues. With the current debate over retail competition in the power market, plans must be developed that recognize and are responsive to the uncertainty of future events. Clearly, plans must be flexible and must not depend on a specific outcome of future events for them to be successful. To that end, CP&L emphasizes diversity and flexibility in its Integrated Resource Plan to meet the objective of providing an adequate and reliable power supply to customers at the lowest reasonable cost and with reasonable protection of the environment.

CP&L's integrated resource plan incorporates a cost-effective mix of demand-side and supply-side resources, and options for complying with applicable environmental regulations. The specific options chosen in the resource plan are consistent with the IRP objective and reduce risks by:

- Incorporating a cost-effective mix of DSM programs--CP&L can adjust the pace of DSM implementation up or down as needed to respond to changing conditions. Cost effective demand-side measures also generally have favorable environmental effects and result in improved efficiencies of energy utilization.

- Utilization of low capital cost, short lead time combustion turbine additions--The additions are planned in small unit sizes (approximately 100 megawatts) which can achieve a closer match of supply to demand, and contribute to improved system reliability. The short lead time for construction increases flexibility to respond to changing conditions and the relatively low capital cost reduces financial risks to the Company and its customers.

- Incorporating a flexible and cost-effective strategy for environmental compliance--Compliance plans meet applicable environmental laws and regulations, and provide the flexibility and diversity of options necessary to reduce the risks posed by uncertainties in potential environmental regulations.

Carolina Power & Light Company's challenge is to meet customer needs for electric power with an energy supply that is reliable and economic, and provides reasonable protection of the environment. The Company's plans are continuously reviewed and appropriate changes are made to account for changing conditions, regulations, and availability of alternative resources. By incorporating a balance of options and strategies that provides maximum flexibility to adapt to uncertain and ever-changing futures, CP&L's Integrated Resource Plan ensures that the challenge will be met.

Chapter 1
Introduction

This report describes CP&L's integrated resource planning process and presents its current Integrated Resource Plan which includes compliance plans for the sulfur dioxide (SO_2) and nitrogen oxides (NO_X) requirements of the CAAA. The resource planning process provides for on-going evaluation of resource options and conditions that influence the plan, and timely revisions to the plan in response to changing future events.

Description of the IRP process

CP&L's IRP process is a continuing cycle of planning, implementation, and evaluation. This dynamic process is necessary in today's planning environment to assure changing conditions are taken into account in a timely manner. The process encourages communications among appropriate areas of responsibility within the Company and allows CP&L to take advantage of opportunities and make timely revisions to the IRP when needed. A flowchart of CP&L's IRP process is shown in Figure 1-1.

Demand-side management options

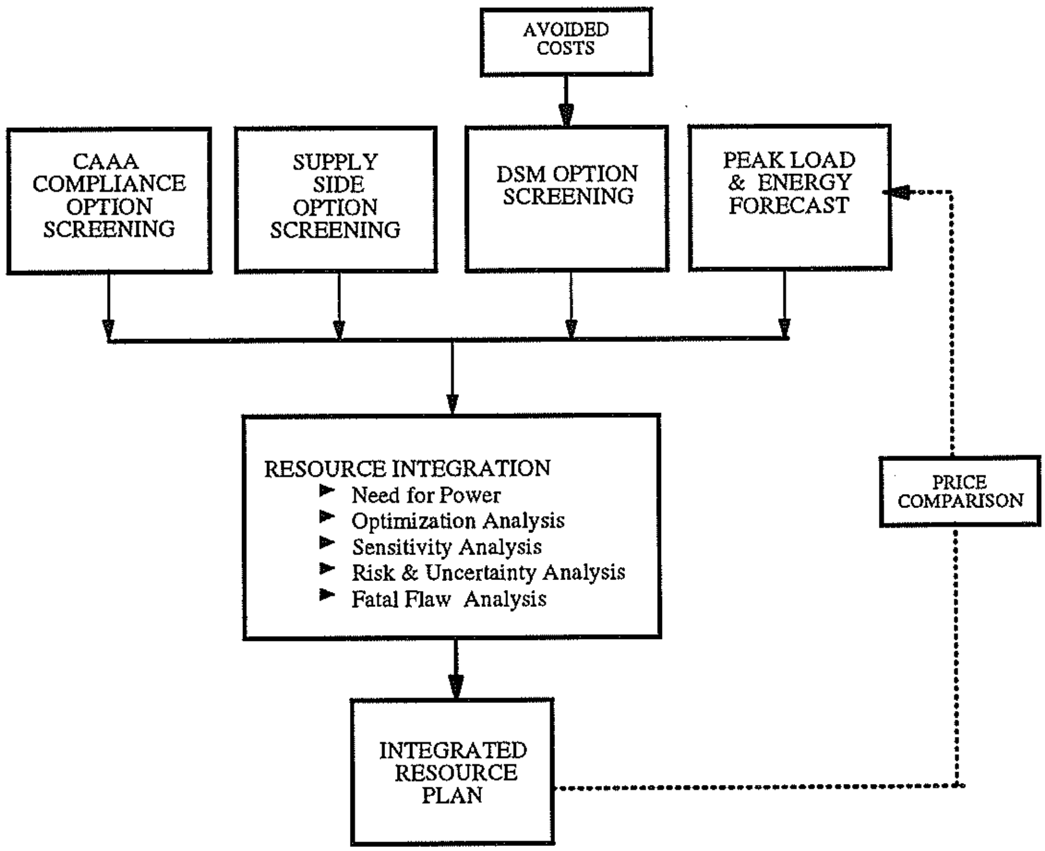
In formulating the demand-side portfolio, a comprehensive assessment of DSM options is performed. The Company examines the costs, benefits, and market potential of programs currently implemented and new programs which appear to hold promise. In assessing programs, multiple criteria relating to economics, operations, financial impacts, technical feasibility, regulation, and marketing are considered.

Cost-effective DSM programs are selected by comparing program costs and benefits. Costs include marketing and administrative costs and expenditures on equipment. Benefits include avoided generation capacity and energy costs and deferred investments in transmission and distribution facilities. Higher and lower levels of DSM resources are also included in the integration analysis since sensitivity analyses show the amount of DSM resources impacts both the optimal addition of supply resources and the optimal Clean Air Act Compliance (CAAC) strategy.

Energy and peak load forecast

CP&L's forecasting process produces econometric and end-use energy forecasts and an internally consistent system peak load forecast. A load factor approach is used for developing the load forecast, using the energy forecast as direct input in producing the forecast of annual system peak load. This load forecast method assures a direct coupling between the two forecasts, sharing assumptions and data. The system peak load forecast also uses the load management program effects as a primary input. The net peak load forecast becomes the basis for determining the need for new supply-side resources in the Company's Integrated Resource Plan.

Figure 1-1
Integrated Resource Planning Process



Supply-side options

An indepth study of generation technologies is conducted to determine the types of supply-side resources to pass on to the integration process. Supply technologies are evaluated in a four-step screening process. The screening process eliminates those technologies that are not competitive with other technologies. In addition, purchased power proposals are evaluated as alternative supply-side resource options. Based on results of the screening process, the best supply options are passed to the resource integration process.

Resource integration

Candidate resource plans are developed using combinations of the different levels of DSM and the most economical supply options to meet specified reliability criteria. The candidate plans are evaluated using relevant criteria and taking into consideration critical uncertainties such as load growth, fuel prices, and the performance of existing generating facilities. Based on the evaluation, the best overall plan is selected.

CP&L's resource plans recognize that the future is uncertain. If plans are to be successful, they must not depend on a specific outcome of future events. Therefore, plans must be flexible and excessive reliance on any single resource must be avoided. Decision analysis techniques are used to evaluate the candidate plans taking into consideration critical uncertainties. Such a strategy produces a diversified plan that minimizes cost under uncertainty by maintaining the flexibility necessary to respond to changing conditions. This balance in CP&L's resource planning is expected to lead to consistent savings for customers while managing the risks inherent in an uncertain future.

Customer participation

In the past, CP&L has relied on customer focus groups to obtain customer input on existing and planned DSM programs. To improve this process, the Company has established an IRP Customer Advisory Panel. The Panel is composed of ten customers from throughout CP&L's service area. These customers have various backgrounds and represent a cross-section of customer groups. The initial meetings of the Panel have focused on forecasting, DSM programs, utility economics and integrated resource planning, and tours of CP&L facilities have been included. The panel has reviewed and discussed CP&L's Integrated Resource Plan, its components, and provided feedback to CP&L.

Chapter 2
Energy and Peak Load Forecast

Overview of forecast process

CP&L's forecasting process has been continually enhanced. Currently econometric and end-use energy forecasts, an internally consistent system peak load forecast, and load shape forecasts are produced. A load factor approach is used for the Load Forecast, using the energy forecast as direct input in producing the forecast of annual system peak load. This method assures the direct coupling of energy and load characteristics.

The Econometric and Load Forecast processes have been based on sophisticated statistical methods since the mid-70s. During this time, enhancements have been made to the methodology as data and software have become more available and accessible. Enhancements have also been undertaken over time to meet the changing data needs of internal and external customers. In response to these changing planning needs, CP&L's forecast processes have been expanded to include forecasts at the end-use level. Econometric and end-use energy forecast results for the residential, commercial, and industrial classes are combined to produce the System Energy forecast.

During 1991, energy forecasts were first developed for commercial and residential end-uses in parallel with the econometric forecast. EPRI's COMMEND (Commercial End-use) and REEPS (Residential End-use Planning System) software were used for these end-use energy forecasts, respectively. This year marks the first time the EPRI INFORM (Industrial End-use Model) model was used to produce an industrial end-use energy forecast. All three models combine engineering detail with economic relationships to produce appliance and equipment level forecasts for specific customer groups by modeling consumer and business choices for specific equipment, energy efficiency, and equipment utilization.

End-use forecasting requires a major commitment of time, data, and resources. End-use approaches require collection and analysis of an enormous quantity of data, some of which is not economically available on a utility service area basis. Consequently, EPRI's commercial, industrial, and residential end-use models are provided with some data reflecting national and/or regional characteristics, which is then combined with utility specific data. These national and regional data have been carefully analyzed and often modified to reflect service area specific characteristics.

End-use models should not be seen as a replacement for econometric methods. The parallel use of these two approaches is not superfluous duplication because each forecasting method has unique strengths which largely determine the usefulness of the results. Econometric approaches have the strength of using utility specific, observable, and market-determined trends spanning many years, but do not immediately capture technology details of market behavior. End-use approaches, on the other hand, have the strength of modeling explicit technology, efficiency, and appliance choices, but these models base such choices on data from a single base year.

The end-use and econometric results are compared to assess forecast consistency and reliability. This procedure acts as a verification for the results of each model. In this way, the strengths of each model are maximized. Comparisons of model results show the econometric and end-use models to be very similar and consistent.

Because integrated resource plans typically contain minor timing and magnitude differences from year to year, expected future prices also vary from plan to plan. CP&L's forecast process includes a verification that the prices used in the forecasting models are consistent with those implied by the final integrated resource plan. This comparison continues to show negligible price differences between forecast prices and those implied by the final resource plan.

The remainder of this chapter contains a summary of the 1994 Energy and Peak Load Forecast and a description of the forecast process and assumptions.

Forecast summary

Beginning with the 1995 forecast year, a replacement interchange contract of approximately 230 MW for the Fayetteville Public Commission (FPWC) is reflected in the forecast. While this contract was negotiated to begin in July 1994, it appears for the first time in the 1995 forecast year. The Forecast now also reflects 200 MW of North Carolina Electric Membership Corporation (NCEMC) load being served by another supplier beginning January 1, 1996. While the peak load effects of these changes are nearly offsetting after 1995, energy sales are reduced by approximately one million MWH per year.

Figures 2-1 and 2-2 compare the 1994 Energy and Peak Load Forecasts - including the Fayetteville and NCEMC changes - with the 1993 forecasts. The energy forecast shows an increase in 1995 due to the energy associated with the 230 MW Fayetteville Replacement Interchange Contract. The decrease in energy shown in 1996 corresponds to the 200 MW reduction in NCEMC's load. Even though the Fayetteville and NCEMC loads are both near 200 MW, the NCEMC contract removes load with a 100% load factor while the Fayetteville Replacement Interchange contract adds load with a 30% load factor. The net result of these two changes is to reduce system energy by about one million MWH in each year of the forecast. When all other economic and demographic updates are incorporated into the forecast, the result is a new outlook which almost overlays the prior energy forecast. While these updates and changes also impact peak load, the load forecast closely parallels the prior outlook because the Fayetteville and NCEMC changes in peak load nearly balance after 1995.

CP&L currently has specific retail customers on self-generation deferral rates and wholesale customers on long-term contracts. These rates and contracts have been structured to avoid uneconomic bypass. Retaining customers at rates which recover a portion of the utility's fixed costs keeps rates lower for all customers than would be the case if the utility lost the customer entirely. It is the Company's policy to avoid uneconomic bypass now and in the future. Consequently the forecast assumes that flexible rate guidelines will continue and current customers on these rates will be retained.

Figure 2-1
System Energy Sales Forecast Comparison
Reduced By Conservation and Load Management

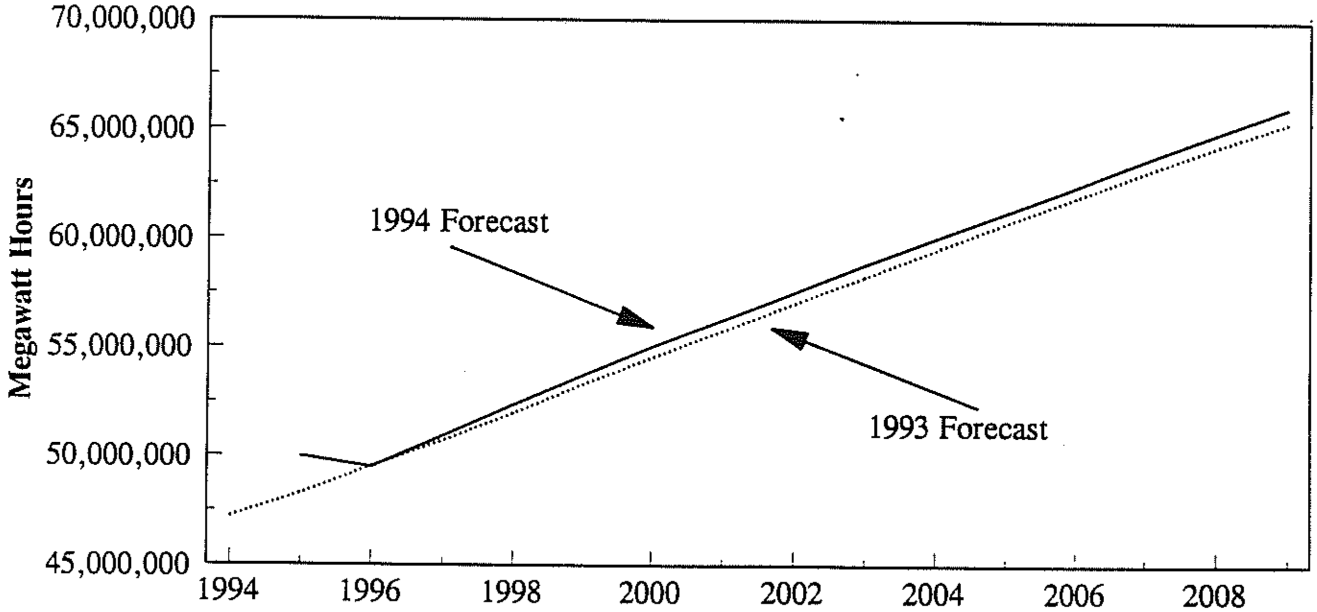
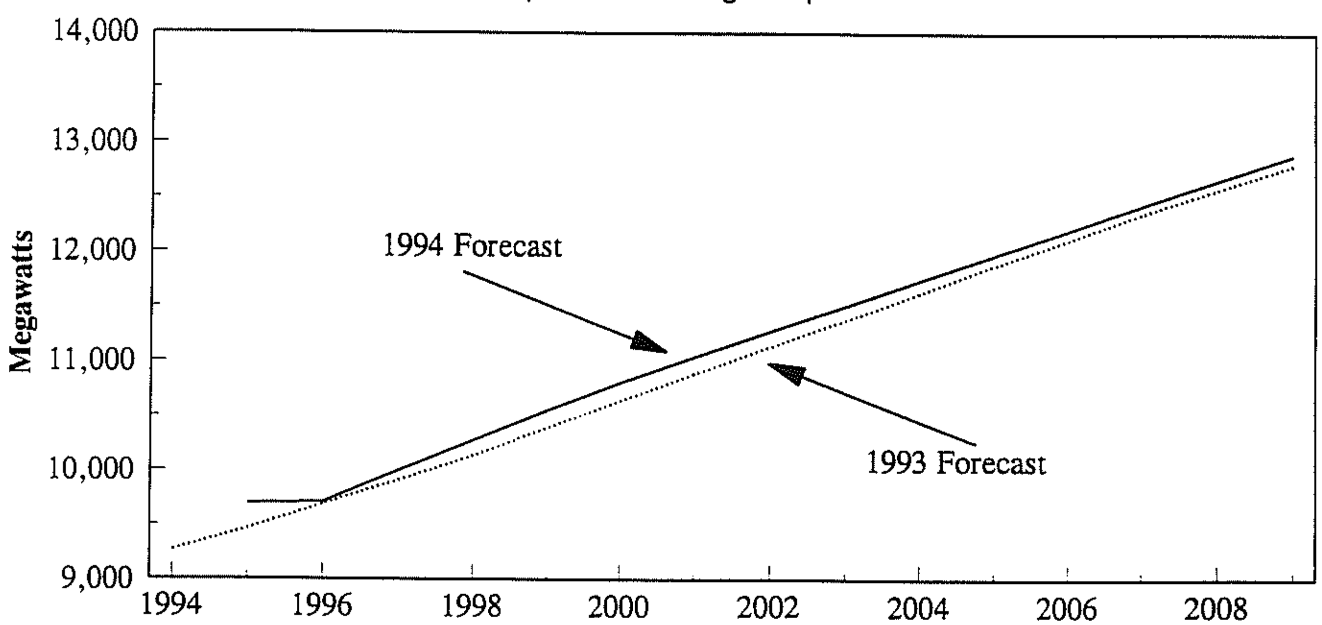


Figure 2-2
System Peak Load Forecast Comparison
Reduced By Conservation and Load Management
At Expected Peaking Temperature



A summary of the 1994 Energy and Peak Load Forecast including the NCEMC and Fayetteville changes is provided on Table 2-1. The table provides annual system peak load, which is expected to occur during the summer season, and annual system energy. Annual energy is provided on the basis of customer usage at meter level and system energy input at generation level. System energy input and system peak load include customer usage plus losses and company uses to reflect the total energy and peak demand required from generation resources. The projections shown in this table include the effects of conservation activities plus the effects of load management activities, except for **Forecast System Peak Load Not Reduced by Load Management Control** as noted below.

Demand-side activities have existed over a long period of time. Because customer electricity usage data includes demand-side actions, the forecasts based on such historic data implicitly contain demand-side effects. If demand-side effects which are already included in customer data used to develop the forecast were subtracted from the projections of future electricity use, a double-counting of these effects would result. Since the System Energy forecast is the foundation for the System Peak Load forecast, those factors which influence a change in forecast energy use also influence similar changes in projected peak load.

Non-price induced load management effects, however, can be treated explicitly in the forecasts because they are controlled by the utility. Table 2-1 illustrates the effect of non-price induced load management on the forecast. Additionally, the System Peak Load forecast is influenced to a greater extent by load management since the nature of these programs is to reduce customer loads for short periods of time during seasonal peaks. A summary of load management reductions is provided in Table 2-3.

Additionally, the system peak load not reduced by load management control programs is also provided at generation level. Such load management control programs are designed to reduce customer loads for short periods of time during seasonal peaks. Use of load control programs is not automatic, but is dependent on the status of the bulk power system, availability of resources, and expected peak load at that specific time. Depending on various circumstances, system peak loads could be reached when the maximum capability of load management control programs is not needed. The **Forecast System Peak Load Not Reduced by Load Management Control** is the peak load level which could be expected should these capabilities not be utilized. **Forecast Peak Load Reduced by Conservation and Load Management** assumes the use of all load management capability at the specific time of system peak. Table 2-1 provides annual energy data and annual system peak load data, which occurs during the summer under normally expected temperature conditions. Winter system peak loads are provided in Table 2-2.

Table 2-1

December 1994 Energy and Peak Load Forecast
Annual Peak Load, Energy and Load Factor
At Expected Summer Peaking Temperatures

Year	System peak load forecast not reduced by load management control at generator (MW)	Forecast reduced by conservation and load management: System peak load at generator (MW)	System energy input at generator (MWH)	System load factor at generator (%)	Customer energy at meter (MWH)
1995	10,270	9,690	52,311,863	61.6%	49,986,960
1996	10,314	9,698	51,794,205	61.0%	49,485,518
1997	10,635	9,986	53,295,484	60.9%	50,918,533
1998	10,955	10,272	54,814,971	60.9%	52,371,549
1999	11,267	10,549	56,223,707	60.8%	53,718,665
2000	11,554	10,802	57,612,241	60.9%	55,046,190
2001	11,821	11,034	58,902,303	60.9%	56,279,800
2002	12,091	11,269	60,229,170	61.0%	57,548,616
2003	12,367	11,509	61,570,881	61.1%	58,831,686
2004	12,632	11,740	62,844,963	61.1%	60,050,313
2005	12,893	11,968	64,099,025	61.1%	61,249,875
2006	13,154	12,197	65,355,910	61.2%	62,452,137
2007	13,416	12,428	66,631,634	61.2%	63,672,131
2008	13,678	12,661	67,911,954	61.2%	64,897,072
2009	13,932	12,888	69,148,060	61.2%	66,079,473
Average annual growth					
1995-2000	257 MW	222 MW	1,060,076 MWH		1,011,846 MWH
	2.4%	2.2%	1.9%		1.9%
2000-2005	268 MW	233 MW	1,297,357 MWH		1,240,737 MWH
	2.2%	2.1%	2.2%		2.2%
2005-2009	260 MW	230 MW	1,262,259 MWH		1,207,400 MWH
	2.0%	1.9%	1.9%		1.9%
1995-2009	262 MW	228 MW	1,202,586 MWH		1,149,465 MWH
	2.2%	2.1%	2.0%		2.0%

Table 2-2

December 1994 Peak Load Forecast
System Winter Peak Load Forecast
At Expected Peaking Temperatures
At Generator Level

Year	Reduced by conservation and load management (MW)
1994/95	9,283
1995/96	9,291
1996/97	9,567
1997/98	9,841
1998/99	10,106
1999/00	10,348
2000/01	10,571
2001/02	10,796
2002/03	11,026
2003/04	11,247
2004/05	11,465
2005/06	11,685
2006/07	11,906
2007/08	12,129
2008/09	12,347

The winter peak is forecast to occur during the period from December through February.

Table 2-3

December 1994 Energy and Peak Load Forecast
Load Management Summer Peak and
Annual Energy Reductions
At Meter Level

Year	Peak load (MW)	Energy (MWH)
1995	774	192,236
1996	848	398,006
1997	897	419,849
1998	940	387,613
1999	981	387,896
2000	1,019	388,170
2001	1,057	388,443
2002	1,096	388,718
2003	1,134	388,993
2004	1,171	389,267
2005	1,208	389,546
2006	1,242	389,807
2007	1,276	390,068
2008	1,308	390,320
2009	1,338	390,564

Forecast perspective

During the forecast period from 1995 to 2009, the average annual growth rate is 2.0% for energy and 2.1% for peak demand. These growth rates translate into an average annual growth of 1,149 GWH for energy and 228 MW for peak demand. The annual growth *percentage* of both annual energy and peak demand generally decreases across the forecast period, while the annual growth in absolute terms remains nearly constant. Declining percentage growth rates given nearly constant absolute growth in MW and MWH arise from an increasingly larger energy sales or peak demand base. In other words, similar amounts of growth appear as lower percentages as the base increases.

Figures 2-3 and 2-4 provide a combination of historic and forecast growth for the period from 1960 through 2009. Examining the energy growth of Figure 2-3 for the 1960-70 and 2000-2009 periods illustrates the phenomena of falling percentage growth while annual change in GWH remains nearly constant. During the decade from 1960 to 1970 energy grew at nearly 1,200 GWH per year during this period, a 10.9% growth rate. By comparison, energy growth for the ten year period 2000-2010 is also expected to be near 1,200 GWH per year, but on a percentage basis this is only a 2.0% growth rate. The significantly lower percentage growth rate results from similar amounts of GWH growth being divided by a much higher base. Figure 2-4 provides comparable peak load growth information.

Figure 2-3
Historical Perspective Of Energy Growth

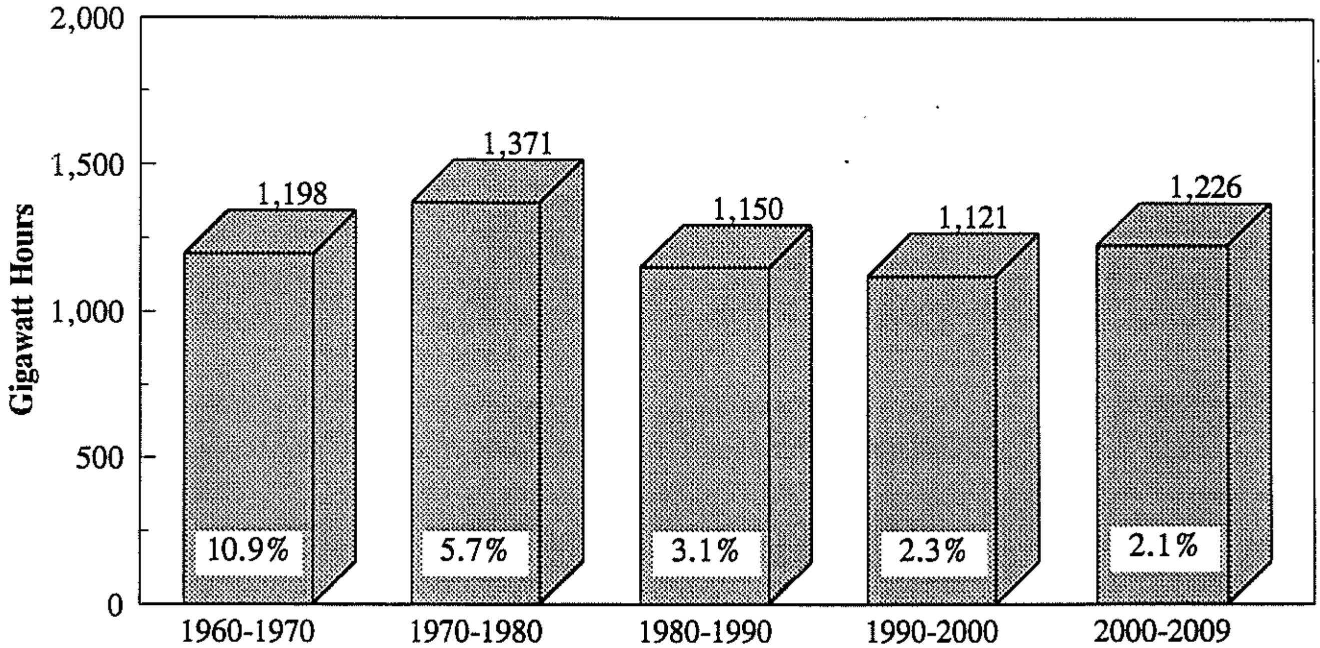
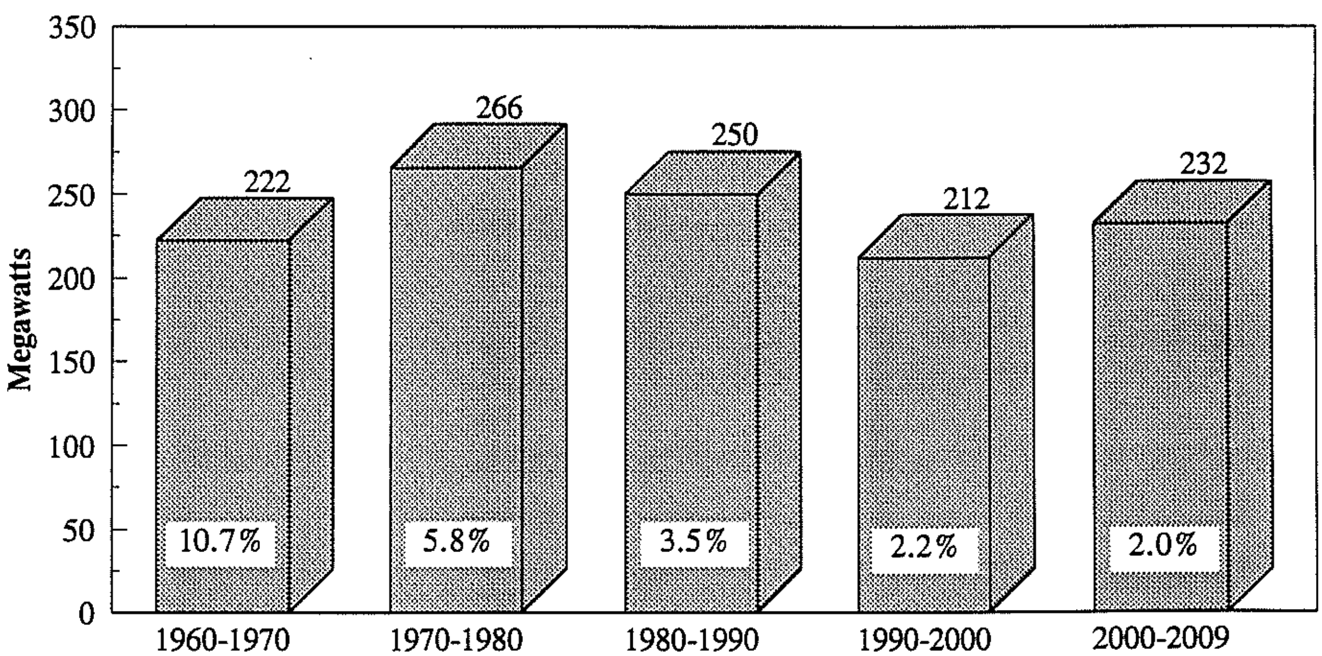


Figure 2-4
Historical Perspective Of Peak Load Growth



Forecast assumptions and considerations

The forecast provided in Tables 2-1 and 2-2 is the most likely unfolding of the future among many other possible, but less likely, futures. This forecast is generally identified as the reference forecast. Two forecast scenarios are also developed to provide a view of the range of forecasts which could be expected due to higher or slower economic growth. A tabulation of the more prominent economic assumptions for the reference forecast and the higher and slower economic growth scenarios are provided in Table 2-4. The results of the higher and slower economic growth scenarios are provided on Table 2-5.

Table 2-4
Economic forecast assumptions

	Reference forecast	Higher growth scenario	Slower growth scenario
GDP growth	2.0% average annual growth	2.5% average annual growth	1.4% average annual growth
Oil prices	Oil prices rise an average 5.8% per year	Oil prices rise an average 3.5% per year	Oil prices rise an average 7.0% per year
Real consumption	1.8% average annual growth	2.2% average annual growth	1.4% average annual growth
Productivity	1.3% average annual growth	1.6% average annual growth	1.0% average annual growth
Consumer price index	3.6% average annual increase 4.0% peak (2003-05)	2.8% average annual increase 3.1% peak (2003-05)	5.2% average annual increase 5.9% peak (2004)
Employment	1.3% average annual growth	1.6% average annual growth	1.1% average annual growth
Hourly earnings	4.4% annual rise	3.2% annual rise	5.3% annual rise

Table 2-5

December 1994 Energy and Peak Load Forecast
Higher and Slower Economic Growth Scenarios
Annual System Peak Load and Energy Input
Reduced By Conservation and Load Management
At Expected Peaking Temperature
At Generation Level

	Higher economic growth		Slower economic growth	
Year	Peak load MW	Energy input MWH	Peak load MW	Energy input MWH
1995	9,752	52,659,521	9,648	52,014,992
1996	9,806	52,394,575	9,621	51,308,478
1997	10,119	54,011,958	9,869	52,555,487
1998	10,434	55,683,813	10,121	53,891,808
1999	10,739	57,241,298	10,363	55,119,214
2000	11,012	58,733,406	10,579	56,300,273
2001	11,271	60,168,261	10,782	57,432,555
2002	11,534	61,637,988	10,987	58,582,327
2003	11,804	63,137,255	11,190	59,715,841
2004	12,073	64,625,968	11,385	60,798,226
2005	12,344	66,117,216	11,577	61,854,722
2006	12,613	67,594,815	11,765	62,883,195
2007	12,889	69,123,335	11,953	63,926,222
2008	13,166	70,629,096	12,135	64,909,797
2009	13,439	72,109,649	12,307	65,843,683

General

Generally, the standard of living as reflected in personal income and GDP will decline modestly relative to that enjoyed today. The labor force can be predicted with some reliability because the working population for the early 21st century has already been born. Real dollar prices are used to enhance model reliability during periods of varying inflation. The forecast assumes that our customers will tend toward continuing energy efficiency in the future. More efficient electrical equipment, continued cost-effective conservation measures, and specific load management programs are expected to result in slower energy growth when compared with the 1970s and 1980s.

The forecast of System energy usage and peak load does not explicitly incorporate periodic expansions and contractions of business cycles, which are likely to occur from time to time during any long-range forecast period. While long-run economic trends exhibit considerable stability, short-run economic activity is subject to substantial variation. The exact nature, timing and magnitude of such short-term variations are unknown years in advance of their occurrence. The forecast, while it is a trended projection, nonetheless reflects the general long-run outcome of business cycles because actual historical data, which contain expansions and contractions, are used to develop the general relationships between economic activity and energy use.

Residential Class

The overall forecast of residential energy usage is slightly higher than last year's projection due to two primary factors. A larger share of our customers are expected to live in all-electric homes in response to forecast decreases in inflation-adjusted CP&L electricity prices. This is balanced in part by increased competition from natural gas, with lower forecast prices and increased availability relative to last year's forecast.

Commercial Class

The commercial energy forecast is slightly higher than last year's projection. This is primarily due to a more rapid than anticipated long-term trend from a manufacturing base to a services oriented economy. Consequently, energy growth in the commercial sector is expected to be stronger than in the industrial sector.

Industrial Class

Because of the substantial variation in the levels of energy intensiveness in this sector, a two-digit SIC code representation is used. It is assumed that labor productivity within CP&L's service area is comparable to the output per employee nationally. National forecasts of output per employee are combined with forecasts of service area employment (by SIC code) to produce a service area production index. The industrial energy usage forecast is slightly above last year's forecast through the forecast horizon. This is attributable to increased productivity and continuing growth in electrotechnologies.

Sales-for-Resale Class

The forecast for energy in the sales-for-resale sector assumes those receiving power from the EMCs and the municipalities within the Company's service area are subject to the same economic conditions, weather, etc., as CP&L retail customers. Weather and the relative price relationship between electricity and alternative fuels are used to develop these energy projections.

Demand-Side Management

The forms of conservation available to customers are diverse. These forms range from the insulation of homes and installation of energy efficient appliances to the adjustment of thermostats and other lifestyle changes. Conservation activities generally result in a reduction in energy consumption. In addition to conservation effects, the System Energy forecast treats explicitly the effects associated with the load management portion of the Company's DSM Program.

Conservation is implicitly reflected in the load forecast as a result of using historical data to develop the System Energy forecast. Because conservation is reflected in the data used in the forecast process, load management alone is subtracted from the gross load forecast. This approach prevents a double counting of conservation effects.

Load management has provided significant reductions to system peak load and is expected to continue to do so in the future. Between 1995 and the end of the forecast period in 2013, load management reductions are expected to increase approximately 675 MW. This represents a reduction of 17% of the forecast system load growth and 27% of retail customer growth during this time period if load management were not available.

Load management program totals used in the load forecast do not include the projected purchases from sell-excess cogenerators and small power producers. These are included in supply-side tabulations as Company Power Resources. Load management affects the growth rates of both system energy sales and system peak load; however, the energy sales reduction is a much smaller percentage than the peak load reduction. This tends to make the growth rate for demand lower than the growth rate for energy and therefore correspondingly increases load factor.

Econometric forecast process

Residential forecast

Number of residential customers

Historically, the total number of residential customers in the CP&L service area has correlated with the North and South Carolina stock of housing units and mobile homes. The total number of CP&L residential customers was regressed on the service area stock of houses and mobile homes.

Data	Source
CP&L service area stock of housing units and mobile homes	CP&L Service Area Economic Model

For forecasting purposes, it is desirable to disaggregate total residential customers into those with electric space heat, electric water heating only, and minimum service. Space heating and water heating fuel choices by residential customers have been modeled in the econometric forecast using a multinomial logit approach. The multinomial logit approach allows these fuel type choices to be modeled using income and relative prices. The results of the logit approach are percentage shares by each subclass. Each subclass share is multiplied by the total number of customers to obtain the number of customers making up each subclass for the service area.

Use per customer

Use per customer is forecast separately for the three subclasses described above; those with electric space heat (all electric), electric water heating only, and minimum service. The forecast equations for the individual subclasses use a common set of variables. Historical monthly usage for each individual subclass was regressed on income, price, a conservation proxy, winter weather, summer weather, and twelve seasonal dichotomous variables (1 for the given month and 0 elsewhere).

Data	Source
Weighted Normal Heating Degree Days	CP&L
Weighted Normal Cooling Degree Days	CP&L
Average Real Price of Electricity for Subclass	CP&L
Real Disposable Income per Capita	CP&L's Service Area Economic Model

Residential total forecast

The total usage for each class was calculated as the product of the average use per customer and the average number of customers. The residential customer total is the sum of the three classes.

Commercial forecast

The commercial models were specified using monthly data and a logarithmic specification. In this form, the coefficients can be interpreted directly as elasticities. To account for the diversity of commercial customers, seven 1-digit commercial SIC Codes were used for the commercial forecast. An annual econometric model for the class as a whole cannot adequately account for the wide variety in the saturation of heating and cooling equipment, resort installations, or deviations from normal weather. To capture the effects of these variables, the CP&L models were specified on a monthly basis.

The individual commercial SIC Code forecasting equations use a common set of variables.

Data	Source
Service area commercial employment	CP&L Economic Model
Weighted Normal Heating Degree Days	CP&L
Weighted Normal Cooling Degree Days	CP&L
Real Average Price of Electricity	CP&L
Seasonal Dichotomous Variables	1 for the given month and 0 elsewhere

Employment in 1) Agriculture; 2) Construction; 3) Finance, Real Estate, and Insurance; 4) Government; 5) Utilities, Communication, Transportation; 6) Services; and 7) Wholesale & Retail Trade are forecast for the CP&L service area in the CP&L Service Area Economic Model.

Industrial forecast

The industrial sector is divided into fourteen two-digit SIC Codes. The remaining SIC Code groups and small users are combined into one group -- Other Manufacturing -- because of data restrictions imposed by the state employment commissions.

The industrial sector models use a local production index, relative price of electricity to gas for the industrial class, and seasonal dichotomous variables.

Data	Source
Local Production Index	CP&L
Relative Price of Electricity to Natural Gas	CP&L economic model
Seasonal Dichotomous Variables	1 for the given month and 0 elsewhere

Sales-for-resale forecast

The Sales-For-Resale models use historical monthly usage, summer weather, winter weather, twelve seasonal dichotomous variables (1 for the given month and 0 elsewhere), and the relative price of electricity versus natural gas.

Data	Source
Weighted Normal Heating Degree Days	CP&L
Weighted Normal Cooling Degree Days	CP&L
Relative Price of Electricity to Natural Gas	CP&L Economic Model
Real Disposable Income	CP&L Economic Model
Average Real price of Electricity	CP&L Economic Model
Average Real price of Natural Gas	CP&L Economic Model

End-use forecast process

Residential end-use forecast

In parallel to the econometric forecasts, the Company develops an end-use forecast of residential energy using the EPRI REEPS (Residential End-Use Energy Planning System) model. REEPS is an integrated end-use/econometric forecasting model which combines engineering detail with economic relationships at the appliance level. The focus of the REEPS model is to develop energy usage patterns for highly detailed end-uses.

REEPS and other end-use models require vast amounts of market information and behavioral assumptions. REEPS models consumer appliance purchase decisions, efficiency choices, and utilization patterns for ten end-uses using statistical multinomial and nested logit systems. These decisions are modeled using information on household and dwelling characteristics, demographic characteristics, fuel prices, fuel availability, weather patterns, and appliance attributes. The models also provide detail by appliance for each of three housing structure types (single family detached, multi-family attached, and mobile homes).

Nine explicit end-uses are forecast: HVAC (heating, ventilation, and air conditioning in 19 various combinations), water heating, dish washing, clothes washing, clothes drying, cooking, first refrigerators, second refrigerators, and freezers. The tenth end-use, "other", represents all remaining appliances and lighting collectively.

Data Sources

While some end-use type data is not economically available on a utility service-area basis, mostly utility-specific data was used to develop this forecast. A list of data sources is shown in Table 2-6.

Forecasts of electricity prices are identical with those used in the econometric forecast. Forecasts of natural gas prices are based on information from the North Carolina Utilities Commission Annual Report and DRI. Fuel oil/other price forecasts are from DRI. Firewood prices are expected to rise at 1% above the rate of inflation.

Forecasts of household income and total structures are identical with those used in the econometric forecast. Forecasts of more detailed demographic variables are based on North Carolina state data. Normal heating and cooling degree days are used for the forecast. Finally, forecasts of efficiency standards are based on existing and likely future efficiency standards consistent with the National Appliance Energy Conservation Act of 1987 and continuing amendments.

Table 2-6
Major inputs to the REEPS model

Data	Sources
I. Fuel Price Forecasts	
A. Electricity	CP&L Forecast
B. Natural Gas	NCUC Report and DRI
C. Oil/Other	DOE/EIA Report and DRI
D. Wood	CP&L Forecast
II. Other Exogenous Variable Forecasts	
A. Income	CP&L Service Area Economic Forecast and the State Data Center
B. Number of Members per Household	CP&L Forecast using the State Statistical Register historic values
C. Forecast of Structures (4 types)	CP&L Service Area Economic Forecast, DRI and CP&L Appliance Information Survey
D. Efficiency Standards	National Appliance Energy Conservation Act of 1987 with 1990 Amendments and growth in these standards consistent with the trends in the standards
E. Weather Data	National Oceanic and Atmospheric Administration data weighted by CP&L area weather stations.
F. Natural Gas Availability	CP&L Appliance Information Survey
G. Rural/Non-Rural Homes	CP&L Forecast using the State Statistical Register historic values
H. Discount Rates	REEPS-provided data

Table 2-6
Major inputs to the REEPS model
(continued)

Data	Sources
III. Appliance Data	
A. Saturations	CP&L Appliance Information Survey
B. Penetrations	CP&L Appliance Information Survey
C. Efficiencies	REEPS-provided data
D. Unit Energy Consumptions	Load Research Section, AEIC Load Research Committee, DSM Section, REEPS-provided data

Commercial end-use forecast

Carolina Power & Light Company uses the EPRI COMMEND model for its commercial sector end-use forecast. COMMEND is a model that develops, organizes, and forecasts commercial energy use at the end-use level. COMMEND reflects the impacts of changes in energy prices, technology efficiencies, and economic growth on the forecast.

The COMMEND model segments the commercial market by building type and end-use. CP&L's end-use forecast includes 11 building types, (office, retail, warehouse, grocery, restaurant, lodging, nursing home, hospital, elementary and secondary school, higher education, and church), and 10 end-uses (space heating, cooling, ventilation, water heating, cooking, refrigeration, interior lighting, exterior lighting, office equipment, and miscellaneous).

Data sources

While some end-use type data is not economically available on a utility service-area basis, mostly utility-specific data was used to develop this forecast. A list of data sources is shown in Table 2-7.

