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Review and Evaluation of Historic Electricity Forecasting Experience (1960–1985)

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by

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ABSTRACT

Power system expansion planning is subject to a considerable degree of uncertainty with respect to load forecast, time and cost-to-completion of new plant, fuel costs and technological innovation. Many power system planners continue to use forecasts of these planning parameters as certainty-equivalent characterizations of the future, despite the generally poor concurrence between these ex-ante forecasts and actual ex-post situations. Such disregard of uncertainty greatly enhances the prospects of future imbalances between the demand for power and the system supply capability, as well as erroneously biasing the selection of plant types to meet demand at least cost.

This study focuses on load forecasts as a source of planning uncertainty by identifying the nature and extent of forecast inaccuracy per se rather than by analysis of the causes of uncertainty. It evaluates the historic performance record of electricity sales forecasts in World Bank member countries, based on over 200 separate forecasts (1,600 annual forecasts) from 45 countries over the period 1960-1985. A comparative evaluation of U.S. forecasting experience is also included.

The study identifies a strong historic bias toward overestimation which cuts across sales forecasts for all regions, vintages, system sizes and economic circumstances. Forecast accuracy deteriorated consistently with longer forecast horizons. More recent forecasts have not tended to become more accurate, despite the general increase in effort and sophistication of forecasting techniques. This appears to suggest that the scope for reducing uncertainty in load forecasting appears to be insufficient to support the deterministic approach to power system planning. The study concludes that planning approaches should explicitly take account of this apparently unavoidable uncertainty, and it presents some recommendations for research into such approaches.

The study also investigated the relationship between forecast accuracy and external conditions, to identify indicators for further research into the structural causes of forecast inaccuracy. The best forecast performance was found among countries that had

good and stable economic growth. Conversely, the poorest forecast performance was found among the countries with the worst economic performance. The performance of short term forecasts tended to improve with increasing system size and per capita national income, but this trend did not appear to persist into the medium and long term. In general, forecasts in developing countries were as accurate as those for U.S. utilities in the medium term (4 to 6 years), although poorer in the short term (2 years).

ACRONYMS

CV	Coefficient of Variation
EEI	Edison Electric Institute
EMENA	Europe, Middle East and North Africa
GWH	Gigawatt hours
GNP	Gross National Product
LAC	Latin America and Caribbean
MPD	Mean Percent Deviation
MAPD	Mean Absolute Percent Deviation
PCR	Project Completion Report
PPAR	Project Performance Audit Report
SAR	Staff Appraisal Report

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SUPPORTING ANNEXES

1 INTRODUCTION

1.1 STUDY BACKGROUND, AND OBJECTIVES: WHAT CAN WE LEARN FROM OUR PAST FORECASTING EXPERIENCE?

Power sector system expansion planning is presently characterized by a considerable degree of uncertainty with respect to many factors, including time and cost-to-completion of a new plant, fuel costs, technological innovation, and the load forecast. The presence of such uncertainty greatly enhances the prospects for imbalances in future supply and demand. Power supplying entities can ill-afford to find themselves in a position of being significantly "under-built" or "over-built" vis-a-vis the short- to medium-term load resource balances at any point in time.

Getting caught short can have serious adverse economic consequences for consumers and the economy at large. On the other hand excess resources can impose undue financial hardships on a utility and its consumers. In addition, this situation results in unnecessary and high economic opportunity costs associated with resource misallocation.

In short, there is a high cost to being wrong. The thrust of a good planning strategy should be to enable the utility to securely and cost-effectively navigate this economic and financial tightrope. Any methodological framework for effectively addressing this problem of planning under uncertainty will require information about the nature and extent of uncertainty associated with the key exogenous planning variables.

This study focuses on the load forecast as a source of planning uncertainty. While planners frequently acknowledge that they have been victims of a "bad" forecast, the majority of utility financial and systems planners continue to use forecasts as certain characterizations of the future. However, in evaluating power projects and sector loans, it is essential that uncertainty related to future loads be explicitly incorporated in the analysis. Analysis in this report underscores the point that one cannot realistically expect that the problem of load forecast uncertainty can be simply dealt with by improvements in the state-of-art in load forecasting. Forecast error is an inescapable reality and apriori there is no load forecast that is the correct forecast or the best forecast. Simply put, the issue in power project evaluation, and in sector expansion planning is not whether demand will grow at X percent or Y percent annually. Rather, the issue is what is the best resource development strategy given that loads are likely to grow between X and Y percent, or equivalently at a rate (X $\pm$ e) percent, where e denotes forecast error (deviation).

Our objective is to identify the nature and extent of forecast inaccuracy per se rather than the causes of this error. When and where and how frequently have forecasting errors occurred? Is error in forecasting a gradually disappearing phenomenon as we expand the "state of the art", or is there an unavoidable level of inaccuracy? If we must accept some forecasting error, is it at least restricted to identifiable circumstances? In general, do "point" forecasts provide an acceptable level of accuracy for planning?

Unfortunately, despite decades of electricity load forecasting experience, there has been very little analysis and synthesis of this historical experience in order to increase our knowledge of this source of uncertainty. A retrospective analysis of forecast performance can help provide useful insights concerning questions of the following type:

- What is the nature and extent of forecast deviation from actual performance associated with this historical experience?
- Is there any pattern to forecast deviation vis-a-vis external conditions such as:
  - Electric system size?
  - National rate of economic growth?
  - National income per capita?
  - Scale of World Bank power sector lending?
- Has forecast performance improved over time?
- How often is it necessary to update forecasts?
- Does year-to-year forecast deviation follow a recognizable trend, or is it purely random?

Against this background, the objectives of this study are to assemble, review, and analyze the historic record of electric load forecasting experience in the World Bank's member countries with a view toward evaluating the accuracy and performance record of previous load forecasts and estimating the extent of forecast deviation. The study also presents some recommendations regarding strategies for incorporating uncertainty into generation capacity planning decisions. It is hoped that these procedures will contribute to enhancing the usefulness and effectiveness of the load forecast input in power sector planning and evaluation activities in support of the Bank's lending programs.

While we believe this study to be the most extensive analysis of forecast experience to date,[1] it would be inappropriate to use this data to draw conclusions about the causes of forecast deviation. The latter task requires data that were not available to us. This aspect is discussed later in the report under the section on Directions for Future Research.

A Note on Terminology

Up to this point we have frequently used the term "load forecast". This phrase is subject to some ambiguity. More than one type of forecast is generally used in utility planning. Forecasts of system requirements ("demand") are needed for medium-to-long term system capacity expansion planning. On the other hand, "sales" forecasts are necessary for short-to-medium term financial planning. The difference between these two forecasts are system losses (both, technical losses, and unbilled consumption).

To address the issue of planning uncertainty, we are interested in both of these forecasts. For very practical reasons, however, our database for this study is largely made up of sales forecasts. We found longer and more consistent forecast series for sales than for generation. To see if our conclusions would be different for an analysis of generation forecasts, we also compiled and analyzed a smaller data set of system loss forecasts.

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1 An earlier Bank study conducted an evaluation of forecast experience during the period 1950-1965: "Ex-Post Evaluation of Electricity Demand Forecasts", IBRD Economics Department Working Paper No. 79, June 1970. However, the era of the 1950s in many ways was quite different than the more recent time period which is the focus of this effort. In addition, that study had substantially fewer data points; approximately 275 to 1,600 in our study.

1.4

Although we continue to use the term load forecast throughout the text, the reader should remember that most of our analysis is based on sales forecasts.

1.2 ORGANIZATION OF REPORT

This report is organized as follows. Chapter 2 describes the methodological approach and data inputs employed to analyze the performance record of load forecasts in a sample of the Bank's member countries. Chapter 3 presents the findings of our retrospective analysis of load forecasts for the period 1960 - 1985. Chapter 4 contains a review of the U.S. experience with forecast performance. Chapter 5 presents our conclusions and recommendations. Finally, several Annexes contain supporting information.

2 METHODOLOGY

This chapter describes the analytical approach used to evaluate the performance record of prior load forecasts. The criteria selected for forecast evaluation are described in Section 2.1. In order to conduct an analysis employing these criteria, we assembled a database of actual and forecasted loads for the period 1960 through 1985. This database is described in Section 2.2.

2.1 CRITERIA FOR EVALUATING FORECAST ACCURACY

The primary purpose in studying the historic performance of load forecasts is to characterize the uncertainty associated with these projections by quantifying their errors. To do so, we need to use evaluation criteria which establish both the magnitude and the direction of forecast deviation. We have established several measures of forecast "accuracy" which are used to compare forecasts. These measures have been applied to the forecast database both longitudinally (that is, by forecast or by a specified horizon within a forecast), and cross-sectionally (that is, for individual years from different forecasts, categorized by years-out from the date of forecast).

The fundamental random variable of interest in this study is the forecast deviation, which is sometimes also referred to as forecast error. This variable in any year is defined as:

$$D_t = \frac{F_t - A_t}{At}, \quad \text{where}$$

F^t = Forecast sales in year t (GWh)

A_t = Actual sales in year t(GWh)

There are several statistical measures of forecast accuracy as defined by forecast deviation. These are:

- mean percent deviation (MPD)
- standard deviation

- mean absolute percent deviation (MAPD)
- error distribution

Mean percent deviation (MPD) is defined as:

$$MPD = \frac{100}{T} \times \sum_{t=1}^{T} D_t, \text{ where}$$

T = the number of forecast years (forecast horizon)

Mean percent deviation is calculated as the error in each year, averaged over the forecast horizon or some specified interval within the horizon. It is primarily a measure of forecast bias. In particular, its sign indicates the direction of any systematic error. However, MPD is not a measure of error magnitude, because for example, the deviation equals zero if the errors cancel each other out.

To address this problem, we separately calculate the mean percent deviation for "over-estimates", i.e., the MPD in forecast years in which percent deviation is greater than zero, and "under-estimates", i.e., the MPD in forecast years in which percent deviation is less than zero.

Mean absolute percent deviation (MAPD) is a measure of the magnitude of forecast error.

$$MAPD = \frac{100}{T} \times \sum_{t=1}^{T} |D_t|, \text{ where}$$

T = forecast horizon

While this measure is a useful means of averaging "over" and "under" estimates, information about the direction of the error (bias) is lost.

The four statistics together, MPD, "over, "under", and MAPD allows us to examine both the direction and magnitude of error. However, neither MPD, nor MAPD measure forecast risk uncertainty. They quantify the dimensions of error bias and error magnitude. In contrast, forecast risk relates to the "spread" of error. This is estimated in the report by the standard deviation.[1] However, where significant reference is also made to the coefficient of variation.

We have also estimated the error distribution to provide insights about other facets of forecast risk that cannot be conveyed by first and higher order moments of the random variable, the forecast deviation.

Finally, in selected instances in the analysis described in Chapter 3, we test for statistical difference between mean forecast deviations for two different samples. In such cases we have employed a hypothesis test for the difference between the two means. The following statistic is used to test the null hypothesis:

$$t = \frac{\overline{X}_1 - \overline{X}_2}{[(s_1^2/n_1) + (s_2^2/n_2)]}$$

with degrees of freedom given by

$$d.f. = \frac{[(s_1^2/n_1) + (s_2^2/n_2)]^2}{[(s_1 2/n_1)^2[1/(n_1-1)] + (s_2^2/n_2^2/n_2)^2[1/(n_2-1)]}$$

rounded to the nearest interger. Here, x, s, and n denote the mean, standard deviation, and sample size for a given group

It should be emphasized that these formulae are appropriate to test the difference between two means when (1) the samples are independent, (2) both populations are normally distributed, and (3) the population variances are unequal and unknown.

