Chapter 3:
Electric Utilities

Energy Use

North Carolina's electric utilities convert imported fuels, hydropower, and other sources of energy into electricity and distribute it to residential, commercial, industrial, and other customers throughout the state. While recent problems in California have created concerns about the reliability and price stability. Utilities have supplied electricity reliably with minimal operating problems in North Carolina. In our growing electronic age, electricity has experienced an exponential growth rate.

Figure 3-1 shows energy use in the electric utility sector. While nuclear energy assumed an increasing share of electricity production in the 1980's, coal maintained and extended its historical dominance in the 1990's. According to Table 3-1, coal-generated electricity currently provides about 60% of total electricity needs for North Carolina, nuclear power provides about 36%, hydroelectric plants supply 2.5%, and natural gas and petroleum supply 1% or less.

Figure 3-1:
Energy Use in Utility Sector

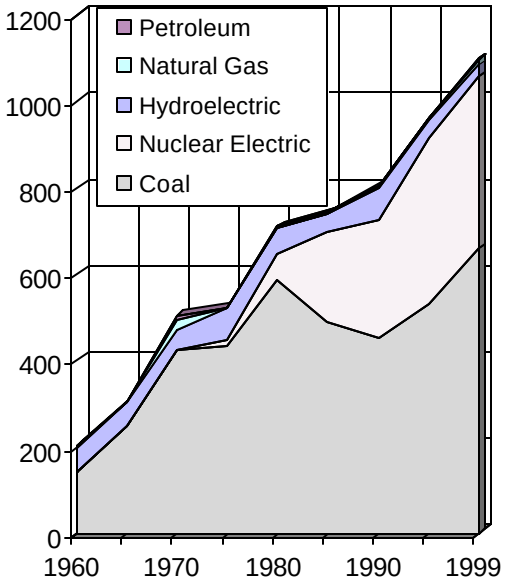


Table 3-1:
Percentage of Total Electrical Production

	Coal	Natural Gas	Petroleum	Nuclear Electric	Hydro-electric
1960	71.1%	2.4%	0.2%	0.0%	26.3%
1965	80.7%	1.0%	0.1%	0.0%	18.2%
1970	84.5%	4.3%	2.2%	0.0%	9.1%
1975	82.6%	0.0%	0.4%	3.0%	14.0%
1980	82.4%	0.3%	0.5%	8.8%	8.0%
1985	65.8%	0.1%	0.3%	28.0%	5.7%
1990	56.1%	0.3%	0.3%	34.4%	9.0%
1991	53.5%	0.4%	0.2%	38.5%	7.4%
1992	62.9%	0.4%	0.2%	29.2%	7.3%
1993	64.8%	0.3%	0.2%	28.6%	6.1%
1994	55.7%	0.1%	0.3%	37.6%	6.3%
1995	55.4%	0.3%	0.2%	39.7%	4.3%
1996	60.3%	0.2%	0.3%	34.6%	4.5%
1997	63.0%	0.4%	0.3%	32.3%	4.0%
1998	58.5%	1.1%	0.3%	36.2%	3.7%
1999	60.0%	1.0%	0.3%	36.2%	2.5%

Electrical customers rely on the state's electric utilities to provide electric power. Because of their practical monopoly on electrical distribution in their service areas, electric utilities have generally been subject to regulation or government oversight during most of the previous century. Recently there has been a significant reevaluation of the regulatory structure that sets

rules for the production, transmission, distribution, and sale of electric power.

Regulatory Background and Issues

Historical Context

The market for electricity is undergoing a transformation that challenges the traditional understanding of the role utility companies, state regulatory entities, and national policy makers play in providing reliable and affordable electricity to customers. In order to understand the issues currently confronting the utility companies, regulatory bodies, legislatures, and consumers, it is necessary to review a brief history of electricity's legal and economic environments. (Source: Energy Information Administration, Electricity Prices in a Competitive Environment: Marginal Cost Pricing of Generation Services and Financial Status of Electric Utilities, August, 1997)

As originally conceived in the early 20th century, the electricity market was considered to be a "natural monopoly" in that the costs and therefore the risks associated delivering electricity to the market were such that exclusive franchises were provided to companies to serve specific geographic areas. In 1935 Congress passed the Public Utility Holding Company Act that broke up massive interstate holding companies and codified a regulated market arrangement by restricting the electric power generating business to domestic utilities that built and operated power plants to serve specific geographic markets without competition. In return, states carefully regulated the companies operating within their borders.