Table 2-7
Major inputs to the COMMEND model

Data	Sources
I. Exogenous Variable Module	
A. Historical Fuel Prices	
1. Electric	CP&L
2. Gas	NCUC Report
3. Oil	DOE Annual Energy Review
B. Forecast Fuel Prices	
1. Electric	CP&L Forecast
2. Gas	DRI
3. Oil	DRI
C. Exogenous Variables	CP&L
II. Floor Stock Module	
A. Employment	
1. Historical	NC Employment & Wages Report
2. Forecast	CP&L Forecast
B. Survival Functions	COMMEND-provided Data
III. Market Profiles Module	
A. Fuel Shares	CP&L Commercial Sector Database prepared by Synergic Resources Corporation and Southern Regional Data
B. EUI Values	CP&L Commercial Sector Database Prepared by Synergic Resources Corporation
IV. Technology Data Module	
A. Heat Pump Data	CP&L Commercial Sector Database Prepared by Synergic Resources Corporation and COMMEND-provided Data
B. Equipment Cost	COMMEND-provided Data
C. Technology Elasticities	COMMEND-provided Data
D. Efficiency Trends	COMMEND-provided Data
E. Cost Trends	COMMEND-provided Data
F. Thermal Interactions	COMMEND-provided Data

Table 2-7
Major inputs to the COMMEND model
(Continued)

Data	Sources
V. Economic Data Module	
A. Discount Rates	COMMEND-provided Data
B. Price Weights	COMMEND-provided Data
C. Choice Elasticities	COMMEND-provided Data
D. Utilization Elasticities	COMMEND-provided Data
E. Fuel Share Inertia Parameters	COMMEND-provided Data
F. EUI Inertial Parameters	COMMEND-provided Data
G. Retrofit Penetrations	COMMEND-provided Data
H. Office Equipment Growth	COMMEND-provided Data
I. Thermal Shell Parameters	COMMEND-provided Data
VI. Standards & DSM	
A. Efficiency Standards	CP&L evaluation of trends

Industrial end-use forecast

Carolina Power & Light Company uses the EPRI INFORM model for its industrial end-use forecast. INFORM develops, organizes, and forecasts industrial energy use at the end-use level. INFORM reflects the impacts of changes in energy prices, technology efficiencies, and economic growth in the forecast.

The INFORM model segments the industrial market into 15 Standard Industrial Classifications (SIC) codes, with six end-uses in each SIC. The end-uses consist of Motors, Thermal Processes, Other Processes, Lighting, HVAC (Heating, Ventilation, and Air Conditioning), and a Miscellaneous category.

Data sources

INFORM requires vast amounts of end-use data, some of which are often not economically available on a utility service-area basis. Utility-specific data was combined with county, regional, and national data. The EPRI contractor who created the INFORM model (Regional Economic Research Incorporated -- RER), provided considerable assistance in tailoring available data to reflect CP&L service area characteristics.

Forecast of electricity price is consistent with that used in the econometric models. Natural gas price is based on the North Carolina Utilities Commission Annual Report and DRI. Other fuel prices are based on DRI's forecast for industrial fuel oil prices.

Forecasts of employment are from the CP&L service-area economic forecast and are consistent with those used in the econometric forecast. Capacity Utilization projections are based on national data. Finally, forecasts of efficiency standards are based on existing and likely future standards consistent with Department of Energy standards.

Table 2-8 follows, providing a summary of data inputs to the INFORM model and the sources of that data.

Cogeneration forecast

The INFORM forecast is adjusted by SIC code for expected increases in displacement cogeneration consistent with adjustments made to the econometric forecast.

Table 2-8
Major Inputs to the INFORM model

Data	Sources
A. Fuel Price Forecast	
1. Electricity	CP&L Forecast
2. Natural Gas	NCUC Report and DRI
3. Other Fossil Fuel	DOE/EIA Report and DRI
B. Exogenous Variables	
1. Output Levels by SIC	CP&L Forecast
2. Employment by SIC	CP&L Data
3. Capacity Utilization	INFORM - provided data
4. Lighting Efficiency	Department of Energy/Energy Policy Act
5. Motor Efficiency	Energy Policy Act
6. Population Growth Index	CP&L Forecast
7. Displacement - Cogeneration	CP&L Service Area Data

Chapter 3 contains a description of CP&L's DSM process, summaries of implemented and potential DSM programs, economic evaluation results for each implemented program, an overview of additional DSM activities and a forecast of DSM impacts.

DSM Process

This section describes the DSM process used to select and develop DSM programs. The major elements of the process are objectives and strategy, program development, economic analysis, customer acceptance, market potential, monitoring and evaluation.

Objectives and strategy

The development of DSM programs is a dynamic process that begins with the formulation of overall demand-side management objectives, and leads to development of a strategy to meet these objectives. Since the corporate situation changes over time, the objectives and strategy are periodically reviewed.

The plan to achieve CP&L's DSM objectives can be characterized in terms of size, mix, pace, and cost. It is composed of a mix of load shape objectives and programs in the residential, commercial and industrial sectors. The load shape mix consists of strategic conservation, load shifting, peak clipping, valley filling, and strategic load growth. The pace can be adjusted up or down depending on progress to date, customer acceptance, anticipated program enhancements, and expected business conditions.

Program development and economic analysis

Individual programs that comprise the DSM portfolio are developed through a process that allows for systematic development and analysis. As programs progress through development, they become increasingly specific in their definition - target market, qualifications, marketing approach, program cost, and expected results. Questions covering areas such as the economic costs and benefits of the program, customer acceptance, and market potential are investigated.

Economic costs and benefits

With regard to the economic analyses of the costs and benefits of DSM, CP&L seeks to develop and promote cost-effective programs which tend to improve system load factor, increase the utilization and efficiency of existing capacity, minimize the need for future generating capacity, provide downward pressure on the level and frequency of future rate increases, ensure customer satisfaction, and support continued sound economic growth within its service area.

Four standard tests are usually considered when assessing the costs and benefits of DSM programs. They are the Utility Cost Test, the Ratepayer Impact Measure (RIM) Test, the

Participant Test, and the Total Resource Cost (TRC) Test. The costs and benefits components of these tests include increases or decreases in participant costs or in utility supply and program costs, changes in revenues to the utility or in bills to the participant, incentives paid to participants and participation charges paid to the utility. Whether a component is a benefit or a cost depends upon which perspective or test is being considered, as well as what the impact of a DSM program is on a particular market segment. For example, an incentive payment is a benefit to the participant, but a cost to the utility; and, promotion of a more efficient appliance will reduce costs for some participants in a program but increase costs for other participants. Thus, not all tests are meaningful for all DSM programs or even necessarily for all market segments affected by a single program. Since DSM programs are made available to all customers, CP&L believes that the RIM Test, which assesses the cost-effectiveness of a DSM program from the point of view of CP&L's body of customers should be the primary economic criteria for determining cost-effectiveness of DSM programs.

The RIM test determines the impact on rates for the utility's body of customers. Those programs which benefit all customers by exerting downward pressure on rates are cost-effective. Those options which cause rates to increase are not cost-effective. This methodology (RIM) results in decisions, which are in the best interest of the utility's entire body of customers. Use of the RIM test to evaluate demand-side management options is also consistent with operating in a more competitive environment because it focuses on minimizing rates.

In addition to the consideration of standard economic tests, utilities must also take into account other factors not explicitly identified in cost-effectiveness evaluations of DSM. Factors such as market potential, technical feasability, reliability, budget constraints, the urgency of load reduction, customer satisfaction, and regulation must also be considered. Therefore, standard economic tests may not be sufficient in themselves to select DSM programs, but serve to provide direction as to the long-term economic feasibility of various DSM programs.

Customer acceptance

Customer acceptance is a vital factor in the success of CP&L's DSM efforts. Communication with our customers provides a vehicle for encouraging and measuring customer acceptance. CP&L utilizes varying communication forums to interact with customers. The Company's advertising and promotional materials educate customers and encourage program participation. CP&L also provides ongoing opportunities for communication with customers and continually seeks input from a variety of perspectives regarding DSM programs.

Market research is conducted to gather information and increase understanding of CP&L's DSM programs and associated advertising. This research provides valuable insight into customer needs which are factored into our DSM strategy and programs.

Market potential

Forecasting the performance of DSM programs is conceptually similar to forecasting the performance of products found in many other industries. Success is driven by such factors as market size, product design and promotion, industry structure, competition, economic growth and other relevant macro-economic variables.

The methodology employed by CP&L uses diffusion curves to model how new products or technologies are disseminated into the market place. It's part of a more general classification of methodologies which has been referred to as "technological" forecasting. This technique is well established in marketing and economic theory, and has been applied to many industries, including utilities.

Under this methodology, the penetration or diffusion of a new product over time is expected to follow some specified functional form. This form is often an S-curve or "learning curve." The S-curve depicts product sales to be moderate at introduction, accelerate as awareness grows and the technology becomes more accepted in the industry, slow down as more of the core customers have already been sold, and finally reach a point of saturation or long-run stability.

In practice, each DSM program is forecasted by (1) identifying the target market, its size and growth, (2) specifying a model or functional form for the diffusion curve and (3) estimating the shape of the curve using historical data, marketing research or other available information.

Monitoring and evaluation

It is critical for CP&L to be able to measure, verify, and document the achievement of its DSM programs. To accomplish this objective, CP&L employs a marketing database, a cost tracking system, and comprehensive program evaluations. Program impacts are monitored through an extensive tracking system called the Marketing Database System. The Marketing Database System provides a record of DSM program participation and customer characteristics for each participant location. As new DSM programs are developed and others are enhanced, data needs are identified and incorporated into the data collection procedures of the tracking system. Additionally, work is underway to implement engineering algorithms into the system to better estimate demand and energy impacts specific to each DSM program participant.

CP&L's "Plan for Evaluation" represents a significant commitment by CP&L as well as an opportunity to achieve savings and to enhance its activities. The Plan includes fundamental actions that address data requirements to support evaluation of DSM programs, and activities for evaluation of the highest priority programs based on the magnitude of expected demand impacts and program expenditure levels. CP&L has completed evaluations of its highest priority programs and is incorporating evaluation requirements into future program plans. The Company is also strengthening its infrastructure to support in-house comprehensive program evaluations.

Implemented DSM Programs

The following pages provide a brief description and the results of economic evaluations for each of the Company's implemented DSM programs. These programs are as follows:

Residential

Common Sense Home (Thermal Efficiency - New Homes)
Thermal Efficiency - Existing Homes
• Homeowner's Energy Loan Program
• Energy Conservation Discount
EZ - $64
Residential High Efficiency Heat Pump
Residential Time-of-Use

Commercial

Commercial Energy Efficient Design
Commercial Energy Audit
Commercial Time-of-Use
Commercial Thermal Energy Storage

Industrial

Industrial Audit/ Energy Efficient Plants
Industrial Time-of-Use
Large Load Curtailment

Residential

Common Sense Home Program (Thermal Efficiency - New Homes)

The Common Sense Home Program encourages the construction of energy-efficient residences. Structures which meet the program's requirements for thermal integrity and equipment efficiency earn the Common Sense Home designation and qualify for CP&L's 5% Residential Energy Conservation Discount.

Current Common Sense Home requirements are: (1) minimum insulation levels of R-30 in ceilings, R-16 in walls, R-19 in floors, and R-5 in slabs; (2) window area limited to 15% of floor area; (3) insulated windows and doors; (4) an electric hot water heater with a minimum tank size of 40 gallons and minimum insulation value of R-12; and (5) an electric heat pump with a minimum 11 Seasonal Energy Efficiency Ratio (SEER) and a sealed duct system.

The Company has implemented a Common Sense Plus Home Pilot Program in the Raleigh area. This pilot program is an effort to further encourage CP&L's residential customers and builders to invest in even higher energy efficient standards. In addition to meeting all the criteria of the enhanced Common Sense Home Program, this pilot program requires quality installation standards for the equipment, prewiring for appliance control, and a larger electric water heater thus resulting in greater comfort and energy efficiency for the homeowner.

Thermal Efficiency - Existing Homes

Thermal efficiency is promoted for existing residential structures through the Homeowner's Energy Loan Program (HELP). Loans are available that can be used for insulation and high-efficiency heat pumps, energy audits, and customer education. In addition, an upgraded structure that meets CP&L's efficiency standards will also qualify for the 5% Residential Energy Conservation Discount which provides a reduction in energy usage costs.

Thermal Efficiency - Existing Homes (Homeowner's Energy Loan Program)

The Homeowner's Energy Loan Program promotes conservation of energy and demand reduction by providing convenient and inexpensive financing of conservation measures for residential homeowners. Under the program, CP&L will loan a homeowner with approved credit up to $3000 for the installation of cost-effective conservation measures for homes with electric heat or whole-house air conditioning at 6% simple interest. The homeowner will have up to five years to repay the loan conveniently via the monthly electric bill.

The approved measures are: ceiling insulation, wall insulation, floor insulation, duct insulation/modification, duct testing/sealing, storm or double glass windows, storm or insulated doors, programmable heat pump thermostats, and energy-efficient water heaters.

EZ-$64 Program

The EZ-$64 Program uses either radio or power-line carrier to interrupt residential customers' central air conditioners for up to four hours per day (maximum of 60 hours during cooling season) and/or electric water heaters for up to four hours per day throughout the year. Participants receive a credit of $2 per month for water heater control and an additional $10 per month ($13 for multiple units) from June through September for air conditioner control with the water heater option. A stand-alone air conditioner option is also available during the summer months offering the customer a discount of $8 per month ($11 for multiple units).

Residential High-Efficiency Heat Pump Program

CP&L's High-Efficiency Heat Pump Program includes customer financing and rebates for high-efficiency heat pumps, a Quality Heat Pump Dealer List, dealer incentives for high-efficiency installations and advertising to inform residential customers about high-efficiency heat pumps. The heat pump financing rate is tied to the SEER rating of the equipment purchased by the residential customer. The higher the efficiency rating, the lower the financing rate.

Residential Time-Of-Use

The Company offers two residential time-of-use rates which use financial incentives through rate design to encourage customers to shift load and usage to off-peak periods. Participating customers may choose an all energy time-of-use rate or a time-of-use rate that contains both demand and energy components.

Commercial

Commercial Energy-Efficient Design Program

Building owners and agents are contacted early in the planning process to discuss the services and programs that are available from CP&L to assist in reducing peak demand and improving overall energy efficiency. Recommendations and proposals are made by marketing representatives and/or power engineers to customers and design professionals with respect to increased energy efficiency and load management. Specific measures recommended include: thermal integrity improvements, the use of energy-efficient lighting, high-efficiency heating/air conditioning equipment, and proper control devices.

Commercial Energy Analysis (Audit) Program

Under the Commercial Energy Analysis Program CP&Ls marketing representatives and/or power engineers make recommendations and proposals to customers with respect to increased energy efficiency and load management in end-uses such as HVAC, energy-efficient lighting, thermal envelope, and other end uses.

Commercial Time-of-Use

The commercial time-of-use rate provides an incentive for customers to reduce on-peak load and shift usage to off-peak hours. Customers have found various ways to reduce on-peak load, including the use of timers, energy management systems, cool storage systems and changes in work schedules.

Commercial Thermal Energy Storage Program

The TES Program emphasis is placed on customer education and working closely with HVAC design professionals and other business associates to make them aware of the various CP&L off-peak rates that are available for Thermal Storage applications. The program encourages the customer, design professional or business associate to perform a payback calculation for the additional first cost expenses associated with a TES installation which will be offset through savings on the electric bill via the appropriate time-of-use or thermal storage rate.

Industrial

Industrial Audit/Energy-Efficient Plants Program

CP&L energy engineers and power engineers have been conducting detailed energy studies and "walk-through"audits for industrial customers system-wide since 1983. Applications addressed include energy-efficient lighting, motors and motor drives, HVAC design and optimization, and energy management systems. Actual on-site measurement supports engineering analyses and conclusions.

The same engineers work during the facility design phase as part of the Industrial Energy-Efficient Plants component of this program. Objectives from both components include reducing peak load, load shifting, and strategic conservation. The Power Quality component was a 1990 program enhancement. Power Quality is an area of major importance to all our customers, especially our industrial customers. The goal of this program is to provide technical expertise to enable the power engineers to better serve our customers.

Industrial Time-Of-Use

Optional time-of-use rates are available to all industrial customers. Demand and energy charges are lower during specified off-peak hours. When feasible, time-of-use rates are used as tools by CP&L's energy engineers and power engineers in conjunction with the industrial Audit/Energy-

Efficient Plants Program to reduce peak load, improve load factor and increase the economic efficiency of our customers.

Large Load Curtailment Program

Customers are provided an economic incentive based upon the avoided peaking capacity cost, to participate in the program. The customer receives a discount monthly for each kilowatt subject to curtailment. For capacity type curtailments, customers are expected to reduce load or "pay" back to the Company a significant portion of discounts previously received. If the curtailment is economic in nature, customers decide whether to curtail or continue to operate at their contract demand level and pay a cents-per-kWh premium. This program is popular with customers who have the ability to increase and decrease significant loads in a short period of time.

Economic Evaluations

The following table presents economic evaluation results for CP&L's DSM programs. The results are represented as benefit/cost ratios for each of the four standard cost-effectiveness tests. A benefit/cost ratio of greater than one indicates that the program is cost-effective.

Table 3-1

Economic Cost Effectiveness Test Results (Benefit/Cost Ratios)

	Utility Cost	Ratepayer Impact Measure	Participant	Total Resource Cost
Residential				
Common Sense Home (Thermal Efficiency-New Homes)	1.26	1.03	6.04	2.56
Thermal Efficiency-Existing Homes	1.77	0.64*	5.04	4.79
EZ - $64	1.14	1.14	**	2.49
Residential High Efficiency Heat Pump	1.42	1.24	NA	3.32
Commercial				
Commercial Energy Efficient Design	60.61	1.39	155.45	47.59
Commercial Energy Audit	70.39	1.28	130.57	49.82
Commercial Thermal Energy Storage	59.32	3.13	3.40	9.45
Industrial				
Industrial Audit/Energy Efficient	23.61	2.12	**	123.61
Large Load Curtailment				
Rider No. 58	0.99	0.99	**	18.92
Experimental TOU	0.44	0.44	**	789.93

* Inclusion of the benefits of High Efficiency Heat Pumps for those customers participating in both the Homeowner's Energy Loan Program and the High Efficiency Heat Pump Program results in a RIM benefit/cost ratio of greater than one; i.e., the program is cost-effective.

** Benefits are positive, but because there are no participant costs, the benefit/cost ratio is indeterminant.

Potential DSM Programs

CP&L has under consideration an array of potential demand-side management programs. The table below provides a listing of the programs for which actions are planned over the next three years. The following pages provide a brief description of each program.

Residential

High Efficiency Water Heater
Heat Pump Water Heater
Home Comfort Analysis
Common Sense Manufactured Home - Enhancement
Common Sense Home Program-Environmental Option

Commercial/ Industrial

Thermal Energy Storage - Schools
Non-Residential Energy-Efficient Heat Pump
Commercial Load Control
Small Load Curtailment

Residential

High-Efficiency Water Heater

The Company is considering development of a program to encourage the installation of high-efficiency electric water heaters.

Heat Pump Water Heater

A Heat Pump Water Heater study is being developed to test the feasibility and customer acceptance of heat pump water heaters in CP&L's service area. A two-year study is planned, beginning in 1995, to test 10 heat pump water heaters. Initial activities will consist of testing equipment in a controlled laboratory environment to determine equipment performance and potential installation problems. Field installation will follow. During the field test, energy, demand and hot water consumption will be monitored. Heat pump water heaters are expected to provide hot water at less cost and at a reduced kW demand when compared to conventional electric water heaters.

Home Comfort Analysis

CP&L is considering development of a formal program with our Quality Heat Pump dealers to address the area of heating and cooling system performance testing and duct system sealing for existing and new homes. The training would be provided by the North Carolina Alternative Energy Corporation or other equivalent agency. The Company currently encourages performance testing and duct sealing in conjunction with other DSM programs.

Common Sense Manufactured Home-Enhancement - Thermal Efficiency, New Homes

The enhanced Common Sense Manufactured Home Program will encourage the construction and sale of new energy-efficient manufactured homes, which utilize a higher-efficiency heat pump for heating and cooling.

Common Sense Manufactured Home Program - Environmental Option

The proposed Common Sense Home Program with the environmental option will encourage builders to incorporate features which improve energy-efficiency and provide environmental benefits. As with Common Sense, the homes incorporate features which increase thermal and equipment efficiencies. In addition, the environmental option includes indoor air quality, water quality, home waste management, high efficiency lighting, and safety features. This program is being promoted nationwide under the auspices of the Edison Electric Institute's (EEI) "E Seal" certification program.

Commercial/Industrial

Thermal Energy Storage - Schools

With the increased emphasis to air condition new and existing educational facilities, a Thermal Energy Storage - Schools pilot project is being investigated as a means to provide the cooling, while limiting the summer demand impact to CP&L and the school system. This project would serve as a demonstration facility, as well as a prototype school, that could revolutionize the present systems being used to condition educational buildings.

Non-Residential Energy Efficient Heat Pump

The objective of the Non-Residential Energy Efficient Heat Pump Program is to increase energy efficiency by providing technical support and education in the selection of state-of-the-art equipment options. Through the existing Energy-Efficient Design Program and the Commercial Audit Program, we are currently working with customers and design professionals to ensure energy-efficient structures. The Non-Residential Energy Efficient Heat Pump Program is under consideration to complement our existing efforts by encouraging the installation of energy-efficient heat pumps. The program was implemented as a pilot in CP&Ls South Carolina service area in 1994.

Commercial Load Control

CP&L conducted a pilot program, using CP&L offices as test sites, to assess the feasibility of commercial load control. Load research equipment was installed to collect demand, energy, temperature and other data. Analysis of this data is not yet complete.

Small Load Curtailment

Customers are provided an economic incentive to reduce load during periods when available capacity is low relative to load. Administration of the program will closely parallel that of the Large Load Curtailment Program. The Company is experimenting with a different incentive (discount) structure which may more appropriately address the value of actual loads curtailed. A greater incentive is provided for available curtailable load when the Company is most likely to need it, in the summer and winter peak seasons.

Additional DSM Activities

This section of Chapter 3 presents summaries of other major DSM activities at CP&L in the areas of planning, evaluation and research. These activities are necessary to support the continued development and improvement of DSM programs.

Planning

The primary role of DSM Planning is to provide the vision, strategic direction and concepts for developing CP&L's DSM plan and programs. This section describes major DSM planning initiatives at CP&L.

DSM Strategic Planning Analysis

The DSM Strategic Planning Analysis is intended to provide high level guidance as to the type and timing of DSM objectives which CP&L should pursue. In particular, long run cost benefit studies were performed on generic load shapes in a variety of market segments. This approach is used to identify desirable options at a high level of aggregation.

The analysis, which is a cost-benefit screen, focuses on load shape changes, rate schedules, and start dates. The goal is to identify potentially cost-effective strategic options. The following incremental load shape impacts were investigated.

- Conservation
- Strategic Conservation (on peak only)
- Valley Filling (off peak only)
- Peak Clip
- Load Shift
- Strategic Load Growth

For this analysis, customer segments were defined by rate schedule. The segments which were investigated are:

- N.C. Residential
- N.C. Small General Service
- N.C. Medium General Service
- N.C. Large General Service
- N.C. Large General Service: Time-of-Use

The analysis consisted of calculating the 25 year Net Present Value (NPV) of benefits and costs for each load shape impact-customer segment combination. The sensitivity of results to program start times was considered by calculating NPV's for each year of the study period, through year 10. A positive NPV indicates that the load shape impact-customer segment combination will exert downward pressure on the frequency and magnitude of future rate increases.

Key findings are summarized below. (**NOTE**: Program costs and incentive payments were not included in this analysis; therefore, no inferences should be made concerning specific DSM programs. Also, because no program costs or incentive payments were included in the analysis, the results represent an optimistic case.)

1. Additional conservation options are not cost-effective today in the residential and commercial market segments, but will become increasingly attractive for commercial customers. In the industrial market, conservation is marginally cost effective for LGS customers provided that the impact of the conservation measure persists for at least 24 years and that the participants are not on the LGS-TOU rate.

2. Strategic conservation is cost-effective today for all rate schedules except LGS-TOU and will be beneficial in that market within 5 years.

3. Load Management, Peak Clip and Load Shift are cost-effective for all time periods of the analysis.

4. Valley filling is cost-effective in all market segments and all time periods.

5. Strategic Load Growth is cost-effective in all markets. While a strategic sales strategy is presently cost-effective in the MGS and SGS markets, a conservation strategy may begin to look attractive within the next 5 years.

The above findings have been used by CP&L in the design of an overall DSM strategy. This strategy guides the development of DSM programs, primarily by identifying markets and load shape impacts that should be considered. CP&L's current DSM strategy emphasizes programs aimed at Strategic Conservation, Load Management (peak clipping and load shifting) and Strategic Load Growth, which includes valley filling. High load factor Conservation is currently not cost effective in any market segments. However, because the strategic planning analysis indicates that Conservation in the commercial market segment may become increasingly attractive over the next 5 years, CP&L will closely monitor this situation and its potential future impact on the overall DSM strategy.

Comprehensive DSM assessment

During 1993 CP&L retained the services of XENERGY, Inc., an international energy consulting company with extensive DSM experience, to assist in the development of a plan to enhance DSM planning activities. In January of 1994, CP&L again retained XENERGY, Inc. to help put that plan into action. Together CP&L and XENERGY, Inc. conducted a comprehensive assessment of DSM market potentials in the CP&L service area.

The comprehensive DSM Assessment Project included the following major activities:

<u>Segment customers:</u> Customers with similar patterns of energy consumption are grouped together. These segments are consistent with a common data specification designed to facilitate sharing between functions, assure consistency, and improve efficiency in data collection and analysis.

<u>Establish baseline usage:</u> For each market segment, baseline energy consumption is developed. These baselines establish the amount of usage which can be impacted by a DSM measure.

<u>Identify DSM measures:</u> Identify a set of DSM measures to be analyzed and their associated load shape objectives.

<u>Characterize measures:</u> Determine the baseline efficiency, impact, and cost of each measure.

<u>Estimate measure technical potentials:</u> Combine baseline usage and DSM measure impacts to estimate technical potential in each market segment for each measure.

<u>Screen measures:</u> Screen each measure for cost-effectiveness based on the Rate Impact Measure (RIM) Test, the Total Resource Cost (TRC) Test and the Participant Test.

<u>Estimate market and achievable potential:</u> Based on economic attractiveness from the customer's perspective, as measured by payback, develop estimates of DSM potential that will be realized by market forces, and DSM potential that can be achieved by a utility program.

CP&L's comprehensive assessment of DSM considered more than 140 DSM measures addressing various load shape objectives across the three major customer classes - residential, commercial and industrial. A summary of the assessment results is presented in Tables 3-1 through 3-4.

The four categories of DSM potential identified in the tables are defined as follows:

Technical potential: The sum of demand impacts and the sum of energy impacts of the measures, regardless of cost-effectiveness.

Economic potential: That portion of the technical potential that passes a given cost-effectiveness test.

Market potential: That portion of the economic potential that will be implemented by customers, without intervention of a utility program.

Achievable potential: That portion of the economic potential that can be obtained or achieved through a utility program.

Significant technical potential for demand and energy savings exists in the residential and commercial classes. In fact, it is estimated that more than 90% of the total technical potential is in the residential and commercial market. While the total technical potential for summer peak load reduction is an impressive 26% of summer peak load, the estimated economic, market and achievable potentials are significantly less. In fact, XENERGY's estimate of achievable summer peak demand reduction as a percentage of total summer peak load ranges from 2.8% for RIM passing measures to 3.8% for TRC passing measures.

This range of incremental achievable DSM potential compares favorably with CP&L's forecast of DSM impacts, contained in this integrated resource plan. Between 1995 and 2009, the impact of CP&L's DSM programs, as a percentage of summer peak load, is expected to increase from 10.6% to 13.4%, a change of 2.8%.

Table 3-2

RIM Perspective Results Summary

Energy Potential (% of 1992 Energy Sales)

	Residential	Commercial	Industrial	Total
Technical	33.00%	35.00%	11.00%	24.00%
Economic	11.00%	2.80%	2.50%	5.30%
Market	1.70%	0.66%	0.83%	1.10%
Achievable	2.20%	0.34%	0.71%	1.10%

Demand Potential (% of 1992 Summer Peak Demand)

	Residential	Commercial	Industrial	Total
Technical	37.00%	27.00%	70.00%	26.00%
Economic	33.00%	5.20%	3.70%	18.00%
Market	12.00%	1.30%	1.20%	6.10%
Achievable	5.20%	0.68%	0.90%	2.80%

Table 3-3

RIM Perspective Results Summary

Energy Potential (GWh)

	Residential	Commercial	Industrial	Total
Technical	3,375	2,582	1,477	7,434
Economic	1,078	206	327	1,611
Market	171	49	108	328
Achievable	222	26	92	339

Summer Demand Potential (MW)

	Residential	Commercial	Industrial	Total
Technical	1,019	388	120	1,527
Economic	905	74	66	1,045
Market	322	19	22	362
Achievable	141	10	16	167

Table 3-4

TRC Perspective Results Summary

Energy Potential (% of 1992 Energy Sales)

	Residential	Commercial	Industrial	Total
Technical	33.0%	35.0%	11.0%	24.0%
Economic	20.0%	30.0%	6.2%	16.0%
Market	5.5%	13.0%	3.0%	6.2%
Achievable	4.6%	9.2%	1.4%	4.4%

Demand Potential (% of 1992 Summer Peak Demand)

	Residential	Commercial	Industrial	Total
Technical	37.0%	27.0%	7.0%	26.0%
Economic	24.0%	22.0%	5.5%	18.0%
Market	8.4%	9.8%	2.7%	7.0%
Achievable	4.3%	6.1%	1.0%	3.8%

Table 3-5

TRC Perspective Results Summary

Energy Potential (GWH)

	Residential	Commercial	Industrial	Total
Technical	3,375	2,582	1,477	7,434
Economic	1,999	2,199	801	4,999
Market	560	934	392	1,887
Achievable	467	683	183	1,333

Summer Demand Potential (MW)

	Residential	Commercial	Industrial	Total
Technical	1,019	388	120	1,527
Economic	657	320	97	1,073
Market	229	141	48	417
Achievable	118	87	17	223

The Center for Electric End-Use Data
Southeast data distribution effort

Carolina Power & Light is participating in an Electric Power Research Institute (EPRI) sponsored project to facilitate the transfer of end-use load research data to utilities in the Southeast. Project management and technical support is being provided by EPRI's Center for Electric End-Use Data (CEED).

The load research consists of end-use metered load data and customer characteristics for 200 residential and 300 commercial customers. The data was collected over an 18 month period in 1992 and 1993. The metered end-uses in the residential sector included water heating, HVAC, refrigerator, clothes dryer, television, microwave, dishwasher, and range. In the commercial sector, the end-uses included water heating, HVAC, lighting, refrigeration, and cooking.

The project will be conducted in two phases: In Phase One, the load and characteristics data set will be verified, transferability will be studied, and the data will be segmented into meaningful subgroups. Monthly energy consumption profiles will then be developed. A data quality review is now underway. If transferability is determined to be feasible, then end-use load shapes will be developed for each participating company in the second phase of the project.

Area costing

CP&L is also working with EPRI and selected contractors to investigate local area marginal costing techniques for T&D capacity and load control strategies. Local area costing capability can provide the basis for targeting of DSM or marketing programs to areas with higher or lower than average marginal costs.

The estimation of marginal T&D capacity costs on a local area basis is a relatively new development. Much of the work in this area has been funded by or sponsored by EPRI and member utilities. The results to date have begun to document the conceptual foundations, analytical methods and business applications of this new marginal costing approach.

The primary objective of CP&L's current work with EPRI is to determine the feasibility of developing a local area costing capability. Current and future applications for local area costing as well as data availability, analysis requirements, organizational requirements and regulatory considerations will all be appraised. If it is determined that local area costing is feasible and beneficial for CP&L and its customers, the Company will move forward with the development of a detailed project work plan.

Evaluation

DSM program evaluations address a broad range of issues concerning the effectiveness of programs in achieving their objectives. They generally fall into one of two categories: impact evaluation or process evaluation. The impact evaluation for each program quantifies the net energy and demand impact attributable to that program, and explores the factors that contribute to that impact. While each program's evaluation has specific issues to be addressed, the basic impact evaluation components are the same for all DSM programs. The overriding objective of process evaluation is program improvement. Process evaluation is designed to provide an ongoing stream of information to the CP&L staff which can be used to plan improvements to current and future programs.

CP&L has developed a comprehensive plan for evaluation of DSM programs, is strengthening its infrastructure to support in-house comprehensive program evaluations, and has completed evaluations of its highest priority programs. Each of these major DSM evaluation activities is summarized below.

Plan for evaluation

CP&L retained XENERGY, Inc., to advise the Company on its program evaluation needs and to recommend appropriate evaluation strategies and plans. XENERGY, Inc., is a leading international consulting firm in the field of DSM planning, implementation, and evaluation.

To develop appropriate recommendations for CP&L's program evaluation, XENERGY, Inc., first reviewed all of CP&L's programs and available data in order to understand CP&L's evaluation needs. This articulation of CP&L's evaluation needs was tested and refined with participation by CP&L management and staff. Next, XENERGY, Inc., applied its understanding as well as recent experience with program evaluation to develop fundamental recommendations to guide program evaluation and planning.

In 1993, CP&L developed a document entitled "Plan for Evaluation". This "Plan for Evaluation" represents a significant commitment by CP&L as well as an opportunity to achieve savings and to enhance its activities. The Plan includes fundamental actions that address data requirements to support evaluation of DSM programs, and activities for evaluation of the highest priority programs based on the magnitude of expected demand impacts and program expenditure levels.

The fundamental actions that address data requirements are the review of engineering algorithms used to calculate program impacts, and revision to program reporting and tracking system requirements to capture and store individual participant data. The highest priority programs are the Common Sense Home Program, EZ-$64 Program, and the Large Load Curtailment Program. Evaluations of these three programs have been completed.

Review and specification of engineering algorithms for DSM program evaluation

CP&L worked closely with XENERGY, Inc., to develop DSM program evaluation algorithms and data requirements in preparation for future evaluations. Algorithms were developed that explain customer-to-customer variations in impacts in order to form the basis for future evaluations. The level of accuracy versus amount of data required was carefully weighed to strive for efficiency in data collection, and algorithms were developed that can be modified and built upon as new programs are added or better engineering data become available.

A final report documenting the requirements for implementing engineering algorithms in CP&L's program tracking system was completed in March, 1994. The engineering algorithms provide for the calculation of estimated demand, energy, and revenue impacts for each program participant. The implementation of the algorithms is being accomplished in order of priority and as new programs are developed and others are enhanced. The first step in implementing the algorithms is collecting and storing in the tracking system the data needed as inputs to the algorithms. The next step is modifying the tracking system to automate the calculation of the impacts based on the data collected. Input data for the algorithms is currently being captured for Common Sense Homes and Apartments and Non-Residential Heat Pumps.

Impact and process evaluation of the Common Sense Home Program

The Common Sense Home Program is a strategic conservation program that encourages the construction of energy-efficient residences. Structures which meet the programs' requirements for thermal integrity and equipment efficiency earn the Common Sense Home designation and qualify for CP&L's Residential Energy Conservation Discount. The program provides incentives for builders and dealers to promote high efficiency heat pumps. CP&L has implemented a Common Sense Plus Home Pilot Program in the Raleigh area. The Pilot Program has somewhat different incentives and requirements.

The Common Sense Home Program Evaluation was performed jointly by CP&L and XENERGY, Inc. The impact evaluation determined energy and demand impacts from the 1994 program participants and relied heavily on an on-site data collection effort to characterize both participant and non-participant building practices. The results from these surveys were inputs into an energy simulation model, the outputs of which yielded the estimated program impacts.

The North Carolina Alternative Energy Corporation (AEC) was the on-site survey subcontractor. XENERGY, Inc. worked with the AEC and CP&L to develop the format of the on-site survey, and AEC trained the field labor staff to collect the required data. The Common Sense Home Program database represents a unique and comprehensive database for planning and research needs.

The process evaluation addressed program delivery and customer satisfaction, supported by phone surveys, trade ally focus groups and staff interviews.

Impact and market evaluation of the EZ-$64 Program

The EZ-$64 Program is a residential direct load control program that ranked as number one among CP&L's DSM programs in terms of expected 1993 demand impacts and program expenditures.

The EZ-$64 Program has two load control components: the Air Conditioning (AC) load control component and the Water Heating (WH) load control component. This program is designed to reduce system peak load during capacity shortage conditions. The current control strategy is shedding. For air conditioners, the shedding can be executed for up to four hours per day for a maximum of 60 hours during the cooling season. For water heaters, shedding can be exercised for up to four hours per day throughout the year. Control is exercised through radio or power-line carrier signals. About 75,000 customers are currently participating in the EZ-$64 Program.

The EZ-$64 evaluation was performed jointly by CP&L and Quantum Consulting, Inc. The evaluation met CP&L's corporate goal of assessing direct load control as a viable component of CP&L's integrated resource portfolio. The analysis methodologies used in this evaluation saved CP&L considerable resources and time by leveraging existing information to yield valuable results.

Specifically, the evaluation produced:

- reliable program estimates for shedding and cycling that are suitable for evaluation and forecasting purposes.
- reliable estimates for various cycling strategies, which can support future program redesign efforts.
- end-use load profiles to support long-term forecasting and scenario planning.
- marketing results that can also support future program redesign efforts.

Impact evaluation of the Large Load Curtailable Program

The Large Load Curtailment Program is a peak clipping program that provides an economic incentive based on avoided peaking capacity costs. Participating customers receive a discount monthly for each kW subject to curtailment. For capacity type curtailments, customers are expected to either reduce load or "pay" back to CP&L a significant portion of discounts previously received. If the curtailment is economic in nature, customers decide whether to curtail or continue to operate at their contract demand level and pay a cents-per-kWh premium.

Metered load data for each participant was used by CP&L to perform the Large Load Curtailment Program evaluation. Actual demand impacts for 1993 and 1994 curtailments were determined. Differences between achieved results and planning estimates, and variability in demand in summer and winter over possible days of curtailment were investigated. Actual load curtailment ability was also assessed. The cost-effectiveness of the Program was examined based on evaluation results.

Research

CP&L is also involved in research that will enhance the Company's knowledge of DSM as well as assist in the development of DSM options. This section describes the research activities.

Commercial thermal energy storage demonstration

The move to year-round schools by the NC Department of Public Instruction represents a large new load that will contribute to summer peak growth and will often require distribution system upgrades. The NC Department of Public Instruction estimates that 250 new schools in the state will be built with air conditioning by 2000. In addition, 400 existing schools will be retrofitted with air conditioning. At least 26 new air conditioned schools are planned for Wake County alone. Schools and other commercial cooling loads could be met with thermal storage systems, which have lower peak load than conventional air conditioning systems. However, architects, engineers and building owners have not begun installing storage systems because of first-of-a-kind risks.

CP&L has already pioneered ice storage for produce cooling at Southern Produce in Faison, NC. In the Faison application, the resulting peak load reduction allowed a $400,000 distribution upgrade to be avoided. In operation, this facility has proven quite versatile by adapting to a large number of unanticipated cooling loads while retaining a very desirable electrical load factor. The heating and cooling needs of commercial and industrial buildings can be met through a variety of heating and cooling equipment options ranging from direct acting systems (no storage) to seasonal cycle storage (storing energy from season to season). Each strategy will be more or less attractive to the operator and utility jointly, depending on the nature of the load. CP&L is working to characterize the type of loads for which the various storage strategies are appropriate.

A variety of research activities are required to achieve market acceptance for thermal storage. Analysis tools need to be refined so that they accurately model building dynamics and account for all the benefits storage offers, including reliability and availability. Also, there is still some need for design improvement and optimization to reduce installed cost.

The project will meet the research needs identified above through three phases. The first phase is to refine the computer based analysis tools that have already been developed at CP&L to evaluate cool storage. The second phase will involve the use of these tools to refine the details of storage strategy. The final phase will be to monitor the performance of a demonstration seasonal cycle thermal storage system and a weekly cycle system at Wake County's Department of Social

Services Building. Transfer of the analysis techniques to at least one independent design team will be an integral part of the demonstration project.

Heat pump monitoring for Demand-Side Management

Peak demand can be reduced and customer satisfaction enhanced by improving the performance of installed heat pumps. CP&L is developing a portable heat pump monitoring system to measure efficiency and to perform system diagnostics on heat pumps and air conditioners in order to maximize system efficiency.

The heat pump monitoring system is a tool developed for diagnostic and efficiency testing of residential and light commercial heating and air conditioning equipment. It consists of a microcomputer coupled to a data collection system which monitors and records equipment operating data. It is designed to be portable and easily installed by field service technicians. It displays results immediately and can also record data for later review. A key feature is the capability to display instantaneous efficiency which provides feedback for technicians working to fine tune a system.

Apart from its diagnostic capabilities, the heat pump monitor also provides a relatively simple way to establish a performance database of existing heat pump, air conditioning, and refrigeration installations. It also provides a method for evaluating new heat pump related technologies such as alternate refrigerants, ground coupling, and multiple or variable speed compressors. It may also provide a tool for evaluating the performance of heat pumps installed under the heat pump incentive programs and helping contractors improve the quality of their installations.

CP&L has assembled a third generation heat pump monitor that puts all instrumentation and the diagnostic computer in a field portable form, constructed a test bed heat pump for comparing heat pump alternatives and performed field testing to improve instrument reliability, simple installation, and reduce set up time. Software is being developed that will be used by equipment technicians and will provide sufficient detail for diagnostics.

Southeast Regional Manufactured Housing Research Center

One of the most important and fastest growing building sectors in the Southeast is manufactured housing: residential structures that are factory built, transported on a permanent chassis, and regulated by the pre-emptive U.S. HUD standards. Despite the potential for significant improvements in the energy performance of manufactured homes, this area of home building has been somewhat neglected by the research community.

Manufactured housing represents over one-third of CP&L's new residential customers. New connect reports indicate that 80% of these homes are all electric - the majority being electric resistance furnaces. Recognizing the large impact that manufactured homes have on present energy use and demand, and the expected rapid growth in the number of new homes that are likely to be connected to electrical service in the future, a number of Southeast utilities, DOE, EPRI and CP&L have embarked on a scoping study to look at creating a Southeast Regional Manufactured Housing Research Alliance. The Alliance would serve several functions including: coordinating research, addressing energy-related problems common to manufactured housing and exploiting opportunities for improving energy efficiency. Outputs of the scoping study include: the role a center for research and development can play in improving electric utilization in manufactured homes, the kinds of activities the Alliance should undertake, and a structure for managing the Alliance, including a framework for decision-making.

DSM Forecast

A breakdown of the 1994 DSM forecast by program and customer class is presented in Table 3-6 and in Figure 3-1. An increase of 834.8 MW of summer peak load reduction capability is projected during the forecast period. Of this total, 422.9 MW or 51% is from the residential sector, 171.7 MW or 21% is from commercial and 240.2 MW or 29% is obtained from the industrial sector. On a cumulative basis the portfolio of DSM resources is a mix of 43% residential, 17% commercial and 40% industrial in the year 2009.

