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STATISTICAL INDICATORS OF POTENTIAL FOR ELECTRIC UTILITY LEAST-COST PLANNING PROGRAMS

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EXECUTIVE SUMMARY

Construction cost overruns, volatility in world oil prices, problems in the nuclear power industry, and the emergence of environmental concerns have led regulators and utilities to seek alternative approachs for planning for future energy services. These efforts have become broadly known as least-cost utility planning (LCUP). Although many definitions of LCUP can be found, they share common themes. The Wisconsin Public Service Commission, a leading example of a regulatory body with a strong commitment to LCUP, defines it as "*a process in which all reasonable options for both the supply and demand are assessed against an array of cost-benefit considerations which are defined as broadly as possible.*"

Today, LCUP in more than 33 states face varying demand/supply situations and prospects. These initiatives have been prompted not only by impending capacity shortages, but also by environmental, regional development, and long-term economic efficiency considerations. From a federal policy viewpoint, it is necessary to understand how LCUP could contribute to the supply/demand balance in various regions of the country. LCUP can have large impacts on this balance because it mobilizes resources that are inadequately or not at all reflected in conventional utility resource plans and projections. On the supply side, these additional resources consist of Qualifying Facilities (QFs), purchased power, and life extension investments. On the demand side, they consist of conservation and load management programs.

The goal of this project is examine the potential for LCUP by estimating **when** and **where** demand-side measures can make a difference in utility resource plans. We make this assessment by linking utility interest in LCUP to a variety of economic and regulatory factors that influence utility resource planning decisions. We have developed two sets of indicators: economic indicators that describe the electricity demand and supply picture by NERC regions and states; and regulatory indicators that summarize the institutionalization of some kind of least cost planning process by state.

The economic indicators describe key aspects of the relationship between electricity supplies and demands as they relate to LCUP. We find:

- If the DOE's analysis is correct, major portions of the country will be short of capacity in just a few years. Mitigating these shortages will require either rapid deployment of supply-side resources or substantial intervention on the demand-side.
- DOE's analysis, however, is based on utility-reported data. We are particularly concerned about the accuracy of utility forecasts of non-utility generation. The issues include strategic motivations by utilities, consistency in the data used to forecast non-utility generation, and the rate of technological change in electricity generation. Similarly, small changes in peak demand growth rates (on the order of 1%/yr) can either severely exacerbate shortages or mitigate them almost entirely.

- If oil and gas prices rise, there are clear economic incentives in the form of increased marginal energy costs for the deployment of less expensive demand-side alternatives.
- If oil and gas prices remain stable or decline, opportunities for demand-side programs will be largely dictated by other considerations, such as peak demand mitigation or imminent need for new baseload capacity.
- In the near-term, utilities in several regions should be considering investments in baseload capacity. This interest is relatively insensitive to alternative demand growth assumptions. In the absence of lower cost supply alternatives, the importance of demand-side programs that displace both peak and baseload energy requirements (e.g. efficient appliances) is enhanced.
- Large uncertainties exist on the supply-side as to whether cheaper supplies will be available from non-utility sources or through bulk power transfers. Identifying the ability of demand-side programs to substitute cost-effectively for baseload generation requirements requires further analysis of these supply alternatives.

Our evaluation of regulatory indicators focuses on state initiatives to foster LCUP programs, commission staffing for LCUP activities, and the use of marginal costs. We find:

- Many states are actively pursuing policies to promote LCUP. In 1987, LCUP programs were in place in 17 states, being developed in 8 states, and under consideration in 4 states.
- Developments by the states are taking place at a rapid pace; most data are already out of date.
- Manpower commitments are required to implement policies, and several states have made substantial staff commitments to LCUP, notably California, Texas, New York and Wisconsin.
- The use of marginal costs is widespread, but, oddly, not always consistent with the presence or absence of explicit LCUP policies.

In a final section, we review major sources of uncertainty and identify directions for further research. These areas include:

- Review and assessment of the availability of non-utility sources of power and of the opportunity for bulk power transfers to address supply-demand imbalances.
- Continuous tracking of state LCUP activities in conjunction with the National Association of Regulatory Utility Commissioners.
- Improved understanding of the underlying reasons for historic utility over- and under-forecasting and the potential for improving future forecasts.

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INTRODUCTION

What is Least-Cost Utility Planning?

Construction cost overruns, volatility in world oil prices, problems in the nuclear power industry, and the emergence of environmental concerns have led regulators and utilities to seek alternative approaches for planning future energy services. These efforts have become broadly known as least-cost utility planning (LCUP). The term "least-cost" can be misleading, however; utility spokespersons often claim that the industry's traditional emphasis on minimizing revenue requirements guarantees that, by definition, least-cost resource plans have always been developed. But advocates of LCUP clearly feel this has not been so.

Although many definitions of LCUP can be found, they share common themes. The Wisconsin Public Service Commission, a leading example of a regulatory body with a strong commitment to LCUP, defines it as "*a process in which all reasonable options for both the supply and demand are assessed against an array of cost-benefit considerations, which are defined as broadly as possible.*" In this definition, contrary to historic utility planning methods, LCUP pays attention to demand-side options and non-economic factors. It does not preclude supply-side options, but requires they be evaluated be made in conjunction with demand-side options and according to more than purely economic criteria.

Today, LCUP in more than 33 states face varying demand/supply situations and prospects. LCUP initiatives have been prompted not only by impending capacity shortages, but also by environmental, regional development, and basic long-term economic efficiency considerations. From a federal policy viewpoint, it is necessary to understand how LCUP could contribute to the supply/demand balance in various regions of the country. LCUP can have large impacts on this balance because it mobilizes resources that are inadequately or not at all reflected in conventional utility resource plans and projections. On the supply side, these additional resources consist of qualifying facilities (QFs), purchased power, and life extension investments. On the demand side, they consist of programs that seek to alter the pattern of future energy use, through either behavioral or technological means.

The goal of this project is to estimate the potential for LCUP by determining **when** and **where** it can make a difference. Ultimately, one would want to know what previously unrecognized resource contributions LCUP initiatives could make by what date. This information would not only address concerns about capacity shortages, but would also provide insight into LCUP contributions to other federal policy goals, such as climate stabilization and reducing oil imports. To perform such a quantitative regional assessment would require a major research effort. In absence of such an effort, the current limited investigation has the more modest goals of

- mapping out in which parts of the country LCUP contributions are likely to soon be of critical importance in defining appropriate measures for avoiding capacity shortages; and
- comparing this regionalized demand/supply picture with state activities in establishing regulatory LCUP initiatives.

What Factors Influence Utilities to Consider LCUP?

In this report, we identify several influences that encourage utilities to consider LCUP; we quantify their impact on utilities, and discuss their limitations.

We focus on three economic indicators, which measure the balance between supply and demand: 1. the need for new generating capacity based on adjusted reserve margins; 2. the dependence of electricity generation on oil and gas fuels; and 3. the number of years until investments in baseload capacity will be required.

State regulatory bodies promote LCUP among utilities -- we call these activities, which are subject to political influence and are difficult to measure rigorously, "regulatory influences." We examine: 1. the status of commission policies to promote LCUP; 2. the size of commission staff working to support these policies; and, 3. the use of marginal costs, an important input to LCUP analyses.

Organization of This Report

This report contains five sections following this introduction. In the next section, we give background for the study with descriptions of the level of analysis, the NERC regions and DOE electric regions, and our data sources. The following two sections describe and report our findings for the supply-demand balance and regulatory indicators, respectively. The final section reviews major uncertainties in the analysis and proposes directions for future research.

METHOD OF ANALYSIS

To develop indicators of utility interest in LCUP, we have analyzed publicly available information from a variety of institutions. This section describes our analysis, introduces the electric regions, and comments on the sources of information we used.

Level of Analysis

The primary data used in the analysis cover total electricity consumed and produced within the continental United States. For the supply-demand balance indicators, transmission interconnections render analysis of individual utilities meaningless. We rely, instead, on the the electric region boundaries established by the North American Electric Reliability Councils (NERC) and the Department of Energy. Primary regulation of utilities is on a statewide basis, so we develop our regulatory indicators state by state.

NERC Regions and DOE Electric Sub-regions

Following the major "northeast blackout" of 1965, utilities, at the urging of the Federal Power Commission, formed the North American Electric Reliability Council to coordinate transmission planning and enhance the reliability of the electric power system. Within the continental U.S., NERC consists of nine regional councils. The formation of the councils was based on historic transmission interconnections (see Figure 1). Although all regions have some transmission linkages to adjacent regions, seven of the councils (ECAR, MAAC, MAIN, MAPP, NPCC, SERC, and SPP) are tightly interconnected, so there are, in fact, only three major, distinct electricity networks in the U.S.

Within the NERC regions, DOE has established 26 electricity subregions (see Figure 2). Each subregion is wholly contained within a single NERC region and several subregions encompass entire NERC regions (e.g. ERCOT, MAAC, MAPP).