During the 1970s the market conditions within the electric industry changed in response to the 1973 Arab oil embargo, the financial collapse of utility stocks following Consolidated Edison's dividend freeze in 1974, and the instability of the political situation in the Middle East manifest with the Iranian revolution of 1978. In response to these threats to the stability of the electricity market, Congress passed the Public Utilities Regulatory Policies Act of 1978 (PURPA) with the intent of ensuring greater energy security. Its effect was to open the door to competition in the electricity supply market by requiring utility companies to purchase electricity from independent generating facilities (known as qualifying facilities) that used cogeneration technology or generated less than 50 megawatts using renewable technologies.

In 1992, the Energy Policy Act opened up the wholesale market for energy to non-utility generators of electricity. A new class of electricity suppliers was created – exempt wholesale generators -– who where allowed to compete for the right to sell electric power. Further, Congress mandated that utilities provide wholesale power transmission service to third parties at cost-based rates, even if doing so caused them to expand their transmission capacity. The Federal Energy Regulatory Commission (FERC) was given the responsibility for implementing open access to the transmission grid as a way of fostering competition in the electricity wholesale market.

Following the 1992 legislation, FERC Orders 888 and 2000 were issued with the intent of fundamentally transforming the utility industry from a

regulated industry to an open marketplace where electricity is generated and sold on the wholesale market much like any other commodity. FERC Order 888 issued in 1996 created an open access policy requirement for all transmission owning entities under its jurisdiction. The Order required transmission owners to provide equal access to all market participants on a first come, first served basis. In order to facilitate this open access rule, FERC required that the vertically integrated utilities (typically IOUs with generation, transmission, and distribution capability) to functionally separate their distribution and transmission units.

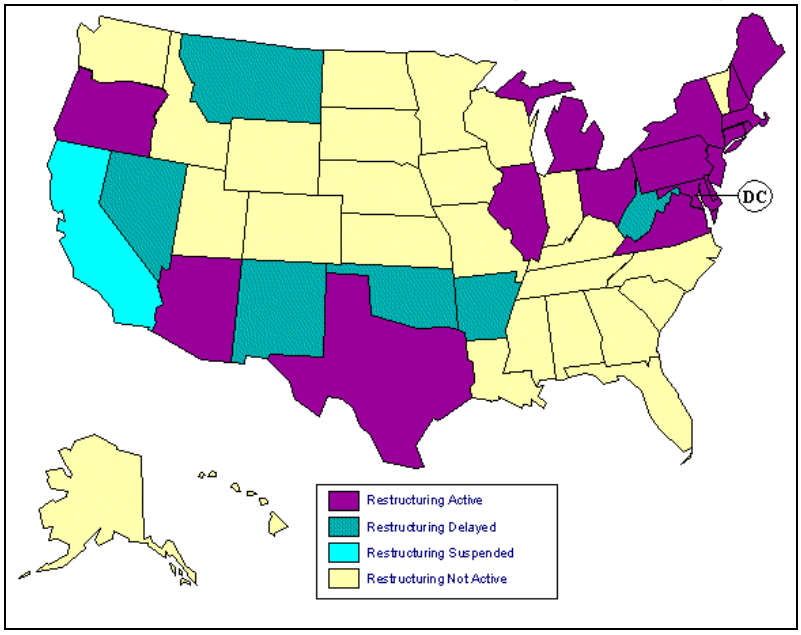
In essence, Order 888 shifted the function of the transmission grid from serving the transmission owners' interests (serving their own customers) to creating a common carrier system for electricity that is open to market use – much like natural gas. In that same year, 1996, California and Rhode Island passed landmark legislation to restructure their electric power industries and to give their consumers the right to choose their electricity supplier. Very rapidly many states followed suit so that by 1998, twenty-four states had passed some form of utility restructuring legislation. Then just as rapidly the momentum behind restructuring quickly faded primarily due to events unfolding in California over the 2000-01 period.