Figure 3-1
1994 DSM Forecast - Reference Case

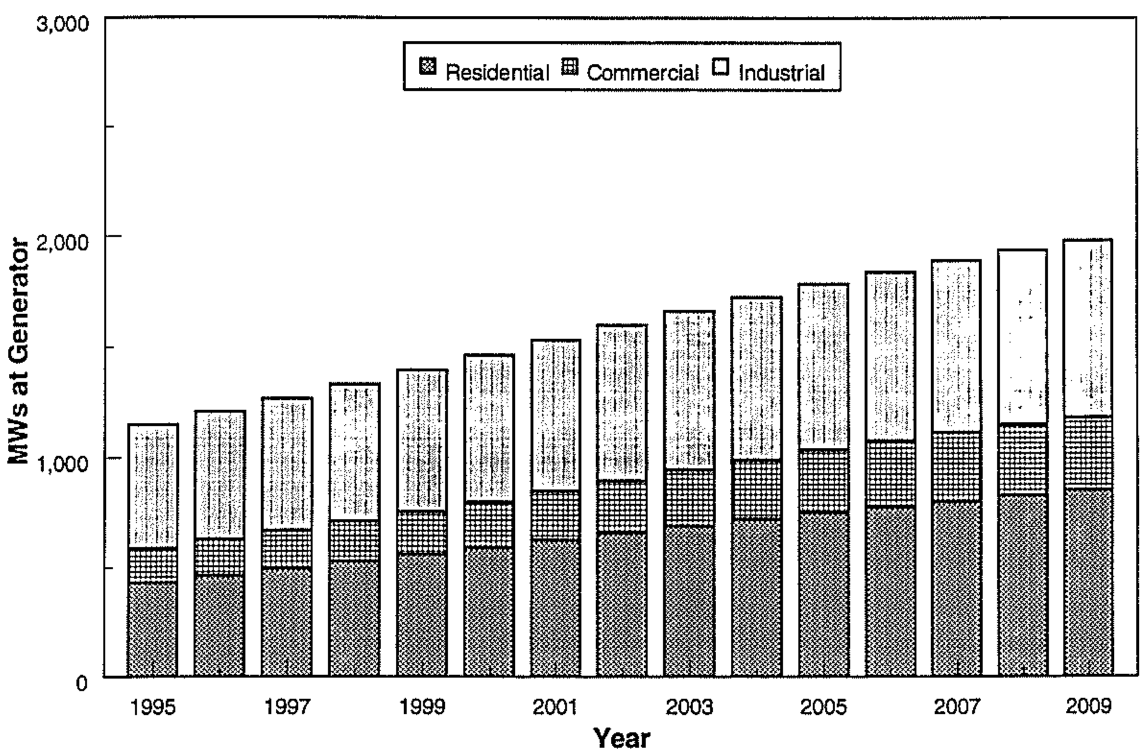


Table 3-6

1994 DSM Forecast Reference Case
Reference Case Summer MW's Mid-Year
(at time of summer system peak)

	Residential Programs							Commercial Programs				Industrial Programs				
Year	Air Conditioner Control	Water Heater Control	Time Of Use Rates	High Efficiency HP and AC	Home Energy Loan/Conserv. Discount	Common Sense Home	Residential Subtotal	Audit	Energy Efficient Design	Thermal Storage	Commercial Subtotal	Large Load Curtail-ment	Time of Use Rates & TES	Audit/ Energy Effic Plants	Industrial Subtotal	Grand Total
1995	182.5	33.4	22.3	24.2	34.1	132.4	429.0	57.9	96.7	2.9	157.5	212.2	116.3	235.7	564.2	1150.7
1996	204.0	36.1	23.4	28.0	35.2	135.2	461.9	60.9	100.3	3.1	164.3	220.6	120.6	242.2	583.4	1209.7
1997	226.4	39.0	24.5	30.8	36.1	137.7	494.5	63.9	105.1	3.4	172.4	224.5	126.3	250.2	601.0	1267.9
1998	249.5	41.9	25.6	32.8	37.0	140.0	526.8	66.8	111.4	3.7	181.9	228.6	131.6	261.9	622.1	1330.9
1999	273.2	45.0	26.5	34.2	37.8	142.4	559.1	70.6	118.3	4.0	192.9	232.6	135.4	277.6	645.6	1397.6
2000	297.2	48.1	27.4	35.3	38.5	144.7	591.4	76.7	125.1	4.3	206.1	235.8	137.6	293.6	667.1	1464.5
2001	321.6	51.3	28.3	36.3	39.2	147.0	623.7	85.3	131.7	4.6	221.6	239.1	139.9	307.7	686.7	1532.0
2002	346.1	54.5	29.1	37.1	39.9	149.4	656.0	95.4	137.9	4.9	238.2	242.9	142.2	320.3	705.5	1599.7
2003	370.5	57.7	30.0	37.8	40.5	151.7	688.1	105.8	143.7	5.2	254.8	246.5	144.6	331.4	722.5	1665.4
2004	394.2	60.8	30.7	38.5	41.1	153.9	719.3	115.5	149.4	5.6	270.4	250.1	146.8	341.3	738.2	1727.9
2005	417.0	63.8	31.5	39.1	41.6	156.0	749.0	124.3	154.8	5.9	285.0	253.7	149.1	350.0	752.8	1786.8
2006	438.6	66.7	32.1	39.7	42.0	157.8	776.9	132.0	159.8	6.3	298.1	257.2	151.4	358.1	766.6	1841.7
2007	458.9	69.3	32.8	40.2	42.4	159.5	803.2	138.8	164.4	6.6	309.9	261.2	153.7	365.7	780.6	1893.6
2008	478.1	71.8	33.4	40.7	42.8	161.2	828.1	144.6	168.7	7.0	320.3	264.6	156.0	372.5	793.1	1941.4
2009	496.5	74.2	33.9	41.2	43.2	162.9	851.9	149.4	172.4	7.4	329.2	267.9	158.0	378.5	804.4	1985.5

Chapter 4
Environmental Considerations

As society as a whole has become more environmentally conscious, public policy in the form of laws and regulations has been expanded. One of the most recent significant changes has been the enactment of the Clean Air Act Amendments of 1990 and the promulgation of associated regulations. This chapter discusses the Clean Air Act Amendments and their impact on CP&L, and examines possible future environmental regulations and the uncertainties associated with them.

The 1990 Clean Air Act Amendments

On November 15, 1990, the Clean Air Act Amendments of 1990 (CAAA) became law. The CAAA contains 11 Titles, four of which have potentially significant implications to electric utilities. The Title with the biggest immediate impact on electric utilities is Title IV. Title IV of the CAAA, the Acid Rain Title, sets three major national goals:

- By the year 2000, reduce the annual level of SO_2 emissions by 10 million tons below the level of emissions in 1980.

- A nationwide cap on SO_2 emissions beginning in the year 2000.

- A two million ton reduction in NO_x emissions below 1980 levels.

These goals are to be met through a two-phase program. In Phase I, part of the SO_2 and NO_x emission reductions are to be achieved through emissions reduction requirements at the largest, highest-emitting generating units in the United States. Emissions from CP&L's fossil plants are among the lowest of all utilities east of the Mississippi River, and thus, CP&L has no units that are affected in Phase I. During Phase II, which begins January 1, 2000, the SO_2 reduction goals are to be reached through more stringent requirements at virtually all fossil fuel generating units. All of CP&L's coal-fired units are Phase II-affected units. NO_x regulations which will be applied to all of CP&L's Phase II-affected units and these regulations will be as stringent as the Phase I reductions. The Environmental Protection Agency (EPA) has until January 1, 1997 to develop more stringent NO_x emission limits that must be met by CP&L's Phase II-affected units.

In response to the Amendments, the EPA has promulgated many new regulations with which the Company must comply. The following sections provide an overview of the compliance requirements that must be met by CP&L.

SO_2 requirements

Under Title IV of the CAAA, Phase I and Phase II affected units are allocated SO_2 allowances (i.e., authorizations to emit up to one ton of SO_2) by the EPA. The number of allowances allocated to each unit is based on the unit's 1985-1987 annual average (baseline) fuel consumption. For most Phase II-affected units, including all of CP&L's fossil steam units, allowances equal 1.2 lbs. of SO_2 per MMBtu multiplied by the baseline fuel consumption.

Under Title IV, utilities are in effect required to meet allowable tonnages for SO_2 emissions on a *systemwide* basis. While Title IV allocates SO_2 allowances to each unit and enforces the SO_2 emission requirements at the unit level (i.e., each *unit* must have enough allowances to cover actual emissions), the SO_2 allowance trading regulations permit the transfer of SO_2 allowances among units. This will enable utilities to substitute emissions reductions at units with lower costs of control for more costly emissions reductions that would otherwise be required at other units. It is important to note that while the 1990 Amendments provided for the allocation of emission allowances to each unit, the underlying Ambient Air Quality Standards (AAQS) were not changed and remain the controlling emission criteria. This means that a unit cannot emit SO_2 at a rate that would exceed the AAQS, regardless of the number of emission allowances allocated to that unit.

Title IV also permits the transfer (i.e., trading) of SO_2 allowances between systems and across state lines by any SO_2 emitting units or by any party outside of the regulated community. Thus, if the number of tons of SO_2 emitted by a unit or system exceeds its allocation of allowances at the end of any year, the unit or system can comply by obtaining additional allowances from units whose emissions are less than their allowance allocations.

Title IV includes several other SO_2 allowance provisions. Earning additional allowances under these provisions requires additional actions and costs. The additional SO_2 allowance provisions include: (1) additional conservation, (2) increases in generation from renewable sources, (3) participating in a Phase I substitution plan, (4) compensating generation and reduced utilization, and (5) industrial options.

NO_x requirements

To reduce annual NO_x emissions, the CAAA establishes NO_x emission performance standards for all tangentially-fired and dry bottom wall-fired (except units applying cell burner technology) boilers. Any coal-fired boiler serving an electrical generator at the 110 powerplants affected under Phase I is required to meet the following maximum allowable NO_x emission rates:

(1) 0.45 lb/MMBtu if it is a tangentially fired boiler, and

(2) 0.50 lb/MMBtu if it is a dry bottom wall-fired boiler (other than those applying cell burner technology).

CP&L's Phase II coal-fired units, must meet at least the same performance standards by January 1, 2000. The CAAA authorizes EPA to lower the NO_x limits that apply to CP&L's Phase II boilers if EPA determines that more effective low-NO_x burner technology is available. By statute, EPA must complete its review by January 1, 1997.

Other provisions in the NO_x regulations provide some flexibility in meeting the specified performance standards discussed above. In particular, an owner of two or more units, such as CP&L, is permitted to use multi-unit emissions averaging.

There are numerous uncertainties in the NO_x arena, primarily caused by the U. S. Court of Appeals for the District of Columbia Circuit which vacated EPA's NO_x regulations on November 29, 1994. The central point in the Court's holding was that EPA improperly interpreted "low-NO_x burner" technology to include low-NO_x burners and overfire air (OFA). The Court held that OFA is not to be included in the regulatory definition of low-NO_x burner technology. This is critical because the CAAA legislation allowed utilities to seek alternative emission limits (AELs) if they could not meet the statutory limits after installing low-NO_x burner technologies. Since the court remanded the rule to EPA, EPA is required to develop new regulations. It is unclear at this time when new rules will be promulgated; however, EPA has published for notice and comment a direct final rule defining low NO_x burners. The direct final rule does not establish the NO_x limits for CP&L's Phase II. Thus, CP&L must wait until no later than January 1, 1997 to determine if its limit for its Phase II, Group I boilers will be more stringent than the Phase I limits.

Continuous Emission Monitoring Systems (CEMS)

Regulations have been established for the monitoring, recordkeeping, and reporting of SO_2, NO_x, and CO_2 emissions, volumetric flow, and opacity data from Phase I and Phase II affected units. The goals of the CEMS program are to confirm SO_2 and NO_x emission reductions and support the market-based SO_2 allowance trading program through accurate data measurement, data availability, and national consistency. Table 4-1 shows the installation deadlines for Phase I, Phase II, and new units.

Table 4-1
CEMS Installation Deadlines

Unit Type	Deadline
Phase I	Tested and operational by 11/15/1993
Phase II	Tested and operational by 1/1/1995
New Units	Tested and operational within 90 days of start of commercial operation

Under the CEMS program, all emissions are measured (or statistically estimated) and reported. Data and information from the CEMS must be electronically reported to EPA on a quarterly basis. All measurements, data, reports, and other information required under the CEMS regulations must be maintained for 3 years.

CP&L completed the installation of CEMS well in advance of the regulatory deadline, providing a period for shakedown of the system and associated procedures. The CEMS chosen by CP&L are dilution extraction systems with redundant analyzers. Identical systems have been installed at all CP&L units to minimize operational and maintenance problems.

Compliance with NO_x requirements

Compliance with the NO_x requirements of Title IV is largely independent of compliance with the SO_2 requirements of the Act. This is because the nitrogen content of coal is not correlated to the sulfur content of the coal and the formation of NO_x is dominated by the conditions of the burning of the coal. A key difference between the NO_x regulations and the SO_2 regulations is utilities must control the rate of NO_x emissions (i.e., the pounds of NO_x per MMBtu) rather than meeting a system emission tonnage cap as for SO_2 emission regulations. Since there are no emission allowances for NO_x as there are for SO_2, allowances cannot be purchased as an alternate to technology based on compliance options. For these reasons, a NO_x compliance plan can be developed independent of the SO_2 compliance plan. Also, since NO_x compliance requires each unit (or group of units in an averaging plan) to meet an emission rate, compliance with NO_x regulations is only minimally impacted by future generation additions identified in a resource plan, and thus, does not influence the development of the resource plan.

As discussed earlier, CP&L is required to comply with certain Phase II NO_x limits by January 1, 2000. However, for the types of boilers CP&L has, the U.S. Environmental Protection Agency (EPA) may adopt more stringent limits before January 1, 1997. Therefore, analyses were conducted over a range of possible NO_x emission limits. This range was established using the Phase I Title IV NO_x limits as the high (upper) limit and the current

Northeast States for Coordinated Air Use Management (NESCAUM) limits as the low (lower) limit. These bounds are reasonable based on CP&L's understanding of NO_x regulations at the time of the analysis. Unit NO_x data from the CP&L NO_x Emission Inventory and the Company's projections of system operation were used to prepare estimates of baseline annual NO_x emissions (tons/yr) for the CP&L generating system. On average, over the period 2000-2010 it is estimated that CP&L will be required to reduce baseline NO_x emissions by 45 to 53 percent to comply with the range of Phase II NO_x limits that were evaluated.

A computer model was developed and utilized to determine the least-cost combination of CP&L generating units and NO_x control technologies to meet assumed Phase II NO_x emission limits. Over 150 different generating unit/NO_x control technology combinations were evaluated. Data from other utility NO_x reduction projects, equipment vendor correspondence, and a variety of published literature were used in preparing cost and NO_x reduction assumptions for generating unit/NO_x control technology combinations.

Sensitivity analyses were conducted to determine the impacts on costs and NO_x reductions caused by changes in assumptions of key variables. Table 4-2 describes the sensitivity analyses that were performed. These analyses tested the impacts associated with regulatory options and uncertainties, forecasts of CP&L generating system operation, and variations in technical assumptions of NO_x control efficiencies and the application of post-combustion NO_x controls such as selective non-catalytic reduction (SNCR). The results of the sensitivity analyses indicate that the parameters that have the greatest impact on compliance costs include emissions averaging, the level of Phase II NO_x emission limits, and the level of operating margin below the regulatory limit.

Table 4-3 summarizes the preliminary NO_x compliance plan for the CP&L generating system and indicates the NO_x control technology to be implemented on each unit. The NO_x control technologies were selected based on least-cost criteria using cost and performance estimates developed in the study.

Table 4-2
Summary Description of Sensitivity Analyses

Sensitivity Case No.	Sensitivity Parameter	Base Case Assumption	Sensitivity Assumptions
1	Phase II NO_x Emission Limits	0.38 (T-Fired), 0.43 (Wall-Fired)	0.45 (T-Fired), 0.50 (Wall-Fired)
2	Emissions Averaging	All Units in Average	Unit by Unit Compliance
3	Alternative Emission Limits (AELs)	No AELs	Asheville 1, Roxboro 3, Sutton 3 as AELs
4	Early Election Units	No Early Election Units	Tuning of CF5, Rob 1 and Sutton 1 and Early Election
5	Early Election Units	No Early Election Units	Tuning of Mayo 1 and Early Election
6	Averaging Groups	All CP&L Units in Average	Asheville and Robinson Separate Average Groups
7	Title I NO_x Requirements	None	Roxboro and Mayo 20% Below Phase I Limits
8	Title I NO_x Requirements	None	Asheville 20% Below Phase I Limits
9	System Load Growth	Expected	Low
10	System Load Growth	Expected	High
11	Forced Outage Rates	Normal Forced Outages	6 Month Outage at Roxboro 4
12	Installation Date of Lee 1 and Robinson 1	Lee 1 and Rob 1 after Fall 1997	Lee 1 and Rob on or before Fall 1997
13	Averaging Plan Margin	No Margin	5% Margin
14	Averaging Plan Margin	No Margin	10% Margin
15	Averaging Plan Margin	No Margin	15% Margin
16	Averaging Plan Margin	No Margin	20% Margin
17	Restrictions on SNCR	No SNCR at Rox 3, 4 and Mayo 1	No SNCR at Units >300 MW
18	Combustion NO_x Control Efficiencies	Expected Vendor Guarantees	10% Below Vendor Guarantees

Table 4-3
Summary of Preliminary NO_x Compliance Plan

Generating Unit	NO_x Control Technology	NO_x Reduction (tons/yr)	Installation Outage
Asheville 1	LNB/OFA	4,700	Fall 1997
Asheville 2	LNB/OFA	3,500	Spring 1997
Cape Fear 5	No Controls	0	
Cape Fear 6	LNCFS II	1,900	Spring 1998
Lee 1	LNCFS II	900	Fall 1998
Lee 2	No Controls	0	
Lee 3	LNB/OFA	3,100	Spring 1997
Mayo 1	LNB/OFA	6,500	Spring 1996
Robinson 1	LNCFS I	1,300	Spring 1998
Roxboro 1	LNB/OFA	13,300	Spring 1995
Roxboro 2	LNCFS II + SNCR 2	10,200	Fall 1996
Roxboro 3	LNB/OFA	23,000	Spring 1999
Roxboro 4	LNB/OFA	5,200	Fall 1998
Sutton 1	LNCFS I	600	Fall 1999
Sutton 2	LNB	600	Fall 1998
Sutton 3	LNB/OFA	6,502	Spring 1999
Weatherspoon 1	LNB	500	Fall 1999
Weatherspoon 2	LNB	500	Spring 1999
Weatherspoon 3	LNCFS II	700	Fall 1998
Total		83,000	

Key:
LNB - Low NO_x Burners
OFA - Overfire Air
LNCFS I, II - Low NO_x Concentric Firing System Level I or II
SNCR 2 - Selective Non-Catalytic Reduction 30% NO_x Reduction

Note:
(1) SNCR installation delayed until 1999.

The installation outages for the NO_x control technologies that are listed in Table 4-3 represent the outages planned for combustion controls that involve low NO_x burners with or without overfire air ports. These NO_x outages take into consideration planned turbine outages and the possible revision of Phase II NO_x emission limits by the EPA. For the generating unit that is planned to have selective non-catalytic reduction (SNCR) in addition to combustion controls, the final decision to install SNCR will be delayed until Phase II limits are reviewed, and the benefits of any actual NO_x retrofits are realized and considered in the NO_x compliance planning model. If the Phase II limits are not revised, sensitivity analyses indicate that SNCR would not be required. In addition, if the emissions from modified units vary significantly from that expected, SNCR requirements may change.

Proper implementation of the recommended technologies becomes key to a low-cost, low-risk NO_x compliance strategy. Only units that are part of least-cost plans for both the upper and lower limit scenarios will be modified prior to the Phase II limits being reviewed on January 1, 1997. The benefits of aligning NO_x outages with CP&L's planned turbine outages versus the potential compliance plan cost increases must also be considered in establishing the implementation schedule. With this approach, CP&L bears minimal risk in implementing a least-cost, least-risk plan. In the event that the final NO_x limits are between the two NO_x limit scenarios, the NO_x compliance planning model can be used to revise the existing compliance plan. For purposes of this IRP, a preliminary NO_x compliance plan has been incorporated in the integration analysis described below. As discussed above, a recent court ruling is requiring EPA to revise the NO_x rules. CP&L is reviewing and will continue to review its NO_x compliance plan to determine what changes may be able to be made once new regulations are promulgated. As a result, the preliminary NO_x compliance plan discussed above is subject to change.

Compliance with SO_2 requirements

Whereas nitrogen oxide emission regulations are based on an emission rate, SO_2 emissions regulations are based on the amount of emissions in tons. Without taking any compliance actions, CP&L's SO_2 emissions are projected to be approximately 205,000 tons in the year 2000. The number of emission allowances allocated to CP&L by the EPA in the year 2000 is 143,968. Therefore, CP&L's emissions are projected to exceed the Phase II limit by approximately 69,000 tons, and some compliance action will be required. How much CP&L's coal units operate has a direct impact on the reductions CP&L must make to comply with the regulations. CP&L's integrated resource plan calls for increasing generation at existing coal-fired units. Since it is possible for changes in the type of resources added to impact the level of emissions, the development of the SO_2 emission compliance plan has to be integrated with the development of the IRP. The review of SO_2 compliance options is discussed in Chapter 5.

Potential future environmental requirements

There are other potential environmental requirements that may have an impact on the Company's resource plan and acid rain compliance plans. The Company will continue to monitor the development of potential regulations. The possibility of new environmental requirements suggests that a flexible strategy that does not make significant, irreversible commitments would moderate the risks posed by future environmental regulations.

Title I nonattainment regulations for NO_x

Title I of the 1990 CAAA revises Clean Air Act requirements for attaining and maintaining national ambient air quality standards (NAAQS). Key provisions of Title I are aimed at bringing cities and other areas which are not in attainment in line with the NAAQS in most areas by 2000 and all areas by 2010. The specific pollution control requirements are determined by the present level of severity of nonattainment. In particular, Title I may require major sources of NO_x in ozone nonattainment areas to install reasonably available control technology (RACT) by 1995. None of the Company's power plants are in locations currently designated nonattainment areas, but three of its power plants (Mayo, Roxboro, and Cape Fear) are located in counties adjacent to Durham and Wake counties which were recently redesignated from nonattainment to attainment. As a condition of the redesignation, the state has been required to develop an ozone maintenance plan which will identify the need (if any) for additional NO_x emission reductions from sources. It is possible that several of the Company's plants may be required to achieve additional NO_x emission reductions. These requirements could result in more expensive post-combustion NO_x control technologies (such as selective catalytic and non-catalytic reduction) or could require the use of natural gas on a seasonal basis.

Air toxics

Title III of the CAAA of 1990 establishes a major new program for the regulation of toxic air pollutants. The combined federal and state program provided in the legislation represents the first comprehensive and coordinated nationwide effort to deal with these pollutants. Under Title III, electric utilities may be subject to requirements to limit air toxic emissions, most notably mercury and other metals.

Results of the electric utility air toxics and mercury studies are presently scheduled to be reported to Congress in 1995. Based on the implementation of similar legislation, it may take about three years for the rules to be promulgated, and another three to five years for utility compliance. Thus, control technologies, if required, would probably not be installed until 2001 to 2004. The control technologies that could be required to control air toxics are uncertain and will primarily be a function of the final EPA regulations, which in turn will be based on the results of the air toxics and mercury studies.

One of the uncertainties surrounding possible air toxic regulations is whether requirements to control mercury emissions will be established. At this time, there is no proven technology to capture all mercury emissions. Some species of mercury can be controlled using technologies such as wet scrubbing and carbon absorption. These technologies are very expensive and result in waste disposal problems. Under regulations which do not include mercury reductions, improvements to electrostatic precipitator (ESP) equipment may be sufficient to control air toxics. Under some circumstances, the addition of baghouses may be necessary.

North and South Carolina have independently adopted state regulations to address air toxic emissions. The South Carolina regulations specifically exempt emissions from sources burning clean, unadulterated fossil fuels such as those used at the Robinson Plant. Regulations in the State of North Carolina establish specific health-based exposure standards for numerous chemicals that will be the basis for setting future emission standards for sources subject to the rules. Among those sources subject to the North Carolina rules are coal-fired utility boilers. The State is in the process of modifying the state adopted rules to eliminate some differences with the federal Title III air toxic program requirements. There is some potential that revised final North Carolina regulations could identify a need to reduce air emissions of certain toxic chemicals released from the CP&L plants.

The implications for CP&L of possible air toxic regulations are two-fold. In order to maintain flexibility and satisfy all SO_2 and potential air toxics requirements at the lowest cost, decisions on investments in ESP equipment should be delayed as long as possible. When decisions have to be made, consideration will be given to the potential need to meet air toxic requirements. Second, decisions to switch to lower sulfur fuel or to build a scrubber should also be delayed for as long as possible, and consideration should be given to making only short to moderate length firm coal commitments. If regulations are passed which would require a technology such as wet scrubbers, lower sulfur fuel contracts would not be necessary. The decision on a scrubber technology should also be delayed. Some wet flue gas desulfurization (FGD) systems may offer better removal of air toxics than other systems.

Short-term SO_2 standard and air quality related value programs

The EPA has been evaluating the potential modification of the National Ambient Air Quality Standards (NAAQS) for SO_2 to meet a short-term (i.e., five minute) averaging standard. The basis for new standards would be the need to protect the health of sensitive individuals such as asthmatics.

In addition, the National Park Service requested comment on alternative SO_2 and NO_x emission control strategies for the states bordering the Great Smoky Mountain National Park region (i.e., Georgia, North Carolina, South Carolina, and Tennessee). New regulations would be designed to improve visibility and other air quality values in and around this region. These additional SO_2 and NO_x requirements could be more stringent than those imposed by Title IV.

New SO_2 and NO_x emission limits resulting from revisions to the NAAQS or for National Park concerns will probably not be implemented and effective at existing power plants until the 2000 to 2005 time frame. This view is supported by the fact that it would likely take several years to promulgate a new rule, several more years for the development of a State Implementation Plan (SIP) revision by the affected states, and some additional time for power plants to come into compliance with any new limit.

The possible effect of the new regulations could be the installation of more scrubbers nationwide. The effect on CP&L is likely to be limited to two plants: the Asheville Plant and the Cape Fear Plant. If the Asheville Plant is impacted, the possible effect would be to require the installation of some type of flue gas desulfurization system. The possible effect on the Cape Fear Plant would require the use of lower sulfur coal. Analysis of the cost to install scrubbers on CP&L's units has shown that the Asheville Plant is not the most cost effective plant on which to install scrubbers. Forced scrubbing of the Asheville Plant would have a significant impact on CP&L's Clean Air Act compliance strategy. A strategy which relies more on the use of allowances and delays the installation of scrubbers would allow CP&L to adapt its compliance plan to this uncertainty.

Potential greenhouse gas legislation

For several years, national and international efforts have been underway to control the emissions of greenhouse gases such as carbon dioxide (CO_2) and methane. The desire to control these so-called greenhouse gases stems from the belief by some that these gases have the potential to change the Earth's climate. In 1992, President Bush signed a United Nations agreement committing the United States to identify actions to slow the growth in greenhouse gas emissions.

There is a possibility that greenhouse gas legislation targeted at controlling CO_2 emissions may be enacted. Both carbon tax and carbon restriction policies have been debated by the U.S. Congress. Carbon restriction policies might require utilities to stabilize carbon emissions or reduce these emissions 20 percent or more below 1990 levels by the 2000 to 2005 time frame. Taxes and/or restriction policies could have a broad range of effects on the electric utility industry ranging from a modest lowering in the growth in electricity demand (due to conservation and improved efficiency) to more significant impacts on demand and greater use of gas or renewable technologies in place of coal. In general, taxes and carbon restriction policies would reduce the prices of allowances and the sulfur premiums between higher and lower sulfur fuels. This would increase the expected cost of a near-term strategy of installing scrubbers relative to a fuel switch and purchase SO_2 allowances strategy.

Greenhouse gas legislation would also have an impact on CP&L's resource plan. For its future generation needs, CP&L would have to carefully consider technologies that do not produce CO_2, such as nuclear power, or that reduce CO_2 emissions such as conversion of older coal units to burn natural gas. However, there is considerable debate as to the validity of the greenhouse theories. Legislation at this time appears unlikely.

Summary

The demands on the electric utility industry to produce electricity in an environmentally sound manner are continually increasing, as is evident from the rate at which environmental regulations have increased over the past 30 years. The Clean Air Act Amendments of 1990 are the latest significant change to which utilities have to respond. The most immediate impact is in the reduction of SO_2 and NO_x emissions. CP&L is working to plan and implement changes at its plants by 2000. Since regulations associated with the CAAA are not complete, the challenge for the Company is to develop plans that will maintain flexibility to respond to changes in regulations associated with the CAAA and potential future requirements. The possibility of new environmental regulations suggests that a strategy that does not make significant, irreversible commitments would moderate the risks posed by future environmental uncertainties.

Chapter 5
Integration Analysis

This chapter discusses the integration analysis performed by CP&L to develop the Integrated Resource Plan. The key inputs and planning assumptions used in the integration analysis are discussed.

Inputs and assumptions

Existing supply resources

CP&L maintains a diverse mix of supply-side resources, consisting of generation from coal, nuclear, oil, natural gas, propane, and hydro facilities, along with purchases from other utilities, and purchases from non-utility generators such as cogenerators. The existing generating capacity as of the end of 1994 is shown in Table 5-1 below, followed by Figure 5-1 which provides a graphical representation of the capacity mix. Generating facilities owned by CP&L are located in both North Carolina and South Carolina. The location of these facilities can be seen in Figure 5-2.

Table 5-1
CP&L Existing Resources

Type	Number of Plants	Number of Units	Generating Capacity (MW)
Nuclear	3	4	3,064
Coal	8	19	5,285
Oil/Gas	9	35	1,046
Hydro	4	15	218
Purchases	39	-	1,596
Total			11,209

Committed supply resources

In 1997 CP&L plans to install 225 MW of simple-cycle combustion turbines at the existing Darlington County Electric Plant located near Hartsville, South Carolina. In 1991 the Company received a Certificate of Environmental Compatibility and Public Convenience and Necessity from the South Carolina Public Service Commission authorizing construction of the plant. The in-service year of this plant had been revised from 1994 to 1996. After the analysis described in this chapter was performed, the Company decided to delay the Darlington addition to begin operation in 1997.

Figure 5-1
CP&L Capacity Mix
11,209 MW

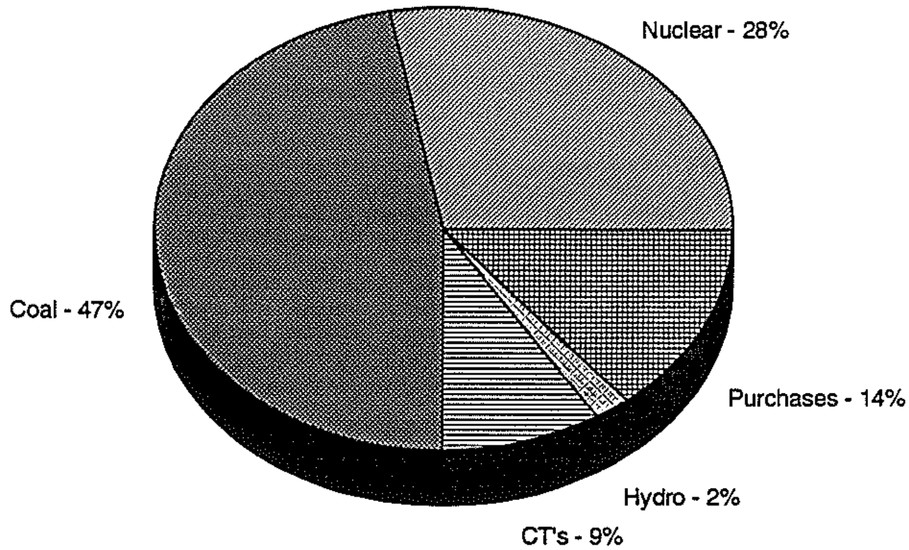
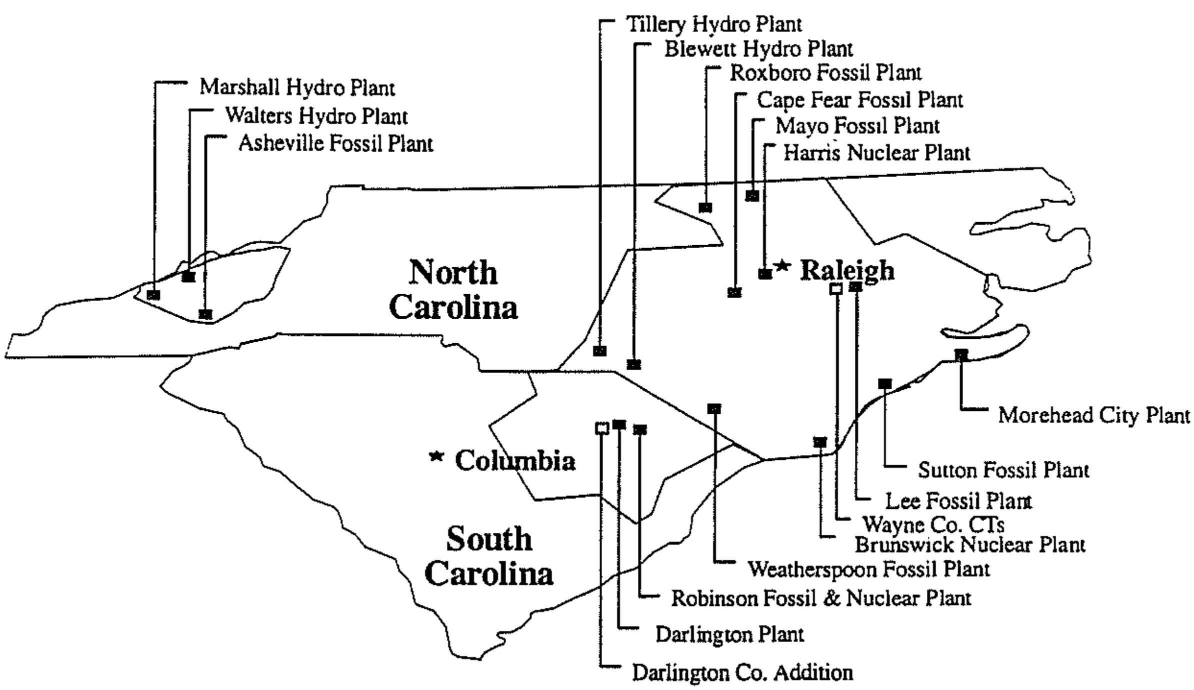


Figure 5-2
Location of CP&L Plants



A second committed resource is the North Carolina Eastern Municipal Power Agency's (NCEMPA) installation of combustion turbines. NCEMPA plans to install approximately 200 MW of combustion turbine peaking capacity in 1998. This power will be available to supply the combined CP&L/NCEMPA load and therefore, is included in CP&L's Integrated Resource Plan. NCEMPA has the option to not build the combustion turbine capacity but must provide notice to CP&L by March 1996 if they are not going to install the resources.

In July 1993 CP&L signed an agreement to purchase power from BCH Energy. BCH Energy plans to construct a waste-to-energy facility on the property of DuPont in Fayetteville, NC. Bladen, Cumberland, and Hoke counties will supply trash/garbage to a facility that will prepare the waste to be used as fuel for a boiler that will drive a 15.3 MW turbine generator. The low pressure steam will be sold to DuPont, and the entire generator output will be sold to CP&L. This facility is scheduled to be completed by the end of 1995.

Generation retirements

For many years CP&L has utilized its maintenance programs to keep its fossil units in the best operating condition that is economically reasonable. These maintenance programs have allowed the Company to operate its units longer than their 30-40 year expected life. Continued maintenance should allow the plants to operate indefinitely; therefore, there are currently no plans to retire any of the fossil units on the system.

The major issue for nuclear plants is plant life extension and the ability to extend the license of older nuclear plants. Currently, no nuclear unit in the United States has obtained an extended license from the Nuclear Regulatory Commission. Given the uncertainty in the requirements for relicensing a nuclear unit, CP&L's long-range planning assumption for nuclear units is to retire the units at the end of their current operating licenses.

This planning assumption does not imply CP&L has made a decision on license extension at this time. CP&L continues to study its options, such as license renewal for periods shorter than a full-term license. Nuclear plant life extension is considered by CP&L as a future resource option. Once more is known about the costs of license renewal, studies may prove it is more economical to obtain a license extension for the existing nuclear units than to retire the units and build new capacity.

Reliability criteria

Determination of the appropriate reliability criteria is a critical factor in the development of the resource plan. Utilities need a margin of generating capacity available to the system, above the capacity used to serve the expected load, to ensure reliable service. At any time during the year, some plants will be out of service for periodic maintenance or due to unanticipated equipment failures. Adequate reserve capacity must be available to provide for this unavailable capacity and also for higher than expected peak demand due to weather extremes. In addition, some reserve must also be available as operating reserve to maintain the balance between supply and demand on a moment-to-moment basis.

The amount of generating reserve needed to maintain a reliable supply of electricity is a function of the unique characteristics of a utility system including load shape, unit sizes, capacity mix, fuel supply, maintenance scheduling, unit availabilities, and the strength of the transmission interconnections with other utilities. Because system characteristics are particular to each individual utility, there is no one standard measure of reliability that is appropriate for all systems.

Carolina Power & Light uses a target capacity margin of 15% to schedule generation additions. Capacity margin is defined as the ratio of the difference between generating capacity and peak load divided by the generating capacity. The 15% capacity margin corresponds to a 17.6% reserve margin. This deterministic planning criteria is based on maintaining a loss of load expectation (LOLE) of one day in ten years as demonstrated by probabilistic assessments. LOLE represents the average number of days that the daily peak load is expected to exceed the available generating capacity. This probabilistic assessment is important because it captures the random nature of system behavior such as generator equipment failures and load variation. Since reserves do not remain at a constant level due to load growth and new capacity being brought in-service, the capacity margin in any year may be higher or lower than the target capacity margin.

Other assumptions

The integration analysis is performed using the Company's standard planning assumptions. These assumptions include using the December 1993 Load and Energy Forecasts and resource plan assumptions. It is also assumed that the Asheville Plant and Roxboro Unit 2 begin to burn very low sulfur coal by the year 2000. The Company plans to begin burning compliance coal at the Asheville Plant in 1997 to satisfy air quality regulations. Roxboro Unit 2 will begin burning compliance coal in 2000 as the result of negotiations with one of the Company's coal suppliers.

The study period for the analysis is 1994 through 2023. Load is held constant for the last ten years of the study period. This is done to minimize end-effects that may occur by generation additions at the end of the planning horizon of 1994-2013.

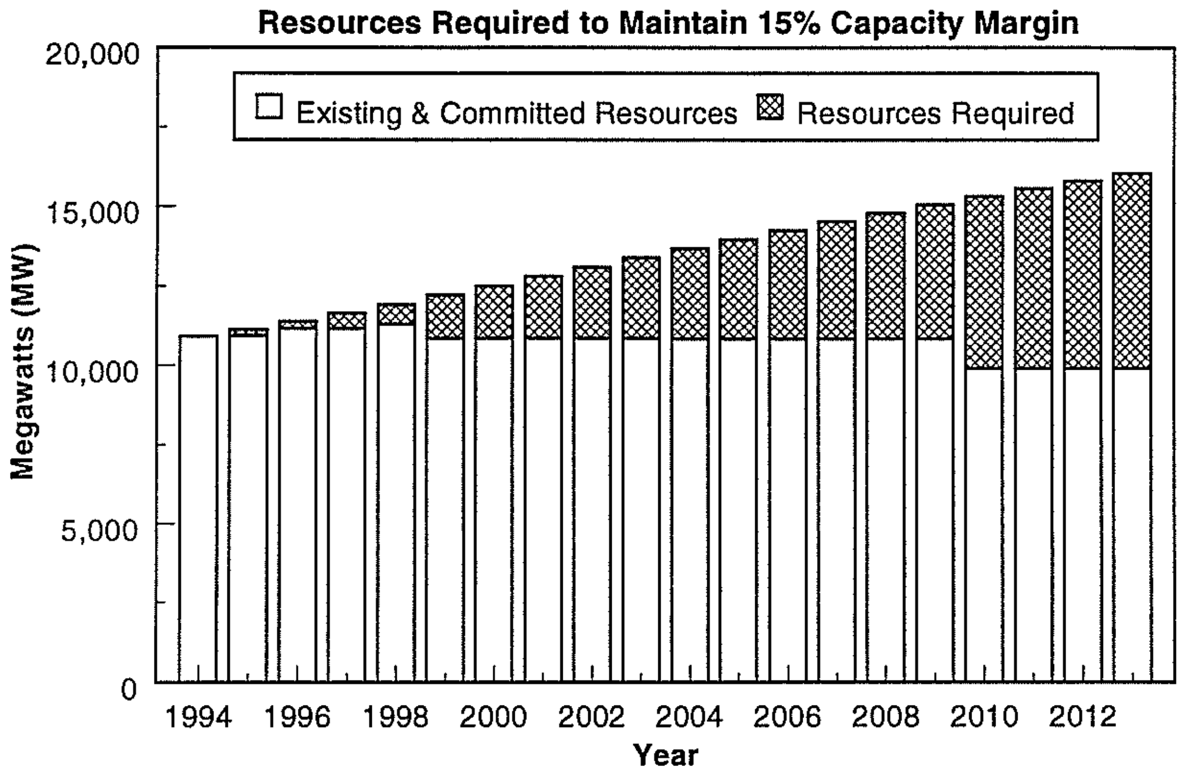
The supply-side technologies available to be selected include combustion turbines, combined cycle units, pulverized coal units, and the repowering of Weatherspoon Unit 3 to gas-fired combined cycle operation. The SO_2 compliance options available include switching to compliance coal, buying allowances, and installing wet limestone scrubbers. The analysis takes into account the emission allowances received from the Environmental Protection

Agency (EPA). Also, the impacts of CP&L's preliminary NO_x compliance plan are included in the analysis. These impacts include capital and operating costs, changes in heat rates, and outage schedule changes.

Need for new resources

Figure 5-3 shows the additional resources necessary to maintain the target capacity margin of 15%. Given the projected load growth, approximately 6,100 MW of new resources will be needed by the year 2013 in addition to the existing and committed supply-side and demand-side resources.

Figure 5-3

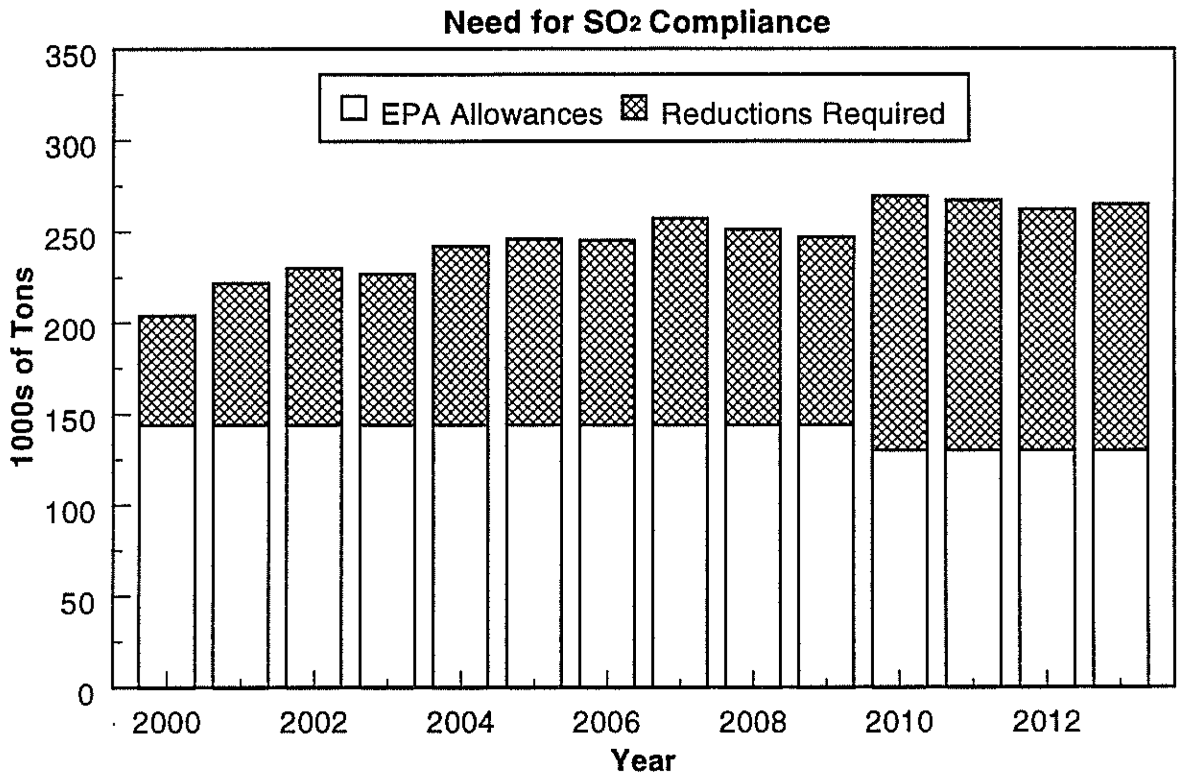


Need for SO_2 compliance

Title IV of the 1990 Clean Air Act Amendments (CAAA) restricts the systemwide level of SO_2 emissions. The Environmental Protection Agency (EPA) has allocated to CP&L 143,968 SO_2 emission allowances each year from 2000 to 2009 and 130,485 allowances for each year beyond 2009. These EPA allowances are shown in the unshaded area of Figure 5-4.