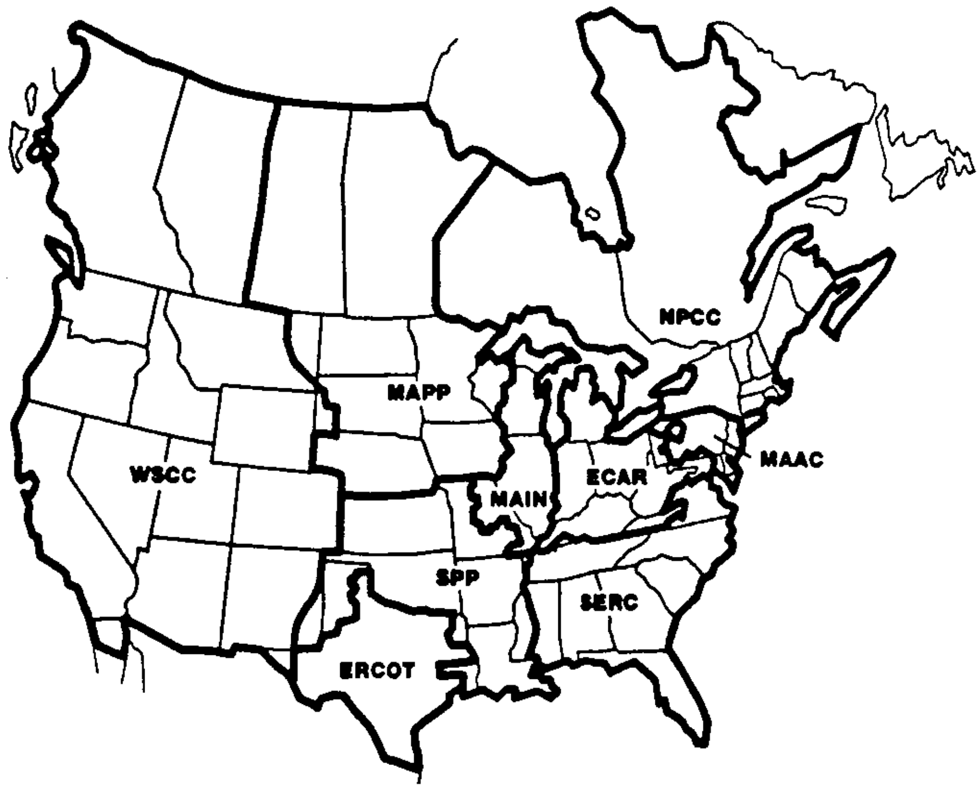

Figure 1. NERC Regions. The planning regions established by the North American Electric Reliability Council.

ECAR
East Central Area Reliability Coordination Agreement

MAIN
Mid-America Interpool Network

SERC
Southeastern Electric Reliability Council

ERCOT
Electric Reliability Council of Texas

MAPP
Mid-Continent Area Power Pool

SPP
Southwest Power Pool

MAAC
Mid-Atlantic Area Council

NPCC
Northeast Power Coordinating Council

WSCC
Western Systems Coordinating Council

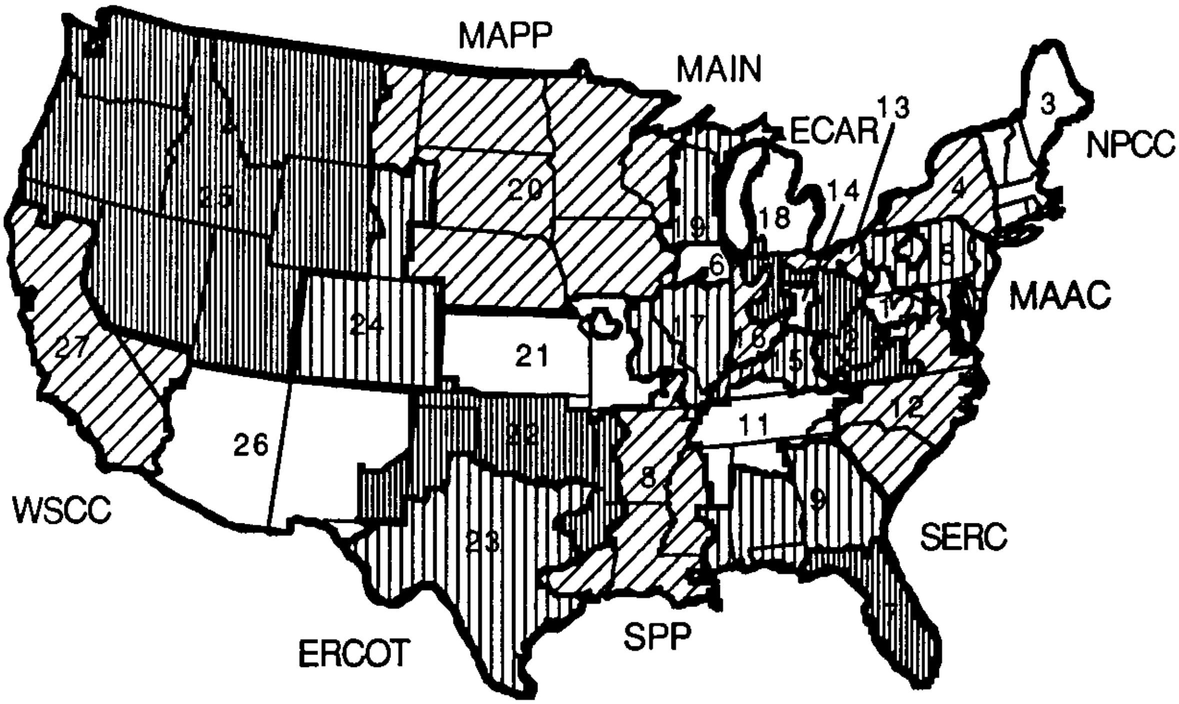

Figure 2. DOE Electric Regions. DOE has established 26 electric planning regions, each of which is contained within a single NERC region.

Reliability Council	Electric Region
ECAR	1. Allegheny Power System (APS) 2. West Virginia-Ohio-Indiana-Michigan Systems (WOIM) 13. Western Pennsylvania-North Central Ohio Group (WPANCO) 14. Cincinnati-Dayton-Hamilton Group (CDH) 15. Kentucky Group (KY) 16. Indiana Group (IND) 18. Lower Michigan Systems (LMS)
ERCOT	23. no subregions
MAAC	5. no subregions
MAIN	6. Commonwealth Edison Company 17. South Central Illinois-East Missouri Group 19. Wisconsin-Upper Michigan Systems Group (WIUM)
MAPP	20. no subregions
NPCC	3. New England Power Pool (NEPOOL) 4. New York Power Pool (NYPP)
SERC	7. Florida Electric Power Coordinating Group (FCG) 9. Southern Company Group (SOCO) 11. Tennessee Valley Authority (TVA) 12. Virginia-Carolinas Group (VACAR)
SPP	8. Southeast Sub-Region (SOEST) 21. Northern Sub-Region (NORTH) 22. West Central Subregion (W[illegible]ENT)
WSCC	24. Rocky Mountain Power Area ([illegible]A) 25. Northwest Power Pool Area (NWPP) 26. Arizona-New Mexico Power Area (AZN 27. California-Southern Nevada Power Area (CASN)

Sources of Information

To develop the supply-demand balance indicators, we used:

- DOE (1987) *Staff Report: Electric Power Supply and Demand for the Contiguous United States 1987-1996.* Each year, nine NERC regional councils submit an annual report to DOE's Office of Energy Emergency Operation (Form IE-411). These reports embody "*the consensus of U.S. electric utilities regarding the parameters of U.S. electric power supply and demand for the next decade.*" The emphasis in DOE's analysis is on assessment of the adequacy of generating capacity to meet expected winter and summer peak demands.

- NERC (1987) *Electricity Supply and Demand for 1987-1996.* NERC separately publishes an annual data summary of expected future electricity generation, based both on data submitted to DOE Office of Energy Emergency Operations and on information that has been reported to NERC directly. Because its emphasis is broader than that of the DOE report, the NERC report also presents information on expected electricity generation by fuel type, while the DOE report presents information only on installed capacities.

- DOE/EIA (1986) *Generating Units Reference File (EIA-860)* U.S. electric utilities annually report current and expected changes to the status of generating units for use in preparing the Energy Information Agency's "Inventory of Power Plants in the United States."

To develop the regulatory indicators of utility interest, we used:

- ACC (1987) *Regulatory Institutions for Least Cost Planning.* The Arizona Corporation Commission supplemented NARUC's efforts with an update and preliminary analysis of state LCUP activities.
- ECC (1987) *A Brighter Future: State Actions in Least-Cost Electricity Planning.* Complementing the Arizona Commission, this report, prepared by the Energy Conservation Coalition, contains a longer review of state regulatory activities.
- NERA (1987) *The Role and Nature of Marginal and Avoided Costs in Ratemaking: A Survey.* National Economic Research Associates conducted a survey to assess utility progress in implementing the marginal cost provisions of the Public Utilities Regulatory Policies Act of 1978.
- IRRC (1987) *Generating Energy Alternatives at America's Utilities.* In 1983, the Investor Responsibility Research Center conducted a survey of demand-side activities at the nation's largest utilities. The current report is

an update of that pioneering effort.

- EPRI (1988) *DSM Regulatory Impacts.* The Electric Power Research Institute contracted with IRRC to survey the activities of regulatory commissions in promoting demand-side options.

Current and prospective non-utility power is a major source of uncertainty in our analyses. We have reviewed several sources of information:

- EEI (1987) *Capacity and Generation, Non-Utility Sources of Energy.* This report is the Edison Electric Institute's first attempt to quantify the level of non-utility electricity production in the U.S.
- HB (1987) *Profile of Cogeneration and Small Power Generation Markets.* This Hagler Bailly report is a tabular summary of applications to FERC by prospective QFs seeking certification.
- GRI (1986) *Impact of Cogeneration on Gas Use.* The Gas Research Institute's forecast of gas-fired cogeneration to the year 2000.

SUPPLY-DEMAND BALANCE INDICATORS

Demand-side programs, when deployed in an LCUP process, will reduce the need for new generating facilities. From a cost-benefit perspective, the value of a demand-side program is the value of the supply-side alternative that is avoided as a result of the demand-side program. Conversely, this value, which is also known as the marginal cost of power, places an upper bound on the cost-effectiveness of demand-side resources. Regional marginal costs, which depend strongly on the need for new capacity, are difficult to measure in practice. Accordingly, we focus on regional needs for new capacity to develop proxies for the marginal value of demand-side resources.

The regional need for new capacity is a function of the relationship between the present and future balance in the supply of and demand for electricity. We have identified three facets of regional supply-demand balances that capture key cost differentials in the marginal cost of power.

1. **Need for New Capacity** measures the adequacy of existing and planned capacity to meet expected demands;
2. **Oil and Gas Dependence** measures the dependence of regional electric utilities on oil and gas for electric generation; and
3. **Need for Baseload Capacity** estimates the number of years until an investment in baseload power plants is required.