Restructuring in North Carolina

North Carolina's response to the restructuring movement of the mid-1990s was the establishment in April 1997 of the Study Commission on the Future of Electric Services in North Carolina. This 30-member body composed of legislators, industry representatives, utilities, and other stakeholder representatives was charged with examining the cost and adequacy of electrical service in the state and to explore the implications of restructuring on a host of issues ranging from reliability to environmental implications. In 1998, the Commission contracted with Research Triangle Institute to serve as consultant to the body and to provide in-depth research on a number of complex issues.

Following three years of hearings, the Commission recommended legislation that would among a number of things allow fully competitive retail electric service as of January 1, 2006, with retail choice available to up to 50% of each power supplier's load as of January 1, 2005 and stranded costs recovery for investor owned utilities with a rate freeze effective through December 31, 2004. The events of the summer of 2001 in California have put these plans on hold. The map in Figure 3-2 portrays the current status of electricity restructuring across the country.

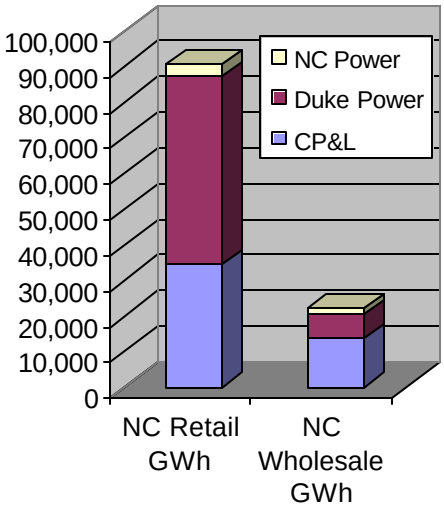
Figure 3-2:
2002 Status of Electricity Restructuring



Source:www.eia.doe.gov

FERC Order 2000 issued in 1999 called for the development of Regional Transmission Organizations (RTOs) which are essentially independent, multistate, transmission-owning entities that would administer the electricity grid within their respective geographic boundaries. This initiative is not without controversy nor is it clear at this point exactly how the RTO system would operate. Initially, in response to this Order, Duke Power, Carolina Power and Light, and South Carolina Electric and Gas announced in March 2000 the formation of GridSouth as the RTO covering the Carolinas. However, based upon additional rulings by FERC attempting to clarify its Order 2000, this proposal was withdrawn by the three utilities in February 2002. Based upon interviews with the Public Staff of the North Carolina Public Utilities Commission and reports prepared in response to FERC directives, it appears that regionalization of the electrical grid may not be in the best interests of North Carolina consumers.

Figure 3-3: Electricity Sales in North Carolina, 2000



Electricity Utilities in North Carolina

The Structure of the Electricity Market in North Carolina

North Carolina electrical customers are served by three investor owned utility (IOUs) companies, 32 electric membership cooperatives (EMCs), and 74 municipally/university owned (MUNIs) electric distribution companies. In 2000, almost 95% of the electricity generated and sold within the state is supplied by Duke Power and Carolina Power and Light. Approximately two-thirds of the utility retail business of both Duke and CP&L is within North Carolina with the remainder in South Carolina.

Approximately 20% of the IOUs' total electric sales in North Carolina are to the wholesale market in North Carolina, consisting primarily of sales to EMCs and MUNIs. Of the 32 EMCs serving North Carolina customers, 27 are headquartered within the state and together they serve 860,000 customers spread across 93 of the state's 100 counties. Twenty-six EMCs are members of the North Carolina Electric Membership Corporation (NCEMC). The NCEMC is the third largest electric cooperative in the United States and the fourth largest based on energy use.

MUNIs service over 500,000 customers spread across the state and most are members of the non-profit corporation, ElectriCities, which provides technical, administrative, and management services for them. North Carolina has two municipal Power Agencies, North Carolina Municipal Power Agency Number 1 (NCMPA1) and North Carolina Eastern Municipal Power Agency (NCEMPA). In the Piedmont and foothills region of North Carolina, 19 municipalities are members of NCMPA1. The agency has 75 percent ownership interest in Catawba Nuclear Station Unit 2 located in York County, S.C., which is operated by Duke Power. It also has an agreement with Duke that provides for electric power through McGuire Nuclear Station and Catawba Unit 1 should Catawba 2 be unavailable for service.