CP&L's emissions, however, are projected to exceed the amount allocated by EPA. The dark shaded area in Figure 5-4 represents the projected amount of compliance required to adhere to the CAAA regulations. Projected SO_2 emissions exceed the EPA allocations by a total of approximately 1.5 million tons for the years 2000 through 2013, or approximately 100,000 tons per year.

Figure 5-4



Review of supply-side options

Process

The generation technologies considered in the supply-side options screening analysis are identified through a survey of industry literature, IRPs prepared by other utility companies, technical journals, and U.S. Government and Company reports. The identified technologies are shown in Table 5-2. Once the technologies are identified, an effort is undertaken to understand and to assess the technologies.

The technologies identified are evaluated using a screening process that eliminates those technologies that are not 1) significantly available in the CP&L service area, 2) at least currently available in the demonstration stage, 3) environmentally compatible with current regulations and public perceptions or 4) economically competitive with other technologies. The economic screening is accomplished using screening, or busbar, curves which plot each technology's total levelized annual cost in $/kW-yr as a function of capacity factor.

After reviewing all the available information, technologies that pass the screening process are passed on to the resource integration phase of the IRP process.

Results of screening analysis

Of the 31 supply technologies reviewed, 13 were eliminated in the first three screens. The remaining 18 technologies were then screened based on annual levelized costs. The results of the screening process are summarized in Table 5-3. Busbar screening curves for peaking/intermediate technologies and baseload technologies are shown in Figures 5-5 and 5-6, respectively. The busbar cost analysis showed subcritical pulverized coal, atmospheric and pressurized fluidized bed combustion, and coal gasification combined cycle being the most economical baseload technologies with very similar cost characteristics. Subcritical pulverized coal technology will be used as a proxy for all coal-fired technologies in the analysis that follows the screening process because there is a high confidence in the cost estimates and operating characteristics due to its mature development status. The technologies passed on to the resource integration phase of the IRP process are: simple cycle combustion turbines, combined cycle combustion turbines, subcritical pulverized coal, and repowering an existing coal unit to combined cycle operation.

Table 5-2
Supply Options

Conventional Generation Technologies

Coal
- Pulverized
- Fluidized Bed
  - Atmospheric
  - Pressurized
- Gasification Combined Cycle

Nuclear - Advanced Water Reactor

Combustion Turbine (CT)

Retrofit CT with Inlet Air Cooling

Combined Cycle (CC)

Fuel Cells

Storage

Pumped Hydro

Compressed Air

Superconducting Magnetic Energy Storage

Battery
- Lead Acid
- Advanced

Purchases

Utility

Non-utility

Renewable Generation Technologies

Geothermal
- Hydrothermal - Convection
- Geopressurized
- Hot Dry Rock

Ocean Energy
- Tidal Energy
- Ocean Thermal Energy Conversion
- Wavepower
- Ocean Current Turbines
- Salinity Gradient Devices
- Ocean Wind Turbines

Solar
- Photovoltaic
- Thermal

Wind

Municipal Refuse

Biomass
- Peat
- Wood

Repowering

Weatherspoon Unit 3
- Combined Cycle

Sutton Unit 1
- Coal Gasification Combined Cycle

Table 5-3
Summary of Screening Process

	1st Screen Avail. in CP&L Service Area	2nd Screen Development Status	3rd Screen Environmentally Acceptable	4th Screen Cost Competitive
Conventional				
Coal				
Pulverized	Yes	Yes	Yes	Yes
Fluidized Bed				
Atmospheric	Yes	Yes	Yes	Yes
Pressurized	Yes	Yes	Yes	Yes
Gasification Combined Cycle	Yes	Yes	Yes	Yes
Nuclear - Advanced Water Reactor	Yes	Yes	Yes	No
Combustion Turbine (CT)	Yes	Yes	Yes	Yes
Retrofit CT with Inlet Air Cooling	Yes	Yes	Yes	No
Combined Cycle (CC)	Yes	Yes	Yes	Yes
Fuel Cells	Yes	Yes	Yes	No
Storage				
Pumped Hydro	Yes	Yes	Yes	No
Compressed Air	Yes	Yes	Yes	No
Superconducting Magnetic Energy	Yes	No	-	-
Battery				
Lead Acid	Yes	Yes	Yes	No
Advanced	Yes	No	-	-

Table 5-3
Summary of Screening Process (continued)

	1st Screen Avail. in CP&L Service Area	2nd Screen Development Status	3rd Screen Environmentally Acceptable	4th Screen Cost Competitive
Repowering				
Weatherspoon 3 Combined Cycle	Yes	Yes	Yes	Yes
Sutton 1 Coal Gasification Combined Cycle	Yes	Yes	Yes	No
Renewable				
Geothermal				
Hydrothermal-Convection	No	-	-	-
Geopressurized	No	-	-	-
Hot Dry Rock	No	-	-	-
Ocean Energy				
Tidal Energy	No	-	-	-
Ocean Thermal Energy Conversion	No	-	-	-
Wavepower	No	-	-	-
Ocean Current Turbines	No	-	-	-
Salinity Gradient Devices	Yes	No	-	-
Ocean Wind Turbines	Yes	No	-	-
Solar				
Photovoltaic	Yes	Yes	Yes	No
Thermal	Yes	Yes	Yes	No
Wind	Yes	Yes	No	-
Alternative Fuels				
Municipal Refuse	Yes	Yes	Yes	No
Biomass				
Peat	Yes	Yes	No	-
Wood	Yes	Yes	Yes	No

Figure 5-5

Peaking/Intermediate Technologies
Levelized Busbar Cost

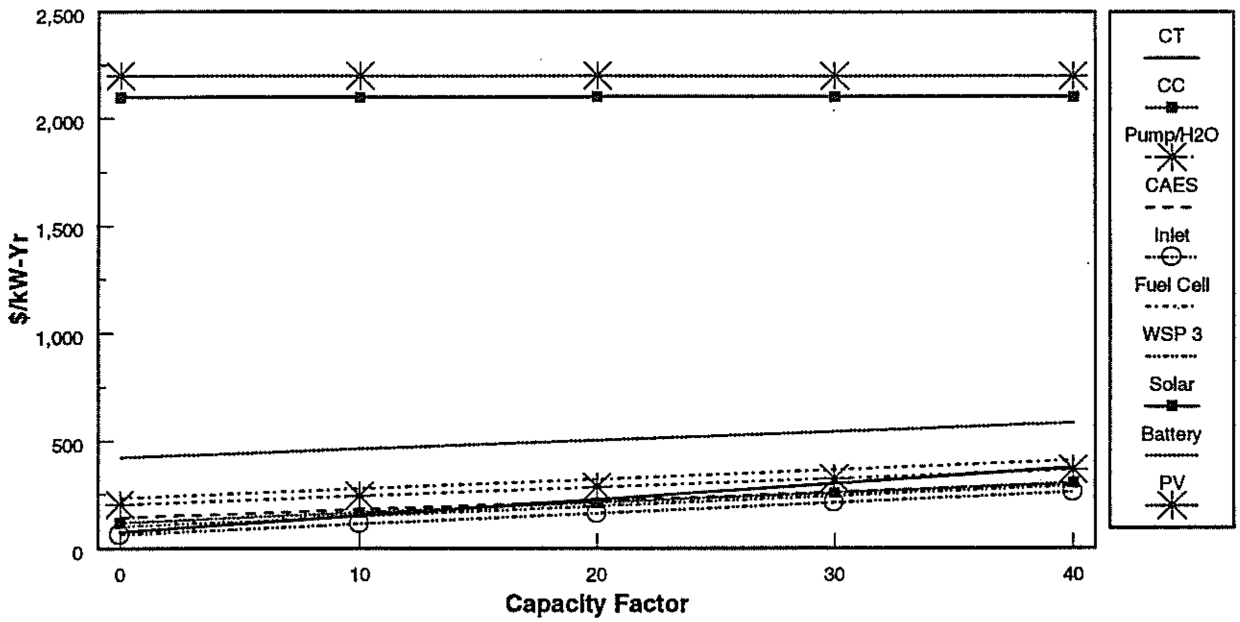
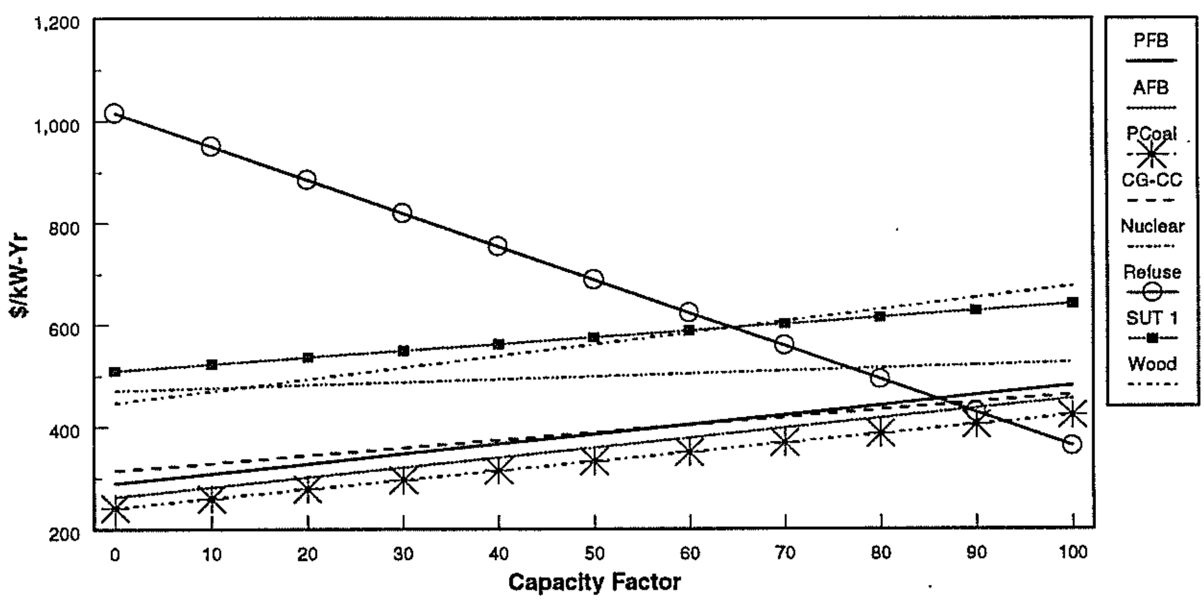


Figure 5-6

Base Load Technologies
Levelized Busbar Cost



Evaluation of purchased power proposals

During the period 1992 through 1994, CP&L received 10 purchased power proposals from eight different sources. Nine of the proposals were from non-utility generators and one was from another utility. Of the nine non-utility proposals, six proposed to build combustion turbines to serve a portion of CP&L's peaking power needs. The one utility proposal was also for peaking power, but from an existing unit. The size of the proposed capacity sales ranged from 55 MW to 582 MW. The specifics on the size, type, in-service date, and term are provided in Table 5-4, below. Proposals C1 and C2 were from the same proposer, as were D1 and D2.

Table 5-4
Summary of Purchased Power Proposals

Proposal	Size (MW)	Type	In-service	Term (yrs)
A	300	CT	1997	20
B	449	CT	1997	25
C1	315	CT	1996	20
C2	210	CT	1996	20
D1	232	CT	1997	25
D2	582	CT	1997	25
E	200	CC cogeneration	1998	25
F	230	CC cogeneration	1996	20
G	100	peaking	1995	5
H	55	municipal waste	1997	25

Each of the proposals were evaluated to determine if a cost-effective purchase could be made which would result in significant savings to the Company's customers. The proposals that were made for CT capacity were evaluated against CP&L's planned combustion turbine additions. Proposals F through H were evaluated against the Company's avoided costs. In each case, the proposal was found to be more expensive than CP&L's alternative. A summary of the cost differences are provided in Table 5-5. The proposal with costs closest to CP&L's own option was Proposal B, whose costs were 16% greater than CP&L's planned CTs. None of the proposals were passed on to the resource integration process.

Table 5-5
Results of Purchased Power Proposals Evaluations

Proposal	Cost difference
A	+66%
B	+16%
C1	+64%
C2	+77%
D1	+21%
D2	+55%
E	+19%
F	+$80 M
G	+$4.8 M
H	+$60 M

Review of SO_2 compliance options

There are a number of options available for reducing SO_2 emissions from fossil-fueled units. The options can be grouped into three main categories: control technology options (for example, scrubbers), fuel switching options (that is, switching to a lower sulfur fuel), and buying allowances. Since the number of options in these categories is very large, processes were developed by CP&L to eliminate the options which do not hold promise at this time so attention can be focused on a smaller number of alternatives.

Control technology options

Sulfur dioxide control technology options reduce emissions by retrofitting flue gas desulfurization (FGD) equipment on the Company's coal-fired units. CP&L has reviewed a number of different FGD (or "scrubber") options. In developing a list of potential technologies, a detailed review of extensive research completed by the Electric Power Research Institute (EPRI) was performed. EPRI has estimated that over 200 SO_2 removal technologies are in some stage of research and development and has prepared a publication summarizing the most promising options. While all of the technologies highlighted by EPRI and some other technologies were reviewed by CP&L, two types of FGD systems were focused upon: wet scrubbers and dry scrubbers (including spray dryers and sorbent injection).

Table 5-6 provides a listing of the technologies considered in the screening evaluation.

Table 5-6
FGD Processes Evaluated

Wet Scrubbers	Spray Dryers	Sorbent Injection
Conventional Processes	Lime Spray Dryer	Limestone Injection Fluidized Activation Chamber (LIFAC)
Limestone Forced Oxidation	Duct Spray Dryer	Sorbent Injection -Furnace
Limestone with Wallboard Production		Sorbent Injection-Economizer
Magnesium Lime		Sorbent Injection - Duct
Other Processes		Limestone Injection Multiple Burner (LIMB)
Limestone Inhibited Oxidation		LIMB Advacate
Limestone Dibasic Acid		Lurgi Circulating Fluidized Bed
Chiyoda 121 (CT-121)		NATEC Dry Sodium
Northern States Bubbler		
Pure Air		
Lime Dual-Alkali		
Limestone Dual-Alkali		
Wellman Lord		
Saarberg Holter		
Magnesium Oxide		
SOXAL		
Passamoquoddy		
ISPRA		
HYPAS		

Screening of control technology options

Two levels of screening were applied. The first level, technology screening, used general criteria to determine if a particular technology should be considered further. A "unit-specific" screening was completed to determine if technologies selected at the first level should be considered at all units or only a subset of units.

The combined result of the technology and unit specific screening evaluations are shown in Table 5-7. Technology selections for further evaluation include wet limestone with forced oxidation and a variation producing wallboard to be considered at Asheville 1 and 2, Lee 3, Mayo 1, Roxboro 1, 2, 3, and 4, and Sutton 3. The CT-121, Pure Air, Saarberg Holter, and magnesium lime scrubbers were selected as options for the same units (excluding Lee 3 and Sutton 3). Furnace sorbent injection was considered for Asheville 1 and 2 and Sutton 3.

Fuel switching options

A second category of options for reducing SO_2 emissions is fuel switching to a lower sulfur fuel. The Company examined a number of coal types as potential fuel switching alternatives and evaluated coals that would be appropriate for burning in units that are retrofitted with scrubbers. Table 5-8 provides a summary of the coals which were evaluated. Another fuel switching option is burning natural gas. Two options were considered: converting existing coal units to burn natural gas in the boilers and repowering existing coal units as gas-fired combined cycle units.

SO_2 emission allowances

Features of emission allowances

One of the important features of the new CAAA is the creation of an SO_2 emission allowance allocation and trading mechanism. One "allowance" permits an affected source to emit one ton of SO_2 during or after a specified calendar year. The allowances allocated to each utility unit can be transferred to other units within its own system (i.e., used to cover another unit's emissions), banked for future use, or sold on the open market. The only restriction is that a utility must have enough allowances to cover its actual SO_2 emissions. Tradeable allowances were created by the CAAA as a way of reducing the national cost of tightened SO_2 emission limits. Congress recognized that the cost of reducing SO_2 emissions would be high for some regions and electric utilities and lower for others. Utilities that can reduce emissions at lower costs can sell their allowances to those whose cost of achieving the same goal would be higher. The net result is lower costs for the country with the same overall national limit on SO_2 emissions. Congress explicitly made reductions in SO_2 emissions in one state equivalent to reductions in another state.

Table 5-7
Technology and Site Screening Matrix

Previously Screened	Asheville		Cape Fear		Lee			Mayo	Roxboro				Sutton			Weatherspoon			Robinson
Unit	1	2	5	6	1	2	3	1	1	2	3	4	1	2	3	1	2	3	1
LMST FOX							*								*				
LMST WBD																			
CT-121							TS	TS	TS	TS	TS	TS			TS				
Pure Air																			
Mag Lime																			
Saarberg Holter																			
Lurgi	TS	TS		TS			TS	TS	TS	TS	TS	TS			TS				TS
Sorbent Injection Furnace								TS	TS	TS	TS	TS			TS *				
Sorbent Injection (E-D)	TS	TS	TS	TS			TS	TS	TS	TS	TS	TS		TS	TS				TS
Duct Spray Dryer	TS	TS	TS	TS	TS	TS	TS	TS	TS	TS	TS	TS	TS	TS	TS			TS	TS
LIMB	TS	TS	TS	TS			TS	TS	TS	TS	TS	TS		TS	TS				TS

TS: Eliminated at technology screening stage

Shaded: Eliminated

*: Exception retained

No marking: Retained for further evaluation

Table 5-8
Coal Types Evaluated

	Sulfur Content lbs. SO_2/MMBtu	Heat Content MMBtu/lb.
Central Appalachian		
Compliance	1.20	12,500
Lower Sulfur	1.60	12,500
Scrubber	2.10	12,500
Powder River	0.85	8,800
Rockies	0.90	11,000

In order to encourage electric utilities to reduce SO_2 emissions more quickly, Congress also provided that if a utility's emissions are reduced below the allocated number of allowances, the excess allowances may be retained for later use, or "banked." The potential to hold allowances for later use has two implications. Utilities that can reduce SO_2 emission cheaply are induced to do so early and utilities that may wish to purchase allowances for later use may do so. Allowance prices will tend to be set by the cost of SO_2 emission reduction measures, such as the use of fuels with less sulfur or the installation of FGD equipment. The SO_2 allowance market is expected to have fairly free trading, and many buyers and sellers. In such a market, allowance prices will be set by the competition among utilities that can reduce SO_2 emissions and by the needs of buyers.

This new allowance market was analyzed carefully as part of the Company's compliance strategy development effort.

Market outlook for allowances

The 1990 CAAA set up a two-phase compliance schedule. Sixty-one (61) utilities are subject to the Phase I requirements. In aggregate, these utilities will receive about 5.7 million allowances per year for the period 1995 to 1999, plus a total of 3.5 million "extension and bonus" allowances available to those Phase I-affected utilities who install scrubbers. In Phase II, nearly every utility is affected. The total annual allowance allocations in Phase II are approximately 9.5 million per year for the years 2000 through 2009 and approximately 8.9 million per year thereafter. CP&L's annual allocation of 143,968 allowances during the 2000 to 2009 period is 1.5% of the national total.

The market price of allowances is expected to be closely tied to the cost which utilities will have to incur to reduce SO_2 emissions. One reason is the allowance market should be competitive, given the relatively large number of potential market participants, the homogeneity of the product, and the lack of any significant market restrictions (i.e., allowances are easy to transfer and may be traded interstate). While there are some factors that may restrict an individual utility's ability to trade, these factors would not likely interfere with market competition to any appreciable degree.

In a perfectly competitive and stable market, allowance values should be set in the long term by the marginal cost of SO_2 reductions across all utilities. Simply put, a utility can compare its marginal cost of reduction (i.e., cost of achieving the next ton of SO_2 reduction) to the price of an allowance and buy allowances if the price is lower and sell allowances if the price is higher. In the short term, prices may vary around the long-term value reflecting such factors as: (1) changing expectations of long-run allowance values; (2) short-run fuel market changes, and (3) interest rates.

Future costs of low and high sulfur coal, demand for electric power, costs of SO_2 control equipment and other factors which will affect the cost to utilities of reducing SO_2 emissions are uncertain. Further, since allowance prices in the near term are closely related to perceptions of future costs, the current market price can change not only as a result of current market factors but also as a result of changes in perceptions. Least predictable and most potent in their possible effect on SO_2 allowance markets are possible new environmental legislation or regulations such as those related to preventing global climate change, tightening of state and local limits on individual power plant SO_2 emissions, and requirements to install scrubbers to reduce emissions of toxic compounds from power plants. Many of these possible changes could result in utility actions that would reduce emissions below the levels which would be allowed under the basic CAAA requirements, thus freeing-up SO_2 allowances.

Economic screening of SO_2 compliance options

This section presents the economic screening of compliance alternatives. The objective of the screening analysis was to eliminate the compliance options that are not economic, preserving only the options that merit further consideration in developing the Company's SO_2 compliance plan.

As discussed previously, technical screening of fuel switching and scrubbing options was completed prior to the economic screening described here. For example, scrubber options were "screened" based on technical criteria such as whether a technology was sufficiently proven at a commercial utility scale. Some fuel switching options were also ruled out based on preliminary screening. Table 5-9 lists the options considered for economic screening.

Table 5-9
Options Considered for Economic Screening

Wet Scrubber Technology

Wet Limestone With Forced Oxidation
Wet Limestone With Wallboard Production
Magnesium Lime
Pure Air
Chiyoda 121

Dry Scrubber Technology
Furnace Sorbent Injection

Low Sulfur Coal Options

Central Appalachian Lower-Sulfur Coal (1.6 lbs. SO_2/MMBtu)
Central Appalachian Compliance Coal (1.2 lbs. SO_2/MMBtu)
Rockies coal
Powder River Basin Coal

Natural Gas
Modification of Coal Units to Burn Natural Gas

Scrubber Coal
Central Appalachian Scrubber Coal (2.1 lbs./MMBtu)

Overview of the economic screening process

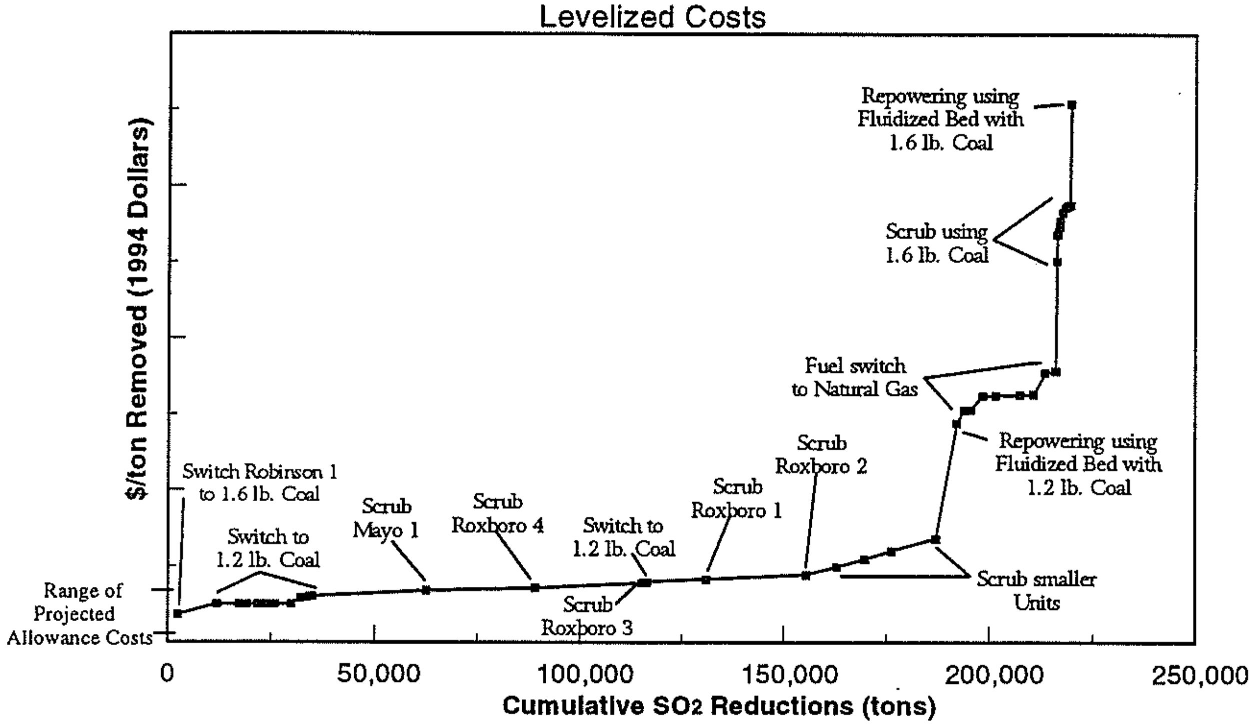
The criteria used for economic screening is relative cost effectiveness as measured by the incremental cost per ton of SO_2 removed. The incremental cost per ton removed is a measure of the cost of the next ton of SO_2 reduced. It is the appropriate criteria for selecting the most cost-effective compliance plan when system (versus unit specific) emissions must be controlled. Based on this economic criteria, a utility would implement all internal compliance measures from least cost to highest cost until it becomes more cost-effective to buy allowances (i.e., the dollar per SO_2 allowance price is lower than the incremental cost to reduce the next ton of SO_2).

Results of SO_2 option economic screen

Figure 5-7 presents an incremental cost curve of SO_2 emission reduction options. An incremental cost curve is constructed by ranking the options from lowest incremental cost to highest incremental cost. The emission reduction of each option is added to the sum of the reductions of all options less costly to calculate the cumulative reductions that would be achieved if all cost-effective options are implemented up to and including a particular option. The curve is developed without consideration of emission allowances, examining only options that involve modification to CP&L's units.

The incremental cost curve can be used to compare the internal cost of controlling emissions (i.e., making modifications to units) to the cost of purchasing allowances. If the amount of reductions required to comply is known, an incremental cost curve can be used to determine the cost of the last increment of control and approximate its incremental cost of reduction. In this manner the curve can be used to roughly determine which options will need to be implemented.

Figure 5-7
Incremental Cost of SO2 Reductions
Levelized Costs



In Figure 5-7, each box represents an individual compliance option. As can be seen, the curve is relatively flat up to approximately 190,000 cumulative tons reduced, where a knee in the curve is formed. Beyond the 190,000 ton level of reductions, further reductions in SO_2 emissions can be achieved only at a significantly higher cost. The curve shows that, up to that point, there are many compliance options available to CP&L that have the same relative incremental cost. These options include fuel switching to 1.2 lbs. SO_2 per MMBtu coal and scrubbing. Beyond the knee of the curve, reductions come from switching to natural gas, scrubbing coal units while burning 1.6 lbs. SO_2 per MMBtu coal, and repowering using fluidized bed combustion. Also identified on the incremental cost curve is the range of projected emission allowance costs.

The average annual reduction required by CP&L for compliance with the CAAA is approximately 100,000 tons of SO_2. Based on this and the cost curve, the options in Table 5-10 were passed on to the resource integration analysis.

Table 5-10
SO_2 Removal Options Passed to Integration Analysis

Switch Robinson Unit 1 to 1.6 lb. SO_2/MMBtu coal
Switch coal units to 1.2 lb. SO_2/MMBtu coal
Wet Limestone scrubbers at Mayo Unit 1, Roxboro Units 1-4 using 2.1 lb. SO_2/MMBtu coal
Buy allowances

Resource Integration

Process

The first part of the Resource Integration process is an optimization analysis and sensitivity analysis. These analyses determine the optimal resource plan and SO_2 compliance plan and test certain planning assumptions to determine which have the most significant impact on the integrated resource plan. Those assumptions which are found to have the biggest impact on the resource plans are identified as the key planning uncertainties.

Using the results of these two analyses, alternative resource plans are developed. The alternative plans are then evaluated using relevant criteria and taking into consideration the key planning uncertainties using risk and uncertainty analysis. A sensitivity analysis is performed to test the robustness of the best evaluated plan to the probabilities assigned to the outcomes of the key uncertainties.

Simulation models

Three computer models are used in Resource Integration. The Wein Automated System Planning Package (WASP), the Integrated Planning Model (IPM), and the Utility Planning Model (UPM) are used to simulate the CP&L generation system.

Both WASP and IPM are capacity expansion and production costing models that optimize utility investments and operations to minimize the costs of meeting customer needs for electricity. Both models optimize resources subject to system reliability constraints. In addition, the IPM has the ability to optimize resources subject to the need to constrain SO_2 emissions consistent with the Clean Air Act Amendments of 1990 (CAAA). The use of IPM allows numerous compliance options to be tested in order to find the least cost combination of compliance options for all units over every year of the study period.

CP&L uses both models because each has their own strengths. The WASP model is a dynamic programming model and will select specific capacity additions to formulate an optimal resource plan. The model utilizes the convolution method of probabilistic simulation to estimate reliability and production costs. WASP, however, does not have the capability to constrain the solution for emissions, and thus cannot develop an optimal compliance plan. IPM, on the other hand, does allow additional constraints, such as SO_2 emissions. Therefore, it is able to develop optimal resource and compliance plans. IPM is a linear programming model. The benefit of such a model is its application in sensitivity analyses where the magnitude of the effect of changes to input assumptions can be more closely evaluated. A linear programming model is able to show, for example, how many megawatts of scrubbed capacity is needed to bring a utility into compliance. The model is not limited to selecting entire units to be scrubbed. While the optimal solution may not be a practical solution, this capability is extremely useful in sensitivity analyses.

The Utility Planning Model is used to evaluate the alternative resource plans under conditions of uncertainty. The UPM fully integrates all planning activities including load modification, expansion planning, production costing, fuel supply, plant accounting, financial analysis, and rates and revenue analysis. UPM is a comprehensive model, yet it provides quick turnaround which makes it an excellent tool for scenario and sensitivity analyses. UPM is used in the resource planning process to measure the attributes used to evaluate the alternative resource plans.

Optimization analysis

The starting point for developing the set of alternative resource plans and compliance plans is the development of the optimal plan. While the screening analyses discussed earlier provided some guidance as to the least cost set of supply options and compliance options, they do not take into consideration the dynamics of the operation of the existing system and any new resource additions. The optimization analysis is used to determine the least cost plan considering factors such as load growth and projected unit utilization.

The optimal resource plan was developed using WASP. The optimal plan contains 3,000 MW of combustion turbines, 600 MW of combined cycle units, and 2,500 MW of coal capacity. The type of capacity selected by WASP to be installed at the beginning of the study period was combustion turbine. Of the 3,000 MW of combustion turbine capacity, 2,200 MW was selected by WASP to be placed in-service from the start of the study through 2002. The first combined cycle unit in the optimal plan is installed in 2003 and the first coal unit in the optimal plan begins operation in 2005.

The optimal SO_2 compliance plan as determined by IPM is for CP&L to purchase allowances. This result is consistent with the results of the SO_2 compliance option screening analysis. If the optimization analysis is constrained to not allow the purchase of allowances, then scrubbing approximately 750 MW of existing coal capacity in 2000 and switching to very low sulfur coal at Lee 1, Lee 3, and Roxboro 1 is the optimal compliance plan.

Sensitivity analysis

Both WASP and IPM were used for sensitivity analyses. The models were used to determine how the optimal plans would change given a change in major input assumptions. The results of the sensitivity analysis are used in two ways. The first is to guide the development of alternative resource and compliance plans. The sensitivity analysis is also used to determine which planning assumptions are most likely to affect the resource and compliance planning decisions and the overall costs of the plans. These key assumptions are used in the evaluation of the alternative plans in the next step of CP&L's IRP process.

In the sensitivity analysis, the optimal resource plan and compliance plan are re-optimized after changing a particular assumption. If there is no significant change in the set of options selected or in the range of costs, the assumption is not considered a key uncertainty. To determine which assumptions should be tested in the sensitivity analysis, an influence diagram is created. The purpose of an influence diagram is to identify the variables and uncertainties which influence a decision. Those variables which have the greatest impact on the optimal plan—that is, change the type and/or timing of the resources picked by WASP or IPM—are chosen as the key uncertainties for the next step in the Resource Integration process. The input assumptions that were tested in sensitivity analysis are shown in the following table:

Table 5-11
Assumptions tested in sensitivity analysis

Sensitivity	Low Value	High Value
Energy growth	-0.7% growth	3.5% growth
Nuclear performance	46% capacity factor	86% capacity factor
Premium fuel price	low forecast	high forecast
CT capital cost	75% of base	125% of base
CC capital cost	75% of base	125% of base
Scrubber capital cost	75% of base	--
Cost of allowances	low	high
Level of DSM	No additional	high forecast

Three of the assumptions in the table above were found to have a significant impact on the optimal resource plan and the optimal compliance plan. As would be expected, system growth has an obvious impact on both resource planning and compliance planning. The amount of load growth on the system affects the need for resources, and the amount of energy growth influences the type of resources needed. Energy growth also affects system emissions by changing the utilization of existing coal-fired generating units.

Similar to load and energy growth, the performance of the Company's existing nuclear units impacts the type and timing of resource additions and the amount of emissions by changing the utilization of existing coal-fired generation. This result occurs because coal plants dispatch after nuclear plants and, therefore, replace nuclear generation if the nuclear units do not operate. Likewise, if nuclear plants operate at high levels of availability, the need for baseload additions is reduced and the existing coal units do not have to operate as much, lessening the amount of SO_2 emissions.

The fuel typically used in combustion turbine and combined cycle units is either natural gas or oil. Historically, the availability and price of these fuels has been subject to volatility. The sensitivity analysis found that the optimal resource plan changed significantly if these fuel prices are higher or lower than the base CP&L assumptions.

Because of the magnitude of the impacts of these assumptions on the optimal resource and compliance plans, the assumptions are recognized as key planning uncertainties and are passed on to the next step of CP&L's IRP process. SO_2 emission allowance prices, scrubber capital cost, combustion turbine capital cost, and combined cycle capital cost were all found to have little impact on the optimal resource and compliance plans. Therefore, they are not considered further as key uncertainties.

Sensitivity analyses were also performed on the level of DSM resources used to meet customer demand. Increasing and decreasing the amount of DSM resources impacted both the amount of supply-side resources contained in the optimal plan and the timing of the first coal unit. Varying the amount of DSM resources also affected the optimal compliance plan. For these reasons, alternative resource plans containing various amounts of DSM resources will be examined.

Alternative resource plans

Based on the results of the optimization and sensitivity analyses, seven alternative resource plans were developed. Two of the plans are based on different amounts of demand-side management resources. As found in the sensitivity analysis, the amount of demand-side resources has a significant impact on the amount and type of supply-side resources needed. The other five plans contain the same amount of demand-side management resources. These five plans (Plans A through E) all begin with combustion turbine capacity additions as the only type of capacity being added through the year 2002. In all of the sensitivity analyses performed, combustion turbines were the only supply-side resource additions during that time period.

The alternative resource plans were developed based on CP&L's December 1993 Load Forecast adjusted for the loss of 200 MW of North Carolina Electric Membership Corporation (NCEMC) load starting in 1996.

A summary discussion of each plan is provided below, followed by Table 5-12 which shows the specific capacity additions in each year for each alternative resource plan.

Resource Plan A

In addition to the combustion turbine capacity, combined cycle capacity and coal unit additions are contained in Resource Plan A. This plan is based on the optimal plan. Plan A contains a total of 3,100 MW of combustion turbines, 300 MW of combined cycle capacity, and 2,500 MW of pulverized coal capacity. The first coal unit is installed in 2006.

Resource Plan B

Resource Plan B is similar to CP&L's December 1993 Resource Plan. It contains combustion turbine additions until 2008 when the first coal unit is added. No combined cycle capacity is contained in Plan B. There is 3,900 MW of combustion turbine capacity and 2,000 MW of pulverized coal capacity in Plan B.

Resource Plan C

Resource Plan C contains a balanced mix of combustion turbine, combined cycle, and coal capacity additions. The first combined cycle capacity is added in 2005 and the first coal addition is installed in 2008. The total amount of combined cycle capacity is 1,350 MW. The total coal capacity in Plan C is 1,500 MW, and the amount of generic combustion turbine capacity added is 3,100 MW.

Resource Plan D

Resource Plan D contains no coal capacity additions. This plan is built around the idea that there is a plentiful supply of natural gas and that coal capacity is no longer viable. After 2002, Plan D contains only combined cycle additions. There is a total of 3,900 MW of combined cycle additions in this plan, as well as 2,000 MW of combustion turbine capacity.

Resource Plan E

Resource Plan E was designed on the theory that in the future natural gas and oil will be available only in limited quantities. Plan E contains 1,900 MW of combustion turbines and 4,000 MW of coal units, with the first coal addition in 2003.

Resource Plan F

Resource Plan F contains a different level of demand-side management resources than the previous five plans. The assumption is made that beginning in 1998, the level of DSM resources is held constant. In other words, after 1997, increases in customer demand are met only with supply-side resources. This represents a reduction in DSM resources of 881 MW through the year 2013, compared to the level of DSM in the Company's 1993 Load Forecast. Plan E contains a total of 3,500 MW of combustion turbine capacity, 450 MW of combined cycle capacity, and 3,000 MW of coal capacity. The first coal unit is installed in 2006.

Resource Plan G

Resource Plan G contains a higher level of DSM resources than any of the other plans. Beginning in 1998, the level of DSM resources is increased each year over the amount in the Company's December 1993 Load Forecast. By the year 2013, an additional 686 MW of DSM resources is implemented. Plan G contains 2,900 MW of combustion turbines, 300 MW of combined cycle capacity, and 2,000 MW of coal capacity. The additional DSM resources in Plan G allow the first coal unit to be delayed until 2008.

Table 5-12
Alternative Resource Plans

	Plan A	Plan B	Plan C	Plan D	Plan E	Plan F	Plan G
1994	-	-	-	-	-	-	-
1995	-	-	-	-	-	-	-
1996	225 Darlington	225 Darlington	225 Darlington	225 Darlington	225 Darlington	225 Darlington	225 Darlington
1997	200 CT	200 CT	200 CT	200 CT	200 CT	200 CT	200 CT
1998	200 CT	200 CT	200 CT	200 CT	200 CT	300 CT	-
1999	700 CT	700 CT	700 CT	700 CT	700 CT	800 CT	700 CT
2000	300 CT	300 CT	300 CT	300 CT	300 CT	400 CT	300 CT
2001	300 CT	300 CT	300 CT	300 CT	300 CT	300 CT	200 CT
2002	300 CT	300 CT	300 CT	300 CT	200 CT	400 CT	300 CT
2003	300 CT	300 CT	300 CT	300 CC	500 Coal	400 CT	200 CT
2004	300 CC	300 CT	300 CT	300 CC	500 Coal	300 CC	300 CT
2005	300 CT	300 CT	300 CC	300 CC	-	400 CT	300 CC
2006	500 Coal	200 CT	300 CC	300 CC	500 Coal	500 Coal	200 CT
2007	-	300 CT	300 CC	300 CC	-	150 CC	200 CT
2008	200 CT	500 Coal	500 Coal	300 CC	500 Coal	500 Coal	500 Coal
2009	500 Coal	-	-	300 CC	500 Coal	500 Coal	500 Coal
2010	300 CT 500 Coal	500 CT 500 Coal	500 CT 500 Coal	900 CC	500 Coal	300 CT 500 Coal	100 CT 500 Coal
2011	500 Coal	500 Coal	450 CC	450 CC	500 Coal	500 Coal	200 CT
2012	500 Coal	500 Coal	500 Coal	150 CC	500 Coal	500 Coal	500 Coal
2013	-	-	-	300 CC	-	-	-

Notes:
All capacity values are in megawatts.
Plan F has no additional DSM resources added after 1997. The total reduction in DSM resources (compared to Plans A-E) through 2013 is 881 MW.
Plan G has additional DSM resources (compared to Plans A-E) starting in 1998. The total increase in DSM resources through 2013 is 686 MW.

Risk and uncertainty analysis

Risk and uncertainty analysis plays a major role in CP&L's IRP process for evaluating and selecting the resource plan. Evaluation of the alternative resource plans demands careful consideration of the key uncertainties identified by the sensitivity analysis. Using a decision analysis methodology allows for the treatment of the uncertainty in major assumptions in the evaluation of whether a candidate resource plan is a "robust" plan. A robust plan generally provides the flexibility to change course should the future not materialize as currently projected, thereby minimizing the adverse impacts of unforeseen changes and producing acceptable results for a broad range of possible events.

The influence diagram and sensitivity analysis discussed above indicate which assumptions should be used as key uncertainties in evaluation of the alternative plans; however, they provide neither the values of the uncertainties nor the probability of a given outcome occurring. The probabilistic relationship of an uncertainty and its possible outcomes may be determined from sources such as historical data or computer simulations, or by judgements obtained through an interview process with individuals qualified to offer expert opinion. The information obtained through these sources is used to develop a cumulative probability distribution which describes the probability associated with the occurrence of a range of possible futures for each uncertainty. Discrete values are determined for each uncertainty from the cumulative probability distributions and used in the decision tree for evaluation of the alternative resource plans. Appendix B provides discussions of the probability encoding process, the development of a cumulative probability distribution, and the development of the discrete values of an uncertainty.

The cumulative probability distributions for the energy growth and nuclear performance uncertainties are shown in Figures 5-8 and 5-9, respectively. The cumulative probability distribution for the energy growth uncertainty was developed based on an interview process conducted with Company experts in the area of energy and load forecasting. The distribution for nuclear performance was based on historic nuclear equivalent availability factors for all nuclear unit types and size ranges, taken from the North American Electric Reliability Council (NERC) Generating Availability Data System (GADS) for the 1988-1992 time period. The probability data for each of the premium fuels used by CP&L were developed in the form of price forecast ranges. Figure 5-10 shows distillate oil prices as an example of a price forecast range. This figure also shows the high, mid, and low price streams used in the decision analysis for resources using this fuel. Similar price forecasts were developed for natural gas and propane.