Need for New Capacity

The first supply-demand balance indicator identifies regions that need new capacity. Because electricity is very difficult to store, a reliable electricity system requires generating capability in excess of expected demands. The amount of excess is called a reserve margin. Historically, low reserve margins have indicated the need for additional generating capacity; of course, low reserve margins can also be mitigated by reducing demands through demand-side programs.

DOE's Office of Energy Emergency Operations (OEEO) uses an adjusted reserve margin criterion of 5% * to identify regions with potentially serious undercapacity problems. We follow OEEO's criteria and illustrate (in Figure 3) the electric region that will fall below the 5% level for four different periods in Figure 3. The analysis is based on

* Adjusted reserve margins refer to reserve margins that have been adjusted downward to account for expected operating conditions at the time of system peak demands. They are a far more accurate measure of reliability because they account for net transfers of power between regions, scheduled unit outages for maintenance, and historic unavailabilities of generating units (forced or other outages). The increased accuracy of an "adjusted" reserve margin permits analysts to use a lower number (5%, versus the 20% used with simple, unadjusted reserve margins) as the yardstick for measuring the reliability of supplies.

data reported by utilities, via the NERC offices, to OEEO for assessing the reliability of U.S. electric power system. In aggregate, peak demands are projected to grow at 2.0%/yr between 1987 and 1996. Table 1 reports the regional peak demand growth rates that underlie this aggregate rate.

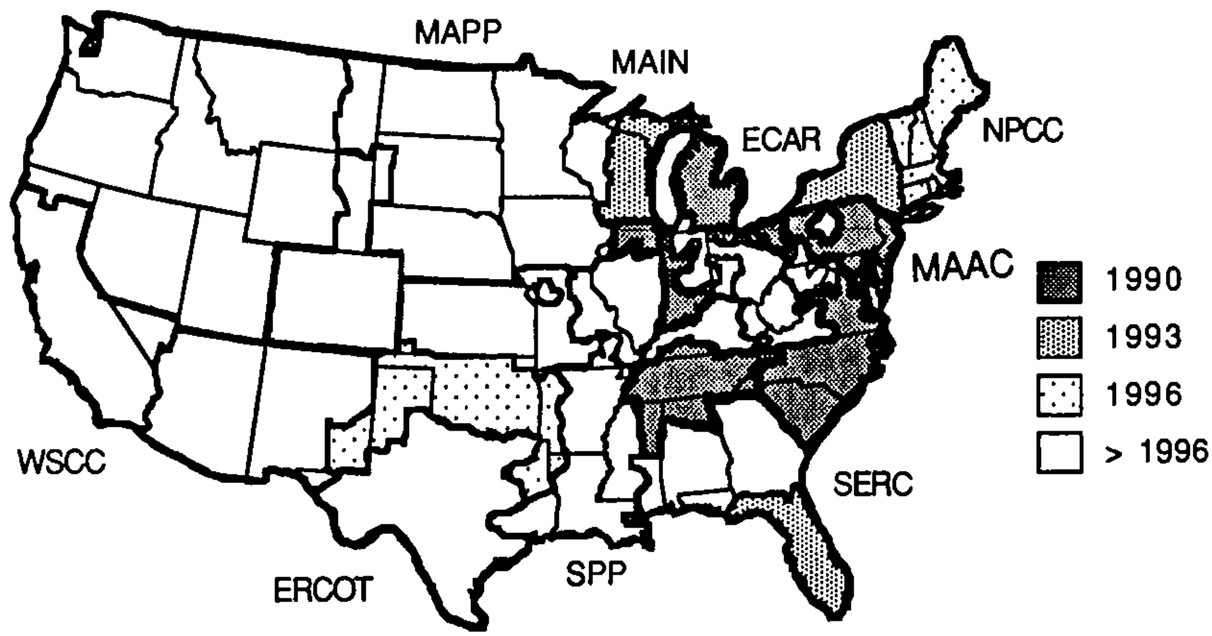

Figure 3. Need for New Capacity based on DOE's Office of Energy Emergency Operations Analysis. The year in which adjusted reserve margins fall below the 5% threshold established by DOE's Office of Energy Emergency Operations, based on OEEO's analysis of NERC IE-411 submissions. Aggregate annual peak demand growth is 2.0%/yr.

Figure 3 indicates that, by 1990, three NERC regions are in danger of under-capacity:

MAAC
MAIN
SERC

These regions jointly accounted for more than 36% of U.S. electricity peak demand in 1987. In addition, two electricity regions within ECAR (WPANCO and IND) will also fall below the 5% criterion. By 1996, two additional NERC regions (ECAR and NPCC) will be short of capacity, representing an additional 23% of U.S. electricity peak demand.

These results are uncertain, however, because utility reports of planned generating capability include non-utility sources of power whose availability is largely out of the control of the reporting utilities *. Exacerbating this uncertainty are the notorious difficulties

* We will describe the magnitude of the uncertainties regarding non-utility power development in our Review of Uncertainties, below.

Table 1. DOE and NERC Forecasts

	Peak Demand			Energy		
NERC Region	1987 Peak Demand (GW)	Fraction (%)	1987-1996 Growth (%/yr)	1986 Energy (TWh)	Fraction (%)	1986-1996 Growth (%/yr)
ECAR	70.1	14.5	1.8	391.5	15.4	1.8
MAAC	35.3	7.3	2.1	198.0	7.8	1.6
MAIN	36.4	7.5	1.2	177.2	7.0	1.8
MAPP	21.6	4.5	1.6	106.8	4.2	2.0
NPCC	41.5	8.6	1.5	229.3	9.0	1.6
SERC	105.8	21.9	2.2	546.9	21.6	2.2
SPP	47.2	9.8	2.0	216.6	8.5	2.1
ERCOT	39.1	8.1	2.9	190.8	7.5	3.3
WSCC	86.6	17.9	2.1	479.3	18.9	2.2
Total	483.6		2.0	2,536.5		2.0

associated with forecasting future peak demand growth accurately. The reliability councils, in preparing the data, must rely on forecasts provided by the reporting utilities.

We can begin to assess the impact of peak demand growth uncertainty by considering the effects of alternative growth rates. Figures 4 and 5 illustrate the effects of high and low peak demand growth rates on adjusted reserve margins. The high and low growth rates were developed by NERC (1987) to represent the effects of different levels of economic activity on electricity demand. DOE's Office of Energy Emergency Operations has conducted similar analyses using different growth rates (DOE/OEEO 1987).

In NERC's high-growth scenario (3.5% annual peak demand growth), an additional two NERC regions, ECAR and NPCC (for a total of five NERC regions) will be short of capacity in 1990 (Figure 4). The additional electric regions contributing to this shortfall are ECAR (CDH), MAIN (WIUM), and NYPP (NEPP, NYPP). By 1996, all nine NERC regions will be short of capacity.

In NERC's low-growth scenario (0.9% annual peak demand growth), the shortfalls are reduced dramatically (Figure 5). No NERC region, taken as a whole, is short of capacity in either 1990 or 1996. Only three electric regions are short of capacity by 1990 (CECO, VACAR, and WPANCO), and only four by 1996 (IND).

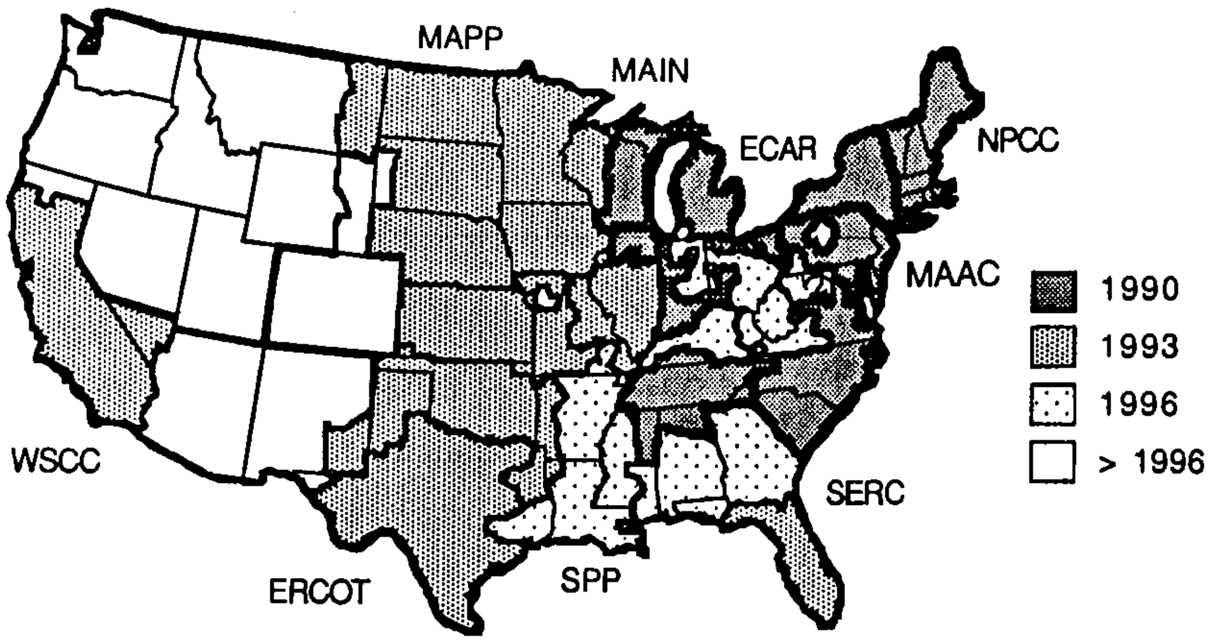

Figure 4. Need for New Capacity based on NERC's High Peak Demand Forecast. Year in which adjusted reserve margins fall below 5% threshold, based on NERC's high demand forecast of 3.5% aggregate annual peak demand growth.