In the eastern part of the state, 32 cities and towns are members of NCEMPA. The agency owns interest in five generating units built and operated by CP&L. These facilities include three nuclear units, Brunswick Units 1 and 2 in Brunswick County and Shearon Harris Nuclear Plant in Wake County, and two coal-fired plants, Mayo Plant and Roxboro Unit 4 in Person County.

The trend of both EMCs and MUNIs in North Carolina is to rely increasingly on power generated from sources other than the state's IOUs. This is especially true of NCEMC which is in the process of diversifying its power portfolio to ensure reliability and lower cost.

Electricity Sales

The data in Table 3-3 indicate that in total sales, Duke Power is the leading provider and retail distributor of electricity in the state with 58 percent of the market. CP&L holds a healthy 38 percent share of the retail market and largely dominates the wholesale market in North Carolina. While NC Power's parent company is a large utility presence in Virginia, its market share in North Carolina is modest as are the two university based suppliers. Both Duke and CP&L experienced a slight decrease in sales from 2000 to 2001 due primarily to moderate weather conditions and a decrease in industrial demand following the state's economic slowdown.

Table 3-2:
Utility Retail Sales, Revenue and Number of Customers in North Carolina

	Investor Owned	Public	Federal	Coop	Total
Number of Utilities	3	72	1	31	107
Number of Retail Customers (thousands)	2,691	508	0.004	807	4,006
Retail Sales (thousand megawatthours)	88,495	13,941	6	12,572	115,015
Percentage of Retail Sales	77%	12%	0%	11%	100%
Revenue from Retail Sales (million dollars)	5,325	1,077	0	1,009	7,412
Percentage of Revenue	72%	15%	0%	14%	100%
Average Revenue per Kilowatthour (cents/kWh)	6.02	7.72	4.06	8.03	6.44
Source:eia.doe.gov-NC Electricity Profile-1999					

Table 3-3:
Electricity Sales in North Carolina, 2000-01

	NC Retail GWh*		NC Wholesale GWh*		Total GWh Sales* (NC Plus Other States)	
	2001	2000	2001	2000	2001	2000
CP&L	33,745	34,747	12,355	13,868	53,561	56,653
Duke	51,921	53,726	5,917	6,718	79,685	84,767
NC Power	3,585	3,359	1,658	1,709	74,520	76,155
New River	208	213	0	0	208	213
Western Carolina	28	30	0	0	28	30

*GWh = 1 Million KWh

Source: ***Annual Report of the North Carolina Utilities Commission***, July 2002.

Supply and Growth in the Electric Market

Over the past twenty years both Duke and CP&L have experienced a summer peak load average annual growth rate of 3%. This has varied from a high of 4.8% during the 1985-90 period for both Duke and CP&L to a low of 1.8% over the 1995-2000 period for CP&L. Winter peak loads have also grown over this period at a slightly lower average rate of 2.8% but the variation in growth over the periods has been greater with a range of 4.5% for CP&L during the 1990-95 period to a 0.6% rate during 1995-2000 for Duke.

Table 3-4:
Summer and Winter Systemwide Peak Loads for CP&L, Duke, and NC Power Since 1980 (in MW)

	CP&L		Duke		NC Power	
	Summer	**Winter***	**Summer**	**Winter***	**Summer**	**Winter***
1980	6,139	6,402	10,364	10,530	8,484	8,451
1985	6,867	7,763	11,204	12,586	9,819	9,836
1990	8,681	7,875	14,046	12,778	12,113	11,076
1995	10,155	9,810	16,888	15,855	14,003	14,910
2000	11,106	11,140	18,773	16,336	15,410	14,729
2001	11,376	9,813	18,105	14,987	16,515	14,188

*Winter Peak following summer peak

Source: ***Annual Report of the North Carolina Utilities Commission***, July 2002.

Approximately 94% of the 92 million megawatthours of electricity supplied in 1999 to North Carolina customers is supplied by Duke Energy (52 million) and Carolina Power and Light (33 million) respectively. Approximately 90% of this generation is from native generating plants included in their retail rate base or obtained pursuant to purchase power contracts with independent power producers operating plants located within each purchaser's control area. (Annual Report of the North Carolina Utilities Commission Regarding Long Range Needs for Expansion of Electric Generation Facilities for Service in North Carolina, June 2001).