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[1] This study calculates the standard deviation of the "percent deviations" (MPD, MAPD) discussed above. The standard deviation is therefore expressed as a percentage rather than as an absolute value as more typically reported.

Assumption 2 is not critical for sample sizes of 25 or larger. This point is relevant in the context of our data. In particular, results in Chapter 3 show that the error distribution is skewed heavily to the right, i.e., it is not normal. Fortunately, forecast horizons up to seven years generally satisfy the minimum sample size requirement noted above. However, this is generally not the case for the years beyond. Thus less confidence can be attached to conclusions made about comparison of forecast performance in year 10 and beyond.

Cross-Sectional vs Longitudinal Analysis

The statistical criteria identified in the preceding can be estimated from longitudinal data (as in the formulae indicated), or from cross-sectional data. Longitudinal analysis measures the average performance of each forecast over specified time intervals, such as, "near term", "mid-term", "long-term". For example, in our context these intervals could be defined as years 1 through 3, years 4 through 7, and years 8 and beyond, respectively.[2],[3]

Cross-sectional analysis focuses on measuring accuracy at specific points in time. To illustrate in our context, system planners are less concerned with the average accuracy of forecasts over given time intervals. Rather, their primary concern is with accuracy in certain critical years, that correspond to lead times for typical power projects. Thus accuracy is most vital for selected future years when generation projects are committed into service, e.g., 3 years out, 7 years out, 10 years out. Cross-sectional analysis is better suited for this purpose. A longitudinal analysis will typically understate forecast accuracy because it averages-out the accuracy achieved over multiple years.

Table 2-1 illustrates the effect of using longitudinal versus cross-sectional data. The table reports summary statistics for each of years 1 through 3 of the global sample (i.e.,

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[2] Our database there are very few forecasts with horizons beyond 10 years.

[3] Longitudinal performance can also be evaluated for the entire horizon of a forecast. However, such a comparative analysis is not very meaningful when comparing forecasts with different forecast horizons.

Table 2-1

COMPARISON OF FORECAST DEVIATION AS MEASURED WITH LONGITUDINAL AND CROSS-SECTIONAL DATA

		SHORT-TERM (YEARS 1 THRU 3)		
		Sample Size	Mean Annual Deviation	Std. Dev. (%)
LONGITUDINAL DATA	"Over"	163	9.0	
	"Under"	28	-3.8	
	MPD	221	5.6	(8.9)
	MAPD	221	8.3	(7.2)

		YEAR 1			YEAR 2			YEAR 3		
		Sample Size	Mean Annual Deviation	Std. Dev. (%)	Sample Size	Mean Annual Deviation	Std. Dev. (%)	Sample Size	Mean Annual Deviation	Std. Dev. (%)
CROSS-SECTIONAL DATA	"Over"	149	6.1		155	10.7		172	13.9	
	"Under"	101	-2.9		76	-4.5		56	-5.8	
	MPD	250	2.5	(8.1)	231	5.7	(11.3)	228	9.1	(14.8)
	MAPD	250	4.8	(7.0)	231	8.7	(9.3)	228	11.9	(12.6)

"Over" = Over-estimates
"Under" = Under-estimates
MPD = Mean Percent Deviation (annual)
MAPD = Mean Absolute Percent Deviation (annual)

cross-section da), and the average of the first three years of forecasts with a horizon of 3 or more years (i.e., the longitudinal data). The changes reflected in the mean, mean absolute deviation, and standard deviations tend to be averaged, and therefore less pronounced. Furthermore, the sample size decreases in the longitudinal analysis since it requires data for three forecast years rather than one. The increased data complicates statistical analysis of longitudinal data, since errors in the three forecast years are serially correlated.

To illustrate this point further, consider the decision to install a combustion turbine which has a 3-year lead time. Clearly, information about forecast accuracy in year 3 is more useful than about years 1 or 2, or information about the forecast accuracy averaged over years 1 thru 3.

2.2 DATABASE

To calculate the statistics described in Section 2-1, we first compiled a database on actual and forecasted sales for the period 1960-1985. These data were derived from the following published Bank sources:

- Staff Appraisal Reports (SAR)
- Project Completion Reports (PCR)
- Project Performance Audit Reports (PPAR)
- Energy Sector Assessment Reports

The specific documents used are cited in Annex 1. In addition to reports from the study period (1960-85), we reviewed documents from prior to 1960 and after 1985 to identify forecasts overlapping our study period. Further, in several cases we were able to supplement these sources with actual electricity sales data from the files of Bank economists.

Data were compiled on power sector projects financed by the Bank in 45 member countries. We included in our database forecasts of total sales in gigawatt hours (GWh) which had been prepared for any clearly defined power sector "entity" or area. For example, a forecast might cover an entire country, a region, an interconnected system, or a specific utility.

Although we reviewed all of the sources noted above, we did not include every forecast contained therein. In general, we limited ourselves to multi-year forecasts of interconnected (vs. isolated) grid systems, e.g., we excluded dozens of one-year forecasts prepared for individual states in India, and many more forecasts of small isolated regions removed from national power systems. We attempted to eliminate overlapping regions for forecasts made in the same year. For example, if for a given country there was both a "national forecast" and a " central region" forecast which accounted for 80 percent of the national total, we selected only the national forecast for our database.

For purposes of this analysis, we define each forecast as a set of "forecast years". To be included in the study, a "forecast year" must include three data elements.

- o Forecast sales (in GWh) for a specific year
- o Actual sales (in GWh) for the same year
- o The initial year of the forecast.

In excess of 300 separate forecasts in over 100 separate systems were identified. Of these forecasts, we successfully matched the above-noted data elements for over 200 forecasts with horizons of up to 12 years, representing over 1600 forecast years. The actual number of forecasts in our sample depends on whether we are taking a longitudinal or a cross-sectional sample, and on the horizon we select. For example, there are 221 longitudinal forecasts of at least 3 years, and 104 of at least 7 years. Cross-sectionally, there are 250 forecasts of horizon year 1, 228 of horizon year 3, and 116 of horizon year 7. Table 2-2 summarizes the forecasts represented in the database.

To facilitate the forecast analysis outlined in the following sections, raw sales data on each forecast was supplemented with the following macroeconomic indicators.

- o *Pre-forecast national GNP growth rate* as defined by the average rate for the three years prior to the first forecast year, derived from GNP figures (expressed in constant 1980 dollars), from the World Bank Tables.

Table 2-2

DATABASE

COUNTRY	AREA/UTILITY	FORECASTS 1	2	3	4	5	6	7	8	9	10	11	12
LATIN AMERICA/CARIBBEAN--													
ARGENTINA	SEGBA	1967-1970	1969-1974	1976-1981									
BOLIVIA	BOLIVIA	1980-1980											
BOLIVIA	ENDE	1969-1974	1973-1977	1975-1980									
BRAZIL	NORTHEAST	1973-1982											
BRAZIL	SOUTH	1976-1985	1980-1985										
BRAZIL	SOUTHEAST	1972-1982	1976-1985										
BRAZIL	CHESF	1974-1982	1979-1985	1985-1985									
BRAZIL	ELECTROSUL	1970-1977											
BRAZIL	FURNAS	1968-1975	1970-1978	1973-1982	1985-1985								
BRAZIL	CBEE	1966-1970											
BRAZIL	CFEE	1978-1983	1979-1983										
BRAZIL	CELPE	1976-1979											
BRAZIL	CELESC	1979-1982											
BRAZIL	CEMIG	1965-1974	1968-1976	1972-1980	1978-1982								
BRAZIL	COPEL	1975-1980	1979-1985										
BRAZIL	ESCELSA	1978-1982											
BRAZIL	FLDP	1966-1970											
BRAZIL	FLMG	1966-1970											
BRAZIL	LIGHT	1972-1976											
BRAZIL	PFL	1966-1970											
CHILE	CIS	1968-1974											
CHILE	ENDESA	1966-1972											
COLOMBIA	EEEB	1960-1968	1962-1970	1968-1974	1969-1978	1978-1984	1979-1985	1981-1985	1985-1985				
COLOMBIA	EPM	1963-1970	1969-1978	1972-1979	1979-1985	1980-1985	1983-1985						
COSTA RICA	NIS	1969-1975	1971-1985	1975-1981	1979-1982								
COSTA RICA	ICE	1960-1969	1969-1973	1971-1977	1978-1983	1979-1983							
ECUADOR	EEQ	1972-1976											
ECUADOR	ECUADOR	1979-1985											
EL SALVADOR	CEL	1960-1969	1963-1972	1970-1974	1972-1978	1975-1985							
GUATEMALA	EEG	1976-1982	1978-1983										
GUATEMALA	INDE	1976-1982	1978-1983										
GUATEMALA	GUATEMALA	1966-1971	1976-1982	1978-1983									
HAITI	PORT AU PR	1975-1985	1978-1983	1981-1985	1984-1985								
HAITI	EdH	1978-1983	1981-1985	1984-1985									
HONDURAS	ENEE	1960-1971	1967-1977	1970-1975	1975-1980	1976-1979	1979-1985						
HONDURAS	ICS	1967-1977	1970-1980	1974-1985	1977-1985	1979-1985							
HONDURAS	CENTRAL	1967-1971	1976-1979										
HONDURAS	NORTHERN	1967-1971	1976-1979										
JAMAICA	JPS	1966-1975	1977-1985	1983-1985									
MEXICO	TOTAL	1968-1971	1969-1973	1971-1976									
NICARAGUA	ENALUF/INE	1960-1963	1960-1969	1966-1972	1968-1974	1972-1985	1976-1985						
PANAMA	IRHE	1962-1971	1969-1977	1972-1982	1977-1983	1979-1985	1982-1985	1985-1985					
PERU	ELECTROLIMA	1960-1969	1963-1967	1975-1980	1982-1985								
PERU	EEA	1968-1971											
URUGUAY	UTE	1960-1963	1970-1974	1979-1983	1982-1985	1985-1985							
VENEZUELA	EDELCA	1963-1979	1965-1975	1969-1980									
VENEZUELA	CADAFE	1964-1968											

Table 2-2 (continued)