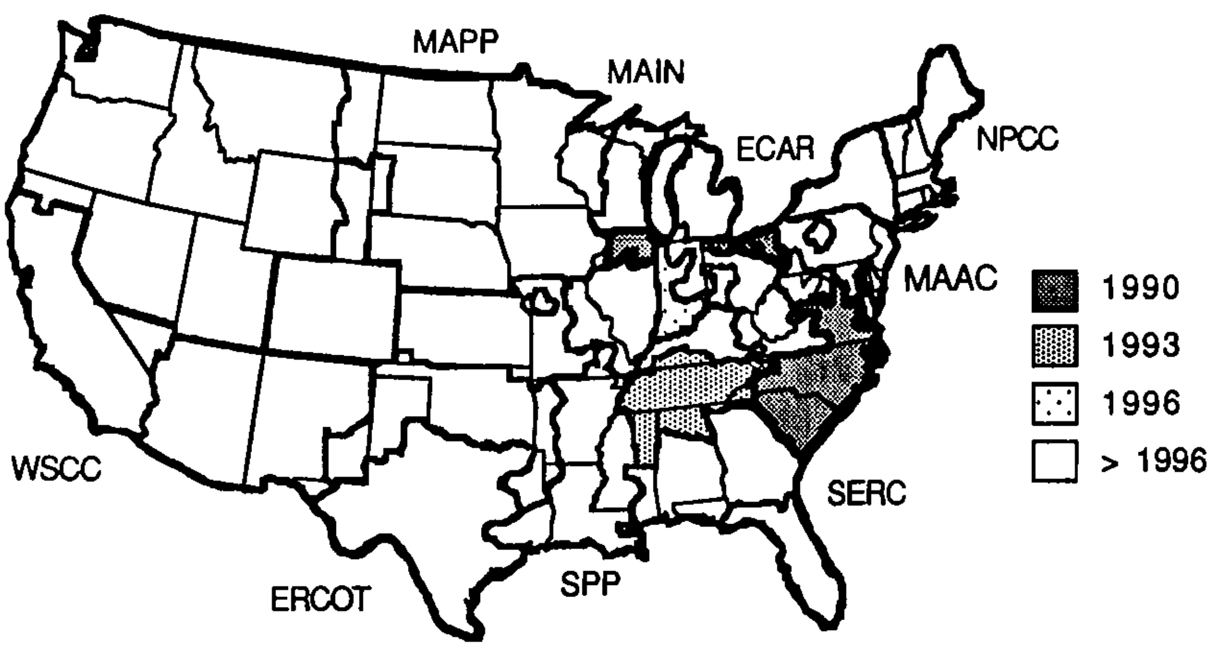

Figure 5. Need for New Capacity based on NERC's Low Peak Demand Forecast. Year in which adjusted reserve margins fall below 5% threshold, based on NERC's low demand forecast of 0.9% aggregate annual peak demand growth.

The implications of the need for new capacity indicator for LCUP are clear:

- If the DOE's analysis is correct, major portions of the country will be short of capacity in just a few years. Mitigating these shortages will require either rapid deployment of supply-side resources or substantial intervention on the demand side.
- DOE's analysis, however, is based on utility-reported data. We are particularly concerned about the accuracy of utility forecasts of non-utility generation. The issues include strategic motivations by utilities, consistency in the data used to forecast non-utility generation, and the rate of technological change in electricity generation. Similarly, small changes in peak demand growth rates (on the order of 1%/yr) can either severely exacerbate shortages or mitigate them almost entirely.

Oil and Gas Dependence

The large nuclear and coal plant construction programs initiated in the 1970's were largely motivated by the high cost of oil and gas. Expectations of future increases in oil and gas prices were a powerful incentive that spurred utilities to displace oil and gas generation with power plants capable of burning less expensive fuels. Although the price of oil and gas has retreated from its historic highs, their price volatility remains an important consideration in generation planning. Most experts agree that the price of oil and gas will rise once again in the 1990's.

For planners, oil and gas generation remains a source of concern because of the fuels' price volatility, related largely to the potential for oil supply disruptions. Figure 6 quantifies the magnitude of these concerns by expressing 1986 electricity generated by oil and gas as a fraction of total generation. Four electric regions currently generate more than 40% of their electricity with oil and gas fuels: ERCOT, NPCC (NEPP), SERC (FCG), and SPP (SOEST). Other electric regions in NPCC (NYPP) and and SPP (NORTH) also rely heavily on oil and gas for electricity generation.

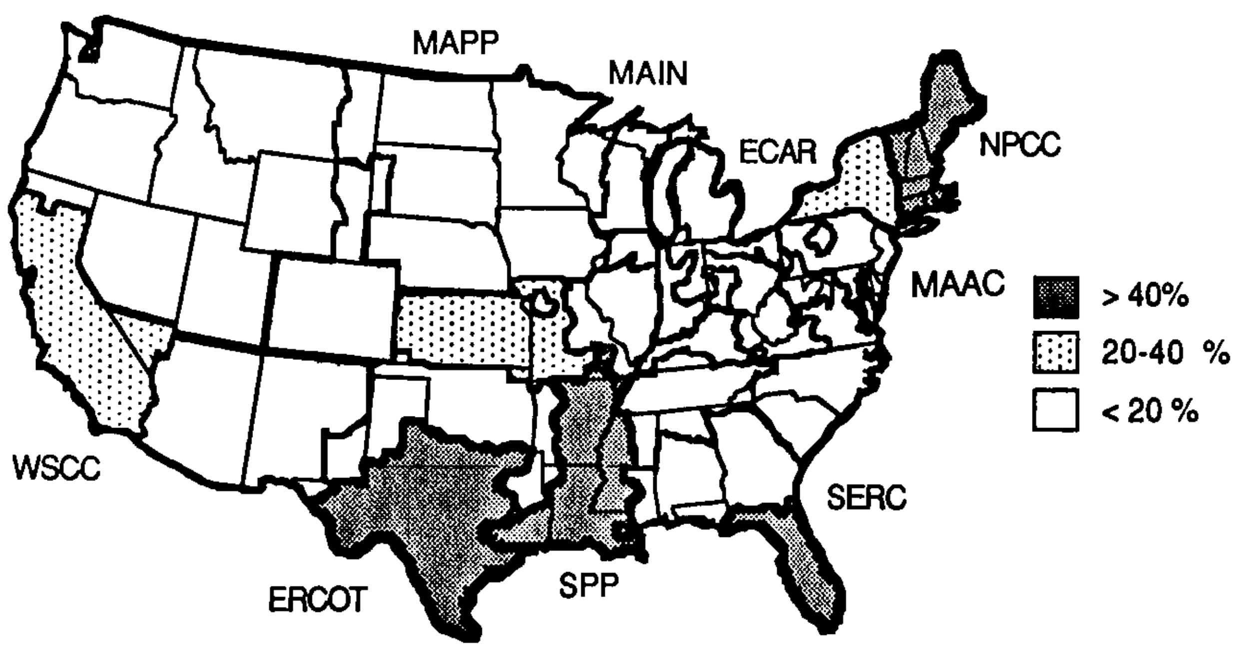

Figure 6. 1986 Oil and Gas Dependence. Oil and gas generation as a fraction of total electricity production in 1986.

It is difficult to draw definite conclusions from existing dependence on oil and gas generation without forecasting future world oil markets.

- If real prices rise, there are clear economic incentives in the form of increased marginal energy costs for the deployment of less expensive demand-side alternatives.
- If prices remain stable or decline, opportunities for demand-side programs will be largely dictated by other considerations, such as peak demand mitigation, imminent need for new baseload capacity, and the availability of non-utility sources of power (the bulk of which may be gas-fired cogenerators).

Need for Baseload Capacity

The final supply-demand balance indicator is based on the presumption that the moratorium on nuclear power plant orders will continue and that utilities will not build additional oil and gas baseload generation for strategic considerations (either availability or fuel price volatility). Accordingly, marginal investments in baseload capacity will be in the form of coal-fired power plants. The indicator, called need for baseload capacity, identifies the time at which different regions of the country will exhaust current coal-fired generating capacity. The primary data for the calculation are taken from NERC (1987). The calculation was developed in an earlier study by Yen-Wood, et al. (1987) and is summarized in an Appendix to this report.

It is important to recognize the tight link between the need for baseload capacity and the other two indicators. The first indicator, need for new capacity, does not discriminate between the need for baseload and peaking capacity; the second indicator, oil and gas generation, only identifies regions where fuel substitution (which, typically, would be made in the form of baseload plants) might be desirable. Unlike the need for new capacity indicator, which is based on capacity (kW), the need for baseload capacity indicator is based on energy (kWh).

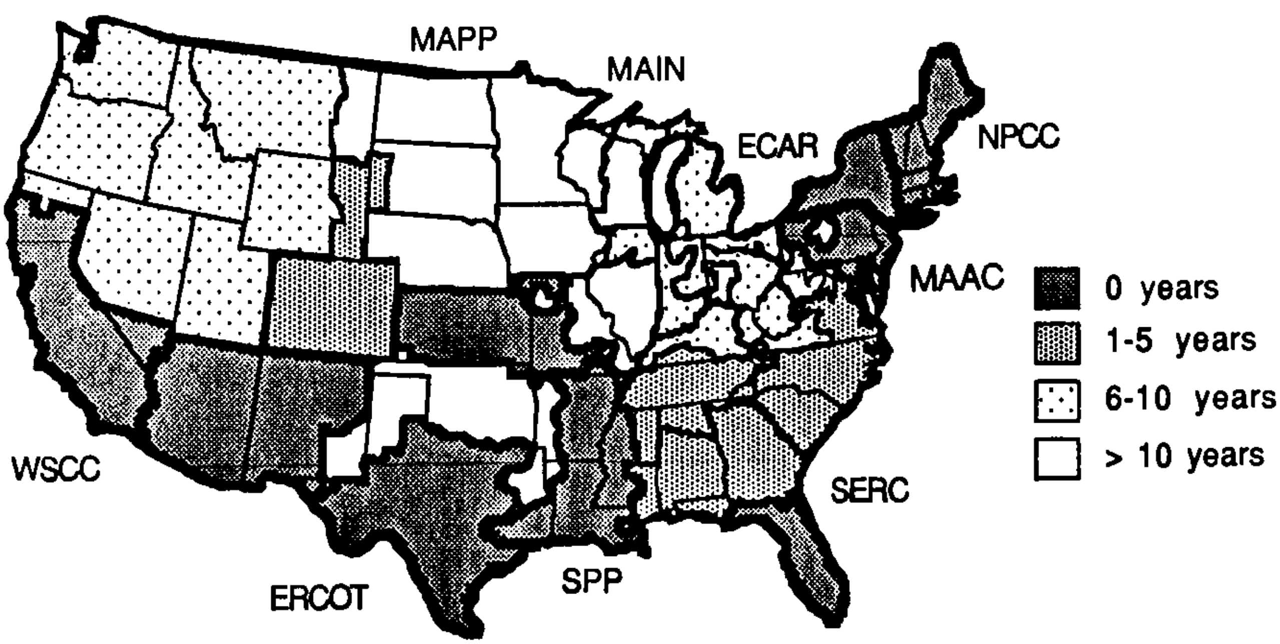

Figure 7. Need for Baseload Capacity based on 1987 NERC Data. Years from 1987 until excess coal power is expended, under assumption of continued demand growth, based on NERC's 1987 Electricity Supply and Demand report.