Additionally, the power supplied to retail customers of the municipal utilities and electric membership cooperatives in the state is provided from local generating plants owned by the municipals and EMCs or purchased from local plants. Essentially, North Carolina companies generate, transmit, and distribute native power to native customers.

According to the Public Staff, "As they now exist, the transmission systems serving North Carolina are very reliable and have adequate reserves for load growth and unexpected contingencies…. Because North Carolina's transmission systems were built predominately for the purpose of moving power locally and currently are being used for this purpose, the use of these

. . . the 'seamless' wholesale energy market the Commission (FERC) is trying to create obviously will negatively impact North Carolina ratepayers . . . (North Carolina Public Utilities Commission)

systems for ***the 'seamless' wholesale energy market the Commission (FERC) is trying to create obviously will negatively impact North Carolina ratepayers.***" (Comments of the North Carolina Utilities Commission on the Standard Market Design and the Structure Working Paper, Docket No. RM01-121-000, April 10, 2002) The essential point made by the Public Staff is that the ratepayers of North Carolina should not be forced to pay for the transmission inadequacies of other regions of the country.

Forecasted Growth in Energy and Peak Load

With the inception of Integrated Resource Planning, North Carolina Utilities have enhanced the accuracy of their end-use forecasts. While an imprecise art at best, the approach employed by the IOUs relies upon historical information and includes specific electrical usages and consumption patterns in addition to general economic relationships. Table 3-5 below displays the projected growth rates for the state's IOUs through 2011.

Table 3-5:
Forecast Annual Growth Rates for CP&L, Duke, and NC Power (2002-2011)

	CP&L		Duke		NC Power	
Summer Peak	177 MW	1.4%	355 MW	2.0%	176 MW	1.1%
Winter Peak	230 MW	2.0%	260 MW	1.6%	146 MW	1.0%
Energy	1,667 GWh	2.7%	2,322 GWh	2.3%	1,174 GWh	1.4%

Source: ***Annual Report of the North Carolina Utilities Commission***, July 2002.

The forecasted growth in supply is lower than the historical growth displayed in the previous decades. This is largely because efficiency, load management, and emerging alternative energy sources represent permanent changes in customer use. However, as the Public Staff point out, " … uncertainties concerning the timing and predictability of the various demand reduction techniques under consideration make it necessary to allow flexibility in planning for generation capacity expansion to match the forecasts."

Generation Capacity and Mix of Fuels

As mentioned previously, North Carolina's primary utility companies produce over 90% of their electrical capacity from native generating plants. CP&L also has plants in South Carolina that provide power for North Carolina customers. The CP&L system, like Duke's system, operates as an integrated whole to dispatch power to customers in both North and South Carolina. These plants are categorized into three types depending upon their role within the supply reliability mix:

- Base load generation – facilities running for more than 5,000 hours a year and provided by large coal and nuclear plants.
- Intermediate generation – facilities operating between 1,000 to 5,000 hours a year and provided by smaller coal, hydroelectric, and

natural gas plants.

- Peaking generation – facilities operating intermittently based upon demand (less than 1,000 hours a year) and provided by combustion turbine and other similar plants.

According to the Integrated Resources Plan updates submitted by CP&L and Duke to the North Carolina Utilities Commission, the generating plants within North Carolina by fuel type is shown in Table 3-6.

Table 3-6:
Installed Generating Capacity by Fuel Type
(Summer Ratings) for 2001

	CP&L	Duke	NC Power
Coal	44%	40%	37%
Nuclear	26%	36%	24%
Hydroelectric	2%	15%	11%
Oil and Natural Gas	28%	9%	28%

Source: ***Annual Report of the North Carolina Utilities Commission***, July 2002.

While the data illustrate the capacity to generate electricity, the actual power produced and sold by the IOUs is determined by what is the most cost efficient production method at any one point in time which is affected by a number of factors including startup and fuel costs.

Table 3-7 shows the actual energy production by energy source. Coal and nuclear power remain the dominant sources, with hydroelectric power, natural gas, and fuel oil playing a rather insignificant role. Although oil and gas plants provide a considerable percentage of total capacity in Table 3-6, they are primarily peaking plants and do not produce much electricity, as shown in Table 3-7. Note that the chart is for system-wide production. Thus, Duke Power and CP&L's capacities include a number of electric power facilities located in South Carolina, and NC Power's data includes the bulk of its facilities, which are located in Virginia.