DATABASE

COUNTRY	AREA/UTILITY	FORECASTS 1	2	3	4	5	6	7	8	9	10	11	12
AFRICA-------------------													
ETHIOPIA	EELPA	1964-1971	1969-1974	1985-1985									
GHANA	VRA	1968-1976	1984-1985										
GHANA	ECG	1967-1972	1970-1978	1976-1981	1984-1985								
GHANA	GHANA	1976-1981											
KENYA	KPLC	1971-1974	1972-1980	1975-1980	1979-1985	1982-1985	1983-1985						
LIBERIA	LEC	1969-1974	1971-1975	1977-1982									
MALAWI	ESCOM	1969-1974	1973-1980	1976-1984	1977-1982								
NIGERIA	ECN	1964-1969											
NIGERIA	PUB. SERVICE	1980-1985											
NIGERIA	NDA	1970-1978	1970-1974										
NIGERIA	NEPA	1972-1981											
S. LEONE	SLEC	1966-1969	1968-1972	1978-1982									
SUDAN	CEWC	1968-1973											
SUDAN	BNG	1968-1975	1974-1981	1983-1985	1979-1985								
TANZANIA	COASTAL	1970-1985	1975-1982										
TANZANIA		1975-1983											
TANZANIA	TANESCO	1970-1976	1975-1981	1981-1985	1982-1985	1984-1985	1985-1985						
ZAMBIA	ZAMBIA	1970-1980	1970-1980										
ZAMBIA	CAPC-ZA	1970-1980											
ZIMBAWE	CAPC-ZIM	1970-1980	1982-1985										
ASIA--------------------													
BANGLADESH	BPDB	1979-1985											
INDIA	INDIA	1978-1978	1979-1979	1980-1980									
INDIA	TEC	1960-1965	1984-1985										
INDIA	EASTERN	1982-1982											
INDIA	ORISSA	1979-1979	1982-1982										
INDIA	BIHAR	1979-1982											
INDIA	MAHARASHTRA	1978-1980											
INDIA	NTPC	1982-1985	1982-1985										
INDIA	A.PRADESH	1962-1971	1966-1971										
INDONESIA	DJAKARTA	1975-1980	1975-1980										
INDONESIA	PLN	1972-1979	1972-1977	1975-1979	1976-1984	1977-1985	1977-1985	1981-1985	1982-1985	1984-1985			
INDONESIA	JAVA	1976-1985	1978-1985	1982-1985									
INDONESIA	WEST JAVA	1974-1985											
MALAYSIA	NEB	1960-1967	1963-1972	1966-1972	1968-1976	1968-1976	1970-1978	1974-1983	1975-1981	1977-1983	1980-1985		
PHILIPPINES	LUZON GRID	1974-1980	1976-1985										
PHILIPPINES	AGUS	1961-1972	1962-1972										
PHILIPPINES	NPC	1967-1974	1972-1976	1974-1980									
SRI LANKA	CEB	1960-1965	1961-1967	1969-1974	1972-1977	1973-1976	1980-1985						
THAILAND	YEA	1963-1970	1964-1970	1967-1975									
THAILAND	EGAT	1969-1974	1971-1977	1973-1982	1977-1985	1979-1985	1979-1985						

Table 2-2 (continued)

DATABASE

COUNTRY	AREA/UTILITY	FORECASTS 1	2	3	4	5	6	7	8	9	10	11	12
EUROPE, M-EAST, N.AFRICA-													
CYPRUS	EAC	1961-1968	1966-1971	1969-1974	1972-1977	1980-1985	1982-1985						
JORDAN	JEPCO	1974-1980	1973-1980	1978-1985	1981-1985	1983-1985							
JORDAN	IDECO	1973-1980	1978-1985	1981-1985	1983-1985								
JORDAN	JEA	1975-1980	1978-1985	1979-1983	1980-1985	1981-1985	1985-1985						
JORDAN	GRID	1975-1980											
MOROCCO	ONE	1973-1977	1975-1980	1982-1985									
PAKISTAN	WAPDA	1970-1975	1976-1983	1985-1985									
PAKISTAN	KESC	1966-1970	1971-1980										
PAKISTAN	EDP	1975-1985	1982-1985										
PORTUGAL	PORTUGAL	1975-1980											
TUNISIA	STEG	1976-1981	1981-1985	1983-1985									
TURKEY	TURKEY	1973-1982	1976-1985	1979-1985									
TURKEY	IETT	1972-1976											
TURKEY	TEK	1970-1977	1973-1982	1973-1984	1976-1985	1979-1985	1982-1985	1984-1985					
TURKEY	CEAS	1962-1970	1964-1970	1969-1973	1971-1974								
TURKEY	KEBAN	1970-1977											
YEMEN AR	YGEC	1977-1985	1981-1985	1982-1985	1985-1985								
YUGOSLAVIA	YUGOSLAVIA	1962-1965	1974-1985										

- *Post-forecast national GNP growth rate.* From the same source, we calculated the average growth rate for the life of the forecast.

- *National GNP per capita.* We used 1985 data, as published in the World Development Report for 1987. We relied on recent data because there does not appear to be significant changes in real GNP per capita of the countries included in the sample relative to each other during the period of study.

- *System size.* Total GWh sales projected in the initial forecast year was selected as a proxy for system size at the time the forecast was made.

3 ANALYSIS OF FORECAST ACCURACY

This chapter presents the findings of a retrospective analysis of load forecasts over the period 1960-1985. Statistics defined in Chapter 2 were computed and used to compare the historical accuracy of load forecasts from a variety of perspectives, including region, vintage, horizon, system size, real income per capita, and economic growth rate. In addition, we have examined the performance of forecasts for individual countries, and in particular those countries which have been large Bank borrowers.

The results summarized in this Chapter are based upon a cross-sectional analysis of forecast accuracy in years 3, 7, and 10 of the forecast horizon. These years are selected as being representative of the lead times associated with generation projects requiring "short-lead times" (e.g., a combustion turbine), "medium- lead time" (e.g., a coal plant), and "long-lead time" (e.g., a large hydro project).[1]

One caveat should proceed this statistical analysis of forecast accuracy. Statistics do not explain deviations between actual and forecast sales, they only report them. A further point to be noted is that the analysis in this Chapter is based upon comparisons of actual system sales and forecasted sales. Embedded in most sales forecasts is some assumption about the extent of unbilled consumption. In reality, this component may turn out higher than projected. This will result in positive forecast error, i.e., forecast sales being greater than actual sales. Similarly, unanticipated supply constraints (i.e., generation deficiencies) will also result in positive forecast error. The potential presence of these effects should be borne in mind in interpreting the results presented in this Chapter.[2]

3.1 GLOBAL FORECAST ACCURACY

Table 3-1 summarizes the global forecast accuracy for each of the three forecast horizons. Reported in the table are the means of all "over-estimates" and all "under-estimates", and the sample size of these groupings. Also presented in the table are the

1 As noted earlier, very few forecasts in our database have horizons beyond 10 years. Therefore, we are forced to restrict the definition of "long-lead time" to 10 years.

2 This aspect is investigated in section 3.8.

TABLE 3-1

GLOBAL FORECAST DEVIATION

	YEAR 3			YEAR 7			YEAR 10		
	Sample Size	Mean Annual Deviation (%)	Std. Dev. (%)	Sample Size	Mean Annual Deviation (%)	Std. Dev. (%)	Sample Size	Mean Annual Deviation (%)	Std. Dev. (%)
"Over"	172	13.9		89	21.2		30	27.3	
"Under"	56	-5.8		27	-15.4		7	-36.6	
MPD	228	9.1	(14.8)	116	12.7	(22.8)	37	15.2	(34.2)
MAPD	228	11.9	(12.6)	116	19.9	(16.8)	37	29.1	(23.6)

mean percent deviation (MPD) and the mean absolute percent deviation (MAPD), along with their respective standard deviations.

On a worldwide basis, there has been a definite bias toward over-estimation in load forecasts. The MPD is always positive and increases from 9.1 percent in year 3, to 12.7 percent in year 7, to 15.2 percent by year 10.

By an overwhelming ratio of over 3-to-1, forecast deviations have tended to be positive rather than negative. The average magnitude of forecast overestimates increases from 13.9 percent in year 3 of the forecast horizon, to 21.2 percent in year 7, to 27.3 percent by year 10. The corresponding magnitudes of forecast underestimates are - 5.8 percent, -15.4 percent, and - 36.6 percent.[3]

The mean absolute percent deviation averages the "over" and "under" estimates. Thus the average magnitude of forecast deviation worldwide (MAPD), increases from 11.9 percent in year 3, to 19.9 percent in year 7, to 29.1 percent in year 10.

Forecast spread as measured by standard deviation of forecast error is substantial even in the near-term and grows substantially over time. In year 3, forecast spread is 14.8 percent, increasing to 22.8 percent by year 7, and 34.2 percent by year 10.

The coefficients of variation (CV), defined as the ratio of the standard deviation and the mean on an all regions basis are 1.63 (year 3), 1.80 (year 7), and 2.25 (year 10). These values are extremely high, highlighting the degree of uncertainty even for short forecast horizons.

3.2 FORECAST ACCURACY BY REGION

When forecasts are studied on a regional basis (Table 3-2), each region displays characteristics similar to the worldwide trend. Forecast overestimates exceed underestimates in every year, small sample sizes excepted. All regions show increasing magnitude of forecast deviation (MAPD) from year 3 to year 7; uncertainty (standard

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[3] A general comment regarding this table as well as all other tables in this chapter relates to the small sample sizes observed in year 10. In such instances less confidence can be attached to any conclusions regarding year 10.

Table 3-2

FORECAST DEVIATION BY REGION

		YEAR 3			YEAR 7			YEAR 10		
		Sample Size	Mean Annual Deviation (%)	Std. Dev. (%)	Sample Size	Mean Annual Deviation (%)	Std. Dev. (%)	Sample Size	Mean Annual Deviation (%)	Std. Dev. (%)
LAC	"Over"	71	11.3		40	22.5		16	24.4	
	"Under"	30	-5.4		14	-14.9		6	-37.7	
	MPD	101	6.3	(10.7)	54	12.8	(25.1)	22	7.4	(36.9)
	MAPD	101	9.5	(8.0)	54	20.5	(19.4)	22	28.0	(25.2)
AFRICA	"Over"	34	15.7		16	22.5		6	17.0	
	"Under"	6	-3.8		2	-8.1		0	-	
	MPD	40	12.8	(13.0)	18	19.1	(17.4)	6	17.0	(11.2)
	MAPD	40	13.9	(11.8)	18	20.9	(15.1)	6	17.0	(11.2)
ASIA	"Over"	34	15.1		21	15.7		4	28.0	
	"Under"	9	-8.2		6	-16.6		1	-29.9	
	MPD	43	10.2	(19.8)	27	8.6	(18.5)	5	16.4	(26.8)
	MAPD	43	13.7	(17.6)	27	15.9	(12.7)	5	28.4	(13.5)
EMENA	"Over"	33	16.4		12	25.1		4	54.0	
	"Under"	11	-5.9		5	-18.5		0	-	
	MPD	44	10.8	(17.2)	17	12.3	(24.4)	4	54.0	(20.5)
	MAPD	44	13.8	(15.0)	17	23.2	(14.4)	4	54.0	(20.5)
ALL REGIONS	"Over"	172	13.9		89	21.2		30	27.3	
	"Under"	56	-5.8		27	-15.4		7	-36.6	
	MPD	228	9.1	(14.8)	116	12.7	(22.8)	37	15.2	(34.2)
	MAPD	228	11.9	(12.6)	116	19.9	(16.8)	37	29.1	(23.6)

deviation of forecast error) rises over the same period in all regions except Asia, where it declines very slightly from 19.8 to 18.5. The small sample size in year 10 makes regional comparison/unreliable.

The "best" forecast performance in year 3 was achieved by the LAC region. Results of the t-tests confirm statistical significance at a level exceeding 90 percent. In contrast, the best year 7 performance was achieved in the Asia region. However, the t-test indicates a statistically significant difference at the 90 percent level only in relation to EMENA.[4]

3.3 FORECAST ACCURACY BY VINTAGE

There has been an increasing emphasis on load forecasting since the beginning of our study period. Methods have become more sophisticated, and greater time and money has been invested in load projections. While our data does not include the information needed to categorize each forecast by methodology, we observed in Bank reports a definite progression from simple trend approaches in the early years to more frequent references in recent documents to more complex econometric techniques, reliance on end-use information, and use of power market and consumer surveys.