Figure 7 summarizes our analysis for NERC's aggregate annual base case forecast of 2.0%/yr energy demand growth (see also Table 1 for a regional breakdown of this growth rate). Our analysis suggests that three NERC regions (ERCOT, MAAC, and NPCC) and five electric regions in three other NERC regions (SERC, SPP, and WSCC) have already exhausted their coal-fired generating capacity. The only reason ERCOT and the electric regions in NYPP (NEPP and NYPC), SERC (FCG), SPP (SOEST, NORTH) and WSCC (AZNM and CASN) are not short of capacity (see Figure 3) is that there is substantial oil and gas generation in these regions (Figure 6). For the other regions, notably MAAC, capacity is short and little oil and gas generation is available. In both situations, the need for baseload power is evident.

As with the need for new capacity indicator, the need for baseload capacity indicator is subject to substantial uncertainties. We are especially concerned about opportunities for future bulk power transfers. For example, current and prospective excess coal generating capacity in NWPP would surely be sold to CASN and AZNM, if not for current transmission constraints.

The need for baseload capacity indicator is relatively resilient to demand growth uncertainties. Under NERC's high-demand scenario of 3.3% annual energy demand growth (recall that NERC and DOE expect peak demand to grow at 3.5%/yr), we find no changes from our earlier results. Under NERC's low-demand scenario of 0.9% annual energy demand growth, we find only small changes in time at which ECAR and electric regions in WSCC exhaust existing coal-fired generation (Figure 8).

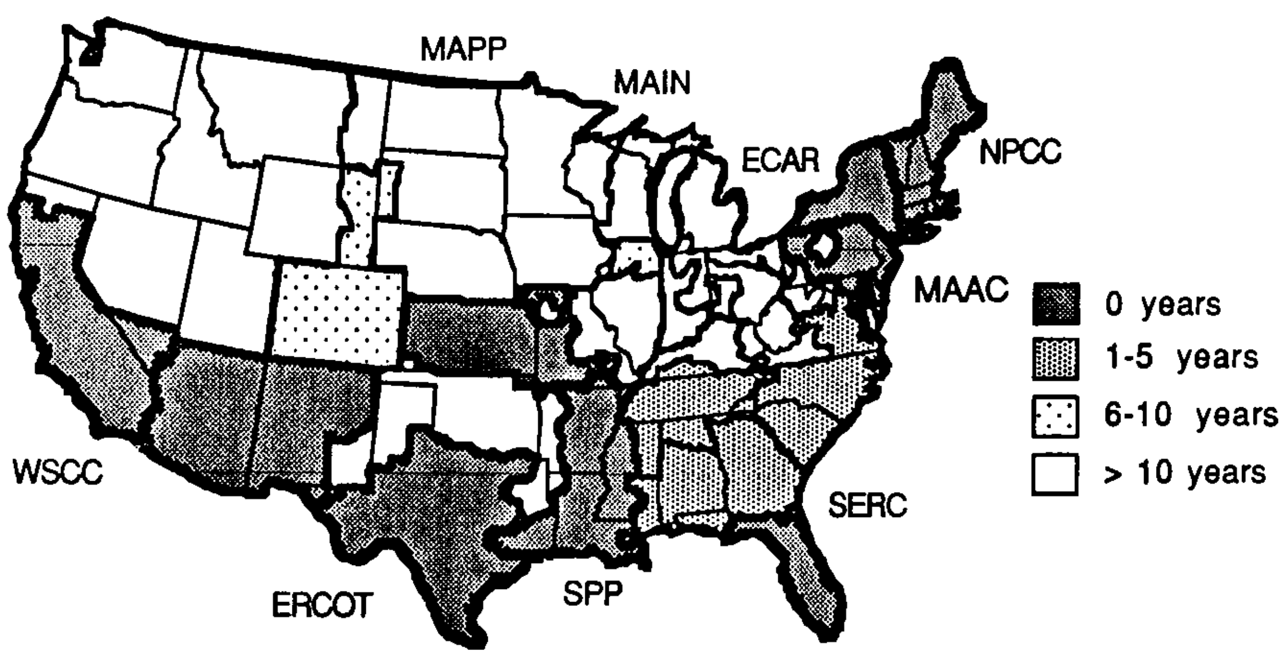

Figure 8. Need for Baseload Capacity based on NERC's Low Energy Forecast. Years until excess coal power is expended, under assumption of continued demand growth, based on NERC's high energy forecast of 0.9% annual energy demand growth.

The implications for demand-side programs in a LCUP process can be summarized as follows:

- In the near term, utilities in several regions should be considering investments in baseload capacity. This interest is relatively insensitive to alternative demand growth assumptions. In the absence of lower-cost supply alternatives, the importance of demand-side programs that displace both peak and baseload energy requirements (e.g. efficient appliances) increases.
- Large uncertainties exist on the supply side about whether cheaper supplies are available from non-utility sources or through bulk power transfers. We need to further analyze the ability of demand-side programs to substitute cost-effectively for baseload generation requirements.

REGULATORY INDICATORS

The regulatory environment in which a utility operates significantly influences the direction of utility resource plans. State commissions set rates for consumers and rates of return for investors. Regulation is a political process, however, so precise quantification of its influence on utility decisionmaking is difficult. We present three regulatory indicators in this section, but they are only proxies for phenomena that can be hard to observe in practice, much less measure systematically.

1. **Status of LCUP Activities by State** is a tabular summary of current activities;
2. **Commission Staffing for LCUP** reveals the extent to which LCUP activities are supported by manpower;
3. **Use of Marginal Costs** examines the role of marginal costs in ratemaking as both a measure of sophistication and as a measure of commitment to a fundamental principle of least-cost planning.

Status of Least-Cost Planning by State

Increasingly, state commissions and legislatures have begun to incorporate least-cost planning into their formal oversight of utilities. Every state is different. Implementation ranges from formal least-cost planning legislation to informal rulings by commissions.

In 1987, the Energy Conservation Coalition prepared a summary of the status of current activities (ECC 1987). The report identified six regulatory mechanisms for implementing or examining LCUP:

Rulemaking Proceedings (RP),
Rate Cases (RC),
Resource Planning Hearings (RPH),
New or Changed Regulations (NC),
Generic Proceedings (GP), and
Internal Investigations/Technical Studies (II).

It also identified three types of legislative actions for LCUP:

Formal LCUP Legislation (LI),
Incorporation of LCUP in Power Plant Hearings (PP), and
Other (e.g., resolutions (R), studies (S), actions (A)).

In a separate analysis of state LCUP activities, a status report was prepared by the Arizona Corporation Commission. We summarize both sets of findings in Table 2 and Figure 9.

Table 2. LCUP Actions by State

	PSC/ PUC	Legis- lature	State		PUC	Legis- lature	State		PSC/ PUC	Legis- lature	State
AL				ME			A,J87	OR		LI	S
AK		LI		MD	II			PA	NR	LI	J87
AZ	II			MA	RC,RPH	PP	A	RI			S
AR			S	MI			S,A	SC	GP	PP	
CA	II		J87	MN		LI	A	SD			
CO	GP			MS				TN			
CT	RC	R	S,A,J87	MO	II	LI		TX	GP		J87
DE			J87	MT				UT			
FL	RPH		A,J87	NE				VT	II		J87
GA		R	S	NV	RPH		A,J87	VA	NR		J87
HI		R		NH				WA	RP,RC,II	LI	J87
ID			A	NJ			A	WV			J87
IL	RP,GP			NM	II			WI	RPH		A,J87
IN			J87	NY	GP		A,J87	WY			
IA			A	NC	RP	LI					
KS			A	ND	RC		A	DC	GP		A
KY	RP			OH	II		J87				
LA				OK			J87				

Sources: ECC, 1987; ACC, 1987

Key to Table 2

RP Rulemaking Proceedings: Commission began rulemaking proceedings to implement least-cost planning regulations.