Table 3-7:
Total Energy Resources by Fuel Type for 2001

	CP&L	Duke	NC Power
Coal	50.1%	48.7%	41.3%
Nuclear	38.4%	47.8%	32.0%
Hydroelectric	0.4%	0.0%	3.8%
Oil and Natural Gas	1.6%	0.1%	8.9%
Purchased Power	9.5%	3.4%	14.0%

Source: ***Annual Report of the North Carolina Utilities Commission***, July 2002.

Table 3-8, based on U.S. Energy Information Administration reports, presents average electricity production data for all utilities in North Carolina and surrounding regions. The table shows that the South Atlantic region uses substantially more petroleum and natural gas than North Carolina. However, the states in the region around North Carolina – South Carolina, Georgia, Tennessee, Virginia, and North Carolina itself – approximate the fuel mix in North Carolina. Florida, one of the states in the South Atlantic region, is most likely the reason that petroleum and natural gas contribute moderate percentages of region-wide electricity production.

The table also shows how construction of 6,000 MW and 9,000 MW of natural gas base load power plants would affect the overall mix. Note that providing the needed capacity with natural gas plants would push the fraction of total electricity provided by natural gas to current levels in Florida. Some have complained that using solely natural gas power plants for future construction would be "putting all of our eggs in one basket." The table shows that it would in fact, promote diversity among three primary fuels – coal, natural gas, and nuclear. The major dilemma is whether natural gas can maintain stable supply prices in the future so as to avoid sudden price hikes. Obviously, the impact of a natural gas price spike when only 0.7% of electricity relies on the fuel is inconsequential, especially when considering a shift to over 20% reliance.

Table 3-8:
Fuel Mix for Electric Power Production -- 2001

	Coal	Petro-leum	Gas	Hydro	Nuclear	Other
North Carolina	*62.7%*	*0.4%*	*0.7%*	*2.0%*	*34.2%*	*0.0%*
South Atlantic	59.1%	5.9%	6.3%	0.9%	27.8%	0.0%
GA, TN, VA, SC, NC	59.1%	0.9%	1.0%	2.3%	36.8%	0.0%
Florida	39.5%	20.2%	21.2%	0.1%	19.0%	0.0%
North Carolina with 6,000 MW gas @ 75% capacity factor (estimated)	*37.1%*	*0.3%*	*20.8%*	*1.2%*	*20.2%*	*0.0%*
North Carolina with 9,000 MW gas @ 75% capacity factor (estimated)	*33.7%*	*0.3%*	*28.2%*	*1.1%*	*18.4%*	*0.0%*

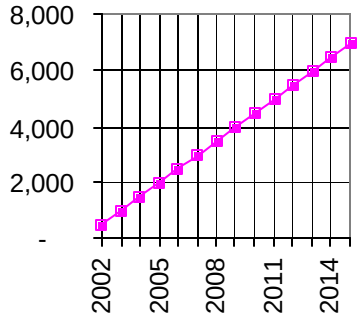
Source: ***EIA Monthly Electric Power Report***, March, 2002

Future Capacity Needs

Based on projections of peak load growth shown earlier, Figure 3-4 shows approximate power needs for the state. Note that by 2015, about 7,000 MW

of new capacity will be needed. Options for reducing the need for this capacity are:

- Reduce electricity generation and peak power requirements via energy efficiency programs.
- Reduce peak power needs via demand side management programs.
- Decrease reserve margin and maintain system reliability via long term contracts with maximum price guarantees.
- In order to reduce needs for fossil fuel-fired power plants, increase use of in-state renewable electricity resources via Green Power programs and Renewable Portfolio Standards, as discussed in the chapter on Renewable Energy.



Demand Side Management Programs

Demand side management (DSM) programs emerged in the 1970s in response to the Arab oil embargo and were an attempt to curb the rate of growth in electric consumption. DSM encompasses a wide variety of actions taken by utility companies to modify their customer's energy demand. Typically, these programs are targeted at reducing energy use (e.g., efficient buildings, equipment and processes), redistributing energy demand to spread it more evenly throughout the day (e.g., load shifting, innovative rates), and/or encourage strategic load growth (e.g., electrification programs). Utilities accomplish these goals by using rebates, audits, loans and free installation of energy efficient equipment, as well as other similar strategies.