Despite this investment in additional complexity, there is no evidence that load forecast performance has improved over time. Indeed the evidence suggests the contrary. Table 3-3 shows forecast performance categorized by vintage. The bias toward over estimation can be observed in most horizon years.[5] Interestingly, the most accurate forecasts for year 3 were prepared in 1960-65 and the bias grows with the more recent forecasts. Differences in MAPD are significant at the .90 level over all periods except 1971-75. A possible explanation for the improved accuracy of the 1971-75 vintage is that forecasts--influenced by economic pessimism resulting from the world oil crisis--

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4 We urge caution in utilizing the data in Table 3-2 to establish confidence intervals for forecast deviation on the basis of the MPD and standard deviation values. In particular, results subsequently presented in this Chapter clearly indicate that the error distribution is heavily skewed and therefore non-normal. Additionally, even if the sample sizes are not small -- as in year 3 and year 7 -- the individual sample observations are not necessarily independent in all instances.

5 The exception is year 10 for forecasts prepared in 1960-65. The observed under-estimation <u>might</u> be the result of small sample size, or perhaps an outcome of the trend-extrapolation methodologies in use at the time.

Table 3-3

FORECST DEVIATION BY VINTAGE OF FORECAST (1960-85)

First Year of Forecast		YEAR 3 Sample Size	YEAR 3 Mean Annual Deviation (%)	YEAR 3 Std. Dev. (%)	YEAR 7 Sample Size	YEAR 7 Mean Annual Deviation (%)	YEAR 7 Std. Dev. (%)	YEAR 10 Sample Size	YEAR 10 Mean Annual Deviation (%)	YEAR 10 Std. Dev. (%)
1960 - 1965	"Over"	14	7.2		13	20.5		7	14.3	
	"Under"	6	-11.1		7	-25.1		5	-50.0	
	MPD	20	1.7	(10.6)	20	4.5	(27.0)	12	-12.5	(35.8)
	MAPD	20	8.4	(6.7)	20	22.1	(16.1)	12	29.2	24.2
1966 - 1970	"Over"	42	14.1		23	16.7		10	18.9	
	"Under"	21	-5.8		11	-8.5		1	-5.0	
	MPD	63	7.5	(16.7)	34	8.5	(15.7)	11	16.7	(16.3)
	MAPD	63	11.3	(14.3)	34	14.0	(11.0)	11	17.6	(15.4)
1971 - 1975	"Over"	45	10.5		26	15.6		11	42.3	
	"Under"	14	-5.2		9	-16.3		1	-1.4	
	MPD	59	6.8	(11.0)	35	7.4	(20.9)	12	38.7	(25.9)
	MAPD	59	9.2	(9.1)	35	15.8	(15.6)	12	38.9	(25.5)
1976 - 1980	"Over"	53	16.8		27	30.9		2	32.4	
	"Under"	13	-3.6		0	-		0	-	
	MPD	66	12.8	(15.3)	27	30.9	(19.2)	2	32.4	(17.8)
	MAPD	66	14.2	(14.0)	27	30.9	(19.2)	2	32.4	(17.8)
1981 - 1985	"Over"	18	18.4		-	-		-	-	
	"Under"	2	-8.2		-	-		-	-	
	MPD	20	15.7	(14.0)	-	-	-	-	-	-
	MAPD	20	17.4	(11.9)	-	-	-	-	-	-
ALL YEARS	"Over"	172	13.9		89	21.2		30	27.3	
	"Under"	56	-5.8		27	-15.4		7	-36.6	
	MPD	228	9.1	(14.8)	116	12.7	(22.8)	37	15.2	(34.2)
	MAPD	228	11.9	(12.6)	116	19.9	(16.8)	37	29.1	(23.6)

may not have been as hopeful about future economic conditions as during other periods.[6]

In both year 3 and year 7, pre-1975 forecasts are more accurate than their successors. These differences are significant at the .90 level. Year 10 data is less conclusive due to the small sample size. Unfortunately, it is not possible to measure the long-term performance of more recent vintages and their generally more sophisticated methodologies. Forecasts prepared after 1976 do not have a 10-year performance record in our database. Furthermore our database does not permit us to analyze the cause of these differences. Interesting hypotheses in this regard, that can be examined in future research on this topic include (1) the types of methodologies used, and (2) the economic growth and energy price volatility in different time periods.[7]

3.4 FORECAST ACCURACY BY SYSTEM SIZE

Table 3-4 presents summary statistics for electricity systems categorized by size. The first year forecast in GWh is used as a proxy for system size. These groupings reaffirm the same trends over time with regard to forecast bias already noted.

Small systems seem to have performed more poorly than larger ones. This trend is most noticeable in the short-term (horizon year 3). The mean absolute deviation for small systems was 14 3 percent, compared to 11.5 percent or better for all other groups. This difference is significant at the 90 percent level of confidence. Differences are less apparent (and statistically less significant) for longer horizons. Again, the problem of small sample size makes it difficult to analyze longer horizons. We have only 5 cases of very large systems (> 12,500 GWh) in year 7, and only 2 in year 10.

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6 We are not arguing that most forecasts have taken explicit account of future economic growth. Rather, we are suggesting that an underlying optimism regarding "increased prosperity" may have frequently led to optimistic conclusions about future electricity requirements across all customer classes.

7 Annex 3 provides some data about economic growth rates in different time periods of our study horizon.

Table 3-4

FORECAST DEVIATION BY SYSTEM SIZE

System Size		YEAR 3 Sample Size	YEAR 3 Mean Annual Deviation (%)	YEAR 3 Std. Dev. (%)	YEAR 7 Sample Size	YEAR 7 Mean Annual Deviation (%)	YEAR 7 Std. Dev. (%)	YEAR 10 Sample Size	YEAR 10 Mean Annual Deviation (%)	YEAR 10 Std. Dev. (%)
< 500 GWh	"Under"	13	-6.4		8	-20.8		3	-52.8	
	MPD	65	11.8	(16.5)	34	11.7	(23.8)	12	1.5	(37.1)
	MAPD	65	14.3	(14.3)	34	21.5	(15.6)	12	27.9	(24.5)
500 - 2500 GWh	"Over"	61	13.8		31	23.1		8	38.8	
	"Under"	27	-6.4		12	-16.3		4	-24.4	
	MPD	88	7.6	(16.1)	43	12.1	(26.1)	12	17.7	(39.5)
	MAPD	88	11.5	(13.6)	43	21.2	(19.4)	12	34.0	(26.8)
2501 - 12500 GWh	"Over"	47	11.8		26	18.1		9	21.9	
	"Under"	14	-4.6		6	-7.3		0	-	
	MPD	61	8.1	(11.0)	32	13.3	(17.4)	9	21.9	(14.5)
	MAPD	61	10.2	(9.0)	32	16.1	(14.9)	9	21.9	(14.5)
> 12500 GWh	"Over"	11	12.6		4	28.2		2	56.5	
	"Under"	2	-1.8		1	-10.8		0	-	
	MPD	13	10.4	(9.4)	5	20.4	(17.0)	2	56.5	(1.9)
	MAPD	13	10.9	(8.8)	5	24.7	(9.7)	2	56.5	(1.9)
ALL SYSTEMS	"Over"	172	13.9		89	21.2		30	27.3	
	"Under"	56	-5.8		27	-15.4		7	-36.6	
	MPD	228	9.1	(14.8)	116	12.7	(22.8)	37	15.2	(34.2)
	MAPD	228	11.9	(12.6)	116	19.9	(16.8)	37	29.1	(23.6)

3.5 FORECAST ACCURACY AND COUNTRY INCOME

Table 3-5 summarizes forecast performance by countries grouped according to real national GNP per capita in 1985. Our general conclusions regarding increasing bias over longer horizons are reconfirmed (small samples excepted). However, there seems to be less pattern to forecast uncertainty.

Accuracy is noticeably better for wealthier economies. In year 3, MAPD of systems in countries with real GNP per capita over $1,000 is lower than for poorer economies. The t-test is significant at over .90. This trend is less clear in year 7, although the richest countries (GNP per capita > $1,600) outperform the poorest (GNP per capita < $400), with MAPD of 17.7 versus 24.0. This difference is again significant at the .90 level. This conclusion is not true in year 10, although our confidence in the data is again reduced due to small sample size.

3.6 FORECAST ACCURACY AND ECONOMIC CONDITIONS

To test the hypothesis that forecast performance is related to national economic growth rate, the database was segmented into three groups, based upon actual growth in the three years prior to the first forecast year. The categories are countries with average annual growth above 6 percent, with growth between 2 and 6 percent, and those with growth rates below 2 percent. We then evaluated the performance of these forecasts in light of achieved economic growth during the forecast horizon. To assure an adequate sample, forecasts of all durations were included in this comparison.

The matrix in Table 3-6 summarizes the findings. The bias in favor of over-estimates is again apparent. Not surprisingly, under-estimates are extremely rare in economies which experienced low (below 2 percent) real growth.

The best accuracy was achieved by forecasts in countries which experienced rapid growth (above 6 percent) both prior to and during the forecast period. These forecasts have an MAPD of 8.6 percent (standard deviation 7.7) compared to 14.7 percent (standard deviation 9.9) when the growth during the forecast years was only 2-6 percent, and to 23.2 percent (standard deviation 20.0) when the growth fell below 2 percent. These differences are significant at the .90 level.

Table 3-5

FORECAST DEVIATION BY INCOME LEVEL

1985 GNP/Capita		YEAR 3 Sample Size	YEAR 3 Mean Annual Deviation (%)	YEAR 3 Std. Dev. (%)	YEAR 7 Sample Size	YEAR 7 Mean Annual Deviation (%)	YEAR 7 Std. Dev. (%)	YEAR 10 Sample Size	YEAR 10 Mean Annual Deviation (%)	YEAR 10 Std. Dev. (%)
< $400	"Over"	47	15.3		22	24.9		5	35.6	
	"Under"	6	-5.0		1	-4.4		0	-	
	MPD	53	13.0	(12.6)	23	23.6	(18.3)	5	35.6	(26.0)
	MAPD	53	14.1	(11.3)	23	24.0	(17.8)	5	35.6	(26.0)
$400 - $1000	"Over"	47	16.4		28	15.1		13	22.3	
	"Under"	12	-8.7		5	-26.4		2	-35.0	
	MPD	59	11.3	(20.2)	33	8.8	(20.3)	15	14.6	(27.5)
	MAPD	59	14.8	(17.8)	33	16.8	(14.4)	15	24.0	(19.9)
$1001 - $1600	"Over"	41	13.6		23	25.4		5	20.5	
	"Under"	19	-4.8		9	-13.4		2	-3.2	
	MPD	60	7.8	(13.1)	32	14.5	(24.2)	7	13.7	(15.9)
	MAPD	60	10.8	(10.7)	32	22.0	(17.7)	7	15.5	(14.1)
> $1600	"Over"	37	9.2		16	20.9		7	35.7	
	"Under"	19	-5.2		12	-13.3		3	-59.9	
	MPD	56	4.4	(9.1)	28	6.3	(23.5)	10	7.0	(49.1)
	MAPD	56	7.9	(6.3)	28	17.7	(16.7)	10	43.0	(24.9)
ALL INCOMES	"Over"	172	13.9		89	21.2		30	27.3	
	"Under"	56	-5.8		27	-15.4		7	-36.6	
	MPD	228	9.1	(14.8)	116	12.7	(22.8)	37	15.2	(34.2)
	MAPD	228	11.9	(12.6)	116	19.9	(16.8)	37	29.1	(23.6)