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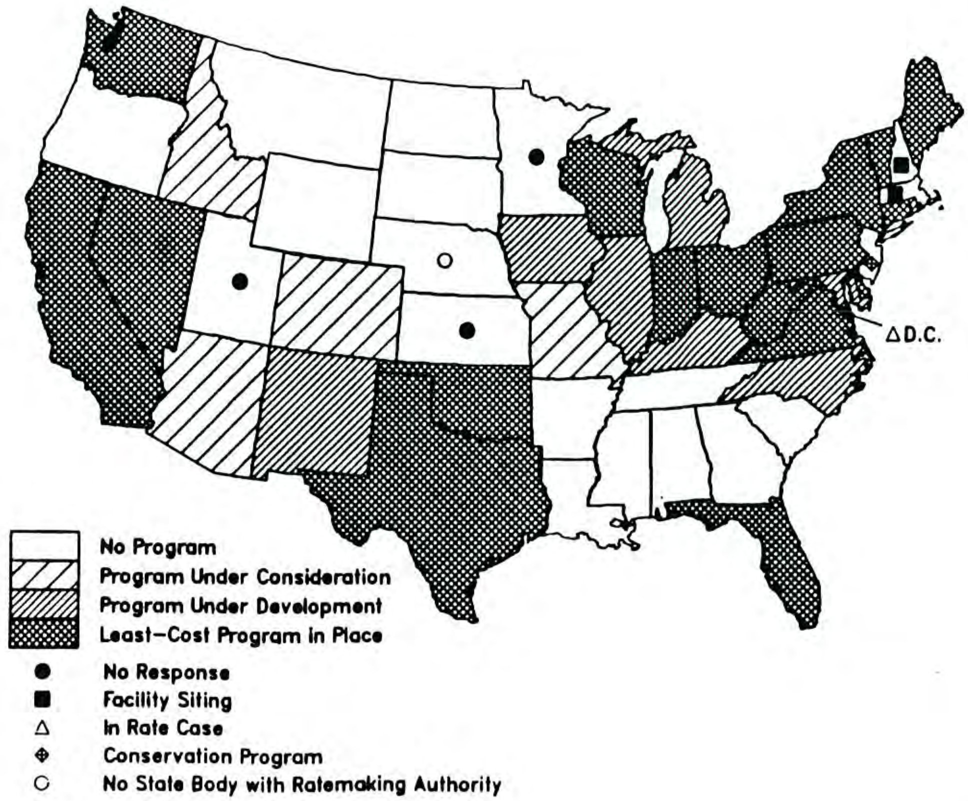

Figure 9. Status of LCUP Legislation by State. In 1987, 17 states had LCUP programs in place, 8 states were developing LCUP programs, and 4 states were considering LCUP programs.

It is clear from these exhibits that many states are actively pursuing to promoting LCUP. In 1987, LCUP programs were in place in 17 states (J87), being developed in 8 states, and under consideration in states. An additional incorporate aspects of LCUP in other programs.

What is less clear is that developments are occurring rapidly. During our analysis, for example, we learned that the District of Columbia had completed its investigation of LCUP and was announcing new LCUP policies. We believe DC's and other's rapid development are indicative of trends that will persist in the coming years and that published sources will always be out of date.

Commission Staffing for LCUP

Commissions need statutory authority for LCUP and must establish regular practices that foster its implementation; in addition, they must commit manpower to the planning process. In their survey of state commissions, the Arizona Corporation Commission requested information on commission staffing for LCUP. The results are presented on Figure 10.

It is, of course, quite difficult to assess staffing for LCUP separate from other regulatory activities. We have acknowledged this problem by consciously avoiding excessive detail in our analysis and focusing, instead, on broad ranges of staffing levels. It is clear from Figure 10, however, that several states have made substantial staff commitments to LCUP, notably California, Texas, New York, Wisconsin, and Connecticut.

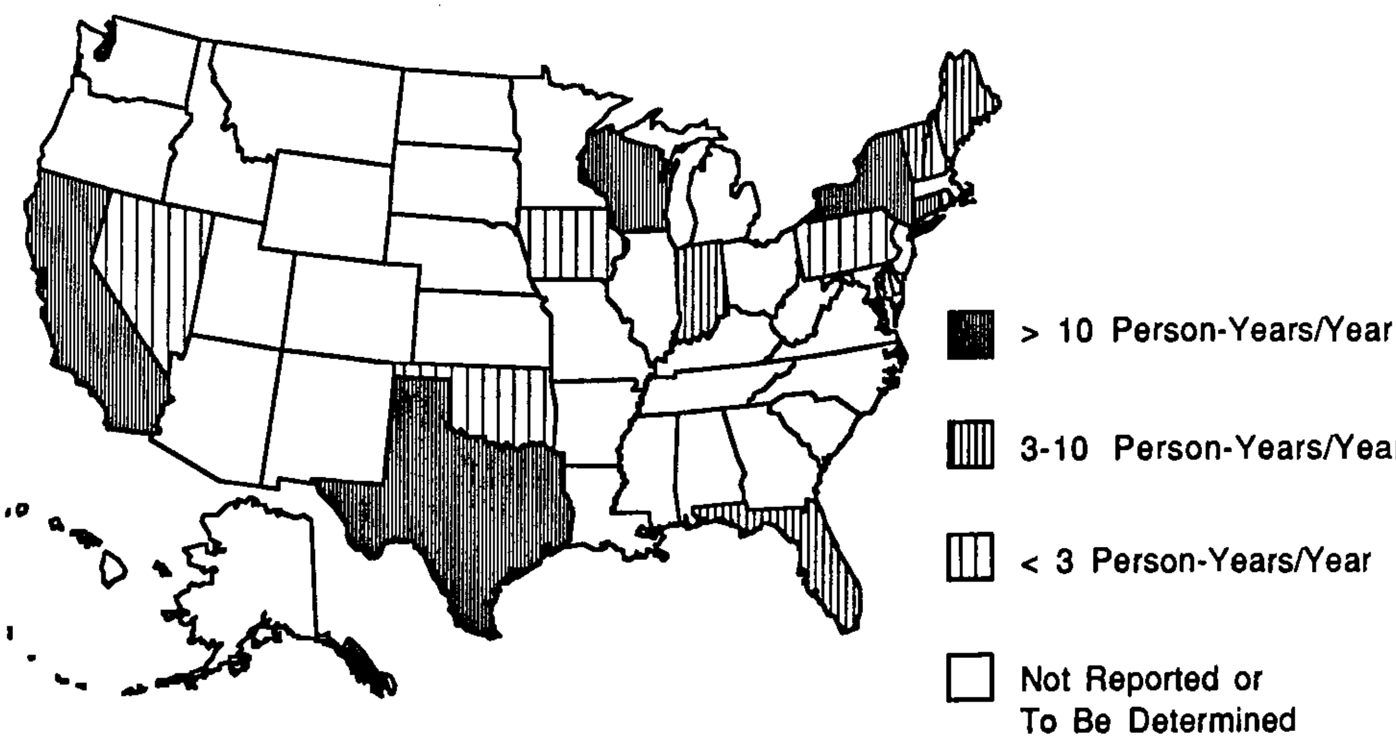

Figure 10. Commission Staffing for LCUP by State.

Use of Marginal Costs

The marginal cost of electricity is a critically important input to a least-cost resource planning process. The fundamental principle of least-cost planning is that one should consider all reasonable energy supply and demand options and choose the option or options that provide reliable service at the lowest possible cost. Implicit in this principle is the need to assess the costs of supply and demand alternatives. On both sides of the equation, the relevant cost is the marginal or incremental cost of each option. The extent to which utilities and commissions have embraced marginal cost principles for purposes other than resource planning indicates both the existence of a level of sophistication to support marginal cost studies and a measure of corporate commitment to the use of these principles.

Figure 11 reports on the use of marginal costs by utilities in each state. Definitions of marginal cost vary substantially, both in time horizons and in measurement techniques; we suppress these distinctions. For our purposes, the major distinction is whether utilities use marginal costs for ratemaking or whether they use them, in isolation, for other purposes such as setting tariffs for the purchase of non-utility power. The distinction addresses the degree to which the use of marginal costs has spread within a utility and its commission.

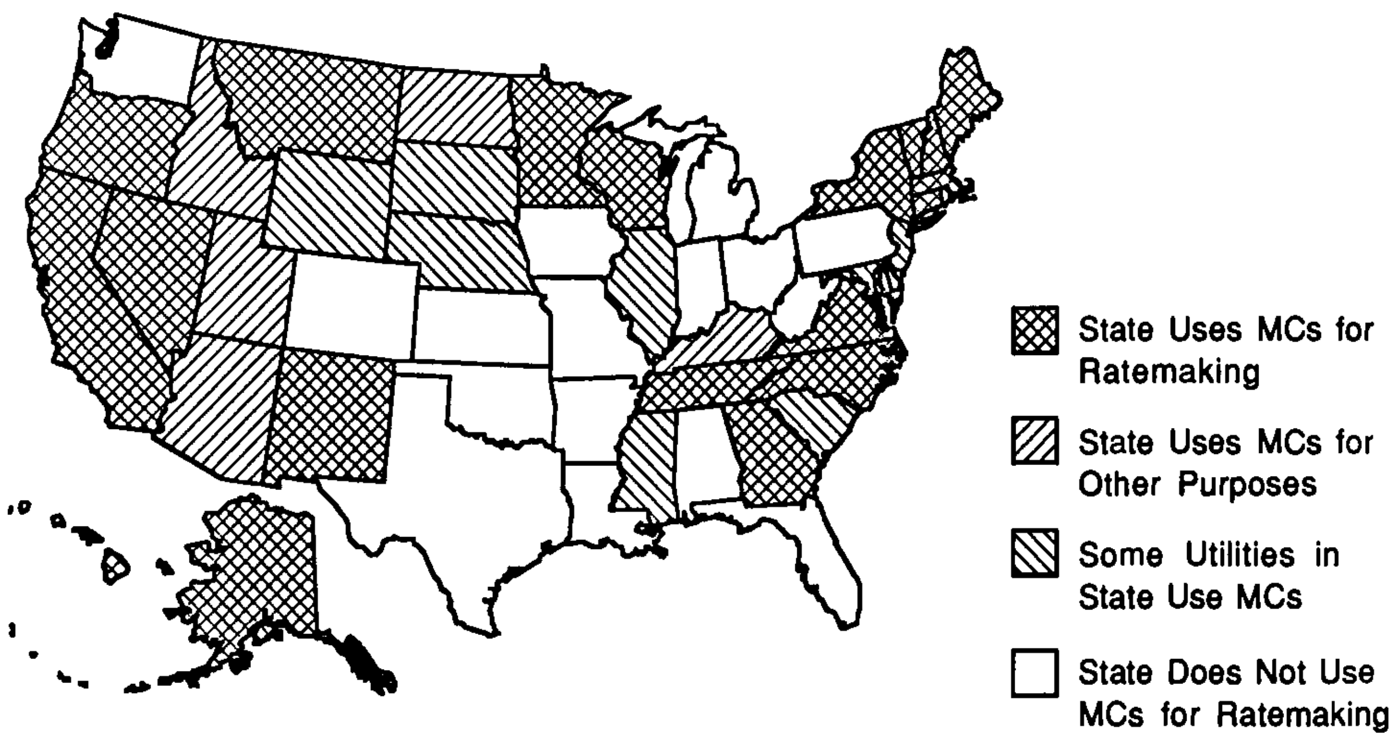

Figure 11. Use of Marginal Costs by State.