Figure 5-8
Energy Growth Uncertainty
Cumulative Probability Distribution

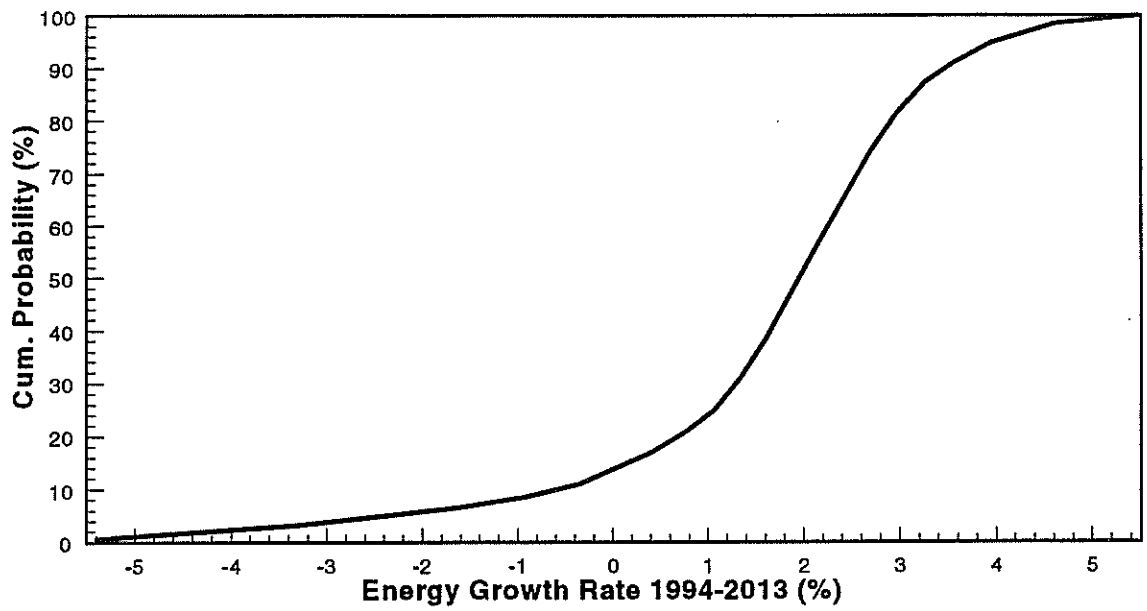


Figure 5-9
Nuclear Performance Uncertainty
Cumulative Probability Distribution

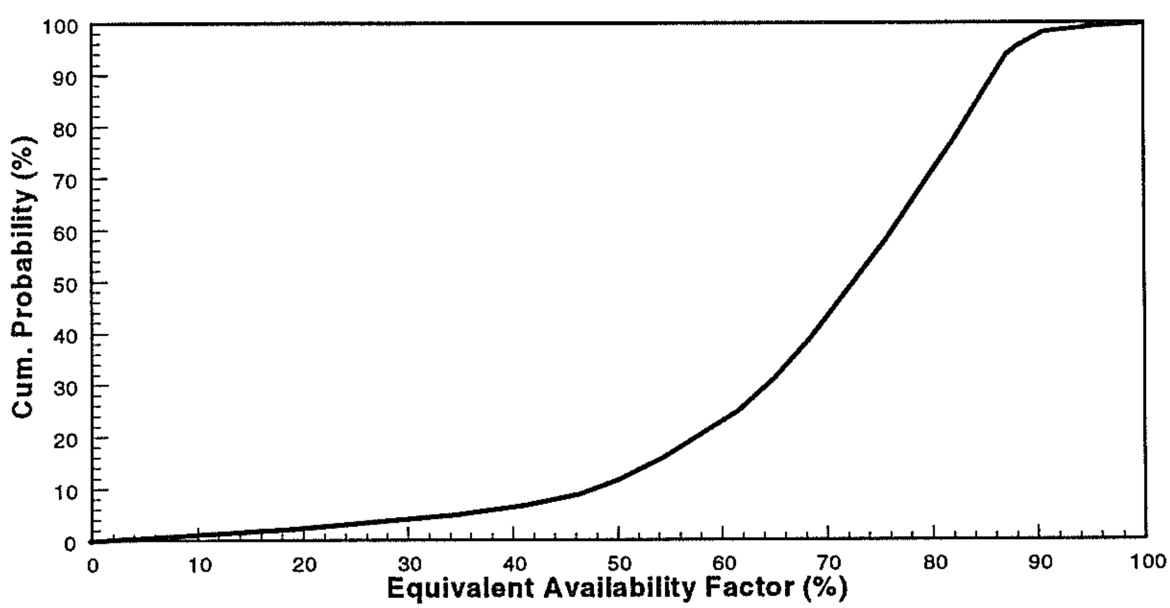
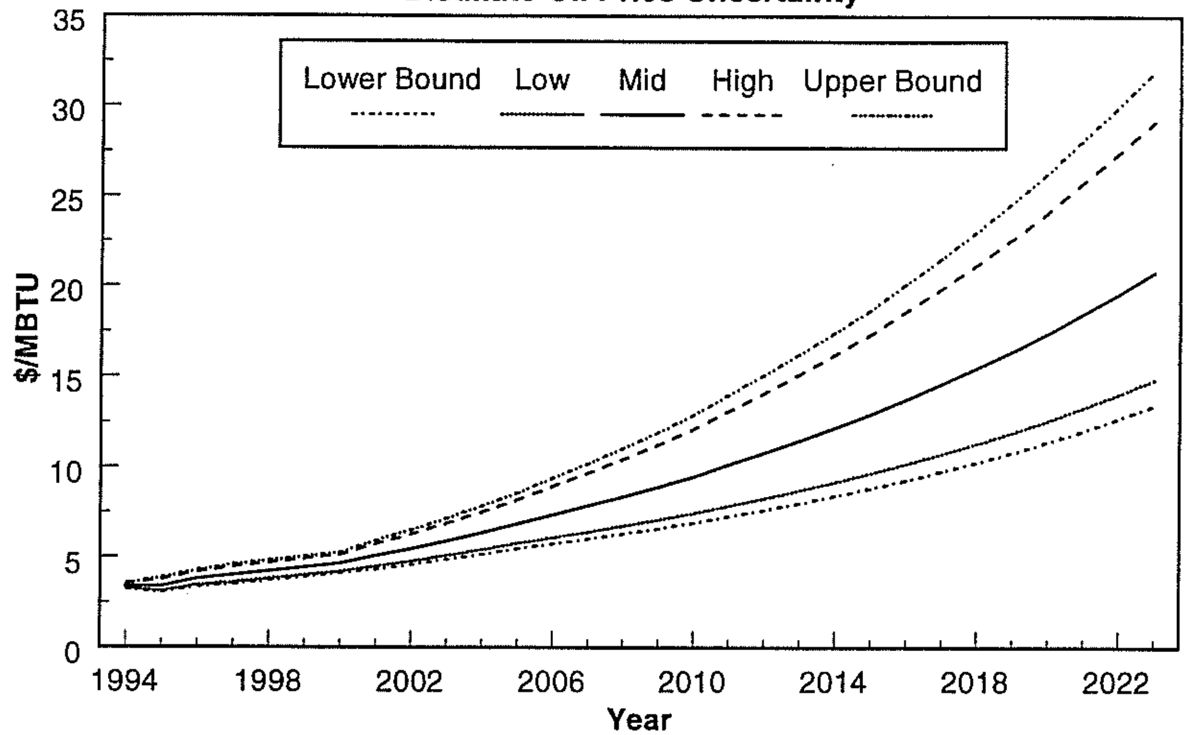


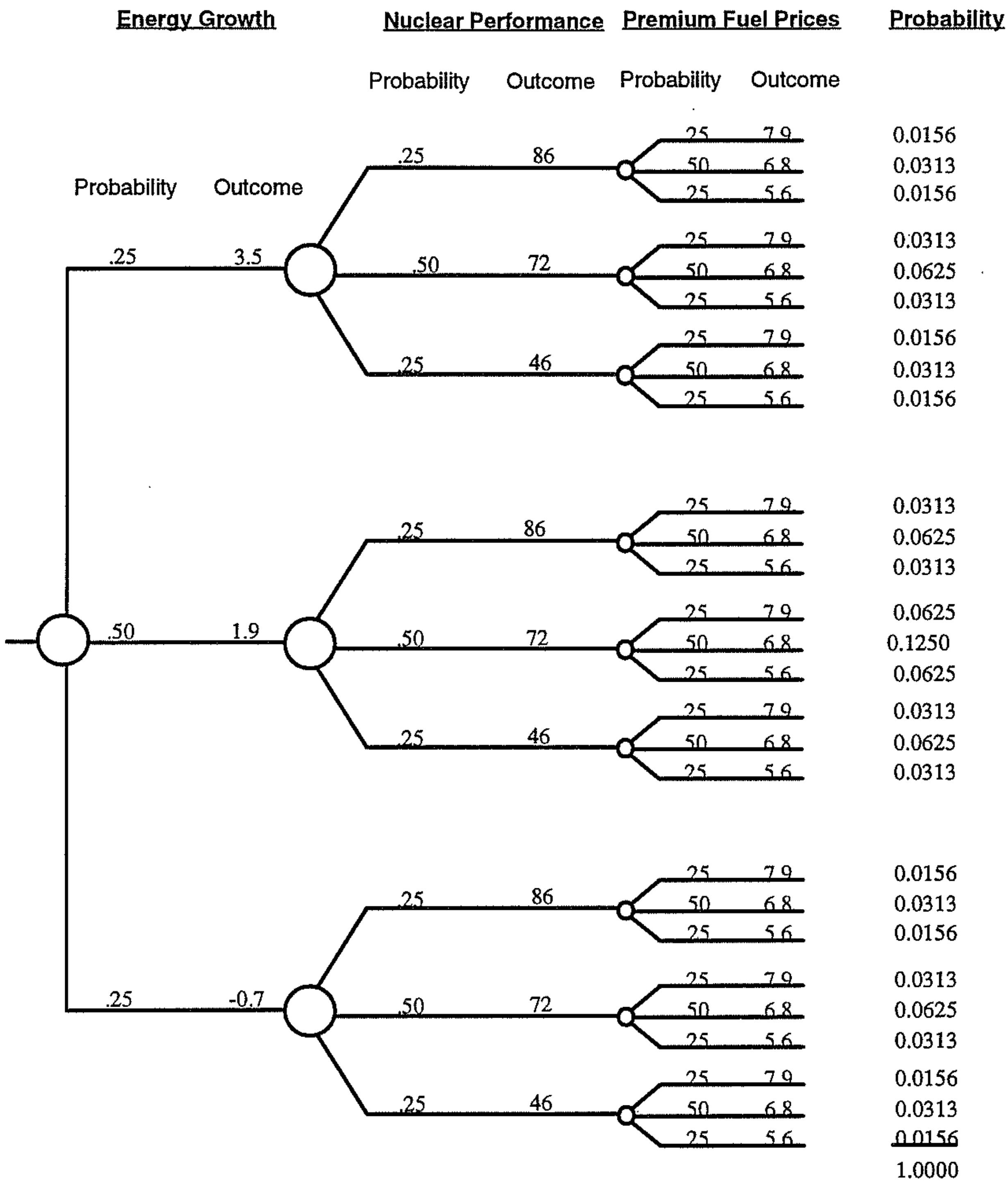
Figure 5-10
Distillate Oil Price Uncertainty



The cumulative probability distributions quantify the range of possible outcomes for the key uncertainties. The distribution for the energy growth uncertainty, for example, shows a wide range of possible outcomes from less than -5% growth to greater than 5% growth in energy. The nuclear performance distribution captures the entire range of availability factors between 0% and 100%. Premium fuel price long term escalation rates ranged from approximately 5.2% to 8.2%.

The decision tree shown in Figure 5-11 was created by combining the branch representations of the uncertainties to provide a graphical representation of all the different combinations of events that can occur and their associated probabilities of occurrence. For instance, the endpoint at the top right of the decision tree represents a scenario where energy growth is high (greater than 3.5%), nuclear performance is high (greater than 86%), and premium fuel prices are high. The probability of a particular scenario occurring is the product of the probabilities of the individual outcomes comprising the scenario. The probabilities for all the endpoints sum to 1.00 (100%) to represent inclusion of all possible scenarios (combinations of uncertainties).

Figure 5-11
Decision Tree



Evaluation of resource plans

As explained earlier, the results of the SO_2 economic screening, optimization, and sensitivity analyses all demonstrate that the purchase of allowances is the most economical compliance option for CP&L. High allowance prices increased the amount of fuel switching by only a small amount. Other sensitivity analyses, such as reducing the capital cost of scrubbers had no impact on the optimal compliance plan. Therefore, in the evaluation of alternative resource plans under conditions of uncertainty, the compliance plan assumed is to buy allowances. This assumption also ensures the resource plans are evaluated on a consistent basis. While the purchase of allowances will produce a least-cost compliance plan, the flexibility and diversity of such a plan may not make it the best compliance plan. These issues will be investigated in the final step of the resource integration analysis.

The cost of the alternative resource plans is used to evaluate each plan's performance under conditions of uncertainty. Two attributes are used to measure cost: the cumulative present value of revenue requirements and the levelized cost per kilowatt-hour. Both attributes include the costs associated with the resource plan and the costs associated with SO_2 emissions compliance as well as the energy- and capital-related costs of existing resources. Revenue requirements is the amount of money needed to recover costs incurred by the Company to produce and deliver electricity to the customers. Since multiple levels of DSM are being evaluated, levelized cost per kilowatt-hour is used to normalize the costs in terms of the amount of electricity sold. This measure distributes the cost of the plan over the energy sales.

The results of the decision analysis, as measured by cumulative present value of revenue requirements and levelized cost per kilowatt-hour for each plan, are shown in Table 5-13. The table shows the expected value over all uncertainties for the two attributes as well as the difference between the expected value for each plan and Plan A. The ranking of each plan from one to seven is also included in the table.

As measured by revenue requirements, Plan F ranks last. This plan assumes that no new DSM resources are added after 1998; that is, DSM resources are held constant beginning in 1998. With no new DSM after 1998, peak loads and energy sales for Plan F are higher than the other plans, producing greater capacity addition requirements, which produces greater fixed costs and higher energy sales, and thus, greater fuel costs. The impact on revenue requirements by the level of sales demonstrates the need to use levelized cost per kilowatt-hour as one of the decision criteria.

Table 5-13
Plan Evaluation Decision Analysis Results

	Cumulative PV Costs			Levelized Cost		
Plan	Expected Value (M$)	Difference from Plan A (M$)	Rank	Expected Value ¢/kWh	Difference from Plan A (¢/kWh)	Rank
A	44,759	0	4	7.7329	0.0000	4
B	44,794	35	5	7.7389	0.0061	5
C	44,643	-116	2	7.7203	-0.0125	2
D	44,677	-82	3	7.7279	-0.0050	3
E	45,083	324	6	7.7874	0.0545	7
F	45,163	404	7	7.7052	-0.0277	1
G	44,602	-157	1	7.7841	0.0513	6

Resource Plan F, as shown in Table 5-13, has the lowest levelized cost per kilowatt-hour. Since Plan F has more energy sales than the other alternative plans, the costs can be distributed among more kilowatt-hours. One reason why Plan F has the lowest expected value of levelized cost is that Plan F performs best in all cases of low load growth. The low load growth uncertainty in the analysis represents a negative growth in load. If energy sales are declining as a result of low load growth, there is no need for additional DSM. Plan F, having no new DSM after 1998, allows the cost of the existing system to be spread over a larger sales base than the other plans which contain more DSM. This gives Plan F an advantage over the other alternative plans in low load growth scenarios.

The second plan containing a different level of DSM is Resource Plan G. Plan G contains an annual increase in DSM resources (beginning in 1998) over the amount in the 1993 Load Forecast. Plan G ranks sixth in levelized cost. Opposite from Plan F, the lower amount of energy sales in Plan G provides a smaller sales base in which to distribute fixed costs. On a revenue requirements basis, however, Plan G ranks first. Greater amounts of DSM produce lower peak loads and energy sales and thus, lower operating costs. As a result, revenue requirements are lower.

Plan G, with a higher level of DSM, contains both DSM programs that are cost-effective and DSM programs that are not cost-effective in evaluations using the Rate Impact Measure (RIM) test. The amounts of DSM in Plans F and G are assumed to be fixed and are not adjusted in the low and high growth scenarios. The magnitude and timing of DSM offerings to the customers can be more dynamic, depending on projected load growth, than what is simulated. CP&L enhanced the IRP process to examine the impact of DSM with key uncertainties. Improvements are needed in the methodology in order to make a recommendation for the appropriate level of DSM. Efforts are currently in progress to examine cost-effective DSM markets, appropriate measures to determine the cost-effectiveness of DSM programs, and the proper timing of DSM additions. Therefore, although Plan F has the lowest levelized cost, it is not appropriate that DSM efforts be abandoned based only on these results.

The remaining alternative plans, Plans A through E, contain the base DSM assumptions. The resource plan that ranks best among these plans as measured by levelized cost is Plan C. The capacity additions of Plan C are a balanced mix of combustion turbines, coal, and combined cycle units. In addition, Plan C also ranks best as measured by revenue requirements.

Sensitivity of uncertainty probabilities

Sensitivity analysis was performed to test the robustness of Plan C to the probabilities assigned to the outcomes of the key uncertainties. This is accomplished by varying the probability assigned to an outcome of a particular uncertainty, while maintaining the original relationship among the probabilities of the other outcomes. For example, assume the original probabilities assigned to the high, mid, and low outcomes of an uncertainty are 25%, 50%, and 25%, respectively. If the probability of the high outcome is being evaluated at 40%, the original 2 to 1 ratio between the mid and low outcomes is maintained. The probability for the mid outcome then becomes 40% and the probability of the low outcome becomes 20%. The probabilities assigned to the outcomes of all other uncertainties are maintained at their original values. The expected values for all the alternatives are then computed and compared. This iterative process is repeated to determine the range of probabilities for each uncertainty outcome for which the highest ranking plan remains the highest ranking plan.

The results of the sensitivity analysis are presented in Table 5-14 as a range of probabilities for the high, mid, and low outcomes for each of the three uncertainties. For example, the high outcome for the energy growth uncertainty has an original probability of 25%. The sensitivity analysis determined that Plan C remains the least cost plan as long as the probability of high energy growth is 99% or less. The most limited range occurs for low premium fuel prices with a probability range of 0% to 43% for which Plan C remains the least cost plan. The analysis shows Plan D becomes the least cost plan for probabilities greater than 43% for the low outcome. Since the base assumption for the low fuel prices probability is 25%, the probability for the low outcome of this uncertainty will have to almost double before this uncertainty will drive Plan D to become the least cost plan.

Table 5-14
Sensitivity Analysis of Uncertainty Probabilities

Uncertainty	Base Value	Range For Which Plan C is Ranked First	Plan Impacting The "Best" Plan
High Energy Growth	25%	0% - 99%	Plan D
Mid Energy Growth	50%	0% - 100%	-
Low Energy Growth	25%	0% - 94%	Plan A
High Nuclear Performance	25%	0% - 100%	-
Mid Nuclear Performance	50%	0% - 100%	-
Low Nuclear Performance	25%	0% - 100%	-
High Premium Fuel Prices	25%	10% - 83%	Plan D - Plan A
Mid Premium Fuel Prices	50%	0% - 100%	-
Low Premium Fuel Prices	25%	0% - 43%	Plan D

With the exception of low premium fuel prices, the analysis shows that Plan C remains the least cost plan for a wide range of uncertainty probabilities. For seven out of the nine uncertainty outcomes, the probabilities can range from 0% to greater than 90% with Plan C remaining the least cost plan. For five of these uncertainty outcomes, Plan C is the least cost plan regardless of the probability assigned to the outcome. Thus, the results of the sensitivity analysis confirm that Plan C is the most robust plan over wide ranges of uncertainty probabilities.

Fatal flaw analysis

Since there is not one plan that is best for all the possible scenarios in the decision analysis process, the best overall plan is further examined to determine if there are any scenarios where the plan exhibits serious deficiencies. This analysis is conducted to better understand the scenarios under which the plan is not the best plan, the severity of any deficiencies, and to determine if any adjustments to the plan are needed.

Resource plan

Resource Plan C was examined for any fatal flaws which may go unnoticed by examining only the expected value of levelized cost and the expected value of cumulative present value of revenue requirements. Since it is unlikely that one plan will be the best for all the scenarios possible under the 27 different combinations of low, mid, and high outcomes for energy growth, nuclear performance, and premium fuel prices, a process of elimination is used to determine where the best overall plan exhibits serious deficiencies. The scenarios where Plan C is not the lowest cost are also reviewed as part of the fatal flaw analysis. This is performed to understand why it is not the lowest cost for those scenarios, and how severe the economic penalty is for adopting the plan should an adverse scenario materialize.

The expected value of levelized cost per kilowatt-hour and cumulative present value of revenue requirements for Plan C are the lowest of all plans, though as expected, they are not the lowest cost in all scenarios. Plan C has the lowest cost in seven of 27 uncertainty scenarios. It is the second lowest cost plan in 16 of them, and is third lowest in the remaining four scenarios. The analysis also determined that Plan C never incurs the highest cost in any uncertainty scenario. This outcome is just as important to having the lowest cost in seven uncertainty scenarios. Furthermore, in those scenarios where Plan C is not the lowest cost plan, it is always within one percent of the lowest cost.

Examining the scenarios for which Plan C is the lowest cost plan revealed that it is the least cost plan in almost all different combinations of the high, mid, and low uncertainties. Three of the seven scenarios in which Plan C results in the lowest cost contain the mid energy growth uncertainty. Two of seven contain high energy growth, and two contain low energy growth. The same distribution is true for the nuclear performance uncertainty. Five of the seven scenarios contain mid premium fuel prices; the other two contain high prices. Plan C is found to perform best in scenarios where one of the uncertainties is at its mid condition. The mid range results are desirable since they are the most likely outcomes to occur (i.e., the outcomes have a probability of occurrence of 50%). The distribution of the results over the various combinations of uncertainties demonstrates that Plan C can achieve good results over a range of future conditions and that Plan C is a robust plan.

The only uncertainty for which Plan C does not perform as the lowest cost plan is the low premium fuel price uncertainty. Under these conditions, Plan C is never the lowest cost plan. Under low premium fuel price conditions, Plan D (with capacity additions of combined cycle units only after 2003) is clearly advantageous with its reliance solely on these fuels being consumed by relatively inexpensive combined cycle units compared to the more capital intensive coal-fired units in Plan C. However, the type of capacity additions in Plan C make it a flexible plan. A comparison of the capacity additions in Plan C and Plan D show they are identical through the year 2002. Plan D adds 300 MW of combined cycle capacity in both 2003 and 2004 while Plan C adds 300 MW of CT capacity in both 2003 and 2004. Beyond

2004, Plan C and D are again identical up to the year 2008. In the period 2008 through 2012, 1,500 MW of coal-fired capacity appears in Plan C, while Plan D adds a similar amount of combined cycle capacity.

Plan C possesses the flexibility to respond to changing conditions while providing clear economic benefits over a wide range of possible conditions. Based on the analysis described here, Plan C does not appear to have any fatal flaws.

Compliance plan

As discussed earlier, SO_2 economic screening, optimization, and sensitivity analyses all found that the purchase of allowances is the most economical compliance option for CP&L. However, consideration must also be given to factors such as risk, balance, diversity, and impact on the environment. Also, such a strategy may be less flexible than desired, and limit the Company's ability to respond to an uncertain future. Therefore, four alternative compliance plans were developed to determine the additional cost of compliance with the SO_2 requirements of the CAAA through methods other than just the purchase of allowances. The alternative compliance plans are discussed below. Common to all compliance plans is the switching of Asheville Units 1 and 2 and Roxboro Unit 2 to burn 1.2 lbs. SO_2 per MMBtu coal by the year 2000.

Compliance Plan 1

Compliance Plan 1 is the total dependence on buying allowances. No fuel switching other than at Asheville and Roxboro 2 is performed. The cost of the other alternative compliance plans will be compared to this plan.

Compliance Plan 2

Compliance Plan 2 contains additional fuel switching. All CP&L coal units are switched to burn compliance coal by the year 2000. Since switching to compliance coal at all of CP&L's units will not bring emissions down to the level of allowances received from EPA, additional allowances are purchased in this plan as needed.

Compliance Plan 3

Compliance Plan 3 contains a balance of compliance options. In addition to switching all units to burn compliance coal by the year 2000, Mayo Unit 1 is scrubbed beginning in the year 2007 at which time it begins to burn higher sulfur coal. Additional allowances are also purchased in this plan.

Compliance Plan 4

Compliance Plan 4 concentrates the SO_2 emission reductions by CP&L in the Western Division and in Person County, North Carolina. The reductions are focused in these areas because the Western Division is in proximity to the Great Smokey National Park, an environmentally sensitive area, and in Person County, where a significant amount of CP&L's coal-fired capacity is located. In Compliance Plan 4, Roxboro Units 1 and 3 are switched to burn compliance coal in the year 2000. In 2005, Roxboro Units 3 and 4 begin operating with scrubbers, burning a somewhat higher sulfur coal. SO_2 emissions are reduced in the Western Division by switching the Asheville units to compliance coal. This plan also buys allowances on an as needed basis.

Compliance Plan 5

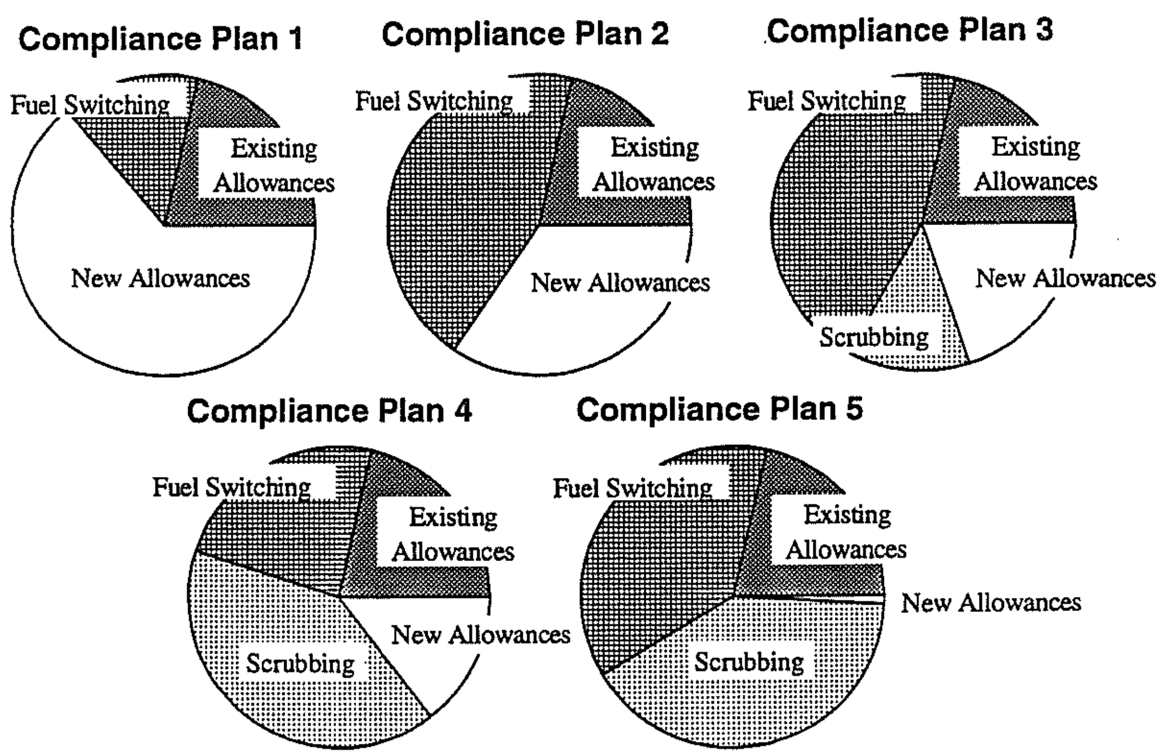
Compliance Plan 5 is designed to comply without having to purchase any additional allowances. In this plan, all units are switched to compliance coal by the year 2000, Roxboro Units 3 and 4 are scrubbed in 2007, and Roxboro Unit 2 is scrubbed in 2011. These three units burn higher sulfur coal when the scrubbers are made operational.

Evaluation of alternative compliance plans

The alternative compliance plans were analyzed in combination with all of the alternative resource plans. This analysis was performed to determine if a particular combination of resource plan and compliance plan might produce lower total cost integrated resource plan than what could be achieved by matching an alternative compliance plan with Resource Plan C. This analysis showed that in terms of levelized cost per kilowatt hour and cumulative present value of revenue requirements, Resource Plan C was the lowest cost resource plan for all the alternative compliance plans. This analysis demonstrates that for current conditions and assumptions that the selection of the compliance plan does not change the selection of the best resource plan. Therefore, further analysis of the alternative compliance plans is discussed with regard to Resource Plan C only.

Compliance obtained through a combination of options provides the Company with balance and diversity. Figure 5-12 represents the amount of compliance achieved by each option for each compliance plan. Compliance Plan 1 achieves compliance through allowance purchases only. In Compliance Plan 2, compliance is achieved through switching to 1.2 lb. sulfur coal and the purchase of allowances. Compliance Plan 2 still has a large number of new allowances (providing 35% of compliance) and no scrubbing. Compliance Plan 3 has a good balance between fuel switching, scrubbing, and allowances. Compliance Plan 4 has a large amount of scrubbing, and a relatively smaller amount of both fuel switching and purchases of allowances. Compliance Plan 5 relies, to a great extent, on achieving reductions in SO_2 emissions through the installation of scrubbers.

Figure 5-12
CAAA SO_2 Compliance by Method



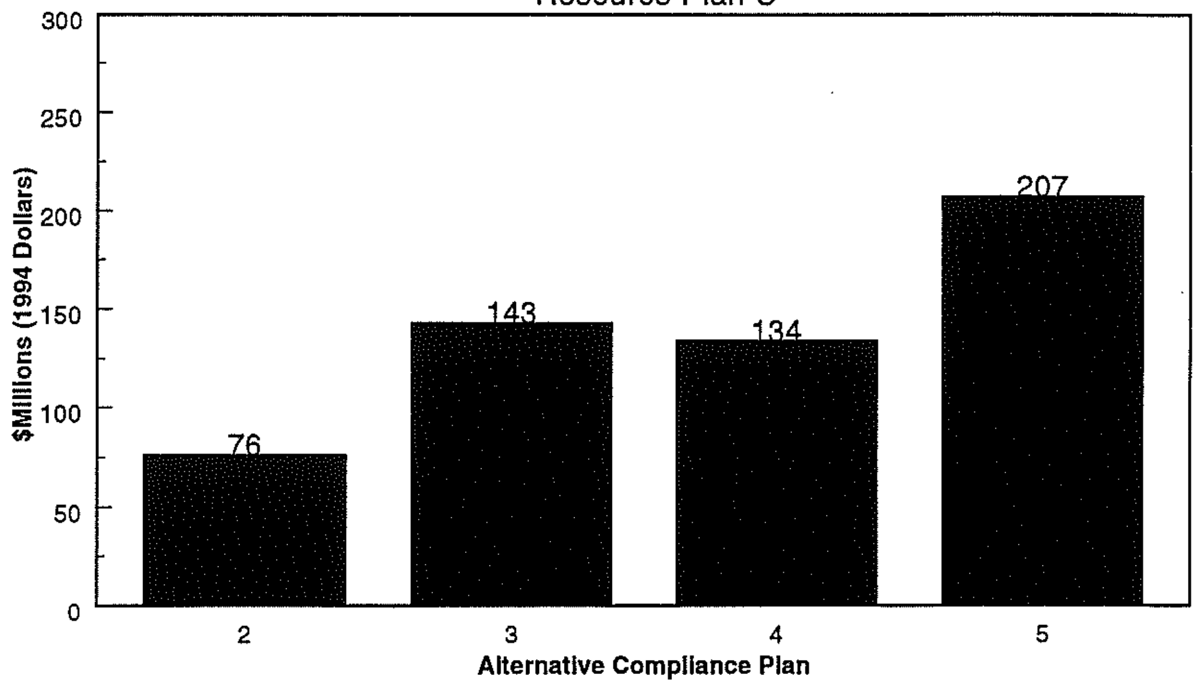
The relative cost of the alternative compliance plans is shown in Figure 5-13. This figure shows the additional cost compared to Compliance Plan 1 for each of the alternative compliance plans. Compliance Plan 2 increases the cost of compliance by $76 million. Compliance Plans 3 and 4 have additional costs that are $60-70 million more than the additional costs of Compliance Plan 2. Compliance Plan 5, which has no new allowance purchases, costs over $200 million more than just buying allowances as in Compliance Plan 1. As discussed above and shown in Figure 5-12, Compliance Plan 3 is more balanced than the other alternative compliance plans. The added diversity of Compliance Plan 3 over Plans 1 and 2 is gained at only slightly higher cost. While Compliance Plan 3 is slightly more expensive than Plan 4, it is more flexible than Plan 4. The additional flexibility is gained by delaying the decision date on the construction of a scrubber until 2002 compared to 2000 for Plan 4 and through the use of more fuel switching.

Figure 5-13

Additional Cost of SO2 Compliance

Cumulative present Value of Revenue Requirements

Resource Plan C



Compliance Plan 3 also has environmental flexibility. Chapter 4 discussed future environmental uncertainties such as greenhouse gas restrictions, air toxics regulation, and non-Title IV restrictions of SO_2 and NO_x emissions. Additional compliance requirements to respond to these uncertainties may be necessary. With this in mind, a strategy without a near-term commitment to capital investments is preferred. Since Compliance Plan 3 does not require a major capital investment decision for scrubbers until 2002, more time is available to respond to potential environmental regulations and to observe the emissions allowance market relative to the other compliance options. This may provide the Company the opportunity to respond to potential regulations associated with air toxics and greenhouse gases in a more efficient manner. By delaying the installation of scrubbers for as long as possible, emerging technologies will also have time to develop and be tested. These new technologies may be able to control emissions of other pollutants in addition to SO_2. Thus, the Company could avoid unnecessary capital expenditures.

Summary and Conclusions

Given CP&L's existing and committed resources and the projected load growth on the system, approximately 4,200 MW of new supply resources will be needed by the year 2009. Through the use of optimization analysis and sensitivity analysis, seven alternative resource plans were developed. Also, three planning assumptions were found to have significant impacts on the optimal resource plan: load and energy growth, the performance of CP&L's existing nuclear facilities, and the price of fuels used by combustion turbines and combined cycle units.

Through the use of risk and uncertainty analysis the evaluation of the seven alternative resource plans determined the best resource plan to be Resource Plan C. Resource Plan C contains a balanced mix of combustion turbine, combined cycle, and coal capacity additions. Additional analysis of Resource Plan C found that the plan possesses the flexibility to respond to changing conditions while providing clear economic benefits over a wide range of possible conditions.

The economic screening analysis of SO_2 compliance options found that the purchase of allowances appeared to be the lowest cost option for compliance with the SO_2 requirements of the Clean Air Act Amendments. The optimization and sensitivity analyses performed in the integration analysis confirmed those results. However, consideration must be also be given to factors such as risk, diversity, and flexibility. A strategy of compliance through the purchase of allowances only does not provide for these dimensions of a robust compliance plan. Therefore, four additional alternative compliance plans were developed and evaluated. These plans increased the cost of compliance; however, Compliance Plan 3 was found to contain more diversity than other plans at only slightly higher costs. Compliance Plan 3 contains a balanced mix of fuel switching, scrubbing, and purchasing of allowances. In addition to switching all coal units to burn compliance coal by the year 2000, Mayo Unit 1 is scrubbed beginning in the year 2007, at which time it begins to burn slightly higher sulfur coal. Flexibility is gained with Compliance Plan 3 by delaying the decision date on the construction of a scrubber until the year 2002. This additional time will allow the Company to observe the emission allowance market relative to the other compliance options and provide CP&L the opportunity to respond to potential environmental regulations. Because of its flexibility and diversity, the recommended SO_2 compliance plan is Compliance Plan 3.

Chapter 6
Integrated Resource Plan

This chapter discusses CP&L's Integrated Resource Plan and Clean Air Act Amendments compliance plans.

Description of the Integrated Resource Plan

The overall objective of CP&L's Integrated Resource Planning process is the development of a flexible resource plan which will provide an adequate and reliable supply of electric power to our customers at the lowest reasonable cost and in an environmentally sound manner. CP&L's IRP achieves this objective by incorporating a cost-effective mix of demand-side and supply-side resources. CP&L's IRP increases the utilization of existing facilities and minimizes the price of electricity. The CAAA compliance plans minimize cost while providing the flexibility needed to respond to uncertain conditions and changing regulations.

The Integrated Resource Plan builds on a well-balanced mix of existing demand-side and supply-side resources. Demand-side resources include conservation and load management programs; supply-side resources consist of coal, nuclear, oil, natural gas, propane and hydroelectric facilities, along with purchases from other utilities, and purchases from non-utility generators such as cogenerators. Table 6-1, below, summarizes the Company's IRP. The table shows the forecasted system energy and peak load, the demand-side and supply-side resources planned, and the resulting annual capacity margins.

The Company continues to experience high levels of growth in peak demand for electricity even with its aggressive DSM efforts. The current forecast projects peak load to grow approximately 2.1% annually through 2009. This level of growth corresponds to approximately 228 MW of additional peak load each year.

Demand-side resources

A key element in CP&L's plan for supplying future demand is to reduce the need for capacity additions by displacing part of the expected load growth through DSM programs. For more than two decades CP&L has been promoting successful energy management options for its customers, and it is expected that DSM will continue to play an important role in CP&L's future integrated resource plans. Demand-side resources at the end of 1994 totaled 1,076 MW. Expressed as a percentage of peak load, the projected cumulative DSM load reduction capability in 1995 is more than 12%. Over the 15-year planning horizon, the Company's plan calls for the addition of approximately 835 megawatts of DSM peak load reduction capability. Table 6-2 outlines the current DSM programs and their corresponding load reduction capabilities. The mix of DSM programs includes programs which impact the timing and magnitude of electric demands on our generating facilities. This "management" of load can produce improvements in load factor, increase utilization of existing capacity, reduce the need for additional peaking capacity, reduce the level and frequency of future rate increases, increase customer satisfaction and encourage economic growth.

Table 6-1
Resource Plan Summary

	Annual Energy (GWH)	Peak Load (MW)	Demand-Side Management (MW)	Supply-Side Resources (MW)	Capacity Margin (%)
1995	52,312	9,690	1,151	-	13.6
1996	51,794	9,698	1,210	15 NUG	13.6
1997	53,295	9,986	1,268	225 Darl. County CT	12.8
1998	54,815	10,272	1,331	500 Wayne County CT* -50 PA/SCPSA 200 PA CT	15.1
1999	56,224	10,549	1,398	700 Wayne County CT* -400 Duke -50 PA/SCPSA	14.6
2000	57,612	10,802	1,465	300 CT**	14.6
2001	58,902	11,034	1,532	300 CT**	14.8
2002	60,229	11,269	1,600	300 CT**	14.9
2003	61,571	11,509	1,665	300 CT**	15.1
2004	62,845	11,740	1,728	200 CT**	14.6
2005	64,099	11,968	1,787	300 CC**	14.8
2006	65,356	12,197	1,842	300 CC**	15.0
2007	66,632	12,428	1,894	300 CC**	15.1
2008	67,912	12,661	1,941	500 Coal**	16.4
2009	69,148	12,888	1,986	-	14.9

* The Company has not committed to a particular design or unit size for the capacity.
** The Company has not committed to a particular design, unit size, or location for the capacity.

Negative numbers indicate the expiration of purchase contracts.

NUG = Non-Utility Generation
CT = Combustion Turbine
CC = Combined Cycle
PA CT = Power Agency CTs

Table 6-2
Planned Demand-Side Management Summer Capability
(Megawatts)

	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009
Residential															
Common Sense Home	132	135	138	140	142	145	147	149	152	154	156	158	160	161	163
Home Energy Loan/ Conservation Discount	34	35	36	37	38	39	39	40	41	41	42	42	42	43	43
EZ-$64	216	240	265	292	318	345	373	401	429	455	481	506	528	550	571
High Efficiency HP & AC	24	28	31	33	34	35	36	37	38	39	39	40	40	41	42
Time-of-Use Rates	22	23	25	26	27	27	28	29	30	31	32	32	33	33	34
Residential Total	429	462	495	528	559	591	624	656	688	719	749	777	803	828	852
Commercial															
Audit	58	61	64	67	71	77	85	95	106	116	124	132	139	145	149
Energy Efficient Design	97	100	105	111	118	125	132	138	144	149	155	160	164	169	172
Thermal Energy Storage	3	3	3	4	4	4	5	5	5	6	6	6	7	7	7
Commercial Total	158	164	172	182	193	206	222	238	255	270	285	298	310	320	329
Industrial															
Audit/Energy Efficient Plant	236	242	250	262	278	294	308	320	331	341	350	358	366	373	379
Large Load Curtailment	212	221	225	229	233	236	239	243	247	250	254	257	261	265	268
Time-of-Use & Thermal Energy Storage	116	121	126	132	135	138	140	142	145	147	149	151	154	156	158
Industrial Total	564	583	601	622	646	667	687	706	723	738	753	767	781	793	804
Grand Total	1,151	1,210	1,268	1,331	1,398	1,465	1,532	1,600	1,665	1,728	1,787	1,842	1,894	1,941	1,986

CP&L's DSM programs have evolved over time in response to specific needs. For more than twenty years the Company has been promoting successful energy management options for its customers. In the early to mid-1970's, load growth was severely taxing CP&L's ability to build enough capacity to meet need. During this period, CP&L focused primarily on conservation with emphasis on a general reduction in energy usage, increased insulation, and overall improved thermal efficiency. During the mid-to-late 1970s, CP&L's programs expanded to focus not only on conservation but also load management. In the early-to-mid-1980s, in addition to the previous conservation and load management programs, CP&L added peak clipping programs supported by curtailable and other rate structures. From the mid-1980's to the present, CP&L's DSM programs have continued to evolve in response to changing resource and customer needs.

As discussed below, CP&L's Integrated Resource Plan indicates only the need for combustion turbines through the year 2004. CP&L's existing base load capacity is adequate until the later part of the planning period with the first coal unit scheduled in 2008. Further, the existing base load generating units have the potential to supply significantly more low cost energy than is currently required to meet customer needs. As a result, CP&L's DSM efforts are focused on cost-effective peak load management, strategic conservation, and strategic sales programs which will help reduce peak load, improve the utilization of existing facilities and defer the need for future rate increases. The comprehensive assessment of future DSM options remains an integral part of the Company's IRP process.

Supply-side resources

In 1994, CP&L had 16 power plants with a generating capacity of 9,613 MW and 1,596 MW of purchases. The mix of generating resources for the CP&L system is 47% coal, 28% nuclear, 2% hydro, 9% oil/gas, and 14% purchases. These existing resources will continue to provide low cost power in the future and are an important part of CP&L's Integrated Resource Plan.

CP&L uses a target capacity margin of 15% to schedule generation additions. The 15% capacity margin corresponds to a 17.6% reserve margin. Reserves do not remain at a constant level due to load growth and new capacity being brought in-service; therefore, the capacity margin in any year may be higher or lower than the target capacity margin. Although capacity margins are slightly below 15% in some years, probabilistic assessments confirmed that the IRP provides adequate reliability in all years of the 15-year planning horizon.

Based on the projected load growth and implementation of DSM programs discussed above and CP&L's 15% capacity margin target, the supply-side resource plan was developed consistent with Resource Plan C described in Chapter 5. The supply-side resource plan is not identical to alternative Resource Plan C in Chapter 5. The timing of the additions has been adjusted to reflect the load growth and DSM additions as shown in Table 6-1. The resource integration analysis discussed in Chapter 5 found Resource Plan C to be the most robust of the alternative resource plans.

In July 1993, CP&L signed an agreement to purchase power from BCH Energy. BCH Energy plans to construct a waste-to-energy facility on the property of DuPont in Fayetteville, NC. Bladen, Cumberland, and Hoke counties will supply trash/garbage to a facility that will prepare the waste to be used as fuel for a boiler that will drive a 15 MW turbine generator. The low pressure steam will be sold to DuPont, and the entire generator output will be sold to CP&L. This facility is scheduled to be completed in the third quarter of 1995.

Also shown in the IRP is North Carolina Eastern Municipal Power Agency's (NCEMPA) arrangement to purchase 100 MW through 1997 and 50 MW in 1998 from South Carolina Public Service Authority (SCPSA). NCEMPA has also notified CP&L of its plans to install 200 MW of combustion turbine peaking capacity in 1998. This power will be available to supply the combined CP&L/NCEMPA load and therefore, is included in CP&L's Integrated Resource Plan. NCEMPA has the option to not build the combustion turbine capacity. If NCEMPA decides not to build the capacity, they must provide notice to CP&L no later than March 1, 1996.

As shown in Table 6-1 a total of 2,825 MW of combustion turbines are added during the 1997 through 2004 time period. The first 225 MW of combustion turbine capacity in the IRP is associated with an addition at the Company's Darlington County Electric Plant located near Hartsville, South Carolina. In 1991, the Company received a Certificate of Environmental Compatibility and Public Convenience and Necessity from the South Carolina Public Service Commission authorizing construction of the plant. The plant was originally scheduled to be placed in-service in 1994. However, this capacity is now not expected to be needed before 1997.

In December 1994, CP&L made a preliminary filing for a proposed new combustion turbine peaking plant in Wayne County, North Carolina, near CP&L's existing Lee Plant. The Company made the preliminary filing at this time in order to maintain the option to construct the plant before the summer 1998 peak based on the lead-time associated with obtaining necessary permits and to allow time for facility construction. The proposed plant will contain up to 1,200 MW of capacity, with some of the capacity beginning commercial operation in 1998.