Table 3-6

FORECAST DEVIATION BY NATIONAL ECONOMIC GROWTH RATE

AVERAGE ANNUAL GROWTH RATE DURING THE PERIOD OF THE FORECAST

			> 6%			2 - 6%			< 2%		
			Sample Size	Mean Annual Deviation (%)	Std. Dev. (%)	Sample Size	Mean Annual Deviation (%)	Std. Dev. (%)	Sample Size	Mean Annual Deviation (%)	Std. Dev. (%)
ANNUAL GROWTH RATE BEFORE FORECAST (3-year average)	> 6%	"Over"	27	8.3		31	15.1		4	32.5	
		"Under"	10	-3.7		7	-5.9		2	-1.8	
		MPD	37	5.1	(7.1)	38	11.2	(13.0)	6	21.1	(22.1)
		MAPD	37	8.6	(7.7)	38	14.7	(9.9)	6	23.2	(20.0)
	2 - 6%	"Over"	15	10.2		37	14.2		15	11.6	
		"Under"	6	-7.7		7	-4.8		2	-0.4	
		MPD	21	5.1	(10.8)	44	11.2	(12.1)	17	10.2	(11.5)
		MAPD	21	11.3	(7.2)	44	13.6	(10.6)	17	11.2	(11.0)
	< 2%	"Over"	6	14.7		10	10.1		6	16.4	
		"Under"	4	-5.5		1	-9.7		2	-7.2	
		MPD	10	6.6	(15.5)	11	8.3	(9.5)	8	10.5	(15.6)
		MAPD	10	12.9	(11.8)	11	10.4	(7.4)	8	14.3	(12.6)
	ALL	"Over"	62	13.3		67	12.7		23	12.5	
		"Under"	19	-4.3		15	-5.4		7	-6.6	
		MPD	81	9.1	(13.1)	82	9.4	(11.9)	30	8.0	(13.5)
		MAPD	81	12.5	(11.0)	82	12.5	(10.0)	30	12.1	(10.6)

It appears that the highest forecast accuracy and lowest uncertainty occurred when the economic growth rate during the forecast period exceeded the growth rate for the immediately preceding years. When the prior rate was 2 to 6 percent and this rose to 6 percent during the forecast period, the MAPD was 11.3 percent (standard deviation 7.2). Similarly, when the prior rate was below 2 percent and then rose to the 2 to 6 percent range during the forecast, MAPD was only 10.4 percent (standard deviation 7.4). The significance of these differences is not high.

These findings are consistent with the hypothesis that forecasters tended to base their planning on anticipation of overall improvement in economic conditions where such conditions were poor at the time of the forecast, or continuation of "good" economic conditions in other situations. If this optimism was realized, good forecasts resulted. In contrast, generally poorer accuracy and higher uncertainty occurred when economic growth slowed during the forecast period. This argument is not intended to suggest that forecasters necessarily made explicit predictions of GNP growth, or even that they were cognizant of the relationship. Rather, we suggest that growth of electricity consumption was forecast as part and parcel of a long-term optimism about economic performance.[8,9]

3.7 FORECAST ACCURACY BY COUNTRY

Table 3-7 presents summary statistics for each country in the database for which we have at least four forecasts reported. Twenty-five countries are included, ranked by MAPD in year 3.[10]

The "+" or "-" sign to the right of the standard deviation indicates that the t-test of significance has shown the result to be significantly different from the world MAPD at a level of .90 or better.[11]

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8 The analysis in Annex 6 further indicates that countries with higher and stable economic growth rates exhibited higher correlations between GNP and electricity generation.

9 An underlying strategic consideration that may have also contributed to overestimation stems from the belief that the economic implications of being caught short are substantially more serious than having to carry excess generating resources.

10 There is some danger in attempting to reach conclusions about individual country experience. For most countries the sample size is small, since our database is drawn from 45 different countries.

11 Strictly speaking, this is not a correct measure of significance, since the samples are not truly independent. Since any one country accounts for only a small fraction (never more than 10 percent, and usually much less)of the forecasts represented in the "World" sample, we have assumed that the

Table 3-7

FORECAST DEVIATION BY COUNTRY

Country	YEAR 3 Sample Size	YEAR 3 MAPD %	YEAR 3 Std Dev* %	YEAR 7 Sample Size	YEAR 7 MAPD %	YEAR 7 Std Dev*	IBRD COMMITMENT TO POWER SECTOR THROUGH 1985 1/ (Rank)	IBRD Current $ Million	IBRD $/Cap	GNP $/Capita
** WORLD **	228	11.9	(12.6)	116	19.9	(16.8)				
1 EL SALVADOR	5	5.0	(2.9) +	3	6.7	(6.3) +		$84	$18	$820
2 MALAWI	4	5.1	(2.9) +	2	23.4	(22.8)		38	5	170
3 COSTA RICA	8	5.3	(1.8) +	4	3.5	(3.3) +		124	48	1,300
4 KENYA	6	5.4	(2.7) +	2	11.8	(2.3) +		242	12	290
5 PERU	4	5.4	(2.7) +	1	15.1	-		209	11	1,010
6 MALAYSIA	10	6.0	(3.3) +	9	10.3	(8.8) +	(10)	464	30	2,000
7 BRAZIL	22	7.4	(5.3) +	9	11.4	(9.2) +	(2)	3,062	23	1,640
8 GUATEMALA	7	8.5	(7.0)	3	52.2	(15.4) -		194	24	1,250
9 CYPRUS	6	9.3	(8.1)	1	9.4	-		35	53	3,790
10 TURKEY	13	9.7	(5.1) +	8	20.2	(4.8)	(5)	457	9	1,080
11 NICARAGUA	4	10.1	(2.7)	5	31.6	(19.9)		75	23	770
12 HONDURAS	12	10.4	(8.2)	7	12.0	(11.2) +		236	24	720
13 PANAMA	5	12.7	(8.7)	5	24.3	(17.3) -		255	116	2,100
14 COLOMBIA	8	13.2	(9.6)	9	22.5	(21.6)	(4)	1,737	61	1,320
15 THAILAND	4	13.5	(9.4)	5	11.0	(9.3)	(7)	642	12	800
16 SRI LANKA	4	14.1	(7.7)	2	38.3	(2.6)		167	11	380
17 INDIA	5	14.2	(14.1)	-	-	-	(1)	5,099	7	270
18 PAKISTAN	11	15.1	(6.8)	3	21.0	(28.4)	(11)	438	5	380
19 JORDAN	10	16.4	(18.3)	4	22.7	(7.4)		58	17	1,560
20 INDONESIA	6	17.4	(13.5)	6	19.6	(10.4)	(3)	1,305	8	530
21 TANZANIA	5	17.4	(9.3)	3	27.9	(8.8)		105	5	290
22 GHANA	5	19.6	(8.1) -	2	19.5	(2.9)		127	10	380
23 HAITI	5	20.7	(13.8) -	1	24.0	-		74	13	310
24 PHILIPPINES	6	21.9	(37.3)	4	40.0	(36.8)		282	5	580
25 SUDAN	4	26.5	(15.1) -	3	32.6	(12.5)		112	5	300

* The "+" or "-" to the right of the standard deviation indicates that the MAPD is significantly different (higher or lower) than the "World" MAPD at the .90 confidence level.

1/ Source: Annex 2

Table 3-7 also identifies some additional statistics for each country: (1) the total Bank committed investment to the country's power sector through fiscal year 1985 in current dollars,[12] (2) the per capita value of this investment based on mid-year 1985 population, and (3) the GNP per capita in 1985.

Table 3-8 ranks the "highest" and "lowest" among these twenty-five countries for each of the above categories. It is interesting to see the pattern of results, although we hasten to emphasize that we are not seeking to identify causality with these comparisons. We have run bi-variate and multi-variate regressions on these factors, and found no significant correlation.

Of the seven countries in our sample with "highest" forecast accuracy based on MAPD in year 3, four are in Latin America. This sounds more impressive than it is: 40 percent of our 25 countries are in Latin America. Only two of the countries which have received the highest absolute amount of Bank power funds -- Brazil and Malaysia -- had notably accurate forecasts. One of the poorer performers (Indonesia) was also in this group.

When we look at this funding on a per capita basis, again only two countries with high funding are in the group of most accurate forecasts -- Costa Rica and Malaysia. Three of the countries with highest per capita income were among the most accurate forecast group -- Malaysia, Brazil, and Costa Rica. Jordan, with high per capita income, is among the lowest group of countries in terms of forecast accuracy.

Three of the seven countries in our sample with the "lowest" forecast accuracy are in Africa -- Tanzania, Ghana, and Sudan. Three of these seven relatively poor performers were in the group which received the lowest (again, relatively) absolute Bank power sector commitment -- Jordan, Haiti, and Tanzania. When these commitments are expressed on a per capita basis, four countries in the lowest recipient group are in the lowest accuracy group, notably Tanzania, Sudan, the Philippines, and Indonesia. It should be noted that Malawi, which received relatively low commitments per capita (and in absolute terms) was among the "highest" accuracy group. Finally, four of the

[12] The "rank" shown in the table reflects the ranking in terms of total dollars committed to the 11 countries which receive two-thirds of all IBRD power sector commitments through 1985.

Table 3-8

FORECAST DEVIATION BY COUNTRY CHARACTERISTICS

Country	YEAR 3 Sample Size	YEAR 3 MAPD %	YEAR 3 (Std Dev) %	YEAR 7 Sample Size	YEAR 7 MAPD %	YEAR 7 (Std Dev) %	IBRD COMMITMENT TO POWER SECTOR THROUGH 1985 1/ (Rank)	IBRD Current $ Million	IBRD $/Cap	GNP $/Capita
** WORLD **	228	11.9	(12.6)	116	19.9	(16.8)				
HIGH ACCURACY										
1 EL SALVADOR	5	5.0	(2.9) +	3	6.7	(6.3) +		$84	$18	$820
2 MALAWI	4	5.1	(2.9) +	2	23.4	(22.8)		38	5	170
3 COSTA RICA	8	5.3	(1.8) +	4	3.5	(3.3) +		124	48	1,300
4 KENYA	6	5.4	(2.7) +	2	11.8	(2.3) +		242	12	290
5 PERU	4	5.4	(2.7) +	1	15.1	-		209	11	1,010
6 MALAYSIA	10	6.0	(3.3) +	9	10.3	(8.8) +	(10)	464	30	2,000
7 BRAZIL	22	7.4	(5.3) +	9	11.4	(9.2) +	(2)	3,062	23	1,640
HIGH IBRD COMMITMENT										
17 INDIA	4	14.2	(14.1)	-	-	-	(1)	5,099	7	270
7 BRAZIL	22	7.4	(5.3) +	9	11.4	(9.2) +	(2)	3,062	23	1,640
14 COLOMBIA	12	13.2	(9.6)	9	22.5	(21.6)	(4)	1,737	61	1,320
20 INDONESIA	10	17.4	(13.5)	6	19.6	(10.4)	(3)	1,305	8	530
15 THAILAND	8	13.5	(9.4)	5	11.0	(9.3)	(7)	642	12	800
6 MALAYSIA	10	6.0	(3.3) +	9	10.3	(8.8) +	(10)	464	30	2,000
10 TURKEY	13	9.7	(5.1) +	8	20.2	(4.8)	(5)	457	9	1,080
HIGH IBRD COMMITMENT/CAPITA										
13 PANAMA	5	12.7	(8.7)	5	24.3	(17.3) -		255	116	2,100
14 COLOMBIA	12	13.2	(9.6)	9	22.5	(21.6)	(4)	1,737	61	1,320
12 HONDURAS	12	10.4	(8.2)	7	12.0	(11.2) +		236	24	720
9 CYPRUS	6	9.3	(8.1)	1	9.4	-		35	53	3,790
3 COSTA RICA	8	5.3	(1.8) +	4	3.5	(3.3) +		124	48	1,300
6 MALAYSIA	10	6.0	(3.3) +	9	10.3	(8.8) +	(10)	464	30	2,000
8 GUATEMALA	7	8.5	(7.0)	3	52.2	(15.4) -		194	24	1,250
HIGH GNP/CAPITA										
9 CYPRUS	6	9.3	(8.1)	1	9.4	-		35	53	3,790
13 PANAMA	5	12.7	(8.7)	5	24.3	(17.3) -		255	116	2,100
6 MALAYSIA	10	6.0	(3.3) +	9	10.3	(8.8) +	(10)	464	30	2,000
7 BRAZIL	22	7.4	(5.3) +	9	11.4	(9.2) +	(2)	3,062	23	1,640
19 JORDAN	11	16.4	(18.3)	4	22.7	(7.4)		58	17	1,560
14 COLOMBIA	12	13.2	(9.6)	9	22.5	(21.6)	(4)	1,737	61	1,320
3 COSTA RICA	8	5.3	(1.8) +	4	3.5	(3.3) +		124	48	1,300

* The "+" or "-" to the right of the standard deviation indicates that the MAPD is significantly different (higher or lower) than the "World" MAPD at the .90 confidence level.