Figure 11 indicates that utilities are using marginal costs for ratemaking in 19 states; utilities are using marginal costs for other purposes, such as developing avoided cost prices for QFs in five states; and some utilities (but not all) are using marginal costs in eight states.

The use of marginal costs is widespread, but not always consistent with the presence or absence of explicit LCUP policies. Reviewing Figure 11 in conjunction with Figure 9, we can see several states in which LCUP policies are in place but the use of marginal costs is not (for example, Washington versus Montana or Georgia). We cannot adequately explain this result without further investigating state regulatory activities.

REVIEW OF UNCERTAINTIES AND DIRECTIONS FOR FUTURE RESEARCH

Throughout our discussion, we have emphasized uncertainties that hinder more definitive analyses than we have done. We believe additional study could reduce these uncertainties and lead to more robust indicators of utility interest in LCUP. In this section, we identify and describe these opportunities.

Supply-Side Resource Availabilities

Two central issues for the future of U.S. electricity supply could not be analyzed with available data. The first is the availability of non-utility sources of power and the second is the opportunity for bulk power transfers. Small changes in the large potential for either resource could dramatically alter the balance between future electricity supplies and demands. Yet, the exact sizes of these potentials are unknown.

For non-utility sources of power, recall that our supply-demand balance indicators were based on utility reports of resource availability. We have gathered data from several industry sources on current levels of and forecasts of future availabilities of non-utility sources of power (see Table 3). The table indicates that there is a substantial lack of consensus about not only future availability but also about present installed capacities.

Table 3. Estimates of Non-Utility Sources of Power

Study	Present (GW)	Additions to 1995 (GW)	Notes
NERC - 1987	13.8	11.5	14.4% of planned additions
EEI - 1987	20.1	n/a	only examined current capacity
Hagler Bailly - 1987	24.3	52.5	QFs only; additions = "active" projects
GRI - 1986	14-19	8-20	analysis of gas cogeneration, only

Opportunities for bulk power transfers are also very uncertain. Our analysis is based on utility reports of the availability of imports and exports of electricity. Figure 12 summarizes current estimates of bulk power transfer capabilities and normal line loadings. On the surface, these data suggest that current inter-regional capabilities could handle more transfers. What is not evident in the Figure, however, is the economic situation that would promote additional transfers or enhance existing transfer capabilities.

In order to reduce uncertainty about future electricity supplies, we recommend a systematic review and analysis of both the availability of future non-utility sources of power and of the opportunities for bulk power exchanges.

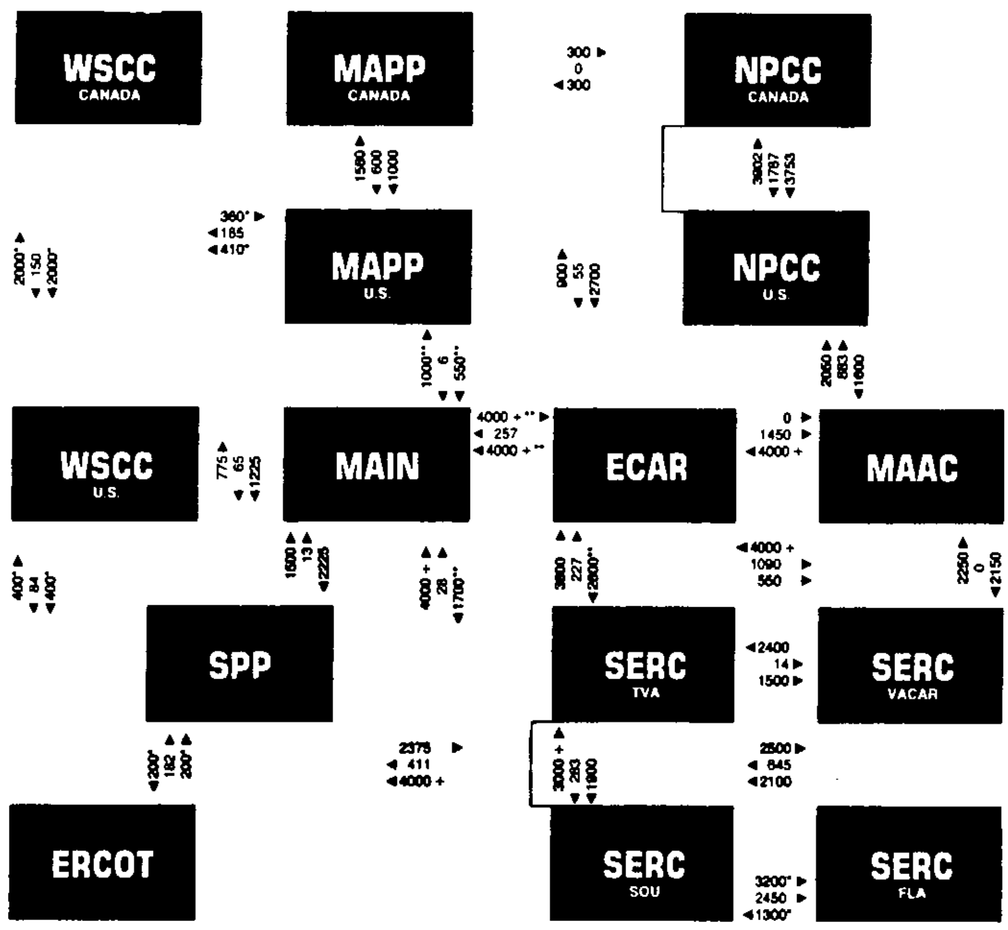

Figure 12. Inter-Regional Transfer Capabilities and Normal Loadings. The amount of bulk power transfer capability currently in-place between NERC regions and subregions, as well as current estimates of how much power is expected to move over these lines in 1988.

Changing Regulatory Environment

State regulation of the utility industry is changing rapidly. The data upon which we based our preliminary assessment are now at least two years old. Since that time, much has happened (e.g., the recent, far reaching proposal to redefine the terms of rate of return regulation by a Maine Commissioner). Primary, as opposed to secondary, data collection and analysis are necessary.

Equally important for a comprehensive treatment of state LCUP activities is an assessment of electricity production and consumption not regulated by state authorities. State regulation of electric utility actions only extends to privately-owned utilities. The distinction between regulation and management of publicly-owned utilities is often non-existent. Figures 13 and 14 illustrate the extent on electricity sales and production not regulated by state commissions.

We recommend the development, in conjunction with the NARUC energy conservation subcommittee, of an ongoing state regulatory tracking system for current regulatory activities.

We also recommend the parallel development, in conjunction with the American Public Power Association, of an ongoing tracking system for current non-state regulated LCUP activities.

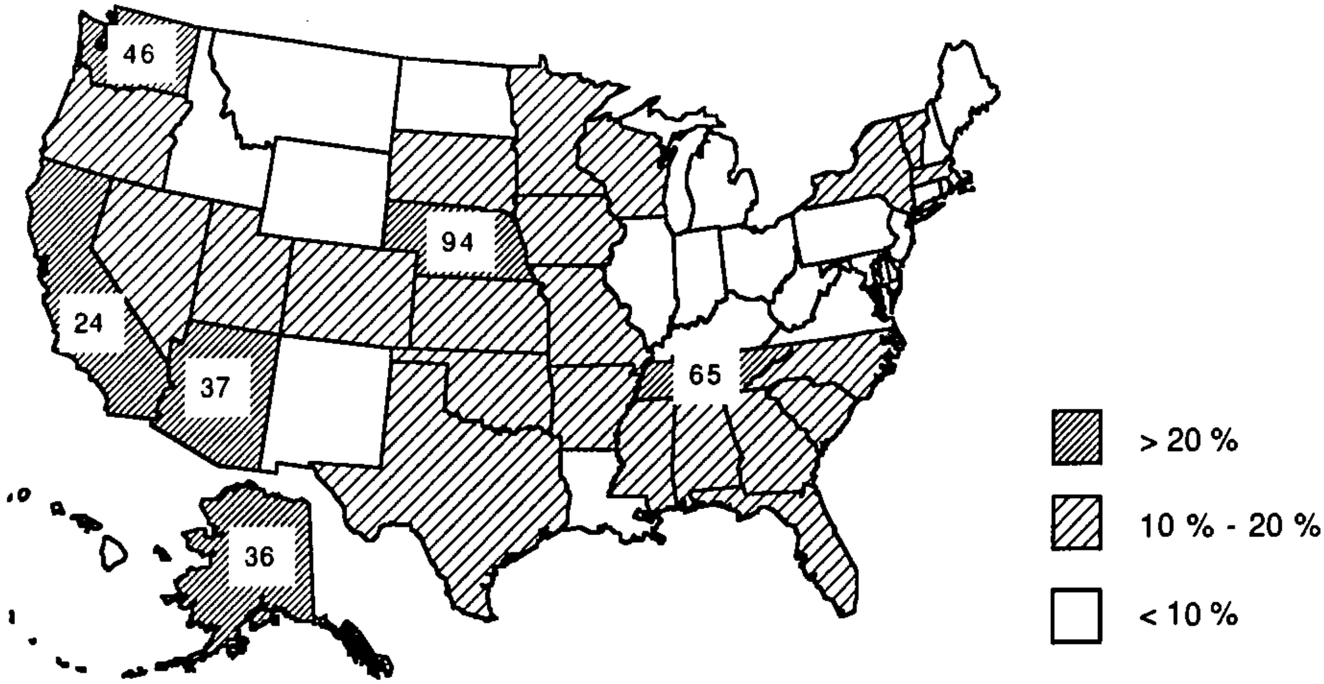

Figure 13. Electricity Sales not Regulated by State Commissions. Expressed as a percentage of total electricity sales in the state. Source: American Public Power Association.