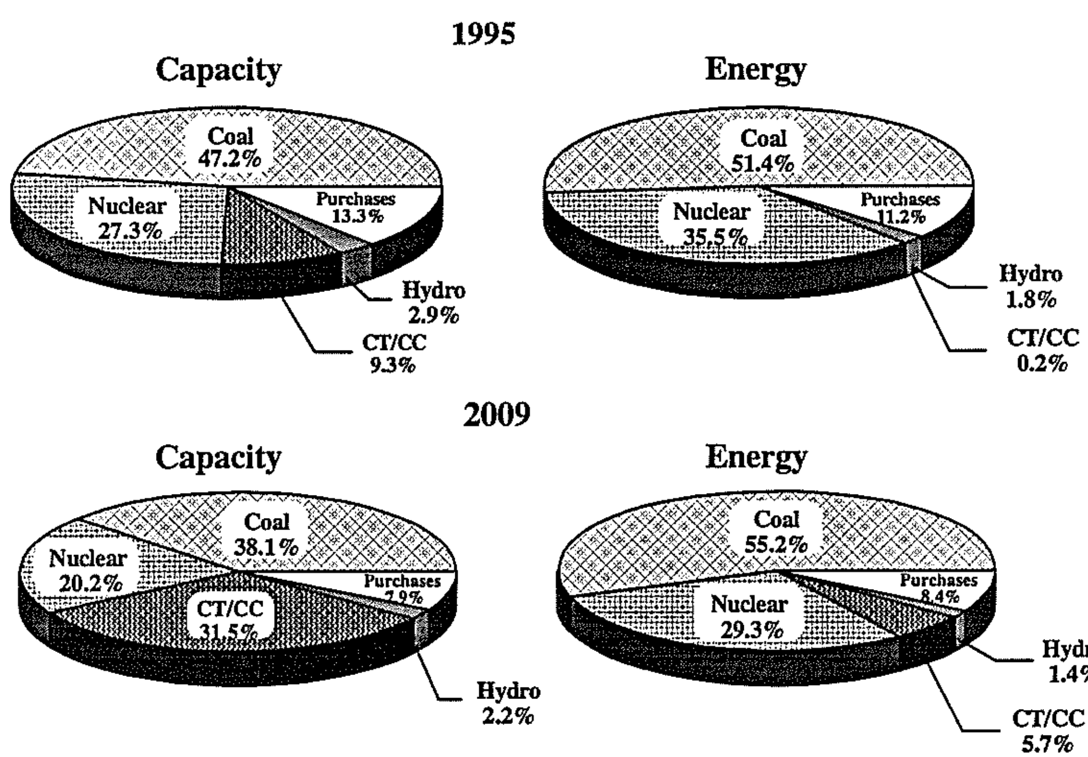
The remaining combustion turbine additions in Table 6-1 are undesignated peaking capacity. As with the Wayne County addition, the Company continues to consider options other than the construction of new facilities such as demand-side management and other supply options.

Also included in the IRP are 900 MW of combined cycle units which are added between 2005 and 2007. As with combustion turbines, the capital and operating costs of combined cycle units has declined over the last few years, making combined cycle units an economical choice for the CP&L system.

Figure 6-1, below, shows that oil/gas-fueled capacity is increasing as a percentage of total supply resources over the 15-year planning horizon. However, the amount of energy projected to be provided by this capacity will be only a small fraction of CP&L's total energy requirements. This small amount of generation from oil/gas-fueled combustion turbines and combined cycle units is a result of the significant daily and seasonal variation in customer electricity usage. Customer demand for electricity increases greatly on cold winter mornings and hot summer afternoons. These peak period demands require large amounts of generating capacity that is used for only short periods of time. This capacity, however, generates a relatively small amount of energy.

Finally, one coal unit is planned to be in-service starting in 2008 to serve baseload capacity needs. A decision on the specific technology has not been made at this time. Currently, coal technology options include coal gasification combined cycle, fluidized bed, and pulverized coal. As the date to begin construction of a baseload unit nears, a specific technology will be chosen.

Figure 6-1
Resource Mix by Fuel Type



A table detailing CP&L's Integrated Resource Plan can be found in Table 6-3. This table contains the demand-side and supply-side resources, along with annual load, resources, and reserves. Tables 6-4 and 6-5 contain projected fuel use and capacity factors for existing and future generating units that result from this resource plan.

Transmission

CP&L's transmission and distribution (T&D) facilities are an important consideration in the Company's plans for providing adequate and reliable service in a cost-effective manner. These systems are continually evaluated and improved to provide for the adequate and reliable transfer of power from the various generation resources to the customers throughout CP&L's service area.

The Carolina Power & Light Company transmission system is planned so as to comply with the requirements of SERC Guideline 3, "Criteria for Reliability in System Planning", and with NERC's Planning Policies, Procedures, Principles, and Guides. Additional criteria are used to assess and test the strength and limits of the CP&L transmission system to meet its load responsibility and to move bulk power between and among other electric systems. In addition, CP&L plans its transmission facilities so as to serve its load without excessively relying on or causing an undue burden on neighboring systems.

Cost effectiveness is one of the primary considerations in planning, constructing, and operating T&D facilities. This is accomplished through the development of alternatives in planning studies, the use of energy efficient and cost effective designs, construction of T&D facilities in an economical fashion compatible with environmental considerations, and by operating those facilities efficiently and reliably. T&D facility improvements are made based on long-term economics taking into account costs associated with engineering and design, construction, and the economic value of losses.

The CP&L transmission system consists primarily of high capacity, low-loss 500 kV and 230 kV facilities. CP&L distribution loads are served primarily from low-loss 23 kV and 12 kV circuits. CP&L was one of the first electric utilities to use low loss high voltage designs, which reduce losses and reconductoring costs. Use of these high efficiency designs minimizes system losses and reduces the need for new supply-side resources.

Table 6-3

Carolina Power & Light Co.
December 1994 Resource Plan
Projected Summer Resources, Load, and Reserves

	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009
Generation Additions															
Darlington CT Addition			225												
Wayne County CT Addition				500	700										
Undesignated CT						300	300	300	300	200					
Undesignated CC											300	300	300		
Undesignated Coal														500	
Installed Generation															
Oil/Gas	1,046	1,046	1,046	1,271	1,771	2,471	2,771	3,071	3,371	3,671	3,871	4,171	4,471	4,771	4,771
Hydro	218	218	218	218	218	218	218	218	218	218	218	218	218	218	218
Coal	5,285	5,285	5,285	5,285	5,285	5,285	5,285	5,285	5,285	5,285	5,285	5,285	5,275	5,275	5,775
Nuclear	3,064	3,064	3,064	3,064	3,064	3,064	3,064	3,064	3,064	3,064	3,064	3,064	3,064	3,064	3,064
Purchases & Other Resources															
SEPA	109	109	109	109	109	109	109	109	109	109	109	109	109	109	109
Non-Utility Generation	454	469	469	469	469	469	469	469	469	469	469	469	469	469	469
Fayetteville Generation	283	283	283	283	283	283	283	283	283	283	283	283	283	283	283
AEP Purchase	250	250	250	250	250	250	250	250	250	250	250	250	250	250	250
NCEMPA/SCPSA Purchase	100	100	100	50											
Duke Purchase	400	400	400	400											
NCEMPA Peaking Project				200	200	200	200	200	200	200	200	200	200	200	200
Total Supply Resources	11,209	11,224	11,449	12,099	12,349	12,649	12,949	13,249	13,549	13,749	14,049	14,349	14,639	15,139	15,139
Total Internal Demand (1)	10,270	10,314	10,635	10,955	11,267	11,554	11,821	12,091	12,367	12,632	12,893	13,154	13,416	13,678	13,932
Air Conditioner Control	183	204	226	250	273	297	322	346	371	394	417	439	459	478	497
Water Heater Control	33	36	39	42	45	48	51	55	58	61	64	67	69	72	74
Large Load Curtailment	212	221	225	229	233	236	239	243	247	250	254	257	261	265	268
Voltage Reduction	152	156	159	163	167	171	175	179	183	187	191	195	199	202	206
Interruptible Load	580	616	649	683	718	752	787	822	858	892	925	957	988	1,017	1,044
Net Peak Load (2)	9,690	9,698	9,986	10,272	10,549	10,802	11,034	11,269	11,509	11,740	11,968	12,197	12,428	12,661	12,888
Reserves (3)	1,519	1,526	1,463	1,827	1,800	1,847	1,915	1,980	2,040	2,009	2,081	2,152	2,211	2,478	2,251
Capacity Margin (4)	13.6%	13.6%	12.8%	15.1%	14.6%	14.6%	14.8%	14.9%	15.1%	14.6%	14.8%	15.0%	15.1%	16.4%	14.9%
Reserve Margin (5)	15.7%	15.7%	14.7%	17.8%	17.1%	17.1%	17.4%	17.6%	17.7%	17.1%	17.4%	17.6%	17.8%	19.6%	17.5%
Annual Energy (GWH) (6)	52,312	51,794	53,295	54,815	56,224	57,612	58,902	60,229	61,571	62,845	64,099	65,356	66,632	67,912	69,148

NOTES: (1) Includes the impact of all DSM programs except interruptible load programs. Includes Fayetteville Replacement. Does not include NCEMC service obligation.
(2) Total internal demand - Interruptible load.
(3) Total supply resources - Net peak load.
(4) Reserves / Total supply resources * 100.
(5) Reserves / Net peak load * 100.
(6) Includes the impact of all DSM programs. Includes F[illegible]ville replacement. Does not include NCEMC service obligation.

Table 6-4
Projected Fuel Use by Type of Generation

	1995	1996	1997	1998	1999
Existing Generation					
Coal (tons)	10,807,934	10,836,080	10,616,167	11,582,875	12,219,797
Nuclear (MBtu)	202,688,468	198,142,959	220,837,997	202,355,478	197,607,651
Combustion Turbine					
Oil (gallons)	1,002,070	1,458,888	1,157,144	947,804	3,240,085
Natural Gas (MCF)	440,116	414,133	379,769	678,878	3,383,291
Propane (gallons)	2,342,728	2,359,368	2,628,154	2,071,384	5,700,570
Future Generation					
Coal (tons)	0	0	0	0	0
Combined Cycle					
Oil (gallons)	0	0	0	0	0
Natural Gas (MCF)	0	0	0	0	0
Combustion Turbine					
Oil (gallons)	0	0	113,670	1,549,338	19,125,169
Natural Gas (MCF)	0	0	237,841	659,956	4,671,976

	2000	2001	2002	2003	2004
Existing Generation					
Coal (tons)	12,077,504	12,886,229	13,368,838	13,208,761	13,805,403
Nuclear (MBtu)	221,373,305	202,355,478	197,607,651	220,836,930	202,891,853
Combustion Turbine					
Oil (gallons)	2,848,177	3,123,207	3,393,848	2,321,314	19,465,073
Natural Gas (MCF)	3,441,874	5,315,789	6,585,869	4,907,978	8,118,655
Propane (gallons)	4,470,492	5,240,697	4,901,461	3,158,425	4,202,642
Future Generation					
Coal (tons)	0	0	0	0	0
Combined Cycle					
Oil (gallons)	0	0	0	0	0
Natural Gas (MCF)	0	0	0	0	0
Combustion Turbine					
Oil (gallons)	24,112,591	39,131,639	63,036,189	58,423,029	72,653,749
Natural Gas (MCF)	5,353,741	8,731,067	12,416,341	10,890,320	14,917,157

Table 6-4 (cont.)
Projected Fuel Use by Type of Generation

	2005	2006	2007	2008	2009
Existing Generation					
Coal (tons)	14,186,027	13,954,000	14,463,097	14,022,497	14,063,788
Nuclear (MBtu)	197,607,651	220,836,930	202,188,983	198,310,521	220,836,930
Combustion Turbine					
Oil (gallons)	2,140,586	1,420,180	1,468,924	1,160,325	933,926
Natural Gas (MCF)	8,711,866	6,082,647	9,753,011	7,564,757	6,170,403
Propane (gallons)	3,788,258	2,674,672	3,633,091	2,074,340	1,904,078
Future Generation					
Coal (tons)	0	0	0	1,362,988	1,432,342
Combined Cycle					
Oil (gallons)	19,880,039	43,599,421	71,386,751	78,411,022	63,890,784
Natural Gas (MCF)	2,663,539	5,841,476	9,564,438	10,505,554	8,560,125
Combustion Turbine					
Oil (gallons)	92,006,646	65,185,575	62,177,550	51,228,355	43,249,657
Natural Gas (MCF)	17,772,759	12,532,863	12,780,369	10,222,574	8,518,420

Table 6-5
Projected Capacity Factor by Type of Generation

	1995	1996	1997	1998	1999
Existing Generation					
Coal	58%	58%	57%	62%	65%
Nuclear	69%	68%	76%	69%	68%
Combustion Turbine	0%	0%	0%	1%	2%
Future Generation					
Coal	--	--	--	--	--
Combined Cycle	--	--	--	--	--
Combustion Turbine	--	--	2%	2%	6%

	2000	2001	2002	2003	2004
Existing Generation					
Coal	64%	68%	71%	70%	73%
Nuclear	75%	69%	68%	76%	69%
Combustion Turbine	2%	3%	4%	3%	6%
Future Generation					
Coal	--	--	--	--	--
Combined Cycle	--	--	--	--	--
Combustion Turbine	5%	7%	9%	7%	9%

	2005	2006	2007	2008	2009
Existing Generation					
Coal	75%	74%	77%	75%	75%
Nuclear	68%	76%	69%	68%	76%
Combustion Turbine	5%	3%	6%	4%	4%
Future Generation					
Coal	--	--	--	92%	81%
Combined Cycle	48%	39%	39%	37%	30%
Combustion Turbine	10%	7%	7%	6%	5%

Cooperation with neighboring utilities for the planning, construction, and operation of interconnected transmission systems provides many advantages over isolated operation. The Company's transmission system has 33 transmission interconnections with seven neighboring power systems. These interconnections permit power exchanges with other utilities and provide both economic and reliability benefits to CP&L's customers. These advantages include emergency assistance, economy sales and purchases, and shared operating reserves which lead to more reliable and economical operation for CP&L and all parties involved. In addition, CP&L's interconnections with other utilities reduce the need for supply-side resources CP&L would otherwise have to provide to ensure an adequate and reliable supply of electric power. A detailed listing of all transmission line improvements/additions for 230 kV and above is located in Appendix A.

CAAA Compliance Plans

Incorporated in the Integrated Resource Plan are compliance plans for the NO_x and SO_2 regulations resulting from the Clean Air Act Amendments of 1990.

NO_x compliance plan

To reduce annual NO_x emissions, the Clean Air Act Amendment establishes that utilities must control the rate of NO_x emissions. Phase II-affected sources, such as CP&L's coal-fired units, must meet the Phase II performance standards by January 1, 2000. However, there are still many uncertainties in the NO_x regulations for Phase II-affected units. In November 1994, the U. S. Court of Appeals for the District of Columbia Circuit vacated a key EPA NO_x rule. Since the court remanded the rule to EPA, EPA is required to develop new regulations. It is unclear at this time when new rules will be promulgated; however, EPA has published for notice and comment a direct final rule defining low NO_x burners. The direct final rule does not establish the NO_x limits for CP&L's Phase II. Thus, CP&L must wait until no later than January 1, 1997 to determine if its limit for its Phase II, Group I boilers will be more stringent than the Phase I limits.

Prior to the Court's ruling, CP&L had developed, pending a possible revision to the Phase II NO_x limits in 1997, a preliminary NO_x compliance plan. The preliminary NO_x compliance plan was incorporated in the integration analysis described in Chapter 5. The preliminary NO_x compliance plan, summarized by technology and implementation year in Table 6-6, includes configurations of low NO_x burners and selective non-catalytic reduction (SNCR) for the Company's existing coal-fired generating units. CP&L is reviewing its NO_x compliance plan to determine what changes can be made once new regulations are promulgated. Therefore, this preliminary NO_x plan is subject to change.

Table 6-6
Summary of Preliminary NO_x Compliance Plan

Generating Unit	NO_x Control Technology	Installation Outage
Asheville 1	LNB/OFA	Fall 1997
Asheville 2	LNB/OFA	Spring 1997
Cape Fear 5	No Controls	
Cape Fear 6	LNCFS II	Spring 1998
Lee 1	LNCFS II	Fall 1998
Lee 2	No Controls	
Lee 3	LNB/OFA	Spring 1997
Mayo 1	LNB/OFA	Spring 1996
Robinson 1	LNCFS I	Spring 1998
Roxboro 1	LNB/OFA	Spring 1995
Roxboro 2	LNCFS II + SNCR 2	Fall 1996 (1)
Roxboro 3	LNB/OFA	Spring 1999
Roxboro 4	LNB/OFA	Fall 1998
Sutton 1	LNCFS I	Fall 1999
Sutton 2	LNB	Fall 1998
Sutton 3	LNB/OFA	Spring 1999
Weatherspoon 1	LNB	Fall 1999
Weatherspoon 2	LNB	Spring 1999
Weatherspoon 3	LNCFS II	Fall 1998

Key:
LNB - Low NO_x Burners
OFA - Overfire Air
LNCFS I, II - Low NO_x Concentric Firing System Level I or II
SNCR 2 - Selective Non-Catalytic Reduction 30% NO_x Reduction

Note:
(1) SNCR installation delayed until 1999.

SO_2 compliance plan

The SO_2 requirements of the 1990 Clean Air Act Amendments call for the reduction of SO_2 emissions on a systemwide basis. CP&L has been allocated approximately 144,000 SO_2 emission allowances for each year from 2000 to 2009. Projected SO_2 emissions exceed the allowance allocation by approximately 930,000 tons over that time period. Since it is possible for changes in the type of resources added to impact the level of emissions, the development of the SO_2 emissions compliance plan was integrated with the development of the IRP.

For planning purposes, CP&L has adopted the SO_2 compliance plan outline in Table 6-7. This plan includes a balance of using emission allowances, switching to lower sulfur coal, and installing one scrubber. This plan follows CP&L's general SO_2 compliance strategy, which is to increase the use of lower sulfur coal, purchase allowances as long as they are more economical than scrubbers, and maintain a scrubber option. As with combustion turbines in the resource plan, compliance options continue to be studied. Current projections of SO_2 emissions show that the Company can postpone the need to take any actions to reduce emissions until 2004 by using the emission allowances already purchased; therefore, major financial commitments are not being made at this time. While the compliance plan in Table 6-7 shows switching to compliance coal at all of the Company's coal units by the year 2000, new fuel contracts will not have to be entered into until 1999 and the Company will be using primarily short- to mid-term length contracts for compliance coal. The Company will continue to evaluate the purchase of additional allowances to delay the need to make major financial commitments. As opportunities present themselves, CP&L will examine the costs, benefits, and risks of additional allowance purchases.

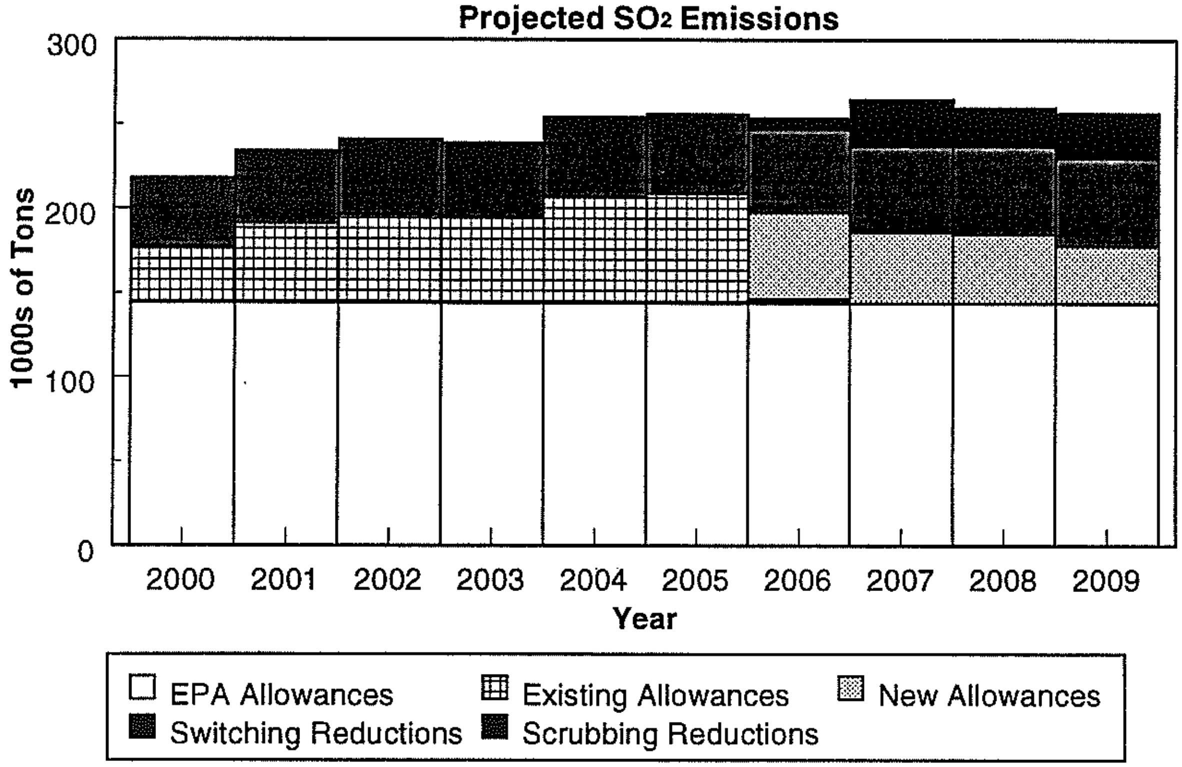
The plan recognizes the uncertainty in future allowance prices, low sulfur coal costs, and scrubber technology. In addition, it provides the flexibility to respond to changing regulations. The SO_2 compliance plan contains a balanced mix of compliance options that provide diversity. This balance and the amount of compliance achieved by each option is illustrated in Figure 6-2. During the 2000 to 2009 time period, a reduction of approximately 454,000 tons of SO_2 are projected to be achieved by switching to lower sulfur coal. Reductions of approximately 81,000 tons of SO_2 are projected to be achieved by scrubbing. In addition, the plan projects the need for approximately 395,000 emission allowances.

Table 6-7
Summary of SO_2 Compliance Plan

Generating Unit	SO_2 Control Technology	Implementation Year
Asheville 1&2	Switch to Compliance Coal	1998
All other coal units[1]	Switch to Compliance Coal	2000
Mayo 1	Install Scrubber & Burn 2.1 lbs. sulfur coal	2007
Emission Allowances	Use existing and EPA-allocated allowances and purchase additional allowances as needed	2000 2007

[1]Mayo Unit 1 and Roxboro Unit 4 currently burn compliance coal.

Figure 6-2
Projected SO2 Emissions



Summary and Conclusions

The overall objective of CP&L's Integrated Resource Planning process is the development of a flexible resource plan which will provide an adequate and reliable supply of electric power to our customers at the lowest reasonable cost and in an environmentally sound manner. CP&L's IRP achieves this objective by incorporating a cost-effective mix of demand-side and supply-side resources.

CP&L's Integrated Resource Plan is a robust plan that provides the diversity of resources and the flexibility necessary to confront uncertainties facing the Company. It is unlikely that one resource plan can be the best for all possible conditions, but from the analysis discussed in Chapter 5, the Integrated Resource Plan was shown to be the most robust plan by performing well among many uncertainty scenarios. To perform well among various scenarios, the IRP must be diverse and not rely excessively on any single resource. The IRP's diversity of demand-side and supply-side resources minimizes cost under uncertainty by not relying on one resource. Sensitivity analysis tested the robustness of the plan with variations in the probability of different outcomes. The IRP was further examined to determine if there were any scenarios in which the plan had serious deficiencies. This analysis found that the plan provides clear economic benefits over a wide range of possible conditions.

The Integrated Resource Plan must be able to respond to uncertainties such as load growth, fuel prices, and regulatory requirements and must not depend on a specific outcome of future events. The uncertainty in load growth, for example, is influenced by factors such as the cost-effectiveness of DSM, environmental regulations, competition and wheeling in the wholesale bulk power market, and the future role of retail wheeling. Competition is a key issue currently facing the electric utility industry and may have significant implications for CP&L. To respond to competition, the Company needs the ability to react to the possible fluctuations in customer demand. Fluctuations in demand may result as some customers are added to our system and as others leave the system. To compete with other utilities, the Company will have to react to competition in terms of the price of electricity, which is affected by our positioning to respond to uncertainties such as load growth. For example, North Carolina Electric Membership Corporation (NCEMC) issued two requests for proposals in November 1994 for three 225 MW blocks of baseload power, currently served by CP&L, over three years beginning in 2001. Also, the North Carolina Eastern Municipal Power Agency (NCEMPA) plans to install 200 MW of combustion turbine capacity in 1998 to replace peaking capacity and energy currently served by CP&L. NCEMPA has the option to cancel the peaking project as late as March 1996, in which case CP&L would be required to provide replacement capacity. The outcomes of these activities can have significant impacts on CP&L's system load growth and the resources needed to serve the demand. The possibility of such events taking place substantiates the argument that the best overall resource plan needs to be a flexible plan designed to contend with an uncertain future rather than an optimal plan dependent on the prediction of a specific future.

The generation additions in the IRP for the first ten years of the planning horizon are combustion turbines. In addition to being the most economical resource to meet CP&L's peaking capacity requirements, combustion turbines improve both the generating system's reliability and the plan's ability to respond to changing conditions. While generation additions cannot be precisely matched to meet load growth, the combustion turbines' small unit sizes of approximately 100 MW help to minimize the fluctuations from the target capacity margin and thus, maintain system reliability. Compared to other capacity additions, combustion turbines have a relatively short construction time. This allows the Company to initiate construction closer to the time the capacity is needed and thereby increases the plan's flexibility by allowing more time to determine and verify the need for additional capacity before committing to significant expenditures. This flexibility does not exist with an obligation to purchase power or a commitment for capacity to be built by someone else. Both of these options lock the Company into a rigid schedule limiting the Company's ability to respond to change. It is important to realize that flexibility in the resource plan comes not only from the type of additions in the plan, but the manner in which they are implemented. Fixing the price and installation date through third party contracts hinders the ability of the Company to revise its plan in response to changing conditions. For example, the Darlington addition was originally scheduled to begin operation in 1994. By not signing a contract with a third party to build the capacity, CP&L has been able to respond to changing conditions by delaying the in-service date, first to 1996, and currently to 1997. During recent years, the cost of combustion turbines has dropped dramatically. As a result of not signing a contract with a third party to build the Darlington addition in 1994 as originally planned, the Company avoided having to pay for capacity that was not needed for a period of time and avoided paying too much for that capacity.

Incorporated into the IRP are the Company's NO_x and SO_2 compliance plans. Additional compliance requirements to respond to environmental uncertainties of greenhouse gas restrictions, air toxics regulation, and non-Title IV CAAA restrictions of SO_2 and NO_x emissions may become necessary. To be able to respond to new environmental requirements, the compliance plans must possess the ability to change. The Company's SO_2 compliance plan has the advantage of not requiring a major capital investment decision for scrubbers until 2002 and new fuel contracts will not have to be entered into until 1999. Without a near-term commitment to capital investments, this plan allows more time to observe the emission allowance market relative to other compliance options. This will provide the Company the opportunity to respond to potential regulations associated with air toxics and greenhouse gases in a more efficient manner. By delaying the installation of scrubbers for as long as possible, emerging technologies will have time to develop and be tested. These new technologies may be able to control emissions of other pollutants in addition to SO_2, and thus, the Company could avoid unnecessary capital expenditures for extra devices needed to comply with possible additional environmental requirements. Risks posed by potential environmental regulations are reduced by the SO_2 compliance plan's diverse mix of compliance options. A compliance plan which depends solely on the purchase of allowances was not chosen because of uncertainties with allowances, such as whether a market will materialize with the number of allowances needed available for purchase. Also, while current forecasts of allowance prices indicate that allowances are economical, the lack of an established market means that prices are more uncertain than what is indicated by the price projections. The use of emission allowances reduces the cost of compliance, and the use of other compliance options reduces risks at only slightly higher costs than a strategy of only purchasing emission allowances.

As discussed in Chapter 4, a recent Court ruling is requiring EPA to revise portions of the NO_x rules. Therefore, CP&L's preliminary NO_x compliance plan is currently under review and is subject to change. Prior to the Court's ruling, CP&L had developed its NO_x compliance plan using both upper and lower NO_x limit scenarios. The NO_x control technologies in CP&L's NO_x compliance plan were selected based on least-cost criteria using cost and performance estimates. Proper implementation of the recommended technologies becomes key to a low-cost, low-risk NO_x compliance strategy. Only units that are part of least-cost plans for both the upper and lower limit scenarios will be modified prior to the Phase II limits being reviewed by January 1, 1997. The benefits of aligning NO_x outages with CP&L's planned turbine outages versus the potential compliance plan cost increases must also be considered in establishing the implementation schedule. With this approach, CP&L bears minimal risk in implementing a least-cost, least-risk plan.

The focus of the IRP process is to communicate CP&L's Integrated Resource Plan at this point in time to CP&L's stakeholders; that is, the Company's customers, investors, and regulatory bodies. In the increasingly competitive electric utility industry, where price is becoming more important and load growth is becoming more uncertain, an integrated resource plan that is flexible is critical to the future success of electric utilities. The same is true of the IRP process. The integrated resource planning process must continue to evolve and improve. A process that does not allow for plans to be changed quickly is a burden to utilities and will hamper their ability to meet the needs of their customers.

Carolina Power & Light Company's challenge is to meet customer needs for electric power with an energy supply that is reliable and economic, and provides reasonable protection of the environment. The Company's plans are continuously reviewed and appropriate changes are made to account for changing conditions, regulations, and availability of alternative resources. By incorporating a balance of options and strategies that provides maximum flexibility to adapt to uncertain and ever-changing futures, CP&L's Integrated Resource Plan ensures that the challenge will be met.

Annual Report Of Updates To Least Cost

Integrated Resource Plans

And

Short-Term Action Plan

Carolina Power & Light Company

June 30, 1995

Table Of Contents

(a) A tabulation of summer and winter peak loads, annual energy forecast, generating capability, and reserve margins for each year.

Tables 1 and 2 provide projected load, resources, and reserves for the fifteen-year period beginning 1995 for summer and winter, respectively. Table 1 also provides system annual energy input (forecasted energy sales adjusted for losses and Company use). Tables 3 and 4 provide projected non-utility generation for the same years for summer and winter, respectively.

Table 1

Carolina Power & Light Co.
December 1994 Resource Plan
Projected Summer Resources, Load, and Reserves

	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009
Generation Additions															
Darlington CT Addition			225												
Wayne County CT Addition				500	700										
Undesignated CT						300	300	300	300	200					
Undesignated CC											300	300	300		
Undesignated Coal														500	
Installed Generation															
Oil/Gas	1,046	1,046	1,046	1,271	1,771	2,471	2,771	3,071	3,371	3,671	3,871	4,171	4,471	4,771	4,771
Hydro	218	218	218	218	218	218	218	218	218	218	218	218	218	218	218
Coal	5,285	5,285	5,285	5,285	5,285	5,285	5,285	5,285	5,285	5,285	5,285	5,285	5,275	5,275	5,775
Nuclear	3,064	3,064	3,064	3,064	3,064	3,064	3,064	3,064	3,064	3,064	3,064	3,064	3,064	3,064	3,064
Purchases & Other Resources															
SEPA	109	109	109	109	109	109	109	109	109	109	109	109	109	109	109
Non-Utility Generation	454	469	469	469	469	469	469	469	469	469	469	469	469	469	469
Fayetteville Generation	283	283	283	283	283	283	283	283	283	283	283	283	283	283	283
AEP Purchase	250	250	250	250	250	250	250	250	250	250	250	250	250	250	250
NCEMPA/SCPSA Purchase	100	100	100	50											
Duke Purchase	400	400	400	400											
NCEMPA Peaking Project				200	200	200	200	200	200	200	200	200	200	200	200
Total Supply Resources	11,209	11,224	11,449	12,099	12,349	12,649	12,949	13,249	13,549	13,749	14,049	14,349	14,639	15,139	15,139
Total Internal Demand (1)	10,270	10,314	10,635	10,955	11,267	11,554	11,821	12,091	12,367	12,632	12,893	13,154	13,416	13,678	13,932
Air Conditioner Control	183	204	226	250	273	297	322	346	371	394	417	439	459	478	497
Water Heater Control	33	36	39	42	45	48	51	55	58	61	64	67	69	72	74
Large Load Curtailment	212	221	225	229	233	236	239	243	247	250	254	257	261	265	268
Voltage Reduction	152	156	159	163	167	171	175	179	183	187	191	195	199	202	206
Interruptible Load	580	616	649	683	718	752	787	822	858	892	925	957	988	1,017	1,044
Net Peak Load (2)	9,690	9,698	9,986	10,272	10,549	10,802	11,034	11,269	11,509	11,740	11,968	12,197	12,428	12,661	12,888
Reserves (3)	1,519	1,526	1,463	1,827	1,800	1,847	1,915	1,980	2,040	2,009	2,081	2,152	2,211	2,478	2,251
Capacity Margin (4)	13.6%	13.6%	12.8%	15.1%	14.6%	14.6%	14.8%	14.9%	15.1%	14.6%	14.8%	15.0%	15.1%	16.4%	14.9%
Reserve Margin (5)	15.7%	15.7%	14.7%	17.8%	17.1%	17.1%	17.4%	17.6%	17.7%	17.1%	17.4%	17.6%	17.8%	19.6%	17.5%
Annual Energy (GWH) (6)	52,312	51,794	53,295	54,815	56,224	57,612	58,902	60,229	61,571	62,845	64,099	65,356	66,632	67,912	69,148

NOTES:
(1) Includes the impact of all DSM programs except interruptible load programs. Includes Fayetteville Replacement. Does not include NCEMC service obligation.
(2) Total internal demand - Interruptible load.
(3) Total supply resources - Net peak load.
(4) Reserves / Total supply resources * 100.
(5) Reserves / Net peak load * 100.
(6) Includes the impact of all DSM programs. Includes Fayetteville replacement. Does not include NCEMC service obligation.

Carolina Power & Light Co.
December 1994 Resource Plan
Projected Winter Resources, Load, and Reserves

	94/95	95/96	96/97	97/98	98/99	99/00	00/01	01/02	02/03	03/04	04/05	05/06	06/07	07/08	08/09
Generation Additions															
Darlington CT Addition				260											
Wayne County CT Addition					575	805									
Undesignated CT							345	345	345	345	230				
Undesignated CC												345	345	345	
Undesignated Coal															500
Installed Generation															
Oil/Gas	1,298	1,298	1,298	1,298	1,558	2,133	2,938	3,283	3,628	3,973	4,318	4,548	4,893	5,238	5,583
Hydro	216	216	216	216	216	216	216	216	216	216	216	216	216	216	216
Coal	5,369	5,369	5,369	5,369	5,369	5,369	5,369	5,369	5,369	5,369	5,369	5,369	5,359	5,359	5,359
Nuclear	3,099	3,099	3,099	3,099	3,099	3,099	3,099	3,099	3,099	3,099	3,099	3,099	3,099	3,099	3,099
Purchases & Other Resources															
SEPA	109	109	109	109	109	109	109	109	109	109	109	109	109	109	109
Non-Utility Generation	450	465	465	465	465	465	465	465	465	465	465	465	465	465	465
Fayetteville Generation	283	283	283	283	283	283	283	283	283	283	283	283	283	283	283
AEP Purchase	250	250	250	250	250	250	250	250	250	250	250	250	250	250	250
NCEMPA/SCPSA Purchase	100	100	100	50											
Duke Purchase	400	400	400	400	400										
NCEMPA Peaking Project					200	200	200	200	200	200	200	200	200	200	200
Total Supply Resources	11,574	11,589	11,589	11,799	12,524	12,929	13,274	13,619	13,964	14,309	14,539	14,884	15,219	15,564	16,064
Total Internal Demand (1)	9,716	9,763	10,060	10,351	10,634	10,894	11,135	11,379	11,627	11,866	12,102	12,340	12,577	12,816	13,049
Water Heater Control	112	122	131	142	152	163	174	185	196	208	218	229	238	247	256
Large Load Curtailment	168	194	202	206	209	212	215	219	222	225	228	231	235	238	241
Voltage Reduction	152	156	159	163	167	171	175	179	183	187	191	195	199	202	206
Interruptible Load	433	472	493	510	528	546	564	583	601	619	637	655	671	687	702
Net Peak Load (2)	9,283	9,291	9,567	9,841	10,106	10,348	10,571	10,796	11,026	11,247	11,465	11,685	11,906	12,129	12,347
Reserves (3)	2,291	2,298	2,022	1,958	2,418	2,581	2,703	2,823	2,938	3,062	3,074	3,199	3,313	3,435	3,717
Capacity Margin (4)	19.8%	19.8%	17.5%	16.6%	19.3%	20.0%	20.4%	20.7%	21.0%	21.4%	21.1%	21.5%	21.8%	22.1%	23.1%
Reserve Margin (5)	24.7%	24.7%	21.1%	19.9%	23.9%	24.9%	25.6%	26.2%	26.7%	27.2%	26.8%	27.4%	27.8%	28.3%	30.1%

NOTES: (1) Includes the impact of all DSM programs except interruptible load programs. Includes Fayetteville Replacement. Does not include NCEMC service obligation.
(2) Total internal demand - Interruptible load.
(3) Total supply resources - Net peak load.
(4) Reserves / Total supply resources * 100.
(5) Reserves / Net peak load * 100.

Table 3

Carolina Power & Light Co.
December 1994 Resource Plan
Projected Summer Non-Utility Generation

	1994 (ACTUAL)	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009
Non-Utility Generation																
Cogentrix (Coal)	266	266	266	266	266	266	266	266	266	266	266	266	266	266	266	266
Stone Container (Coal)	68	68	68	68	68	68	68	68	68	68	68	68	68	68	68	68
Craven Co. Wood Energy (Wood)	45	45	45	45	45	45	45	45	45	45	45	45	45	45	45	45
Texas Gulf (Sulfur)	42	42	42	42	42	42	42	42	42	42	42	42	42	42	42	42
Foster Wheeler (Refuse)	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9
New Hanover Co. (Refuse/Gas)	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8
BCH (Refuse)			15	15	15	15	15	15	15	15	15	15	15	15	15	15
Miscellaneous	16	17	17	17	17	17	17	17	17	17	17	17	17	17	17	17
	-----	-----	-----	-----	-----	-----	-----	-----	-----	-----	-----	-----	-----	-----	-----	-----
Total Non-Utility Generation	453	454	469	469	469	469	469	469	469	469	469	469	469	469	469	469

NOTES: (1) All values are in megawatts.
(2) Columns may not sum due to rounding.

Table 4

Carolina Power & Light Co.
December 1994 Resource Plan
Projected Winter Non-Utility Generation

	93/94 (ACTUAL)	94/95	95/96	96/97	97/98	98/99	99/00	00/01	01/02	02/03	03/04	04/05	05/06	06/07	07/08	08/09
Non-Utility Generation																
Cogentrix (Coal)	266	266	266	266	266	266	266	266	266	266	266	266	266	266	266	266
Stone Container (Coal)	68	68	68	68	68	68	68	68	68	68	68	68	68	68	68	68
Craven Co. Wood Energy (Wood)	45	45	45	45	45	45	45	45	45	45	45	45	45	45	45	45
Texas Gulf (Sulfur)	42	42	42	42	42	42	42	42	42	42	42	42	42	42	42	42
Foster Wheeler (Refuse)	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5
New Hanover Co. (Refuse/Gas)	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8
BCH (Refuse)			15	15	15	15	15	15	15	15	15	15	15	15	15	15
Miscellaneous	16	17	17	17	17	17	17	17	17	17	17	17	17	17	17	17
	-----	-----	-----	-----	-----	-----	-----	-----	-----	-----	-----	-----	-----	-----	-----	-----
Total Non-Utility Generation	449	450	465	465	465	465	465	465	465	465	465	465	465	465	465	465

NOTES: (1) All values are in megawatts.
(2) Columns may not sum due to rounding.

(b) A list of the existing plants in service with capacity, location, and any technological innovations to be backfitted to improve environmental quality to the extent known.

NOTE: In November, 1990, President Bush signed amendments to the Clean Air Act (CAA) which incorporate a two-phased emissions reduction program. The first phase becomes effective in 1995, while the second phase, which contains more stringent provisions, will become effective in the year 2000. The Company is in compliance with the first phase and, with regard to the second phase, continues to evaluate numerous compliance alternatives, including switching to lower sulfur coal at some units, the purchase of SO_2 Emission Allowances, Low - NO_X burner technology, flue gas conditioning system, Electrostatic precipitator upgrades and the possible use of scrubbers on some units. Compliance will likely result in significant additional expenditures by the Company. A plan for compliance with the Clean Air Act Amendments of 1990 must be submitted to the Environmental Protection Agency by January, 1996.

Carolina Power & Light Company
Existing Plants In Service

Name/Location	MDC Rating (MW)	Planned Environmental Protection Additions
Brunswick S.E.P. Southport, N. C.	1,521	Groundwater Monitoring Wells
H.B. Robinson Unit 2 Hartsville, S. C.	683	NPDES permit received. CP&L will identify any environmental modifications which may be appropriate.
Shearon Harris N.P.P. New Hill, N. C.	860	New sewage plant completed in 1994.
Asheville S.E.P. Skyland, N. C.	392	All Units - Continuous Emission Monitoring System (CEMS) Low - NOx - burner technology (LNB Tech)
Blewett H.P./C.T.G. Lilesville	74	None

Name/Location	MDC Rating (MW)	Planned Environmental Protection Additions
Cape Fear S.E.P./C.T.G. Moncure, N. C.	400	All Units - CEMS Unit 6 - LNB Tech and Flue Gas Conditioning (FGC) System
Lee S.E.P./C.T.G. Goldsboro, N.C.	498	All Units - CEMS Unit 1 - LNB Tech Unit 2 - Mill Upgrades Unit 3 - LNB Tech
Mayo S.E.P. Roxboro, N. C.	745	Unit 1 - CEMS, LNB Tech, and possibly Scrubber
Marshall H.P. Marshall, N. C.	5	None
Morehead City, C.T.G. Morehead City, N. C.	15	None
Robinson Unit 1/C.T.G. Hartsville, S. C.	189	Groundwater Monitoring Well NPDES permit received. CP&L will identify any environmental modifications which may be appropriate. Unit 1 - CEMS, LNB Tech, FGC System
Roxboro S.E.P./C.T.G. Roxboro, N. C.	2,477	All Units - CEMS Unit 1 - LNB Tech Unit 2 - LNB Tech Roxboro 3 & 4 - LNB Tech
Tillery H.P. Mt. Gilead, N. C.	86	None

Name/Location	MDC Rating (MW)	Planned Environmental Protection Additions
Walters H. P. Waterville, N. C.	105	FERC license issued, implementation of the provisions in progress.
Weatherspoon S.E.P./C.T.G. Lumberton, N. C.	314	All Units - CEMS Units 1 & 2 - LNB Tech & FGC System Unit 3 - LNB Tech & Mill Upgrades

(c) A list of generating units under construction or planned at plant locations for which property has been acquired, for which certificates have been received, or for which applications have been filed with location, capacity, plant type, and proposed date of operation included.

Location	Capacity	Plant Type	Proposed Date of Operation
Darlington County South Carolina	Approx. 225 MW*	Combustion Turbine	June 1, 1997
Wayne County North Carolina	Up to 1200 MW*	Combustion Turbine	June 1, 1998

*Actual generation output will be determined following selection of specific machines, installation, and testing of the units.

(d) A list of proposed generating units at locations not known with general location, capacity, plant type, and date of operation included to the extent known.

Location	Capacity (MW)	Plant Type	Proposed Date of Operation
Undesignated	300	CT	2000
Undesignated	300	CT	2001
Undesignated	300	CT	2002
Undesignated	300	CT	2003
Undesignated	200	CT	2004
Undesignated	300	CC	2005
Undesignated	300	CC	2006
Undesignated	300	CC	2007
Undesignated	500	Coal	2008

(e) A list of units to be retired from service with location, capacity and expected date of retirement from the system.