1/ Source: Annex 2

Table 3-8 (continued)

FORECAST DEVIATION BY COUNTRY CHARACTERISTICS

Country	YEAR 3 Sample Size	YEAR 3 MAPD %	YEAR 3 (Std Dev) %	YEAR 7 Sample Size	YEAR 7 MAPD %	YEAR 7 (Std Dev) %	IBRD COMMITMENT TO POWER SECTOR THROUGH 1985 (Rank)	Current $ Million	$/Cap	GNP $/Capita
** WORLD **	228	11.9	(12.6)	116	19.9	(16.8)				
LOW ACCURACY										
25 SUDAN	4	26.5	(15.1) -	3	32.6	(12.5)		112	5	300
24 PHILIPPINES	6	21.9	(37.3)	4	40.0	(36.8)		282	5	580
23 HAITI	5	20.7	(13.8) -	1	24.0	-		74	13	310
22 GHANA	5	19.6	(8.1) -	2	19.5	(2.9)		127	10	380
21 TANZANIA	5	17.4	(9.3)	3	27.9	(8.8)		105	5	290
20 INDONESIA	6	17.4	(13.5)	6	19.6	(10.4)	(3)	1,305	8	530
19 JORDAN	10	16.4	(18.3)	4	22.7	(7.4)		58	17	1,560
LOW (RELATIVE) IBRD COMMITMENT										
9 CYPRUS	6	9.3	(8.1)	1	9.4	-		35	53	3,790
2 MALAWI	4	5.1	(2.9) +	2	23.4	(22.8)		38	5	170
19 JORDAN	10	16.4	(18.3)	4	22.7	(7.4)		58	17	1,560
23 HAITI	5	20.7	(13.8) -	1	24.0	-		74	13	310
11 NICARAGUA	4	10.1	(2.7)	5	31.6	(19.9)		75	23	770
1 EL SALVADOR	5	5.0	(2.9) +	3	6.7	(6.3) +		$84	$18	$820
21 TANZANIA	5	17.4	(9.3)	3	27.9	(8.8)		105	5	290
LOW (RELATIVE) IBRD COMMITMENT/CAPITA										
17 INDIA	5	14.2	(14.1)	-	-	-	(1)	5,099	7	270
18 PAKISTAN	11	15.1	(6.8)	3	21.0	(28.4)	(11)	438	5	380
21 TANZANIA	5	17.4	(9.3)	3	27.9	(8.8)		105	5	290
25 SUDAN	4	26.5	(15.1) -	3	32.6	(12.5)		112	5	300
24 PHILIPPINES	6	21.9	(37.3)	4	40.0	(36.8)		282	5	580
2 MALAWI	4	5.1	(2.9) +	2	23.4	(22.8)		38	5	170
20 INDONESIA	6	17.4	(13.5)	6	19.6	(10.4)	(3)	1,305	8	530
LOW GNP/CAPITA										
2 MALAWI	4	5.1	(2.9) +	2	23.4	(22.8)		38	5	170
17 INDIA	5	14.2	(14.1)	-	-	-	(1)	5,099	7	270
21 TANZANIA	5	17.4	(9.3)	3	27.9	(8.8)		105	5	290
4 KENYA	6	5.4	(2.7) +	2	11.8	(2.3) +		242	12	290
25 SUDAN	4	26.5	(15.1) -	3	32.6	(12.5)		112	5	300
23 HAITI	5	20.7	(13.8) -	1	24.0	-		74	13	310
22 GHANA	5	19.6	(8.1) -	2	19.5	(2.9)		127	10	380

* The "+" or "-" to the right of the standard deviation indicates that the MAPD is significantly different (higher or lower) than the "World" MAPD at the .90 confidence level.

countries with the lowest GNP power capita -- Tanzania, Sudan, Haiti, and Ghana -- fall into the "lowest" accuracy forecast group. We should note, however, that at least the three African countries in this group were experiencing virtual total economic collapse, and it is unlikely that any meaningful forecasting was possible in this economic environment.

Five of the countries which recorded the highest accuracy in year 3 were among the top seven of our sample in year 7 -- Costa Rica, El Salvador, Malaysia, Brazil, and Kenya. Similarly, three of the seven countries which recorded relatively low forecast accuracy in year 3 remained near the bottom of our sample in year 7 -- Tanzania, Sudan, and the Philippines. This frequency suggests that forecast results in any given year are not random, and that deviation trends observed in early years are not likely (on average) to be reversed in subsequent years.

Forecast Learning Curves

To test the hypothesis that frequent forecasting might enhance accuracy, we studied performances over time for two utilities in each region which had prepared at least 5 forecasts during our study period (1960-85). Table 3-9 summarizes the results.

There appears to be no discernible pattern indicating that forecasts tended to improve over time. In many cases, the opposite trend can be observed, supporting our observation that forecast deviations appear to have increased in recent years (see Section 3.2).

3.8 ERROR DISTRIBUTION

Table 3-10 shows the frequency distribution of mean percent deviation recorded by all of the forecasts in our study at different horizons. The block of numbers at the top of the page is derived from longitudinal data. The first column ("All Forecasts") shows the distribution of mean deviations for all complete forecasts, regardless of horizon. The columns identified as "Short", "Medium", and "Long" capture performance over different time horizons within forecasts, i.e., "Short" covers years 1 through 3, "Medium" includes years 4 through 7, and "Long" incorporates all subsequent years. The block of numbers

TABLE 3-9

LEARNING CURVE OF UTILITY ELECTRICITY FORECASTING PERFORMANCE

COUNTRY	UTILITY		INITIAL YEAR	HORIZON	MEAN PERCENT DEVIATION YEAR 3	YEAR 7
COLOMBIA	EEEB	Fcast 1	1959	10	3.8	10.9
		Fcast 2	1962	9	21.1	16.5
		Fcast 3	1968	7	10.1	8.0
		Fcast 4	1969	10	22.5	14.3
		Fcast 5	1978	7	12.9	62.5
		Fcast 6	1979	7	26.1	61.1
		Fcast 7	1981	5	31.8	-
PANAMA	JRHE	Fcast 1	1962	10	-	21.1
		Fcast 2	1969	8	28.5	4.2
		Fcast 3	1972	11	8.2	53.3
		Fcast 4	1977	7	15.6	32.3
		Fcast 5	1979	7	4.8	10.7
		Fcast 6	1982	4	6.2	-
KENYA	KPLC	Fcast 1	1971	4	-6.5	-
		Fcast 2	1972	9	4.3	9.5
		Fcast 3	1975	6	3.5	-
		Fcast 4	1979	7	6.2	14.1
		Fcast 5	1982	4	10.1	-
		Fcast 6	1983	3	1.7	-
TANZANIA	TANESCO	Fcast 1	1970	7	11.9	38.8
		Fcast 2	1975	7	19.8	17.2
		Fcast 3	1981	5	24.3	-
		Fcast 4	1981	5	30.6	-
		Fcast 5	1984	2	-	-
INDONESIA	PLN	Fcast 1	1972	8	-	12.6
		Fcast 2	1972	6	9.7	-
		Fcast 3	1975	5	10.8	-
		Fcast 4	1976	9	4.9	7.1
		Fcast 5	1977	9	7.6	11.8
		Fcast 6	1977	9	24.1	27.8
		Fcast 7	1981	5	6.3	-
		Fcast 8	1982	4	16.2	-
		Fcast 9	1984	2	-	-
MALAYSIA	NEB	Fcast 1	1960	8	-2.8	-27.4
		Fcast 2	1963	10	-6.8	-17.5
		Fcast 3	1966	7	-2.3	-1.7
		Fcast 4	1968	9	4.5	1.1
		Fcast 5	1968	9	-2.1	-6.7
		Fcast 6	1970	9	3.8	0.0
		Fcast 7	1974	10	9.5	6.8
		Fcast 8	1975	7	6.9	13.7
		Fcast 9	1977	7	8.7	17.8
		Fcast 1	1980	6	12.3	-
JORDAN	JEA	Fcast 1	1975	6	3.2	-
		Fcast 2	1978	8	13.5	23.5
		Fcast 3	1979	5	32.8	-
		Fcast 4	1980	6	6.8	-
		Fcast 5	1981	5	-12.4	-
TURKEY	TEK	Fcast 1	1970	8	14.7	20.2
		Fcast 2	1973	10	11.4	24.9
		Fcast 3	1975	10	-1.3	20.2
		Fcast 4	1976	10	6.5	29.7
		Fcast 5	1979	7	15.0	-
		Fcast 6	1982	4	-	-
		Fcast 7	1984	2	-	-

Table 3-10

FREQUENCY DISTRIBUTION OF FORECAST MEAN DEVIATIONS
(percent)

LONGITUDINAL DATA BY FORECAST HORIZON

	All Forecasts	Short (1-3 yrs)	Medium (4-7 yrs)	Long (8yrs +)
< -50%	0.0	0.0	0.0	0.0
-50% to -20%	0.0	0.0	0.0	0.0
-20% to -10%	4.1	1.4	5.8	4.2
-10% to -5%	5.6	5.0	3.8	4.2
-5% to 0%	12.2	19.9	11.5	12.5
0% to 5%	21.9	28.1	16.3	8.3
5% to 10%	20.4	23.1	21.2	29.2
10% to 20%	15.8	14.5	20.2	12.5
20% to 50%	19.4	8.1	20.2	29.2
50% to 100%	0.5	0.0	1.0	0.0
> 100%	0.0	0.0	0.0	0.0
Total	100.0	100.0	100.0	100.0
Sample Size	196	221	104	24

CROSS-SECTIONAL DATA BY FORECAST YEAR

	YEAR 1	YEAR 2	YEAR 3	YEAR 4	YEAR 5	YEAR 6	YEAR 7	YEAR 8	YEAR 9	YEAR 10	YEAR 11	YEAR 12
< -50%	0.0	0.0	0.0	0.0	0.0	0.6	0.9	2.4	3.6	5.4	0.0	0.0
-50% to -20%	0.0	0.4	0.9	0.9	3.0	3.7	5.2	7.3	5.5	8.1	7.7	20.0
-20% to -10%	0.8	1.7	2.6	4.0	4.5	5.6	6.9	4.9	9.1	0.0	0.0	0.0
-10% to -5%	5.6	9.1	7.0	7.2	6.6	8.6	4.3	6.1	1.8	2.7	7.7	0.0
-5% to 0%	34.0	21.6	14.0	8.5	8.1	4.3	6.0	7.3	7.3	2.7	23.1	0.0
0% to 5%	33.6	21.6	18.4	16.1	11.6	5.6	12.1	8.5	9.1	10.8	0.0	0.0
5% to 10%	16.0	22.1	18.9	18.4	11.1	16.7	9.5	12.2	5.5	8.1	0.0	20.0
10% to 20%	7.6	13.0	21.5	20.6	23.7	22.2	24.1	20.7	16.4	21.6	15.4	0.0
20% to 50%	2.0	10.0	15.4	20.2	26.3	25.3	25.0	24.4	30.9	21.6	30.8	20.0
50% to 100%	0.4	0.4	0.9	3.6	4.5	6.8	6.0	6.1	10.9	18.9	15.4	40.0
> 100%	0.0	0.0	0.4	0.4	0.5	0.6	0.0	0.0	0.0	0.0	0.0	0.0
Total	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0
Sample Size	250	231	228	223	198	162	116	82	55	37	13	5

at the bottom of the page is derived from cross-sectional data. It reflects the frequency distribution of mean deviations at horizons from 1 to 12 years after forecasts were made.