In the mid-1990s, utility companies began to reduce discretionary spending and to scale back their DSM programs. There were two main driving forces behind utility cutbacks in DSM -- the economics changed-i.e., the cost of new gas-fired generation dropped substantially and the move toward deregulation caused many utilities to enact cost-cutting programs that included DSM programs and staff. As a result, utility spending nationally on DSM and other energy efficiency programs declined from a peak of $2.74 billion in 1993 to $1.4 in 1999. (ACEEE, State Scorecard on Utility Energy Efficiency Programs, April 2000)

The national decline in DSM programming was mirrored in North Carolina. According to a national study conducted by the American Council for an Energy Efficient Economy, spending (measured as the percentage of revenue) on DSM programs in North Carolina declined from 0.31% in 1993 to 0.14% by 1998 or by over half. In terms of energy savings attributed to DSM as a percentage of total sales, North Carolina utilities reported a drop of 1.78% in 1993 to 0.94% in 1998, again nearly one half in five years.

ACEEE reports that spending on DSM programs in North Carolina declined from 0.31% of revenue in 1993 to 0.14% by 1998 or by over half. In terms of energy savings attributed to DSM as a percentage of total sales, North Carolina utilities reported a drop of 1.78% in 1993 to 0.94% in 1998, again nearly one half in five years.

Table 3-9 displays the planned DSM Summer peak Load reductions reported by the state's IOUs over the next nine years as reported to the NC Utility Commission. It shows a slight increase for CP&L and a modest decrease by Duke and NC Power. Thus, unless current trends are reversed, demand side management programs will in no way reduce peak power requirements and thus decrease the need for new power plants.

Table 3-9: Projected DSM Summer Peak Load Reductions (in MW)

	2002	2011
CP&L	372	385
Duke	888	826
N C Power	61	49

Both public and private sector policy leaders in North Carolina should continue to monitor and remain vocal in the development of national policies affecting the transmission of reliable and affordable power to NC consumers.

Reserve Capacity

In order to assure reliable service, utility companies are required to maintain a margin of generating capacity available to their system to cover both scheduled (typically maintenance) and unscheduled (typically mechanical failures) interruptions of service. This reserve margin is also designed to cover uncertainties in forecasted generation capacities. The amount of generating reserve needed to maintain a reliable power supply 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 strength of the transmission interconnections to other utilities.

According to CP&L and Duke's 2001 IRPs submitted to the NC Utility Commission, both utilities report having adequate reserve capacity in their respective systems. CP&L reports, "Reliability assessments have shown that reserves projected in CP&L's September 2001 Resource Plan are appropriate for providing an adequate and reliable power supply. Reserves, expressed either as reserve margin or capacity margin percentages, are lower than historical levels due to a number of factors. Growth in generating system and the addition of smaller and highly reliable combustion turbine increments to the company's resource mix decreases the capacity margin percentage needed to maintain adequate reliability." (CP&L IRP 2001, p. 21)

Table 3-11:
Projected Reserves for CP&L, Duke, and NC Power

	Reserve Margins
CP&L (2002-2011)	12.1-15.2%
Duke (2002-2011)	17.0-17.6%
NC Power (2002-2011)	12.5-13.5%

Source: Annual Report of the North Carolina Utilities Commission, July 2002**.**

Duke reports, " In 1997, Duke adopted a planning reserve margin target of 17%. Duke adjusted its target reserve margin at that time to reflect availability of generation, shorter construction lead times, and the evolving market for purchased power….Based upon successful operations utilizing the 17% planning reserve margin, Duke concludes that its continued use is appropriate at this time." (Duke IRP 2001, p. 3-4)

Figure 3-5 displays the percentage reserve capacity reported by Duke and CP&L through 2011. The data indicates that Duke reports higher reserve margins than CP&L for the summer months with Duke maintaining a consistent 17% margin over this period while CP&L and NC Power report margins between 12-15% over the next decade. Winter margins are typically higher peaking at slightly over 25% in the near term and generally drifting downward over the time period.

Figure 3-5:
Projected Reserve Margins for Electric Utilities

The State Energy Office, North Carolina Public Utilities Commission, and in particular, the state's electric utility industry should investigate potential combinations between electrical generating plants and nearby industrial facilities requiring high levels of steam for thermal energy needs.