The fossil maintenance programs utilized by CP&L have allowed the Company to operate its units longer than their 30-40 years expected life. CP&L believes that continued maintenance will allow its fossil plants to operate indefinitely. Thus, no CP&L generating units are currently scheduled to be retired during the period covered by the IRP.

(f) A list of units which are being considered for life extension, refurbishment or upgrading. The reporting utility shall also provide the expected (or actual) date removed from service, general location, capacity rating upon return to service, expected return to service date, and a general description of work to be performed.

For many years CP&L has utilized its maintenance programs to keep its units in the most up-to-date and the best operating condition that is economically reasonable. These maintenance programs deal both with replacement of worn parts to restore equipment to its original condition and with replacements intended to upgrade the equipment to a more reliable and more efficient condition. Because of this type of program, CP&L has no plans for major comprehensive life extension projects.

Key elements of our ongoing maintenance/testing programs are:

- Periodic inspection, overhaul, repair, and/or refurbishment of turbines and generators. Overhaul frequencies range from 5-7 years dependent on factors such as operating experience, equipment performance, industry experience, vendor recommendations, etc.

- Annual boiler inspection and periodic overhauls/repairs/refurbishment based on operating experience, vendor recommendations, industry experience, etc.

- Annual and 10-year inspections of nuclear facilities as part of an ongoing in-service inspection program.

- Periodic inspection, testing, and maintenance of other major equipment based on established periodic testing, preventive maintenance, and predictive maintenance programs.

One-year and five-year maintenance schedules are developed annually for our generating units. These schedules are periodically reviewed and adjusted as appropriate based on system conditions/needs, unit operating performance, etc.

The process of continually maintaining generating units, in conjunction with new test data and changing regulatory requirements, occasionally results in some uprating or derating of facilities. Units are periodically reviewed to determine if their capability ratings need to be revised; however, the overall impact on the resource plan of these changes is expected to be minimal.

(g) A list of transmission lines and other associated facilities (200 KV or over) which are under construction or proposed including the capacity and voltage levels, location, and schedules for completion and operation.

CP&L Transmission Line Additions and Improvements

Year	Location From	Location To	Capacity MVA	Voltage KV	Comments
1995	Kinston DuPont	Wommack	534	230	New
	Harris Plant	Fort Bragg Woodruff Street	1068	230	Relocate & Extend
	Fayetteville	Fort Bragg Woodruff Street	1068	230	Relocate & Extend
	Fayetteville East	Fort Bragg Woodruff Street	617	230	New
	Fayetteville	Fayetteville East	600	230	Uprate
1996	Roxboro Plant	(DPCo) East Durham Interconnection West	1068	230	Relocate & Extend
	Roxboro Plant	(DPCo) East Durham Interconnection East	1068	230	Relocate & Extend
	Method	(DPCo) East Durham Interconnection	1068	230	Relocate & Extend
	Durham Switching Station	(DPCo) East Durham Interconnection	1068	230	Relocate & Extend
	Roxboro Plant	Falls	534	230	Uprate

Year	Location: From	Location: To	Capacity MVA	Voltage KV	Comments
	Falls	Milburnie	534	230	Uprate
	Milburnie	Person	534	230	Uprate
	Darlington County Plant	Robinson Plant	784	230	New
	Robinson Plant	Laurinburg	637	230	Relocate from Darlington County Plant
	Darlington County Plant	Sumter East	534	230	Relocate from Robinson Plant
	Darlington County Plant	Darlington (SCPSA)	534	230	Relocate from Robinson Plant
	Durham Switching Station	Falls	1234	230	New
1998	Milburnie	Wake	1068	230	Uprate
	Havelock	Cherry Point	408	230	Conversion
	Person	(APCo) Axton Interconnection	4025	500	New
	Lee	Wommack South	1068	230	Relocate & Uprate
	New Bern	Wommack South	617	230	Relocate
1999	Brunswick Plant	Castle Hayne East	534	230	Relocate
	Havelock	Carteret Craven EMC Havelock 115 kV POD	308	115	Rebuild for 230 kV, Operate 115 kV

Year	Location From	Location To	Capacity MVA	Voltage KV	Comments
	Method	Milburnie South	308	115	Rebuild for 230 kV, Operate 115 kV
	Sutton Plant	Delco	1068	230	Reconductor
	Lee 230 kV Substation	Mount Olive	308	115	Rebuild for 230 kV, Operate 115 kV
2000	Cape Fear Plant	Sanford	617	230	New
	Sutton Plant	Castle Hayne North	617	230	Conversion
	Lee	Selma North	1234	230	Relocate & Uprate
	Milburnie	Selma	1234	230	Relocate & Uprate
2001	Havelock	New Bern	617	230	Conversion
2002	Rocky Mount	Wilson	617	230	Conversion
	Fayetteville	Fayetteville East	1234	230	Reconductor
	Florence DuPont	(SCPSA) Hemingway	308	115	Rebuild for 230 kV, Operate 115 kV
2004	Aurora Switching Station	New Bern West	617	230	New
2005	Method	Milburnie South	617	230	Conversion

Year	Location: From	Location: To	Capacity MVA	Voltage KV	Comments
2008	Lenoir	Wake	4025	500	New
	Greenville	Kinston DuPont	617	230	New

CP&L Substation Additions and Improvements

Year	Substation Name	County	State	Voltage (KV)	MVA	Comments
1995	Kinston DuPont	Lenoir	NC	230/115	300	New
	Wommack	Lenoir	NC	230/115	200-400	Increase
	Fort Bragg Woodruff Street	Cumberland	NC	230/115	150	New
1997	Person	Person	NC	500/230	1000-2000	Increase
1999	Falls	Wake	NC	230/115	300-600	Increase
	Durham	Durham	NC	500/230	1500	New
	Whiteville	Columbus	NC	230/115	300-600	Increase
2001	Asheville Plant	Buncombe	NC	230/115	500-600	Increase
2008	Lenoir	Lenoir	NC	500/230	1000	New

(h) A list of any generation and associated transmission facilities under construction which have delays of over six months in the previously reported in-service dates and the major causes of such delays. Upon request from the Commission Staff, the reporting utility shall supply a statement of the economic impact of such delays.

None

(i) A list of future probable sites giving general location and description, major advantages, and whether the site is wholly owned, partially owned or not owned by the utility.

As stated in item (d), CP&L has identified the need for additional capacity beginning in the mid-1990s. The first block of combustion turbine capacity is planned to be located at the existing Darlington County Electric Plant for 1997. Additional blocks of CT capacity are planned for 1998 and 1999 at the proposed Wayne County Site adjacent to the existing Lee Steam Electric Plant. The Company owns the site property.

Attachment A

Short-Term Action Plan

Carolina Power & Light Company

June 30, 1995

Table Of Contents

Introduction

The Short-Term Action Plan summarizes those actions planned by CP&L over the 1995-1997 period to implement its Integrated Resource Plan (hereinafter the "Resource Plan or IRP"). Specifically, the Short Term Action Plan describes anticipated activities regarding the following electric system resources:

* Demand-Side Programs
* Purchased Power from Non-Utility Generators
* Purchased Power from Other Utilities
* Capacity Additions

The Short-Term Action Plan is a snapshot in time of the Company's Corporate Planning Process as it relates to the implementation of the Company's Integrated Resource Plan (IRP). Each year the Company reviews its IRP in light of changing conditions and evaluates the impact these changes have had or may have on its resource plans, including purchases and other resource options.

Planning Overview

The Short-Term Action Plan is a product of the Integrated Resource Planning Process. It is developed based upon decisions and actions specifically relating to implementation of the Company's Integrated Resource Plan. CP&L's Short-Term Action Plan includes a summary of the resource options or programs contained in the current Integrated Resource Plan for which specific actions must be taken by CP&L within the next three years. For each resource option or program, the summary includes:

(a) The objective of the resource option or program;

(b) Criteria for measuring progress toward the objective;

(c) The implementation schedule for the program over the next two to three years; and

(d) Actual progress toward the objective to date.

CP&L continues to evaluate and analyze cost effective means of meeting the energy needs of its customers. One way of meeting these needs is through cost-effective demand-side resources.

CP&L's demand-side programs include: encouraging thermally efficient homes and buildings through the use of high efficiency heat pumps and greater insulation; interruptible service programs; time-of-use rates to encourage valley filling and load shifting; and audit services provided to commercial and industrial customers. The Company is also pursuing development of new programs such as its Common Sense Manufactured Home and Commercial Load Control Program. All of CP&L's demand-side programs are designed to impact the timing and magnitude of electric demands resulting in increased utilization of existing generating capacity, and reduced need for additional capacity.

Elements of the Integrated Resource Plan

CP&L's strategy of maintaining a diversified mix of resources is apparent in its Integrated Resource Plan. The plan builds on a well-balanced mix of existing demand-side and supply-side resources that includes conservation and load management programs, coal, nuclear, oil/gas, and hydroelectric generation facilities, and purchases from non-utility generators and other utilities. The Company's planned resource additions continue to reflect a diverse portfolio of conservation and load management programs in addition to new supply resources.

Demand-Side Management Resources

Summary of DSM Programs

The Company's demand-side management programs are part of CP&L's portfolio of resources utilized to meet customer demand in a reliable and cost-effective manner. DSM programs offer customers options that encourage them to use electricity economically and help the Company to achieve its load shape objectives. This "management" of load can produce improvements in load factor, increase utilization of existing capacity, reduce the need for additional peaking capacity, reduce the level and frequency of future rate increases, increase customer satisfaction and encourage economic growth.

Implementation Schedule of DSM Programs

During the period 1995-1997, the Company plans to increase the capability of its demand-side management programs by an additional 203 MW. The following table provides a listing of programs by customer class, the objective of each program, and forecasted incremental megawatt reductions at the time of summer peak for the years 1995-1997. Additional information on the Company's programs can be found on the pages referenced in the table.

Implementation Schedule of DSM Programs

Program	Pg #	Incremental Peak Load Reductions (MW) 1995	1996	1997
Residential				
Common Sense Home (Thermal Efficiency-New Homes)	11	2.8	2.8	2.5
Thermal Efficiency (Existing Homes)	13	1.0	1.1	1.0
EZ - $64	15	24.6	24.2	25.2
High Efficiency Heat Pump	16	4.4	3.7	2.8
Residential Time-of-Use	19	1.2	1.2	1.1
Commercial				
Commercial Energy Efficient Design	20	2.9	3.6	4.9
Commercial Energy Audit/Time-of-Use	21, 22	3.9	3.0	2.9
Commercial Thermal Energy Storage	23	.5	.2	.3
Industrial				
Industrial Audit/Energy Efficient Plants	24	6.1	6.4	8.1
Industrial Time-of-Use	25	2.2	4.3	5.6
Large Load Curtailment	26	35.8	8.5	3.9
Grand Total		85.4	59.0	58.3

Summary of Annual DSM Impacts

The following table presents a summary of projected annual DSM impacts by major rate class:

Year	Residential Subtotal (MW)	Commercial Subtotal (MW)	Industrial Subtotal (MW)	Grand Total (MW)
1995	34.0	7.2	44.2	85.4
1996	33.0	6.8	19.2	59.0
1997	32.6	8.1	17.6	58.2
1998	32.3	9.6	21.1	63.0
1999	32.2	10.9	23.5	66.7
2000	32.3	13.2	21.4	66.9
2001	32.3	15.5	19.7	67.5
2002	32.4	16.6	18.7	67.7
2003	32.1	16.6	17.0	65.8
2004	31.2	15.6	15.7	62.5
2005	29.7	14.5	14.6	58.8
2006	27.9	13.2	13.8	54.9
2007	26.2	11.8	13.9	51.9
2008	24.9	10.4	12.5	47.8
2009	23.8	8.9	11.3	44.1

Potential DSM Programs

The following table provides a listing of potential DSM programs. Additional information on potential DSM programs can be found on the pages referenced in the table.

Implementation Costs

The following tables show actual 1994 and projected expenses directly allocated to programs included in the Short-Term Action Plan. Lost revenues are excluded.

Demand-Side Management Program Costs
1994
(Millions of Dollars)

Residential	
Common Sense Home (Thermal Efficiency New Homes)	2.7
Thermal Efficiency-Existing Homes (6% Energy Loan)	.4
Energy Conservation Discount	10.2
EZ-$64	8.4
High Efficiency Heat Pump	8.7
Time-of-Use	.7
R&D/General	.5
Commercial	
Thermal Energy Storage/Time-of-Use	.2
Energy Audit/Energy Efficient Design	.3
R&D/General	.2
Industrial	
Audit/Energy Efficient Plants	.4
Thermal Energy Storage/Time-of-Use	.2
Large Load Curtailment	17.3
R&D/General	.1
General	
General DSM Planning/Evaluation/R&D Support	3.0
Total	$53.2*

*Itemized expenses may not sum to total due to rounding.

Demand-Side Management Program Costs: 1995-1997

Listed below are the projected demand-side management costs by customer class for the period 1995-1997. Lost revenues are not included.

CUSTOMER SECTOR

(Millions of Dollars)

	1995	1996	1997	Total 1995-1997
Residential	33.2	34.6	36.1	103.9
Commercial	0.7	0.8	0.8	2.3
Industrial	20.0	20.5	20.8	61.3
General	3.1	3.2	3.3	9.6
Total	57.0	59.1	61.0	177.1

Implemented DSM Programs

The following pages provide the objective, program description, criteria for measuring progress, implementation schedule, and progress to date for each of the Company's implemented DSM programs. These programs are as follows:

Residential

Common Sense Home (Thermal Efficiency - New Homes)
Thermal Efficiency - Existing Homes
- Homeowner's Energy Loan Program
- Energy Conversation Discount

EZ - $64
Residential High Efficiency Heat Pump
Residential Time-Of-Use

Commercial

Commercial Energy Efficient Design
Commercial Energy Audit
Commercial Time-of-Use
Commercial Thermal Energy Storage

Industrial

Industrial Audit/Energy Efficient Plants
Industrial Time-Of-Use
Large Load Curtailment

Common Sense Home Program
(Thermal Efficiency - New Homes)

Objective: Improved thermal efficiency for new homes, apartments, and manufactured homes. This program provides greater comfort and energy savings for customers. The program also results in better utilization of CP&L facilities and improved load factor, as well as a reduction in summer peak load.

Description: The Common Sense Home Program encourages the construction of energy-efficient residences. Structures which meet the program's requirements for thermal integrity and equipment efficiency earn the Common Sense Home designation and qualify for CP&L's 5% Residential Energy Conservation Discount.

Current Common Sense Home requirements are: (1) minimum insulation levels of R-30 in ceilings, R-16 in walls, R-19 in floors, and R-5 in slabs; (2) window area limited to 15% of floor area; (3) insulated windows and doors; (4) an electric hot water heater with a minimum tank size of 40 gallons and minimum insulation value of R-12; and (5) an electric heat pump with a minimum 11 Seasonal Energy Efficiency Ratio (SEER) and a sealed duct system.

The Common Sense Program offers incentives to builders of new homes and apartments who meet program criteria which start at $100/ton of installed heat pumps and increases in $25 increments as the efficiency of the heat pump increases.

The Company has implemented a Common Sense Plus Home Pilot Program in the Raleigh area. This pilot program is an effort to further encourage CP&L's residential customers and builders to invest in even higher energy efficient standards. In addition to meeting all the criteria of the enhanced Common Sense Home Program, this pilot program requires quality installation standards for the equipment, prewiring for appliance control, and a larger electric water heater thus resulting in greater comfort and energy efficiency for the homeowner. Builders who build homes to these standards are eligible for an incentive similar to Common Sense, but starting at $200/ton of installed heat pumps.

Common Sense Home Program
(Thermal Efficiency - New Homes)
(continued)

Criteria for Measuring Progress: The major criterion for measuring progress is cumulative megawatts of peak load reduction capability.

Thermal efficiency is verified by field representatives and reported by customer name, location and other identifiers through the Customer Information Management System.

Implementation Schedule:

Year	1995	1996	1997
Incremental MW:	2.8	2.8	2.5
Incremental MWh:	14,200	14,200	12,800

Progress to Date: 128.3 MW of peak load reduction through December 1994

Thermal Efficiency - Existing Homes

Objective: Encourage customer options which conserve energy and reduce peak load to reduce the need for future generating capacity and improve customer satisfaction.

Description: Thermal efficiency is promoted for existing residential structures through the Homeowner's Energy Loan Program (HELP) used for insulation and high-efficiency heat pumps, energy audits, and customer education. In addition, an upgraded structure that meets CP&L's efficiency standards will also qualify for the 5% Residential Energy Conservation Discount which provides a reduction in energy usage costs.

Criteria for Measuring Progress: The major criterion for measuring progress is cumulative megawatts of peak load reduction capability.

Thermal efficiency is verified by field representatives and reported by customer name location and other identifiers through the Customer Information Management System.

Implementation Schedule:

Year:	1995	1996	1997
Incremental MW:	1.0	1.1	1.0
Incremental MWh:	4,200	4,400	4,000

Progress to Date: 32.6 MW of peak load reduction through December 1994

Thermal Efficiency - Existing Homes
(Homeowner's Energy Loan Program)

Objective: Provide customers with options that encourage energy conservation and peak load reduction which can reduce the need for future generation capacity and improve customer satisfaction.

Description: CP&L developed the Homeowner's Energy Loan Program in 1981 to promote conservation of energy and demand reduction by providing convenient and inexpensive financing of conservation measures for residential homeowners.

In 1990, the maximum loan amount was increased from $600 to $1500 and in 1993, again increased to $3000. The Homeowner's Energy Loan Program was also enhanced to allow further conservation by residential customers. The Company recognized the need to add additional conservation measures to allow residential customers to have more control over their electricity usage.

Under the enhanced program, CP&L will loan a homeowner with approved credit up to $3000 for the installation of cost-effective conservation measures for homes with electric heat or whole-house air conditioning at 6% simple interest. The homeowner will have up to five years to repay the loan conveniently via the monthly electric bill.

The approved measures are: ceiling insulation, wall insulation, floor insulation, duct insulation/modification, duct testing/sealing, storm or double glass windows, storm or insulated doors, programmable heat pump thermostats, and energy-efficient water heaters.

Criteria for Measuring Progress: This program is a component of Thermal Efficiency - Existing Homes. Peak load reductions are accounted for through Thermal Efficiency - Existing Homes.

Implementation Schedule: Refer to Thermal Efficiency - Existing Homes.

Progress to Date: Refer to Thermal Efficiency - Existing Homes.

EZ-$64 Program

Objective: Reduce peak demand and defer the need for additional peaking capacity.

Description: The EZ-$64 Program uses either radio or power-line carrier to interrupt residential customers' central air conditioners for up to four hours per day (maximum of 60 hours during cooling season) and/or electric water heaters for up to four hours per day throughout the year. Participants receive a credit of $2 per month for water heater control and an additional $10 per month ($13 for multiple units) from June through September for air conditioner control with the water heater option. A stand-alone air conditioner option is also available during the summer months offering the customer a discount of $8 per month ($11 for multiple units).

This program underwent a comprehensive evaluation which included an impact and market analysis. The evaluation was completed in the last quarter of 1994.

Criteria for Measuring Progress: The major criterion for measuring progress is cumulative megawatts of peak load reduction capability.

The Company tracks participation in the program by customer name, location and other identifiers, net of dropouts, through the Customer Information Management System.

Implementation Schedule:

Year:	1995	1996	1997
Incremental MW:	24.6	24.2	25.2

There is no projected impact on annual megawatt-hours. It is assumed that the reduction in megawatt hours occurring during controlled periods is offset by increased megawatt hours following the controlled periods.

Progress to Date: 206.8 MW of peak load reduction through December 1994, 32.6 MW of peak load reduction achieved through the water heating control, and 174.2 MW of peak load reductions achieved through air conditioning control.

Residential High-Efficiency Heat Pump Program

Objective: Encourage the use of high-efficiency equipment to reduce system peak and reduce the need for future generation capacity. This also helps to assure a balanced and optimized future system design.

Description: CP&L's High-Efficiency Heat Pump Program includes customer financing and rebates for high-efficiency heat pumps, a Quality Heat Pump Dealer List, dealer incentives for high-efficiency installations and advertising to inform residential customers regarding high-efficiency heat pumps.

The heat pump financing is tied to the SEER rating of the equipment purchased by the residential customer. The following table shows the current SEER levels and applicable interest rates:

Seer Levels		Interest Rate
Package Heat Pump	Split System Heat Pump	
9.7 - 9.99	10.0 - 10.99	12%
10.0 - 10.99	11.0 - 11.99	9%
11.0 - Up	12.0 - Up	6%

The Heat Pump Rebate for existing customers is also tied to the SEER rating of the equipment purchased by the residential customer. The following table shows the current SEER levels and applicable rebates:

Residential High Efficiency Heat Pump Rebate Schedule
Existing Houses, Apartments, And Manufactured Housing

Seer Level	Rebate
11.0 - 11.99	$100/TON
12.0 - 12.99	$125/TON
13.0 - 13.99	$150/TON
14.0 - 14.99	$175/TON
15.0 - UP	$200/TON

Dealers in the CP&L service area who satisfy CP&L's program guidelines and who demonstrate quality installation and service will be eligible to become part of the Company's Quality Heat Pump Dealer List. A list of these dealers is given to residential customers who ask for advice on heat pump installations and is promoted as containing those dealers who meet requirements that will help ensure quality installations.

Dealers included on the Quality Dealer List receive dollar credits for each high-efficiency heat pump installed. The dealers use the accumulated credits toward an equivalent amount of heat pump training and/or equipment for servicing heat pumps, so that higher quality installations and service are encouraged. Also, a limited amount of the credits may be used to fund advertising focused on high-efficiency heat pumps in order to educate residential customers about heat pump operation and to promote the benefits of high-efficiency heat pumps.

During 1994 CP&L made more than 12,000 heat pump loans.

Criteria for Measuring Progress: The main criterion for measuring progress is cumulative megawatts of peak load reduction capability. Field reports identify SEER levels and size of high efficiency heat pumps and central air conditioners by customer name, location and other identifiers.

Implementation Schedule:

Year:	1995	1996	1997
Incremental MW:	4.4	3.7	2.8
Incremental MWh:	4,200	3,600	2,700

Progress to Date: 21.5 MW of peak load reduction through December 1994

Residential Time-Of-Use

Objective: Shift demand and energy to the off-peak periods.

Description: The Company offers two residential time-of-use rates which use financial incentives through rate design to encourage customers to shift load and usage to off-peak periods. Participating customers may choose an all energy time-of-use rate or a time-of-use rate that contains both demand and energy components.

Criteria for Measuring Progress: The major criterion for measuring progress is cumulative megawatts of peak load reduction capability.

The Company tracks participation in the program by customer name, location and other identifiers, net of dropouts, through the Customer Information Management System.

Implementation Schedule:

Year:	1995	1996	1997
Incremental MW:	1.2	1.2	1.1

There is no impact on annual megawatt-hours because usage is shifted from the on-peak hours to the off-peak hours.

Progress to Date: 21.1 MW of peak load reduction through December 1994

Commercial Energy-Efficient Design Program

Objective: Assist commercial customers with the design of energy-efficient new and renovated facilities.

Description: Building owners and agents are contacted early in the planning process to discuss the services and programs that are available from CP&L to assist in reducing peak demand and improving overall energy efficiency. Recommendations and proposals are made by marketing representatives and/or power engineers to customers and design professionals with respect to increased energy efficiency and load management. Specific measures recommended include: thermal integrity improvements, the use of energy-efficient lights, high-efficiency heating/air conditioning equipment, and proper control devices.

Criteria for Measuring Progress: Results from the Energy Efficient Design Program are reported by marketing representatives and/or power engineers. Company representatives gather information regarding program-induced energy conservation and load management actions taken by customers and provide documentation of the customer action. Implementation reports are entered into the Marketing Database System by customer name, location and other identifiers.

Implementation Schedule:

Year:	1995	1996	1997
Incremental MW:	2.9	3.6	4.9
Incremental MWh:	6,500	8,100	11,000

Progress to Date: 93.5 MW of peak load reduction through December 1994

Commercial Energy Analysis (Audit) Program

Objective: Provide commercial customers with detailed on-site energy recommendations and proposals to increase energy efficiency and load management in end uses and site operations.

Description: Under the Commercial Energy Analysis Program CP&L marketing representatives and/or power engineers make recommendations and proposals to customers with respect to increased energy efficiency and load management in end uses such as HVAC, energy-efficient lighting, thermal envelope, and other end uses.

Criteria for Measuring Progress: Results from the Commercial Energy Analysis Program are reported by marketing representatives and/or power engineers. Company representatives gather information regarding program-induced energy conservation and load management actions taken by customers and provide documentation of the customer action. Implementation reports are entered into the Marketing Database System by customer name, location and other identifiers reduction goal.

Implementation Schedule:

Year:	1995	1996	1997
Incremental MW	3.9	3.0	2.9
Incremental MWh:	7,000	5,400	5,300

Progress to Date: 53 MW of peak load reduction through December 1994

Commercial Time-of-Use

Objective: Provide price signals which encourage customers to shift load and energy use to off-peak periods.

Description: The commercial time-of-use rate provides an incentive for customers to reduce on-peak load and shift usage to off-peak hours. Customers have found various ways to reduce on-peak load, including the use of timers, energy management systems, cool storage systems and changes in work schedules.

Criteria for Measuring Progress: The commercial time-of-use rate is used as a tool in the Commercial Energy Analysis (Audit) Program, and peak load reduction is measured through the Audit Program.

Implementation Schedule: Refer to Commercial Energy Analysis (Audit) Program.

Progress to Date: Commercial time-of-use is used as a tool in the Commercial Energy Analysis (Audit) Program, and peak load reduction is measured through the Audit Program.

Commercial Thermal Energy Storage Program

Objective: Promote the installation of Thermal Energy Storage (TES) with emphasis on the utilization of cool storage for off-peak air conditioning in order to shift peak summer load.

Description: The TES Program emphasis is placed on customer education and working closely with HVAC design professionals and other business associates to make them aware of the various CP&L off-peak rates that are available for Thermal Storage applications. The program encourages the customer, design professional or business associate to perform a payback calculation for the additional first cost expenses associated with a TES installation, which will be offset through savings on the electric bill via the appropriate time-of-use or thermal storage rate.

Criteria for Measuring Progress: The major criterion for measuring progress is cumulative megawatts of peak load reduction capability.

Site-specific load reductions are identified and verified on a case-by-case basis, and documented in the Marketing Database System by customer name, location and other identifiers.

Implementation Schedule:

Year:	1995	1996	1997
Incremental MW:	.5	.2	.3

Progress to Date: 2.1 MW of peak load reduction through December 1994

Industrial Audit/Energy-Efficient Plants Program

Objective: Influence the specification and installation of state-of-the-art energy-efficient technologies to improve the Company's load shape and maximize the efficiency of the customer's facility and/or process.

Description: CP&L energy engineers and power engineers have been conducting detailed energy studies and "walk-through"audits for industrial customers system-wide since 1983. Applications addressed include energy-efficient lighting, motors and motor drives, HVAC design and optimization, and energy management systems. Actual on-site measurement supports engineering analyses and conclusions.

The same engineers work during the facility design phase as part of the Industrial Energy-Efficient Plants component of this program. Objectives from both components include reducing peak load, load shifting, and strategic conservation. The Power Quality component was a 1990 program enhancement. Power Quality is an area of major importance to all our customers, especially our industrial customers. The goal of this program is to provide technical expertise to enable the power engineers to better serve our customers.

Criteria for Measuring Progress: Implementations that result from the Industrial Audit/EEP Program are reported by power engineers and are entered into the Marketing Database System by customer name, location and other identifiers.

Implementation Schedule:

Year:	1995	1996	1997
Incremental MW:	6.1	6.4	8.1
Incremental MWh:	34,800	36,400	45,700

Progress to Date: 239.3 MW of peak load reduction through December 1994.

Industrial Time-Of-Use

Objective: Provide price signals which encourage customers to shift load and energy use to off-peak periods.

Description: Optional time-of-use rates are available to all industrial customers. Demand and energy charges are lower during specified off-peak hours. When feasible, time-of-use rates are used as tools by CP&L's energy engineers and power engineers in conjunction with the industrial Audit/Energy-Efficient Plants Program to reduce peak load and improve load factor and increase the economic efficiency of our customers.

Criteria for Measuring Progress: Implementations that result in the shifting of load to off-peak periods are reported by power engineers and are entered into the Marketing Database System which records progress towards peak load reduction.

Implementation Schedule:

Year:	1995	1996	1997
Incremental MW:	2.2	4.3	5.6

There is no impact on annual megawatt-hours because usage is shifted from the on-peak hours to the off-peak hours.

Progress to Date: 113.4 MW of peak load reduction through December 1994

Large Load Curtailment Program

Objective: Reduce peak load at times when available generating capacity is low relative to system load or when capacity is available, but at a relatively high generation cost.

Description: Customers are provided an economic incentive based upon the avoided peaking capacity cost, to participate in the program. The customer receives a discount monthly for each kilowatt subject to curtailment. For capacity type curtailments, customers are expected to reduce load or "pay" back to the Company a significant portion of discounts previously received. If the curtailment is economic in nature, customers decide whether to curtail or continue to operate at their contract demand level and pay a cents-per-kWh premium. This program is popular with customers who have the ability to increase and decrease significant loads in a short period of time.

Criteria for Measuring Progress: The criterion for measuring progress is the difference between the contractual firm demand during a curtailment and the average peak demand for summer and winter.

Implementation Schedule:

Year:	1995	1996	1997
Incremental MW:	35.8	8.5	3.9

There is no impact on annual megawatt-hours because the reduction in megawatt hours occurring during curtailments is offset by increased megawatt hours during non-curtailed periods.

Progress to Date: 163.9 MW peak load reduction through December 1994

Potential DSM Programs

CP&L has under consideration an array of potential demand-side management programs. The table below provides a listing of the programs for which actions are planned over the next three years. The following pages provide an objective, description, and status of each program.

Residential

High Efficiency Water Heater
Heat Pump Water Heater
Home Comfort Analysis
Common Sense Manufactured Home
Common Sense Home Program-Environmental Option

Commercial/ Industrial

Thermal Energy Storage - Schools
Non-Residential Energy-Efficient Heat Pump
Commercial Load Control
Small Load Curtailment

High-Efficiency Water Heater

Objective: Encourage energy-efficiency through installation of high-efficiency electric water heaters.

Description: CP&L is considering development of a program to encourage the installation of high-efficiency electric water heaters.

Status: Market Research to determine market potential was completed in November 1994. Based on those results and surveys of other utility programs, program criteria will be designed and a program will be considered for implementation in 1995.

Heat Pump Water Heater

Objective: Increase energy-efficiency and reduce peak demand.

Description: A Heat Pump Water Heater study is being developed to test the feasibility and customer acceptance of heat pump water heaters in CP&L's service area. A two-year study is planned, beginning in 1995, to test 10 heat pump water heaters. Initial activities will consist of testing equipment in a controlled laboratory environment to determine equipment performance and potential installation problems. Field installation will follow. During the field test, energy, demand and hot water consumption will be monitored. Heat pump water heaters are expected to provide hot water at less cost and at a reduced kW demand when compared to conventional electric water heaters.

Status: Equipment is being tested in both a laboratory and field environment. As of March 1995, 6 heat pump water heaters have been installed in CP&L employees' homes.

Home Comfort Analysis

Objective: Strategic conservation and increased comfort for the customer.

Description: Develop a formal program utilizing CP&L's Quality Heat Pump dealers to address the areas of heating and cooling system performance testing and duct system sealing for existing and new homes. The training would be provided by the North Carolina Alternative Energy Corporation or other equivalent agency. The Company currently encourages performance testing and duct sealing in conjunction with other programs.

Status: The Company is moving forward to train CP&L personnel on the use and benefits of performance testing and duct sealing. CP&L encourages any Quality Heat Pump dealers who have completed the North Carolina Alternative Energy Corporation duct diagnostic and repair training to utilize CP&L's Home Energy Loan Program to finance performance testing and duct sealing. CP&L is also considering a pilot program in one Region during 1995.

Common Sense Manufactured Home-Enhancement (Thermal Efficiency - New Homes)

Objective: Improved thermal efficiency for new manufactured homes. This program will provide greater comfort and energy savings for customers. The program will also result in better utilization of CP&L facilities and improved load factor as well as reduction in summer peak load.

Description: The Enhanced Common Sense Manufactured Home Program will encourage the construction and sale of new energy-efficient manufactured homes that utilize a higher efficiency heat pump for heating and cooling.

Status: CP&L has worked with the North Carolina Alternative Energy Corporation, Duke Power, N. C. Power, Virginia Power, and the Electric Cooperatives to establish one state-wide energy efficient manufactured home standard for the state. CP&L is planning to implement this program in the second quarter of 1995.

Common Sense Home Program - Environmental Option

Objective: The objective of this program is to encourage energy-efficiency and environmental awareness among our residential customers. The program will result in better utilization of CP&L facilities, improved load factor, reduction in summer peak load, and improved customer satisfaction.

Description: The proposed Common Sense Home Program with the environmental option will encourage builders to incorporate features which improve energy-efficiency and provide environmental benefits. As with Common Sense, the homes incorporate features which increase thermal and equipment efficiencies. In addition, the environmental option includes indoor air quality, water quality, home waste management, high efficiency lighting, and safety features. This program is being promoted nationwide under the auspices of the Edison Electric Institute's (EEI) "E Seal" certification program.

Status: Program development is completed. CP&L's program design was approved by EEI in April 1994. CP&L is the fourth utility in the nation to qualify to use the "E Seal" certification. The program is being considered as a pilot to be initiated in 1995 in the Northern Region of CP&L.

Thermal Energy Storage - Schools

Objective: Shift demand and energy to off-peak periods.

Description: With the increased emphasis to air condition new and existing educational facilities, the Thermal Energy Storage - Schools pilot program is being investigated as a means to provide the cooling, while limiting the summer demand impact to CP&L and the school system. The pilot program will address the technology transfer from the Faison Iceberg Project to a new school application. This project would serve as a demonstration facility, as well as a prototype school, that could revolutionize the present systems being used to condition educational buildings.

Status: CP&L has worked with two schools to investigate the feasibility of installing TES. However, due to the higher cost of the TES systems as compared to conventional systems, and other factors, such as adverse site soil conditions, CP&L and the schools elected not to install the TES System.

Non-Residential Energy-Efficient Heat Pump

Objective: Encourage the installation of energy-efficient heat pumps in the new and replacement non-residential market.

Description: The objective of the Non-Residential Energy-Efficient Heat Pump Program is to increase energy efficiency by providing technical support and education in the selection of state-of-the-art equipment options. Through the existing Energy-Efficient Design Program and the Commercial Audit Program, we are currently working with customers and design professionals to ensure energy-efficient structures. The Non-Residential Energy-Efficient Heat Pump Program is under consideration to complement our existing efforts by encouraging the installation of energy-efficient heat pumps. Through these efforts, CP&L expects to help its customers achieve higher efficiency levels in the use of electricity.

Status: CP&L implemented the Non-Residential Heat Pump Pilot Program in South Carolina in September 1994.

Commercial Load Control

Objective: Investigate the potential for developing and implementing a program to interrupt service to air-conditioning (cooling) systems in the Commercial sector.

Description: CP&L conducted a pilot program, using CP&L offices as test sites, to assess the feasibility of commercial load control.

Status: CP&L implemented a pilot commercial load control program in 15 CP&L business offices in the summer of 1993. Load research equipment was installed to collect demand, energy, temperature, and other data through the summer of 1994. Analysis of the load research data is not yet complete.

Small Load Curtailment

Objective: The program is designed to achieve the same peak load reduction objectives of the Large Load Curtailment Program. The experiment measures customer response, peak load reduction, and cost savings for curtailable loads characteristic of smaller commercial and industrial customers. An alternative incentive is also being evaluated.

Description: Customers are provided an economic incentive to reduce load during periods when available capacity is low relative to load. Administration of the program will closely parallel that of the Large Load Curtailment Program. The Company is experimenting with a different incentive (discount) structure which more appropriately addresses actual loads curtailed. A greater incentive is being provided for available curtailable load when the Company is most likely to need it, in the summer and winter peak seasons.

Status: The program is available on an experimental basis through December 31, 1996, to a maximum of ten customers.

Supply-Side Resources

Summary of Supply-Side Additions

During the period 1995-1997, CP&L will continue to evaluate options for meeting the need for additional supply-side resources. The table below provides a listing of the supply-side resource additions currently included in the Company's integrated resource plan and for which actions must be taken over the next three years. A summary discussion of each planned supply-side addition is included following the table.

Planned Supply-Side Resource Additions

Peaking Resource Additions	Capacity	Year
Darlington County Addition	225 MW	1997
Wayne County	500 MW	1998
Wayne County	700 MW	1999
Utility Purchases		
NCEMPA CT	200 MW	1998
Non-Utility Generators		
BCH Energy	15 MW	1996

Darlington County Electric Plant
Combustion Turbine Addition

The Combustion Turbine Addition will be installed adjacent to eleven existing combustion turbine generating units and will supply approximately 225 megawatts of peaking generating capacity.

Objective: Provide the necessary generating capacity to insure reliable electric service to our customers while maintaining the flexibility to defer generation additions in order to accommodate and respond to future uncertainty.

Criteria for Measuring Progress: Achievement of milestones necessary to have the capacity on-line when needed.

Implementation Schedule: Attached is the schedule for placing the Combustion Turbine Addition in-service on June 1, 1997.

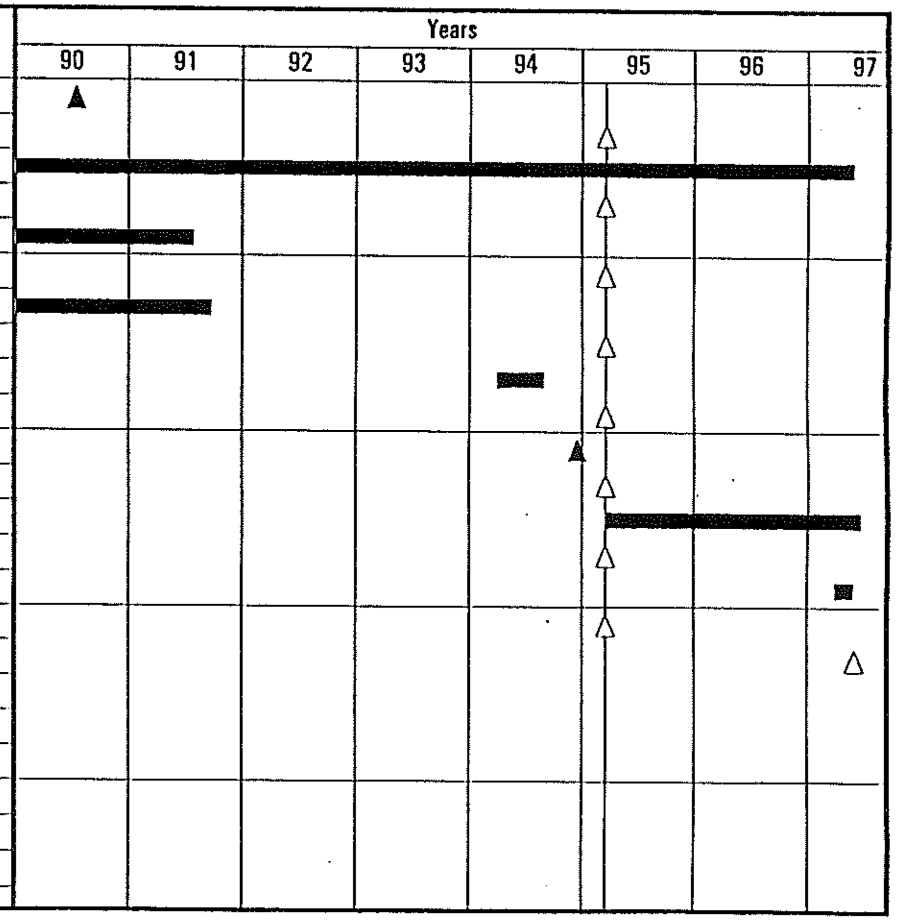
Progress To Date: On July 16, 1990, the Company announced plans to add combustion turbine generating units at the Darlington County Electric Plant near Hartsville, South Carolina. An application for a Certificate of Environmental Compatibility and Public Convenience and Necessity was filed with the South Carolina Public Service Commission (SCPSC) on November 30, 1990. The public hearing was held before the Commission on February 7, 1991. The Certificate was issued by order of the South Carolina Public Service Commission on July 16, 1991. The Air Permit Application was submitted to the South Carolina Department of Health and Environmental Control on February 7, 1991. The Air Permit was issued on September 25, 1991. The initial Air Permit was to expire on March 23, 1993. On January 15, 1993, CP&L applied for an extension of the Air Permit with a new expiration date of September 23, 1994, to accommodate the two-year delay of the in-service date to June 1, 1996. The Air Permit was extended on March 23, 1993. On June 6, 1994, CP&L applied for a revision to the Air Permit to allow use of a different CT model. A new revised Air Permit was issued on August 31, 1994 with an expiration date of February 28, 1996. In December, CP&L revised the in-service date to June 1, 1997. On December 9, 1994 CP&L executed a purchase agreement with Westinghouse Electric Corporation to provide and install the combustion turbines for this project.

Implementation Costs: Assuming a 1997 in-service date, transmission plant costs including AFUDC are estimated to be approximately $10 million and generation plant costs including AFUDC are estimated to be approximately $61 million.

Problems Incurred and Resolution: None.

Figure No. 1
Darlington County Combustion Turbines
Project Milestone Schedule

Task Name	Start	End
Site Selection	July, 1990	July, 1990
Budget: Prod/Trans	Jan, 1990	May, 1997
Certificate to Construct	Jan., 1990	July, 1991
Original Air Quality Permit	Jan., 1990	Sept., 1991
Revised Air Quality Permit	Apr., 1994	Sept., 1994
Turnkey Contract	Dec., 1994	Dec., 1994
Engineer/Procure/Construct	Mar., 1995	May, 1997
Startup/Testing	Apr., 1997	May, 1997
Commercial Operation	Jun., 1997	Jun., 1997



Wayne County Electric Plant
Combustion Turbine Addition

CP&L has announced plans to add approximately 1000-1200 MW (summer rating) of combustion turbine (CT) generating units at a site in Wayne county adjacent to the Lee Steam Electric Plant near Goldsboro, NC.

Objective: Provide the necessary generating capacity to insure reliable electric service to our customers while maintaining the flexibility to defer generation additions in order to accommodate and respond to future uncertainty.

Criteria for Measuring Progress: Achievement of milestones necessary to have the capacity on-line when needed.

Implementation Schedule: Attached is a preliminary schedule for placing 500 MW in-service on June 1, 1998 and 700 MW in-service on June 1, 1999.