In both blocks, we observe that forecast risk (spread) increases with forecast horizon. The graphical presentation in Figure 3-1 helps visualize these trends. There are separate bar-graphs for each of five horizon years (years 1, 3, 5, 7, and 10). The y-axis of each graph is the frequency (in percent). The x-axis represents the ranges for each frequency bar. Each range is defined by the value at the bottom of a column and the number immediately to its left, e.g., the label "-20%" is equivalent to the range from "-50% to -20%". In addition to the frequency bars for specific horizon years, each graph also includes a line showing the frequency distribution for the relevant longitudinal horizon group (e.g., "Short" for the year 1 graph) and another line corresponding to the average frequency distribution of all forecasts in all years.

The following trends can be seen. The average MPD gradually shifts away from the "low error" ranges as the horizon increases. Nearly 70 percent of all forecasts fall in the "-5% to 5%" band in year 1, but only about 15 percent of forecasts do so by year 10. The mean shifts to the right, although there is also a clear and gradual increase in under-estimates. As the horizon lengthens, the distribution becomes increasingly skewed to the right.[13] The frequency distributions for longitudinal horizon groups smooth out some of the volatility in the year-to-year bars, but the same general trend is apparent.

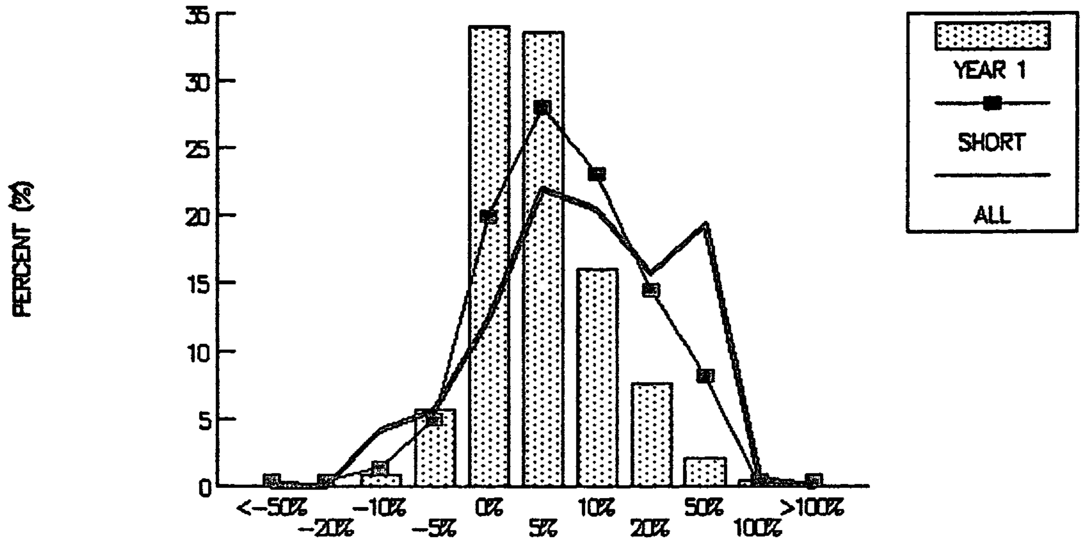
3.9 ANALYSIS OF SYSTEM LOSS FORECASTS

Both sales and generation forecasts are critical for electricity system planning. Short to medium-term sales forecasts are important for utility financial planning. Medium to long-term forecasts of total generating requirements are the foundation for system expansion planning.

13 This can also be inferred from the fact that CV values in this report are in the range 0.08 to 0.15 times MAPD. In contrast, for the normal distribution which has a symmetric density function, the CV can be analytically shown to be about 1.25 times MAPD.

Figure 3–1

MEAN DEVIATION DISTRIBUTION



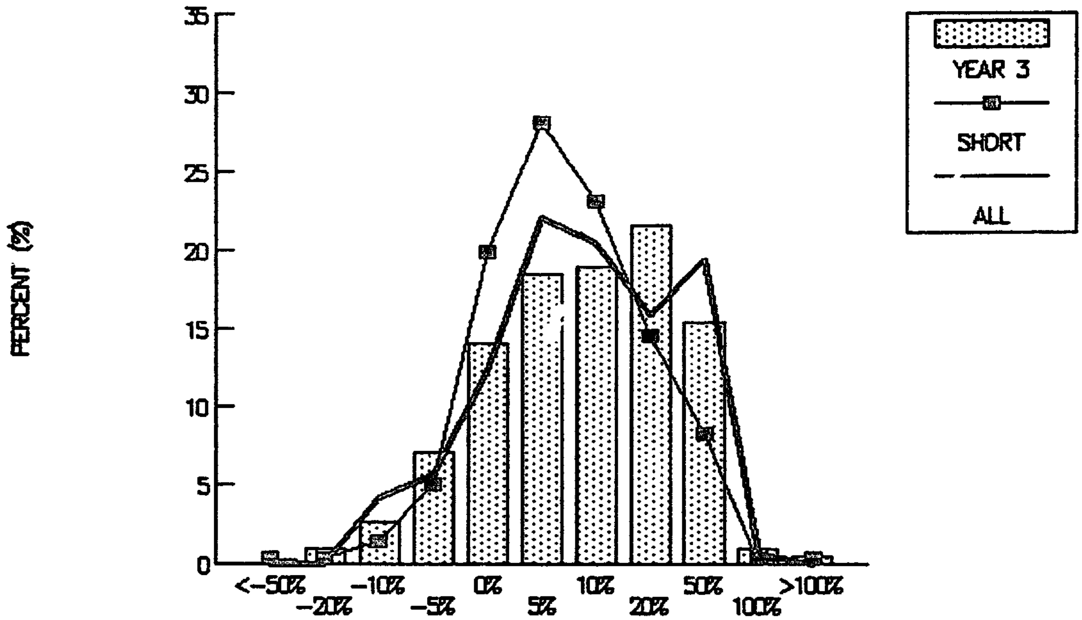
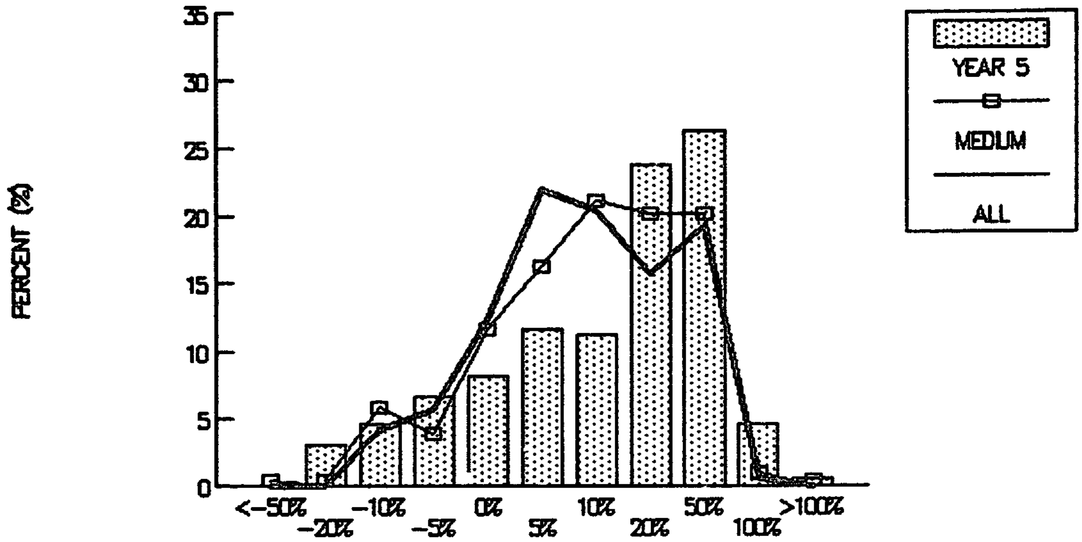


Figure 3-1 (continued)

MEAN DEVIATION DISTRIBUTION



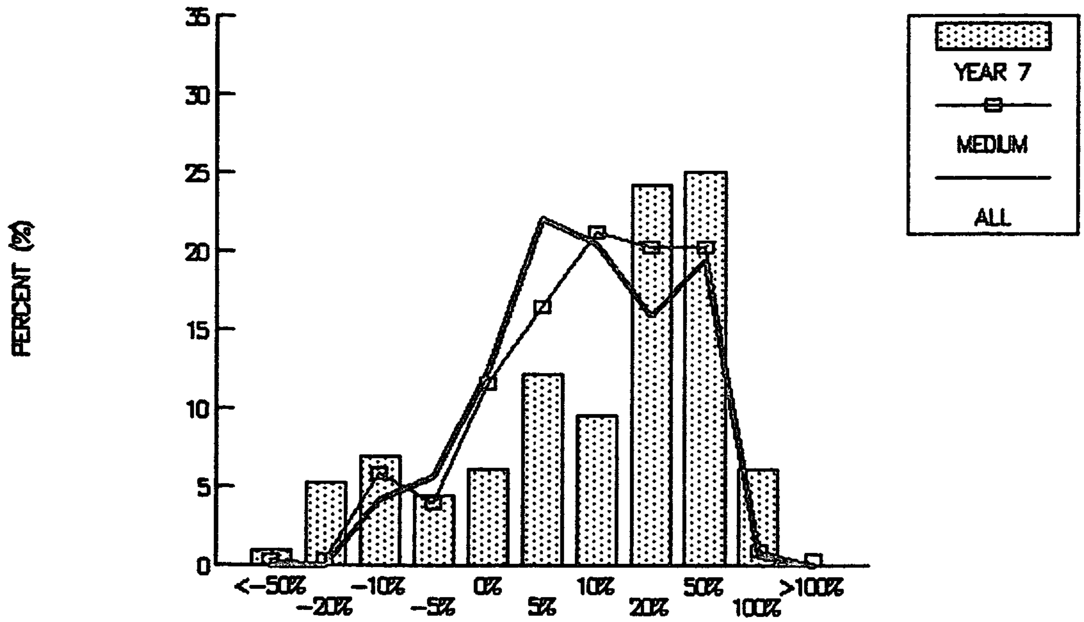
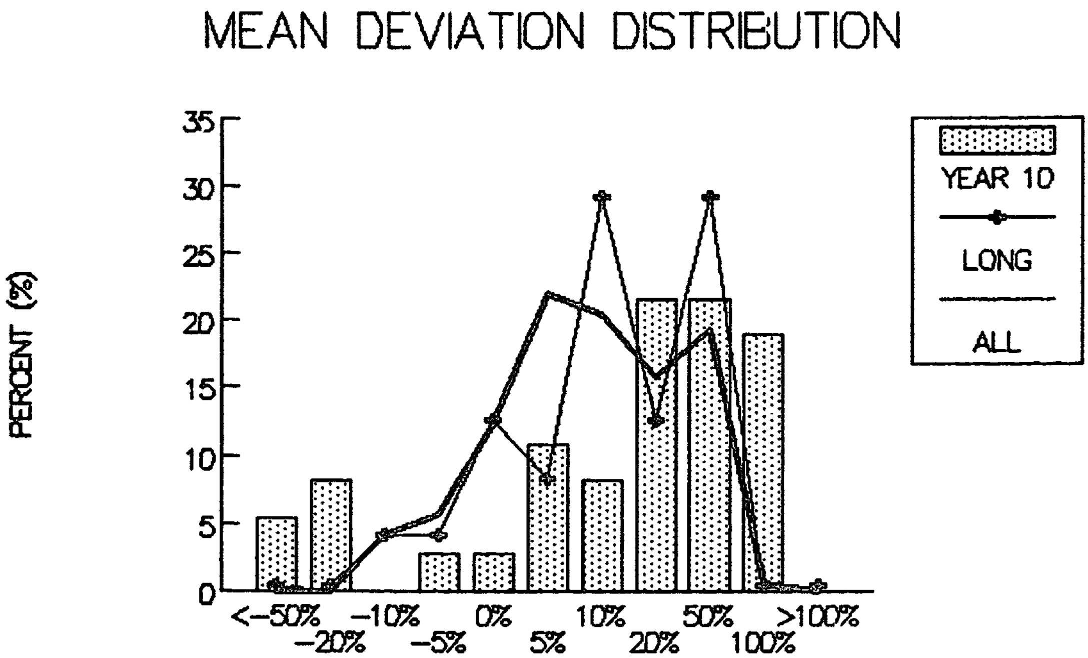