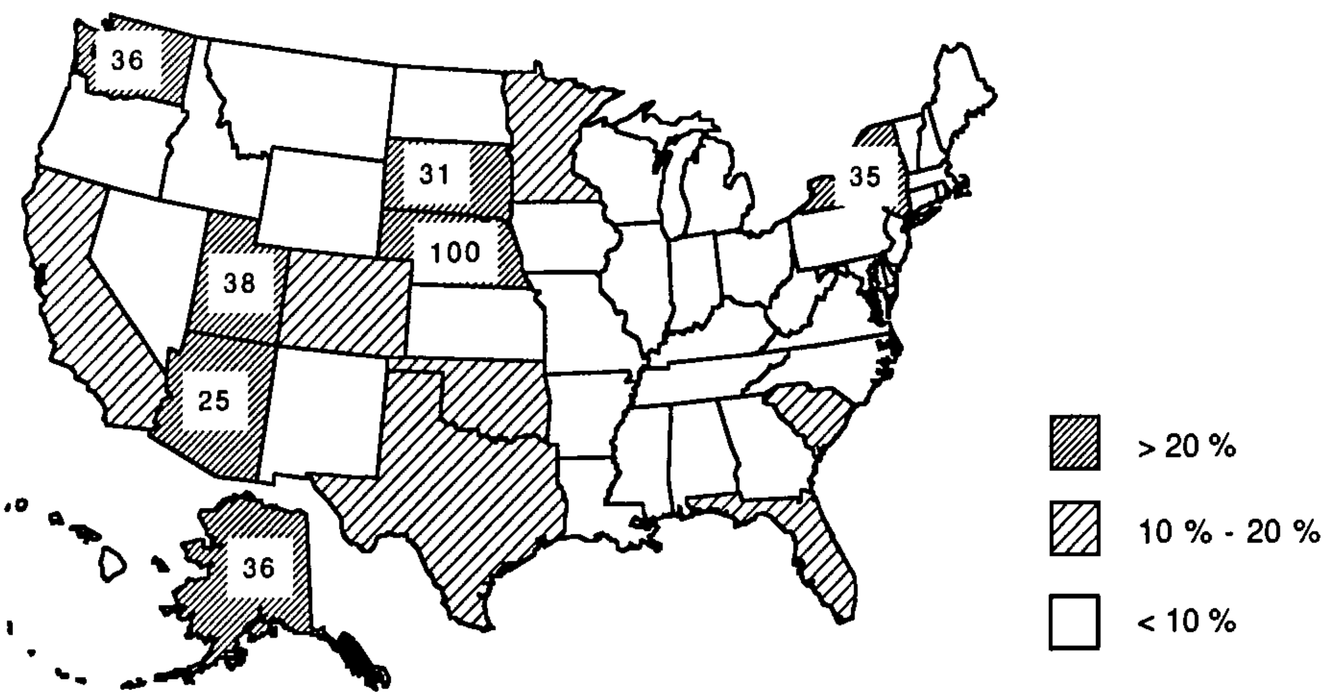

Figure 14. Electricity Production not Regulated by State Commissions. Expressed as a percentage of total electricity production in the state. Source: American Public Power Association.

Energy and Peak Demand Growth

Since the early 1970's, industry forecasts of electricity demand growth have consistently mis-forecast recorded sales and peak demands. The NERC "fan" summarizes this situation (see Figure 13). Figure 13 compares past peak demand growth to NERC's annual ten-year forecasts. Until very recently, NERC reported demand growth far in excess of subsequent recorded demands.

Peak Demand: Actual and NERC Forecasts

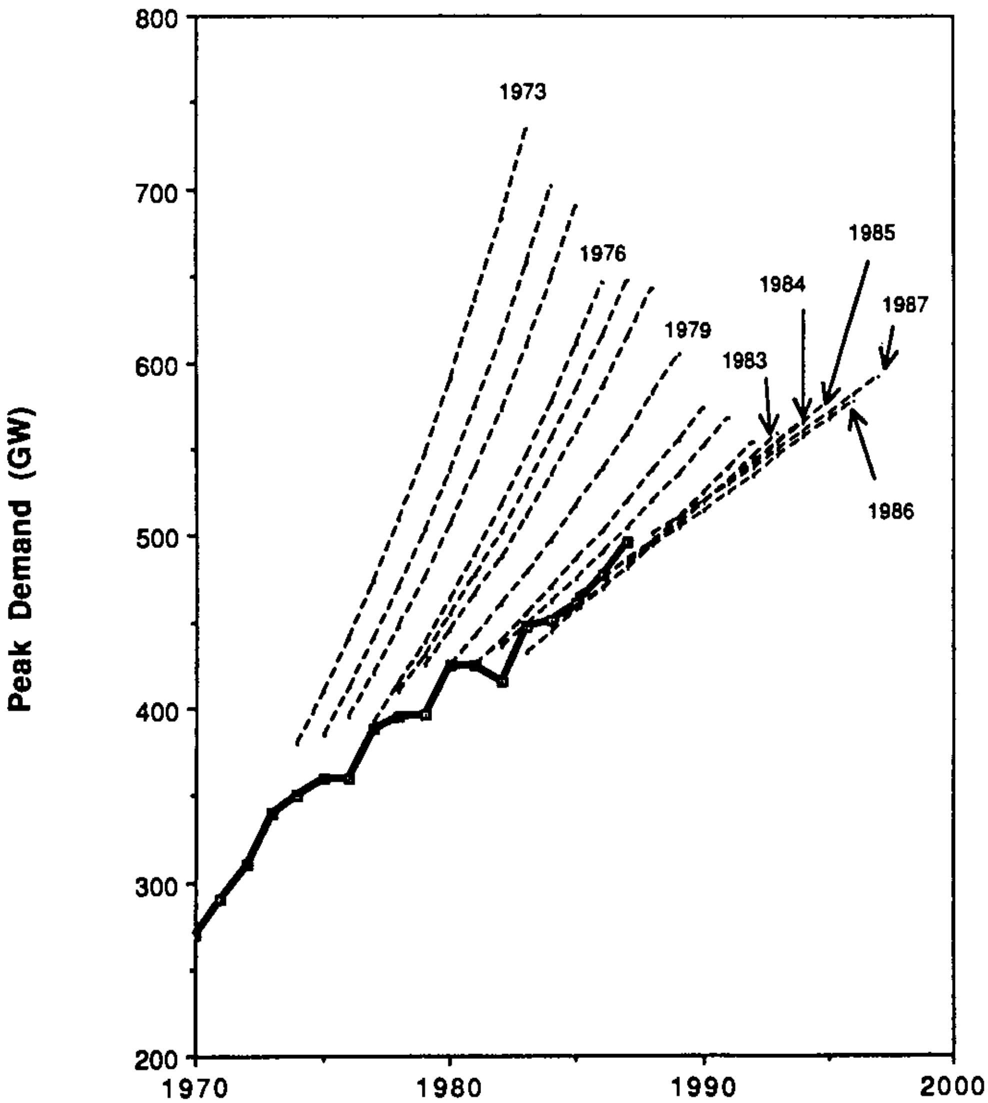

Figure 15. The NERC Fan. Relationship between past NERC ten-year forecasts and recorded peak demands shows consistent overforecasting by NERC in early years. Recent evidence indicates that this trend is reversing.

Today, however, there are strong reasons to believe that competitive pressures from non-utility sources of power, and corporate reluctance to commit to large capital-intensive construction programs have led utilities to underpredict future demand growth. For example, in 1987 energy demand growth was 4.5%, far greater than even NERC's "high" demand forecast for 1987. The NERC fan has begun to fold back.

We have illustrated the impact of alternative industry demand forecasts on the supply-demand balance indicators. In the case of the adjusted reserve margin indicators, the effects are substantial. Better understanding of the past reasons for poor forecasts should help to reduce this uncertainty.

We recommend a detailed review and analysis of past NERC forecasts to better understand the causes of divergence from recorded energy use and peak demands.

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APPENDIX

Estimating the Need for Baseload Capacity

Estimating the need for baseload capacity is based on the assumption that marginal investments in baseload capacity will be in the form of coal-fired power plants. Given this assumption, to objective of the calculation is to determine the date when existing coal-fired power will be exhausted.

The calculation can be summarized in five steps:

1. Determine the amount of energy available of non-coal-fired baseload capacity, which includes nuclear, hydro, geothermal, pumped storage, and reported (firm) purchases. We assume that generation from these sources would not be displaced by new baseload power plants.
2. Subtract the energy calculated above from total energy demand. The result is the amount of energy that could be supplied by coal-fired electricity generators.
3. Determine the maximum amount of energy available from existing coal-fired capacity by assuming a maximum capacity factor of 65%.
4. Subtract 2 from 3 to determine the current excess/deficit of available coal-fired generating capacity relative to the demands that could be met by coal-fired electricity.
5. When there is an excess of available coal-fired electricity over demand, use forecast energy demand growth rates to determine the year in the excess will be exhausted.

Table 2. LCUP Actions by State

	PSC/ PUC	Legis- lature	State
AL			
AK		LI	
AZ	II		
AR			S
CA	II		J87
CO	GP		
CT	RC	R	S,A,J87
DE			J87
FL	RPH		A,J87
GA		R	S
HI		R	
ID			A
IL	RP,GP		
IN			J87
IA			A
KS			A
KY	RP		
LA			

	PUC	Legis- lature	State
ME			A,J87
MD	II		
MA	RC,RPH	PP	A
MI			S,A
MN		LI	A
MS			
MO	II	LI	
MT			
NE			
NV	RPH		A,J87
NH			
NJ			A
NM	II		
NY	GP		A,J87
NC	RP	LI	
ND	RC		A
OH	II		J87
OK			J87

	PSC/ PUC	Legis- lature	State
OR		LI	S
PA	NR	LI	J87
RI			S
SC	GP	PP	
SD			
TN			
TX	GP		J87
UT			
VT	II		J87
VA	NR		J87
WA	RP,RC,II	LI	J87
WV			J87
WI	RPH		A,J87
WY			
DC	GP		A

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