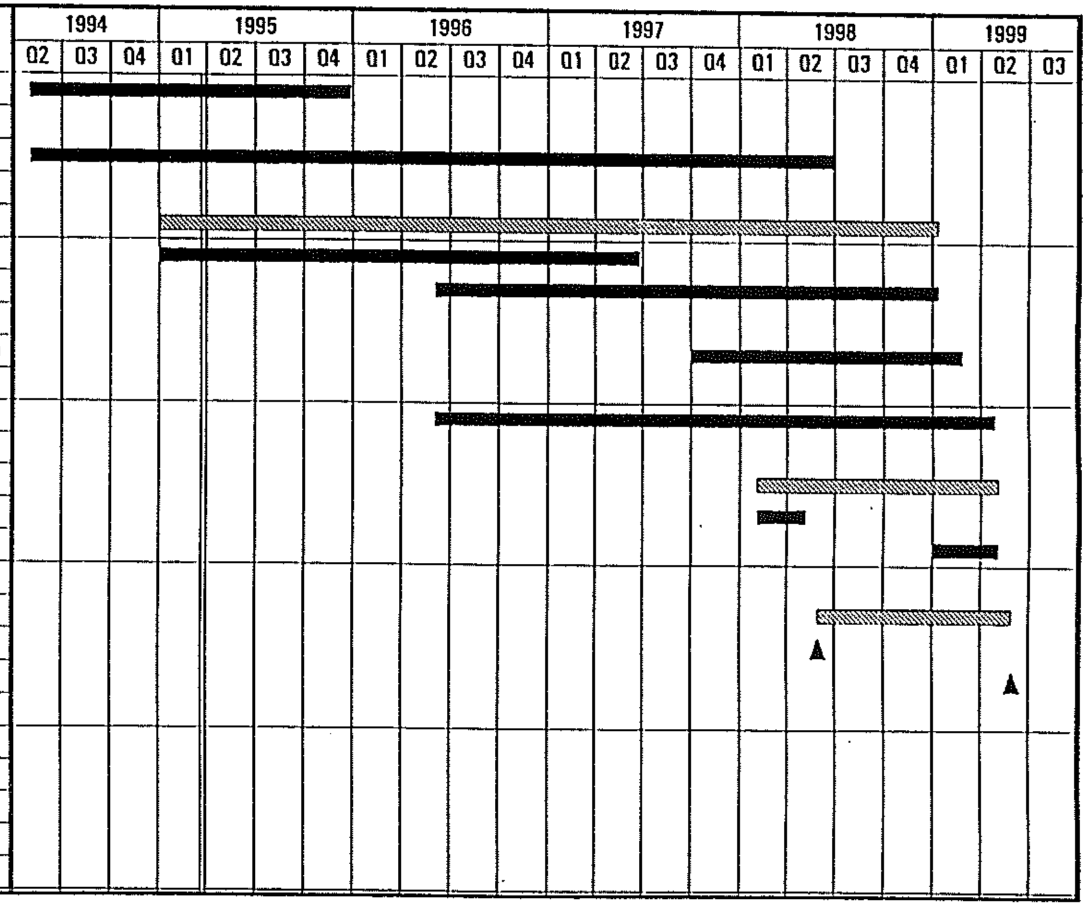
Progress To Date: On December 14, 1994 the Company announced plans to add combustion turbine generating units at the Wayne County site adjacent to the Lee Steam Electric Plant near Goldsboro, NC. On December 19, 1994 the Company filed Preliminary Plans (R8-61 information) with the N.C. Utilities Commission, and the Air Permit Application was submitted to the N.C. Division of Environmental Management.

Implementation Costs: Assuming in-service dates of 1998-99, transmission plant costs including AFUDC are estimated to be approximately $21 million and generation plant costs including AFUDC are estimated to be approximately $280 million, based on 1100 MW (summer rating).

Problems Incurred and Resolution: None.

Figure No. 2
Wayne County Combustion Turbines
Project Milestone Schedule

Task Name	Start	End
Permitting	May, 1994	Dec., 1995
Engineering	May, 1994	July, 1998
Procurement		
Combustion Turbines	Jan., 1995	June, 1997
Balance of Plant	June, 1996	Jan., 1999
Equipment Delivery	Oct., 1997	March, 1999
Construction	June, 1996	May, 1999
Startup & Test		
First Block	Feb., 1998	May, 1998
Second Block	Jan., 1999	May, 1999
Units In Service		
First Block	June, 1998	June, 1998
Second Block	June, 1999	June, 1999



North Carolina Eastern Municipal Power Agency
Combustion Turbine Addition

The North Carolina Eastern Municipal Power Agency (NCEMPA) has given CP&L notice that it plans to install approximately 200 MW of combustion turbine peaking capacity for operation in 1998.

Objective: NA

Criteria for Measuring Progress: NA

Implementation Schedule: In an agreement signed on April 7, 1993, Carolina Power & Light Company and the North Carolina Eastern Municipal Power Agency (NCEMPA) agreed to restructure portions of their power supply contracts. The agreement included a three-year delay in the in-service date of NCEMPA's planned peaking generation project. This project is now scheduled for in-service in 1998. NCEMPA has the option to cancel this project and must notify CP&L by March 1, 1996 if it is not going to install the combustion turbine addition.

Progress to Date: NA

Implementation Costs: NA

Problems Incurred and Resolution: None.

Purchased Capacity from Non-Utility Generators

Non-Utility Generation Project - BCH Energy

BCH Energy, L.P. will construct a waste to energy facility on the property of DuPont in Fayetteville, NC. Cumberland, Hoke, and Bladen Counties will supply trash/garbage to a facility in which the waste would be prepared for fueling a boiler that will drive a 15 MW back pressure turbine generator with low pressure steam being sold to DuPont. The facility is scheduled to be completed by the end of 1995.

Objective: NA

Criteria for Measuring Progress: NA

Implementation Schedule: On July 19, 1993, BCH Energy and CP&L signed an Electric Power Purchase Agreement to sell the entire generator output to CP&L. The initial term of the agreement is 25 years.

Progress to Date: The facility is currently under construction.

Implementation Costs: The contract with BCH Energy provides for a purchase of all power at a rate equivalent to Schedule CSP-15A with 15-year fixed energy and capacity credits. The rate for the final 10 years will be the variable energy credit available during that period. No capacity credit will be paid during the final 10-year period.

Problems Incurred and Resolution: None.

Introduction

Utilities have experienced dramatic economic, demographic, technological, and regulatory changes in recent years. These changes introduce significant uncertainties that influence the complexity of the utility operating and planning environment. Uncertainty can be described as the extent to which outcomes differ from their expected value. In planning to meet future resource needs, utilities face substantial uncertainties regarding future load growth and the resources needed to satisfy that growth.

This appendix briefly describes several methods used within the utility industry for treating uncertainty in the context of the Integrated Resource Planning (IRP) framework. Focus is then given to the decision analysis (DA) techniques used by CP&L in its IRP process to identify the key uncertainties used in developing a robust integrated resource plan. The discussion includes structuring the decision analysis problem using an influence diagram and the sensitivity analysis employed to determine the key uncertainties. The probabilistic evaluation is described including the probability encoding process and development of the discrete representation of an uncertainty.

Discussion of the decision analysis techniques used in the Company's integrated resource planning process demonstrates how the consideration of a range of possible outcomes in the probabilistic treatment of an uncertainty is accomplished. The energy growth uncertainty used in development of the 1995 Least Cost Integrated Resource Plan (LCIRP) Filing is used as an example to illustrate some of the concepts and techniques practiced in the probabilistic phase.

Uncertainty analysis methods

Some of the techniques used within the utility industry for treating uncertainty include scenario analysis, sensitivity analysis, portfolio analysis, and probabilistic analysis (decision analysis). These terms are commonly used throughout the literature on uncertainty analysis, although the description of a particular method and the techniques employed may sometimes differ among sources.

Scenario analysis

Scenario analysis consists of initially constructing alternative visions of the future. The alternate futures, such as economic boom or economic bust, reflect internally consistent combinations of uncertain factors such as fuel prices, environmental regulations, and load growth. Plans consisting of supply and demand resources are then identified for each future. Resources and actions which appear under several scenarios would be viewed as favorable alternatives and can be combined into a unified plan. Scenario analysis may be less analytical and rely more on management judgement and discussions within the organization compared to other methods. The likelihood or probability of the scenarios unfolding is not considered in this methodology.

Sensitivity analysis

Sensitivity analysis typically involves development of a preferred resource plan consisting of a combination of demand and supply resource options. The performance of the plan is then tested to examine the sensitivity to variations in original input assumptions. The original plan may be modified in an attempt to identify resource options that perform well under the changing assumptions. This methodology does not consider the probability of the outcomes occurring for the variations tested in original input assumptions.

Portfolio analysis

In portfolio analysis, multiple resource plans are developed each in response to a particular set of objectives or goals such as environmental mitigation or reliance on demand-side management (DSM). The different plans may be subjected to sensitivity analysis or probabilistic analysis to evaluate the performance of each plan. The process allows selection of the most robust plan or elements of plans. The portfolio analysis methodology relates more to the identification and development of alternative plans versus the evaluation of alternative plans.

Decision analysis

In the decision analysis process, alternative plans are evaluated using a systematic series of phases for making decisions under uncertainty. The decision analysis process goes beyond other methods in the sense that key uncertainties are identified and the correlations among the uncertainties are explicitly considered. For example, the process considers whether the possible outcomes of each uncertainty are independent or dependent on the possible outcomes of the other uncertainties. Probabilities, typically based on expert judgement or historical data, are assigned to the different values of the key uncertainties. A decision tree is used to evaluate the outcomes associated with the different values of the key uncertainties in combination. Results from the decision analysis process allow an evaluation of the merits of the alternatives considered by comparing the expected outcome (expected value) and the range of possible outcomes (risk) for each alternative.

IRP decision analysis process

The methods used in the utility industry for treating uncertainty often comprise a variety of techniques since no one analytical method is best in all cases. CP&L employs the decision analysis methodology to treat key uncertainties in the development of its IRP, although techniques incorporated in the process also reflect some of the strengths of other methods.

For example, sensitivity analysis is used to test input assumptions to determine the key uncertainties to be treated probabilistically in the process. Sensitivity analysis is also used in a later phase of the process to measure the sensitivity of the recommended plan to the probabilities assigned to the outcomes of the uncertainties. Development of some of the alternative resource plans for probabilistic evaluation may follow the concept of portfolio analysis since a plan may be keyed to satisfying a certain objective such as minimizing dependence on oil and natural gas. The concept of scenario analysis is used in the Company's IRP process for development of the cumulative probability distribution through the assessment of expert judgement. This process, described in more detail in the Probability Encoding section later in this appendix, involves identifying and discussing scenarios that would result in extreme values for the uncertainty being assessed. Also, each endpoint of the decision tree represents a combination of outcomes for the uncertainties and thus represents a particular scenario.

The decision analysis process used in development of the Company's IRP has evolved over time and is comprised of some of the strengths of techniques from other methodologies. The decision analysis process is preferred over the other methodologies since more information is available to the decision maker such as the likelihood of an outcome and the risk associated with a decision. The remainder of this appendix focuses in detail on the decision analysis techniques applied to identify the key uncertainties, the approach used to identify the range of possible outcomes for the uncertainties, and development of the discrete values used in the IRP process to determine the most robust resource plan.

Problem structuring

The initial phase of the decision analysis process involves structuring the problem to develop a clear statement of the decision including the interrelations of the alternatives, uncertainties, and values. An influence diagram is used to provide a concise statement of the problem and graphically represent the uncertainties and their interrelationships. The influence diagram is created to help identify which assumptions should be tested to determine the sensitivity of the decision to changes in the assumptions from their base values. Figure B-1 is an example of an influence diagram.

The basic steps for constructing an influence diagram are as follows:

- Identify the measure to be used in making the decision. This measure is referred to as the value node and is represented by an octagon with a written description of the measure. In Figure B-1, the value node is Levelized Cost/kWh.

- Identify uncertainty nodes that would help resolve the value node if their outcomes were known. These nodes are represented by circles (or ovals) with a written description of the variables.

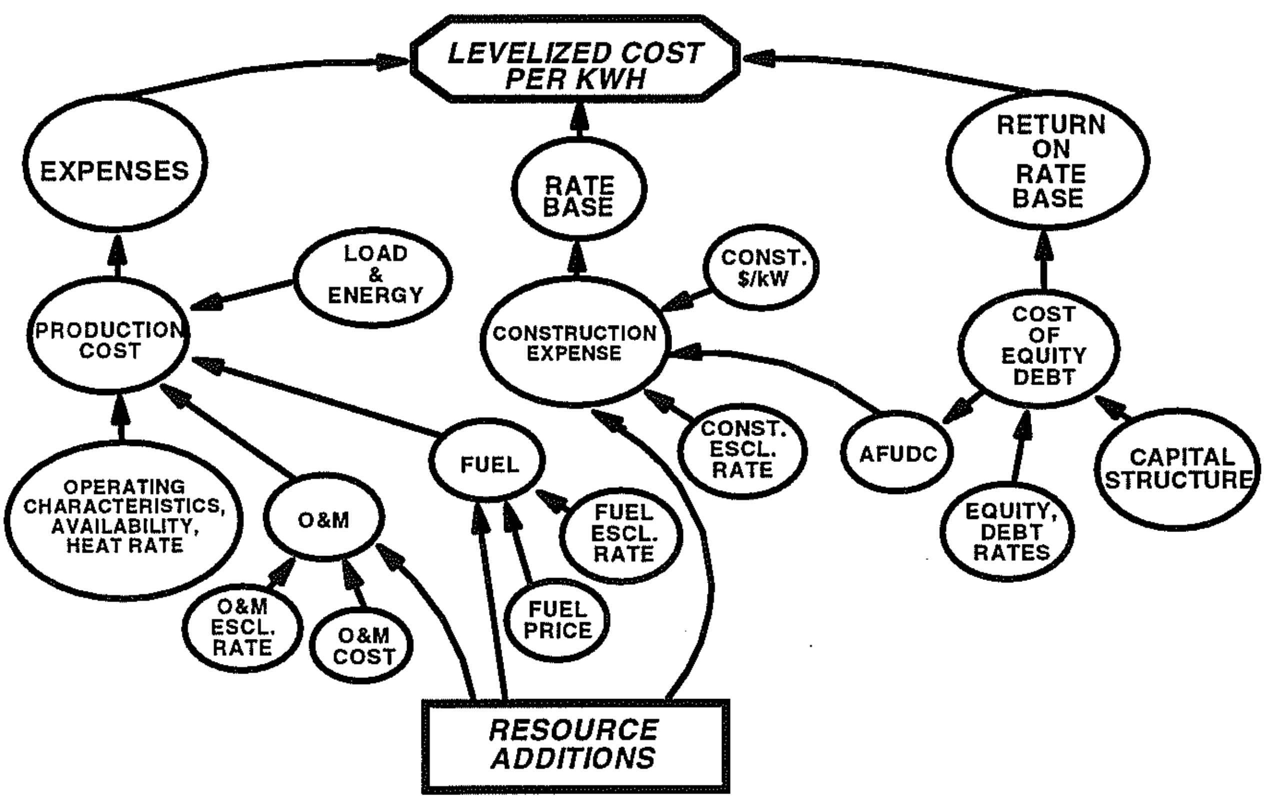
- Draw arrows from the uncertainty nodes to the value node to reflect the concept of influence or flow of knowledge. In Figure B-1 for example, the arrow from the Expenses node to the Levelized Cost/kWh node implies that expenses influence levelized cost.

- Repeat this process until all uncertainties influencing the value node have been identified.

- Determine if there are other uncertainties that would help resolve any previously identified uncertainties and add them to the diagram showing the appropriate influences.

- Represent decision nodes by a rectangle with the appropriate descriptor to identify the set of events the decision-maker is choosing. In Figure B-1, Resource Additions is shown as a decision node since the decision-maker must choose the particular set of demand and supply options comprising the resource additions.

Figure B-1
Influence Diagram for Integrated Resource Plan
Levelized Cost per kWH



Sensitivity analysis

The primary objective of sensitivity analysis in the early phase of the decision analysis process is to determine the sensitivity of the value measure to variations in planning assumptions, and to reduce the number of uncertainties that need to be treated formally in the probabilistic assessment. A simple criterion for determining sensitivity may be to test whether any decision is changed when an uncertain variable is set to extreme values (e.g., its 10th or 90th percentile values) while holding all other variables at their nominal values. Combinations of variables that affect the decision may also be evaluated. If no decisions are changed in evaluating the sensitivity to a particular variable, such as no significant change in the set of options selected or in the range of costs, the variable can be treated as known and set at its nominal value. In the Company's planning process, a planning model such as WASP (Wien Automatic System Planning Package) is used to test the sensitivities. The uncertainties that are determined to be key to the decision are treated probabilistically as described in the following section.

Probabilistic assessment

Probabilities are used to clearly communicate and describe uncertainty. While verbal descriptions of uncertainty such as "likely" or "very likely" tend to be ill-defined, numerical probability statements clearly and unambiguously describe an uncertain variable. The probabilistic relationships may be obtained from sources such as historical data or computer simulations, or judgements which may be obtained from individuals considered qualified to offer expert opinion. This section discusses the typical process used to encode the probability distribution from a qualified expert and discretize the data for use in the decision tree. The energy growth uncertainty used in the 1995 LCIRP Filing is utilized to illustrate the concepts of the probabilistic assessment.

Probability encoding

Probability is a statement of how likely an individual thinks an event is to occur and thus represents a person's state of knowledge about a chance event. The probabilities assigned to the occurrence of an uncertain event are often obtained through an interview process to encode the probability distribution. While there are no correct or incorrect probabilities, it is important to chose an individual who is expert in the relevant area. It is also important during the encoding process to assure clarity in defining the uncertainty and to remove any biases that may not appropriately represent the expert's knowledge. The probability encoding is generally accomplished by an analyst interviewing a qualified expert (or experts) for the uncertainty. Two Company experts in load and energy forecasting were consulted to elicit probabilities concerning the uncertainty in the load and energy growth variable. The encoding process follows the general steps outlined below.

Structuring

In the structuring phase of the probability encoding process the uncertainty being assessed is precisely defined to eliminate any ambiguity regarding the variable. An appropriate measuring scale is also selected. It is important to ensure the uncertainty is one which can be treated individually since it is extremely difficult to give meaningful probabilities on an uncertainty that is too complex or one which includes factors beyond the expert's immediate knowledge. Any hidden assumptions that the expert is making in thinking about the variable are also elicited. The load and energy forecast uncertainty used in the 1995 LCIRP Filing was defined as the Energy Growth Rate expressed in percent. The following assumptions were also noted to better define the variable:

- Constant class load factor (class growth rates for load and energy are equivalent before load management reductions)
- Growth rate is over a 20 year planning horizon
- Growth rate is gross of DSM (i.e., does not include reductions for new DSM programs)
- Potential exists for mandate requiring consideration of environmental externalities
- Potential exists for enactment of global warming legislation

Conditioning

The purpose of the conditioning stage is to counteract any hidden biases that may exist by asking the expert to describe scenarios that would result in extreme values of the variable being assessed. Discussion of events or scenarios that would result in extreme values of the uncertainty helps to broaden an individual's thinking about the variable. The encoder would also explore for the presence of any anchoring biases such as corporate plans or forecasts. The scenario identified for extreme high energy growth included the following:

- High growth of the economy
- Greater economic development
- Trade embargo resulting in greater production of goods and services in the Company's service area
- Nuclear generation accepted as an option for environmental mitigation resulting in shift of independent loads to the Company
- Increased marketing emphasis
- Advancements in the development and use of electro-technologies

The events identified which would contribute to an extreme low energy growth scenario included the following:

- Mandate requiring consideration of environmental externalities
- Enactment of global warming legislation
- Deregulation of retail wheeling and wholesale load
- Natural gas pricing resulting in a shift from electric energy usage to natural gas usage
- Occurrence of a catastrophic event resulting in greater emphasis on conservation and environmental mitigation
- Instability or war in the Middle East

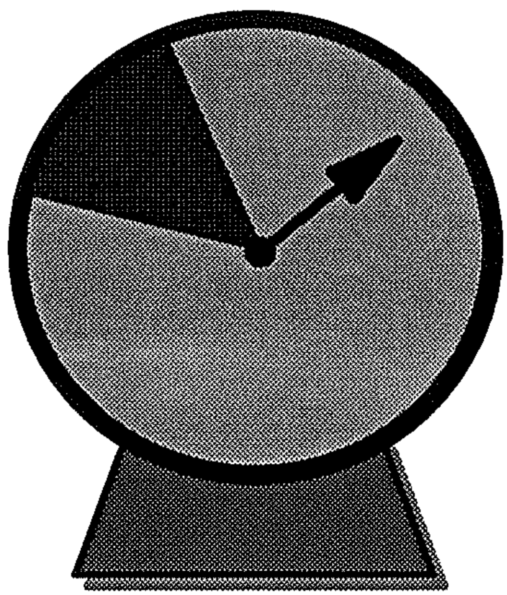
Encoding

Techniques used to encode the probability distribution describing an uncertainty generally consist of questions that require responses from the subject in the form of numbers (either values of the uncertainty or probabilities), or require the subject to choose between two or more alternatives (bets). In assessing the energy growth uncertainty, the two experts were interviewed simultaneously. This approach allowed each expert to develop an individual response and then discuss any differences and reasoning to arrive at a consensus response. An alternative approach would be to conduct separate interviews for each expert; however, there may be greater challenges in resolving any differences in the distributions that may result. The process conducted for the energy growth uncertainty discussed below illustrates several techniques for encoding the probability distribution.

The probability distribution for the energy growth uncertainty was developed by initially focusing on extreme values for the uncertain quantity. The experts were asked to consider the extreme high and low growth scenarios previously defined and to give their responses to questions such as, "There is a one percent chance that energy growth will be greater than what value?" The questions can be reversed to make the expert rethink the question and adjust the answer if appropriate, such as "There is a 99 percent chance that energy growth will be less than what value?"

After bounding the distribution, a probability wheel was used to define various points along the distribution. A probability wheel is shown in Figure B-2 and is divided into two sectors (e.g., dark and light shaded areas) with a pointer in the center of the disk. The relative sizes of the sectors can be adjusted, thus altering the probabilities of the pointer indicating either sector when the disk is spun. The wheel serves as a visual aid in the encoding process and helps to isolate the expert from any motivational biases such as corporate information or forecasts. The subject is given a choice between two events - an event relating to the uncertain quantity or the pointer landing in the light sector when the wheel is spun. For example the expert may be asked, "Would you rather bet that energy growth will be less than 2% or that the pointer will land in the light area?" The relative sizes of the dark and light sectors are adjusted and the process is repeated to converge on the point where the expert is indifferent between the probability of the two events. A scale on the back of the wheel gives the probability of the event. The encoder alters the format of the questions and shifts the focus between high and low values to foster a genuine response from the expert for each individual question. The wheel is effectively used for probabilities in the range of 0.1 to 0.9 since it is difficult to differentiate between sizes of small sectors. The probability wheel was used to arrive at several values for the energy growth probability distribution.

Figure B-2
Probability Wheel



An interval technique was also used to generate values for the energy growth rate probability distribution. For example, the median value can be assessed by asking the expert, "What value has equal probability that the variable will be greater than or less than this value?" Quartiles or other intervals can also be assessed using this technique. It may be helpful to sketch a typical probability distribution to illustrate which intervals are being assessed. A final technique was used in assessing the energy growth uncertainty by reversing the questions such that the encoder gives the value of the variable and the expert gives the probability. For example, "What is the probability that energy growth will be greater than 2%?"

Throughout the encoding process, the encoder plots and numbers the data points and notes any inconsistencies or discontinuities. These values are revisited and assessed using the different techniques to aid the expert in clearly thinking about the variable. A shift in the data points may occur if the expert thinks of new information that affects their assessment of the variable.

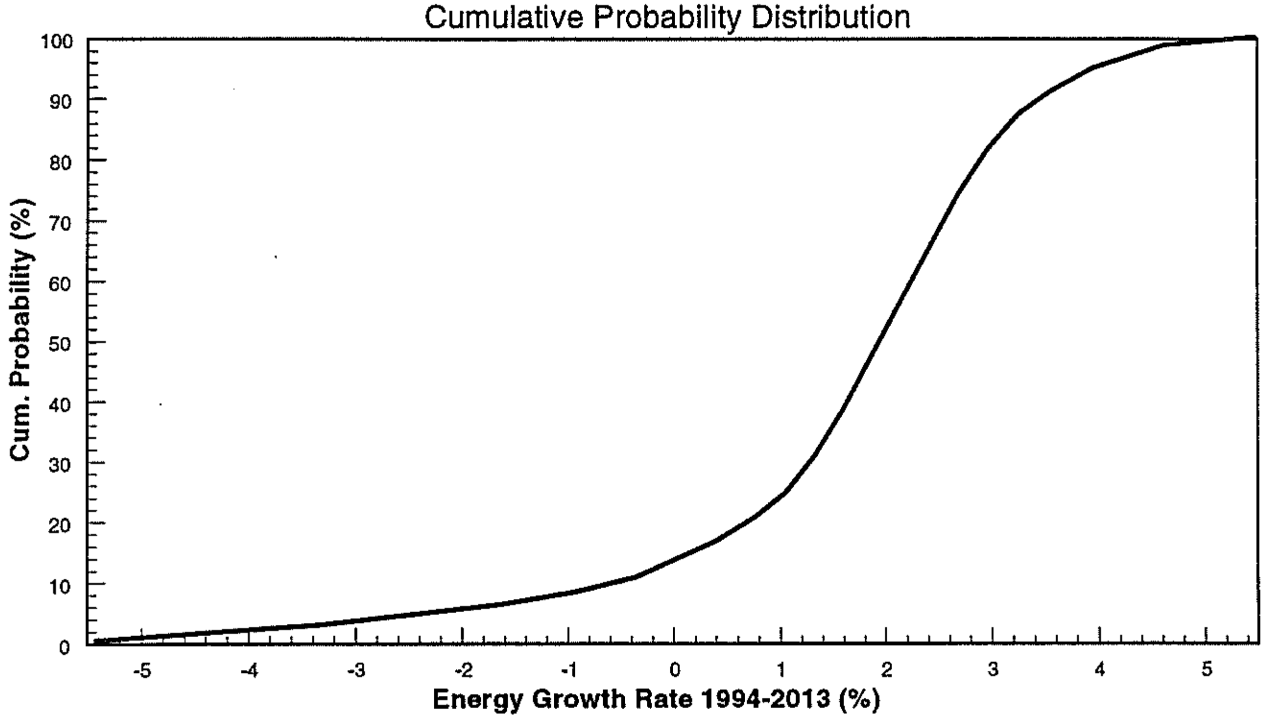
Earlier data points are discarded if the expert's perspective has been improved. A curve fitted to the collection of points yields the cumulative probability distribution.

A well executed encoding process should result in a distribution that appropriately reflects the expert's state of knowledge for an uncertain event. The cumulative probability distribution is an efficient means of presenting information for decision analysis. The distribution gives the probability (vertical axis) that the uncertainty's value will be less than or equal to the value shown on the horizontal axis. Figure B-3 shows the cumulative probability distribution resulting from the encoding process for the energy growth rate uncertainty. The distribution shows there is a 1% cumulative probability that energy growth will be -5% or less and a 99% cumulative probability that energy growth will be 5% or less, demonstrating a broad range of values for the energy growth uncertainty.

Figure B-3

Energy Growth Uncertainty

Cumulative Probability Distribution



Verification

The final stage of the probability encoding is to review the encoded distribution with the subject to test the judgements obtained in the encoding stage. The objective of this activity is to verify that the distribution adequately reflects the subject's knowledge and thinking about the variable. The discretized data to be used in the decision tree analyses may also be included in the review (discussion of developing a discrete approximation of the probability distribution is given in the following section). It is important that the subject be aware of the verification step at the on-set of the probability encoding to promote a more free and open exchange during the session.

Discrete approximation

The cumulative probability distribution data is characterized in the decision analysis model as a chance event with discrete states. The states of an event must be defined as non-overlapping (mutually exclusive) ranges that encompass all possible outcomes (collectively exhaustive). The result is that a continuous variable is converted to a discrete variable for use in the decision tree to simplify the analysis. The discrete approximation of the continuous distribution improves as more states are used. However, the number of states used has to be balanced with practically since the size of the decision tree and resulting number of computations grow rapidly as more states are added.

A widely used technique to perform the discrete approximation is to initially select the number of states and assign a probability and a value to represent each state. A typical decision analysis problem may use three outcomes to represent a variable with probabilities of 0.25, 0.50, and 0.25 for the low, mid, and high ranges respectively. These states were used for the energy growth uncertainty as shown in Figure B-3. The value of each state was determined by finding the expected value of each range. The expected value is a single measure that represents the value of the uncertain venture. As shown in Figure B-4, a horizontal line was drawn at 0.25, 0.75 (0.25 + 0.50 = 0.75), and 1.0 (0.25 + 0.50 + 0.25 = 1.0), to define the three probability ranges. For the low range, a vertical line was then drawn at -0.7, choosing this value such that the area **a** to the left of the vertical line is equal to the area **a** to the right of the vertical line. Selecting the discrete value in this manner is a visual method of finding the expected value for the range. This process was followed in a similar fashion to arrive at the expected values 1.9 and 3.5 for the mid and high probability ranges respectively.

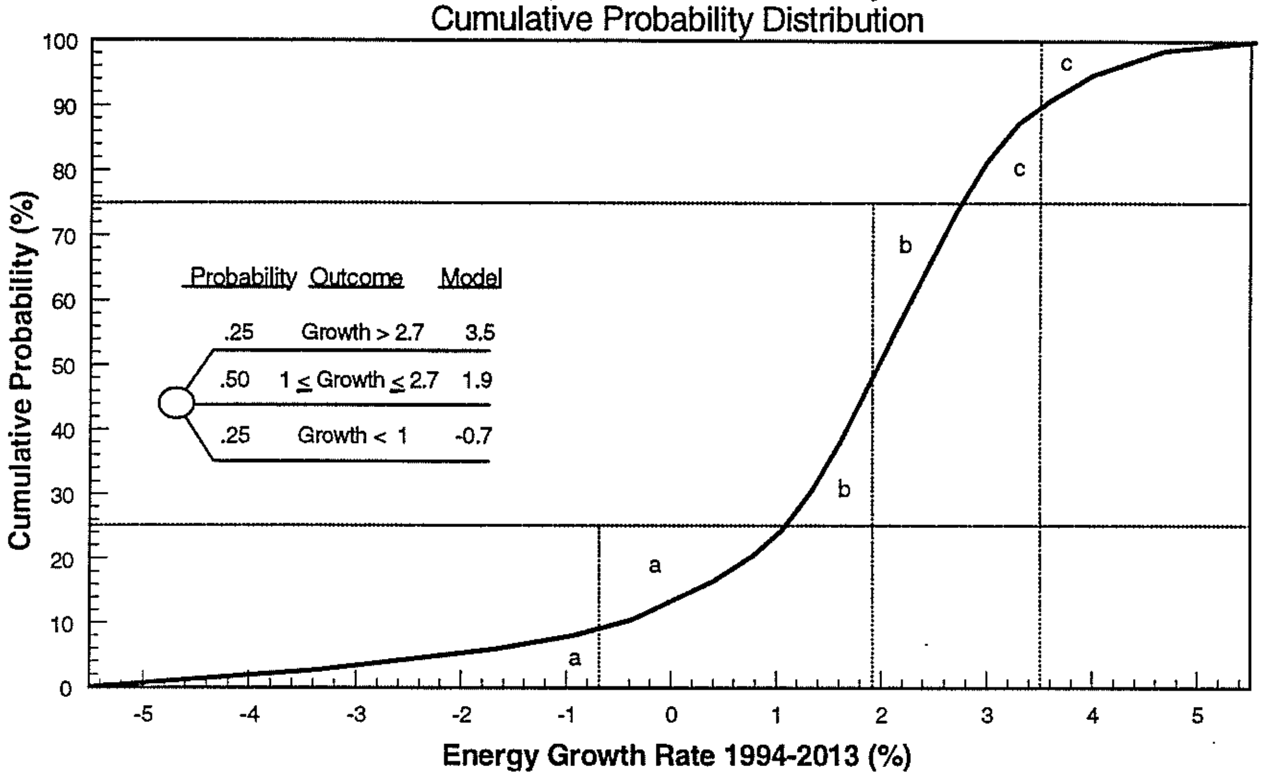
The discrete approximation is graphically described in a distribution tree format which gives the branch representation for the uncertainty. The insert in Figure B-4 shows the discrete probability distribution tree for the energy growth uncertainty. At the branching point on the left of the distribution tree is a circle to indicate an uncertainty or chance node. The distribution tree has a line (branch) for each possible outcome of the uncertainty which depicts the probability associated with each outcome. The low range, from negative infinity to 1%, was approximated by value -0.7% with a probability of 0.25. The mid range, from 1% to 2.7%, was approximated by value 1.9% with a probability of 0.50. The high range, from 2.7% to infinity, was approximated by value 3.5% with a probability of 0.25. The result is that a continuous distribution is represented by a discrete approximation to incorporate the impact of the uncertain variable in the decision analysis process.

The data in distribution tree format are combined to create a decision (or probability) tree that provides a graphic representation of all the different combinations of events that can occur and their associated probabilities of occurrence. Each of the key uncertainties identified from the influence diagram becomes an uncertainty or chance node in the probability tree. Using other decision analysis techniques, the decision problem can be numerically analyzed with the decision tree. The decision analysis process used in the Plan Evaluation phase of the 1995 LCIRP Filing is discussed in Chapter 5, Integration Analysis.

Figure B-4

Energy Growth Uncertainty

Cumulative Probability Distribution



Sensitivity analyses of the final results are typically conducted as part of the Company's IRP decision analysis process to test the robustness of the best alternative. The sensitivities include assessing the probabilities assigned to each state of the key uncertainties. The range of probabilities for which the best plan remains the highest ranking plan is determined for each state of an uncertainty. Findings from this type of analysis show the sensitivity of the overall results to the discrete approximations used in the process. Judgement can then be made regarding whether a more detailed modeling of the distribution would add value to the results.

Summary

Decision analysis provides a comprehensive framework for making decisions under uncertainty. An influence diagram serves as a powerful tool for structuring a complex decision problem and communicating the interrelationships among the uncertainties. Sensitivity analyses are conducted on uncertainties identified from the influence diagram to determine the key variables to be treated probabilistically in the decision analysis. One method of assessing the probability of a key uncertainty is by encoding informed experts. The numerical probability statements obtained through encoding expert opinion clearly describe the uncertainty and represent a precise way of expressing a person's knowledge and information about an uncertain event. A discrete approximation is developed from the cumulative probability distribution data to characterize the chance event in the decision analysis model. These components of the decision model are carried forward to develop a fully-specified decision tree which is used to formally evaluate the decision problem.

The uncertainty in energy growth was used to illustrate the concepts and techniques utilized in the probabilistic assessment phase of the decision analysis process. The probability encoding techniques were shown to appropriately capture expert judgement and resulted in a broad range of possible outcomes for the uncertainty. Conversion of the continuous probability distribution to discrete states for use in the decision tree was also illustrated.

Introduction

The integration process CP&L has used for a number of years competitively selects supply and demand resources to meet multiple alternative forecasts. In this process, all economical DSM resources are used to develop a DSM forecast. The selection of cost-effective programs for inclusion in the Integrated Resource Plan is insured by comparing program costs to CP&L's avoided costs. These avoided costs represent the supply-side capacity and energy costs that can be avoided by implementing DSM programs options. Avoided costs are updated annually and are also the basis for determining payments to cogenerators and small power producers. This use of common avoided costs insures that supply-side resources and demand-side management programs can compete heat-to-head so as to produce a least cost Integrated Resource Plan.

CP&L's IRP process also complies with the second objective of the stipulation, which is to select resources to meet multiple alternative forecasts. The integration process used by CP&L makes use of decision analysis to examine the impact of uncertainties on alternative resource plans. Energy growth is one of the key uncertainties CP&L examines and as such, the Integrated Resource Plan is subjected to multiple alternative forecasts. The process used to develop the multiple alternative energy and load forecasts is discussed in Appendix B.

Overview of integration methods

There are two basic ways of competitively selecting supply and demand resources in an integration process. Both of the methods maintain a level playing field between demand and supply options. The first method attempts to treat DSM options in a manner similar to supply options. In this method, data describing the characteristics of both DSM and supply options are input to a computer model. The model then evaluates all options at the same time and selects the most economical options. This method is sometimes referred to as the simultaneous integration method. In the second method, avoided costs are used to identify cost-effective DSM options. These DSM options are then used to adjust the load and energy forecasts. Supply options are then added to meet the net demand. Marginal costs and electricity prices resulting from the new plan are compared to those produced by the current plan which were used to develop the beginning load and energy forecasts and evaluate DSM options. This method is sometimes referred to as the iterative integration method. Additional discussion of these two methods is provided below.

Simultaneous integration method

In the simultaneous integration method, demand-side and supply-side option costs and characteristics are input into a computer model which develops an optimal plan. The model compares the costs of each of the options and selects the most cost-effective among all the resource options, typically with the objective of minimizing total revenue requirements or the cost of electricity. In this method, the linkage between marginal cost and DSM is not explicit since the model is simultaneously optimizing the demand with respect to the cost of the marginal supply options.

Advantages and disadvantages of the simultaneous integration method

The technical appeal of the simultaneous integration method is obvious. The use of computer models allows a direct comparison of demand and supply options and provides a dynamic approach to the analysis of DSM options. Also, the level and timing of DSM additions can be assessed directly. However, the use of such models is very time consuming. Because of the sheer number of DSM options available, analysis of each measure in such models is impractical. Instead, options have to be grouped in some manner. Models that perform simultaneous iteration are complex by nature. This complexity leads them to become "black boxes" in which many times, the users are unsure of what exactly is going on inside the model. The technical appeal of the model and process can produce analyses which overstate the knowledge the problem and the solution. Finally, the result of an analysis using a simultaneous integration method is a base case solution. Additional analyses have to be performed to examine risk and uncertainty. Also, the development of the base plan in such a model may neglect to take into account the feedback of rate impacts on the load and energy forecasts.

Models examined to perform simultaneous integration

A number of computer models are available which claim to be able to integrate demand and supply options simultaneously. CP&L undertook a study to review and evaluate some of the models available. The model review examined the strengths and weakness of each model as it applies to the CP&L system and the model's ability to simultaneously evaluate demand- and supply-side resources. Models were also reviewed with regard to desired improvements to the IRP planning process, impact on the operating budget, and implications of the use of the model on other areas of the Company. The models that were reviewed (and their vendors) are: Integrated Planning Model (ICF Resources), PROVIEW (EDS/EMA), EGEAS (EPRI/Stone & Webster), STARRSS (RCG/Hagler, Bailly), MIDAS (EPRI/M. S. Gerber & Associates), IRPManager (Electric Power Software), and WASP III (Argonne National Lab).

In reviewing the models, three were found that either can not perform the functions required for the simultaneous integration of supply and demand resources or do not have all the capabilities required to perform other needed analyses such as the impacts of the Clean Air Act Amendments. Those models were: IRP Manager, STARRSS, and WASP III. IRP Manager is not an optimization tool but rather a model which integrates demand-side, supply-side, and other functions into one tool. This model is similar to the Utility Planning Model currently being used by CP&L. The STARRSS model is a Clean Air Act compliance screening model and is not an all-encompassing optimization tool. The WASP model, which is currently used by CP&L, has been enhanced to allow the examination of demand-side resources and is now referred to as

WASP III. However, the model does not have the functionality to examine Clean Air Act compliance options. The remaining models have the capability to assess both demand and supply options to some degree. CP&L has reviewed the documentation of all of the models and has attended training sessions for three of the four models.

One of the models evaluated was implemented by CP&L on a test basis. The Integrated Planning Model (IPM) was used by CP&L to assist in the development of its 1993 Clean Air Act Compliance Strategy. IPM was used because the vendor, ICF Resources, provided the model free of charge for an 18-month period. The model has the capability to evaluate supply and demand resources simultaneously. CP&L tested the model in this mode, but did not have satisfactory results with respect to DSM resources. In performing an analysis, a number of DSM options were input to the model, some of which were known to pass the Rate Impact Measure (RIM) test, and some which did not. In the first analysis with the DSM programs modeled, IPM selected all the DSM measures, meaning all of them were economical compared to other resource options. In testing the sensitivity of the results to the cost of the DSM measures, the model kept selecting the DSM measures regardless of the costs input. These results were later discovered to be related to a misunderstanding of the data input requirements and the way the model processed DSM programs. This issue has been discussed with the vendor and improvements are being made to the model and the documentation. CP&L intends to further examine the use of IPM and to test the simultaneous integration method and its ability to meet the needs of the CP&L IRP process.

Iterative integration method

Demand-side and supply-side resources compete on a level playing field in the iterative integration method through the use of avoided costs. Avoided costs are used to represent the cost of new supply-side resource options. The costs of DSM options are compared to the benefits that would accrue by avoiding supply-side resource additions. In this manner, demand-side options are competing head-to-head with supply-side options. DSM options that have benefits that exceed the costs are accepted options. The sum of the load and energy impacts of the DSM options that pass the economic (and other) tests are used to reduce the load and energy forecasts. The net load and energy demands are then met using supply resources. This method includes explicit feedback loops comparing the price of electricity and marginal costs used in the energy forecast and DSM option evaluations to the price of electricity and marginal costs resulting from the integrated resource plan.

Advantages and disadvantages of the iterative integration method

The primary advantage of the iterative integration method is that it is relatively straight-forward and easily understood. By using avoided costs to test the cost effectiveness of DSM options, a true least cost mix of resources can be established. After the development of an integrated resource plan, both resource costs (i.e., avoided costs) and rate impacts (i.e., the price of electricity) can be assessed to determine if additional iterations are warranted. One of the disadvantages of the method is that it can be time consuming. Multiple iterations through the process to fully optimize resource selection may be too time consuming. Fortunately, if the marginal costs are fairly stable, as at CP&L, this feedback loop does not necessarily have to occur in a single planning cycle.

Summary

CP&L has evaluated a model in an effort to demonstrate the simultaneous integration method. Given non-intuitive results during testing, CP&L continues to use the iterative integration approach to integrated resource planning. This process is a valid approach and has several strengths, primarily being its straightforward approach and ease of comprehension.

Economic Cost-Effectiveness

CP&L evaluates the economic cost-effectiveness of demand-side management options from four different perspectives; 1) the utility point of view - the Utility Cost Test, 2) the ratepayers' perspective - the Ratepayer Impact Measure (RIM) Test, 3) the potential participant in a demand-side management option - the Participant Test and 4) the utility and its ratepayer as a whole - the Total Resource Cost (TRC) Test.

The net present value (NPV) results of these four economic tests are measures of cost-effectiveness, weighing the benefits against the costs of a demand-side management option. However, since each test represents a different perspective, the assignment of benefits and costs vary for each test. The costs and benefits components measured for input to these tests include supply costs, utility program costs, participant costs, changes in revenues to the utility or changes in bills to the participant, incentives paid to participants and participation charges paid to the utility. The definitions of costs and benefits also vary by load shape objective. For example, demand-side management options designed to achieve strategic conservation, load shifting, or peak clipping avoid supply costs. Therefore for these load shape objectives, supply costs are considered a benefit because these costs are avoided. However, supply costs become a component of the total costs when evaluating valley filling or strategic load growth demand-side management options since they increase the need for the supply of energy. The following tables summarize the classification of costs and benefits among each economic test and load shape objective.

Table D-1
Strategic Conservation, Load Shifting, Peak Clipping
Load Shape Objectives

	Benefits	Costs
Utility Cost	Avoided Supply Costs Participation Charges	Incentives Utility Program Costs
Ratepayer Impact Measure	Avoided Supply Costs Participation Charges	Incentives Utility Program Costs Revenue Loss
Participant	Incentives Bill Reductions	Participant Costs Participation Charges
Total Resource Cost	Avoided Supply Costs	Utility Program Costs Participant Costs

Appendix D
Avoided Cost Methodology

CP&L uses the component method (sometimes called the "peaker method") to determine avoided costs. This methodology uses the cost of the minimum capital cost generation alternative as the avoided generation capacity cost and the utility system's incremental (or decremental) energy cost as the avoided energy cost. The incremental cost of the transmission system and distribution system are also considered. Where appropriate, the costs are adjusted by reserves, losses and working capital. CP&L uses avoided costs to evaluate DSM programs, for payments to qualifying facilities and for internal cost-benefit studies. Avoided costs provide a linkage between demand and supply-side planning.

The component methodology was developed by National Economic Research Associates and has been extensively documented in the literature. Use of the minimum capital cost generation option as the avoided capacity cost is derived from an understanding of generation planning and the trade-off between capital and energy costs. The current minimum capital cost option is the combustion turbine (CT). CP&L used the following avoided costs in the analysis of its DSM programs in the 1995 IRP:

Table D-1
Avoided Capacity Costs
(1994 dollars)

Generation	\$363/kW
Transmission	\$260/kW
Distribution	\$606/kW

Table D-2
Avoided Energy Costs
(Nominal ¢/kWh)

Year	On-Peak	Off-Peak
1994	1.63	1.43
1995	1.76	1.47
1996	1.97	1.55
1997	1.94	1.57
1998	2.28	1.64
1999	3.52	1.89
2000	3.79	2.21
2001	4.48	2.48
2002	5.68	2.94
2003	5.42	2.87
2004	6.33	3.29
2005	7.82	3.97
2006	7.96	4.00
2007	8.94	4.65
2008	9.69	4.48