Policies Recommended for the Utility Sector

Both public and private sector policy leaders in North Carolina should continue to monitor and remain vocal in the development of national policies affecting the transmission of reliable and affordable power to NC consumers. While FERC Orders appear fluid as of this time, it is essential that North Carolinians not be forced to pay for transmission problems in other regions of the country.

There is potential in North Carolina for increased efficiency of energy use via Combined Heat and Power (CHP) Plants. ***The State Energy Office, North Carolina Public Utilities Commission, and in particular, the state's electric utility industry should investigate potential combinations between electrical generating plants and nearby industrial facilities requiring high levels of steam for thermal energy needs.*** Standard power plants are only 30% to 40% efficient. CHP facilities have efficiencies in the 60% to 70% range. Individual industries could also construct their own CHP facilities, most likely on a smaller scale than electric utilities. However, there are a host of regulatory restrictions on how electricity produced at an independent facility can be transmitted and sold. The chapter on Renewable Energy addresses several policy issues needed to create potential for independent CHP development.

Duke and CP&L have some of the most efficient power plants in the nation. Specifically, in November 1999, Duke Power was ranked first nationally in coal power plant thermal efficiency with an average heat rate of 9,382 Btu/kWh among its eight plants. While the efficiency ratings these power plants have earned is certainly admirable, it is critical to the economic and environmental future of North Carolina that these efficiency levels be maintained and improved if at all possible. Insuring North Carolina's power

The Public Utilities Commission should require a study to ensure that electric utility facilities are operating at optimal efficiencies. Efforts to improve the efficiency of electricity generation, transmission, and distribution should be reported in each IRP.

plants are operating at optimal efficiency levels will contribute to reduced energy imports as well as reduced air pollutant emissions. ***The Public Utilities Commission should require a study to ensure that electric utility facilities are operating at optimal efficiencies. Efforts to improve the efficiency of electricity generation, transmission, and distribution should be reported in each IRP.***

It is therefore essential that the state develop a program or set of programs to replace the DSM programs that have been eliminated by the IOUs. Public benefit funds and renewable portfolio standards are examples of what other states have adopted in the face of declining effort in DSM programs.

The state's heavy reliance on coal as the primary source of fuel for generating electricity and the age of the plants burning the coal pose serious environmental hazards. A recent agreement between the state and the two largest IOUs to install equipment to mitigate the release of harmful chemicals into the environment is a very positive step in the right direction (more on this in the Environment Chapter). In the long term however, it is imperative that cleaner fuels be given greater attention, especially renewable fuels, as a larger portion of the generation supply. The recently endorsed Green Power Program by which all North Carolina customers will be offered the opportunity to purchase blocks of their monthly electricity supply from renewable sources is, again, a very positive step in the right direction. If this program is to succeed it will be necessary to aggressively promote the development of renewable energy supplies through incentives, subsidies, and perhaps regulations.

The reduction in effort on Demand Side Management programs is a cause of great concern. While understandable that the state's IOUs would look for ways to reduce their operating costs in anticipation of a restructured electricity market, neglecting the need to promote greater efficiency, load management, and distributed generation is not in the public's interest. Additionally, some of the DSM programs in place from the 1990's simply did not meet minimum cost-effectiveness parameters.

While some of the utilities' DSM programs only reduced demand for electricity and did little to reduce consumption, many other programs targeted both demand and consumption. Programs that reduce consumption, such as lighting retrofit projects in commercial buildings, industrial process changes, or energy efficiency programs for new homes, are cost effective for utility customers. Thus, these DSM programs not only reduced demand, but also provided an important service. In fact, electric utility staff members working on DSM programs have given excellent energy outreach assistance during the 1980 to 1995 period. This service has been reduced substantially in recent years. ***Thus, North Carolina needs to develop a program or set of programs to replace the DSM programs that have been eliminated by the IOUs. Public benefit funds and renewable portfolio standards are examples of what other states have adopted in the face of declining effort in DSM programs.*** These programs are discussed in detail elsewhere in the plan.

A host of other issues concern the interface between the electric utility industry and private power producers, particularly with smaller electricity generators. The policies that concern these issues are contained in the chapter on Renewable Electricity.

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