Figure 3–1 (continued)



As noted in the Introduction and elsewhere, this study focuses on measuring the accuracy of electricity sales forecasts (either billed or total consumption). We chose sales rather than net or gross generation because we were able to identify a larger pool of historical data. The analysis might be repeated with forecasts of system generation to see if similar patterns emerge.

In most cases, generation forecasts are derived from the sales forecast by projecting system losses. For this reason, we have investigated system loss forecasts to see if the same general conclusions about sales forecast deviations also apply to losses and thus to the total load forecast.

Data on over 100 forecasts of system losses were accumulated for this purpose. These forecasts come from the same primary sources identified in Chapter 2. Following the pattern of this Chapter, statistics were computed and used to compare the historical accuracy of system loss forecasts.[14]

Loss forecast deviations should be interpreted in relation to the level of system losses. For example, a 20 percent loss forecast deviation in a system with 20 percent technical and non-technical losses would introduce a planning error equivalent to 4 percent of total sales. Similarly, a 30 percent loss forecast deviation in a system with 30 percent system losses would introduce a planning error of 9 percent of total sales. If the sales forecast is over-estimated while the loss forecast is under-estimated, the offsetting effects would result in a forecast of total generation requirements that is more accurate

[14] The definition of forecast deviation has been modified here to account for the fact that losses are the difference between generation and sales. Specifically, forecast deviation in any year t is defined as:

$$D_t = (F_t - A_t)/A_t$$

F_t = Forecast losses in year t in percent
= (Generation Forecast - Sales Forecast)/Sales Forecast

A_t = Actual losses in year t in percent
(Actual Generation - Actual Sales)/Actual Sales

Thus, a positive deviation indicates that the percentage of losses to total sales was over-estimated in the forecast; a negative deviation indicates that percentage losses were under-estimated.

than the sales forecast. If the errors are of a like direction, the generation forecast will be less accurate.

In the following pages, results on the accuracy of loss forecasts have been disaggregated by region, system size, and real per capita income.

Loss Forecast Accuracy by Region

Table 3-11 summarizes loss forecast accuracy by region for each of the three forecast horizons. In sharp contrast with the sales forecasts, worldwide ("all regions") there appears to be no clear bias toward over or under-estimation. The MPD is slightly negative in years 3 and 7, becoming positive in year 10.

The number of forecast over-estimates and under-estimates are approximately equal in all three horizon years. The magnitude of over-estimates is 21.2 percent in year 3 and 37.1 percent in year 7. The corresponding magnitude of under-estimates are -20.8 in year 3 and -32.7 in year 7.[15] Reflecting this balance between over and underestimates, the MAPD is 21 percent in year 3 and 34.5 percent in year 7.

Forecast variance, as measured by the standard deviation of forecast error, is large. In year 3 this spread is 28 percent, and in year 7 it is 45.6 percent.

Regional forecast deviation is notably similar to worldwide averages. The Asia region performed slightly better in each horizon year, with an MAPD of 15.7 in year 3 and 19.5 in year 7. These differences from other regions were not highly significant.

In summary, while there has been a pattern to the magnitude of forecast error, about 20 percent in year 3 and 35 percent in year 7 across all regions, the direction of these errors has been fairly evenly dispersed between over-estimates and under-estimates in every region.

---

15 The very small sample size noted for year 10 allows us to place much less confidence in any observed trends.

Table 3-11

LOSS FORECAST DEVIATION BY REGION

		YEAR 3			YEAR 7			YEAR 10		
		Sample Size	Mean Annual Deviation (%)	Std. Dev. (%)	Sample Size	Mean Annual Deviation (%)	Std. Dev. (%)	Sample Size	Mean Annual Deviation (%)	Std. Dev. (%)
LAC	"Over"	21	22.8		6	54.1		2	47.1	
	"Under"	24	-21.7		9	-30.1		2	-29.6	
	MPD	45	-4.6	(27.9)	15	3.6	(45.3)	4	8.7	(45.5)
	MAPD	45	22.2	(16.8)	15	39.7	(22.0)	4	38.4	(25.9)
AFRICA	"Over"	7	16.0		5	43.6		0	-	
	"Under"	8	-21.6		5	-43.4		0	-	
	MPD	15	-4.1	(24.3)	10	0.1	(61.4)	0	-	-
	MAPD	15	19.0	(15.6)	10	43.5	(43.4)	0	-	-
ASIA	"Over"	6	21.8		3	14.3		1	30.0	
	"Under"	11	-12.4		5	-22.7		1	-19.1	
	MPD	17	-0.4	(21.4)	8	-8.8	(25.1)	2	5.5	(24.5)
	MAPD	17	15.7	(14.5)	8	19.5	(18.1)	2	24.5	(5.5)
EMENA	"Over"	16	21.1		7	27.6		2	41.8	
	"Under"	19	-24.2		6	-35.9		4	-20.2	
	MPD	35	-3.5	(32.1)	13	-1.7	(40.3)	6	0.5	(36.4)
	MAPD	35	22.8	(23.0)	13	31.4	25.3	6	27.4	(23.9)
ALL REGIONS	"Over"	50	21.2		21	37.1		5	41.6	
	"Under"	62	-20.8		25	-32.7		7	-22.7	
	MPD	112	-2.1	(28.0)	46	-0.8	(45.6)	12	4.1	(38.3)
	MAPD	112	21.0	(18.7)	46	34.7	(29.5)	12	30.6	(23.4)

Loss Forecast Accuracy by System Size

Table 3-12 presents summary statistics for electricity systems categorized by size. Due to smaller sample size, the categories differ somewhat from those used in Section 3.3; four groups have been condensed into three.

There seems to be a bias toward under-estimation among small systems which disappears among larger ones. The MPD for small systems is -9.1 in horizon year 3, while it is -2.1 for medium systems and 3.1 for larger systems. The difference between the small and large groups is significant at the 90 percent level. This trend continues in years 7 and 10, but conclusions for these years can be made with less confidence due to the very small sample size.

Paralleling sales forecast deviations, small system loss forecasts have been less accurate than larger systems in the short-term. The mean absolute deviation for small systems was 25.5 percent in horizon year 3, compared with 15.7 percent for medium systems and 21.6 percent for larger systems. The difference between the first two groups is significant at the 90 percent level. Again, small sample size limits our ability to draw conclusions about longer forecast horizons.

Loss Forecast Accuracy and Country Income

Table 3-13 summarizes forecast performance for country groups categorized by real GNP per capita in 1985. In the short term (horizon year 3), loss forecast deviations are notably similar across income groups. The mean absolute deviation falls within the range of 20.5 and 21.9 percent for all groups. Variance, as measured by the standard deviation of mean percent deviation, ranges from 25.6 for the poorest countries (GNP per capita < $400), to 29.9 for the wealthiest (GNP per capita > $1600). These differences are not significant for our samples. There is greater variation in years 7 and 10, but the sample is small.

Impact of Loss Forecasts on Generation Forecast Accuracy

Logically, if loss forecasts are biased in the same direction as sales forecasts, the result on average is generation forecasts of even less accuracy. For the most part, our analysis

Table 3-12

LOSS FORECAST DEVIATION BY SYSTEM SIZE

		YEAR 3			YEAR 7			YEAR 10		
		Sample Size	Mean Annual Deviation (%)	Std. Dev. (%)	Sample Size	Mean Annual Deviation (%)	Std. Dev. (%)	Sample Size	Mean Annual Deviation (%)	Std. Dev. (%)
	"Over"	12	22.6		5	30.9		0	-	
2000 GWh	"Under"	21	-27.2		12	-37.1		2	-29.6	
	MPD	33	-9.1	(28.6)	17	-17.1	(36.8)	2	-29.6	(22.0)
	MAPD	33	25.5	(15.8)	17	35.3	(20.1)	2	29.6	(22.0)
	"Over"	16	14.4		7	45.1		1	20.5	
2001 - 10000 GWh	"Under"	18	-16.9		2	-26.6		0	-	
	MPD	34	-2.1	(20.9)	9	29.1	(53.9)	1	20.5	-
	MAPD	34	15.7	(13.9)	9	41.0	(45.5)	1	20.5	-
	"Over"	22	25.3		9	34.3		4	46.8	
< 10000 GWh	"Under"	23	-18.1		11	-28.9		5	-20.0	
	MPD	45	3.1	(31.0)	20	0.4	(41.1)	9	9.7	(39.2)
	MAPD	45	21.6	(22.5)	20	31.3	(26.5)	9	31.9	(24.7)
	"Over"	50	21.2		21	37.1		5	41.6	
ALL SYSTEMS	"Under"	62	-20.8		25	-32.7		7	-22.7	
	MPD	112	-2.1	(28.0)	46	-0.8	(45.6)	12	4.1	(38.3)
	MAPD	112	21.0	(18.7)	46	34.7	(29.5)	12	30.6	(23.4)

Table 3-13

LOSS FORECAST DEVIATION BY INCOME LEVEL

1985 GNP/Capita		YEAR 3 Sample Size	YEAR 3 Mean Percent Deviation	YEAR 3 (Std Dev)	YEAR 7 Sample Size	YEAR 7 Mean Percent Deviation	YEAR 7 (Std Dev)	YEAR 10 Sample Size	YEAR 10 Mean Percent Deviation	YEAR 10 (Std Dev)
	"Over"	12	18.6		5	43.6		0	-	
< $400	"Under"	15	-22.0		6	-36.3		2	-33.3	
	MPD	27	-4.0	(25.6)	11	0.0	(57.8)	2	-33.3	(18.3)
	MAPD	27	20.5	(15.9)	11	39.7	(42.0)	2	33.3	(18.3)
	"Over"	10	23.4		6	33.6		1	30.0	
$400 - $1000	"Under"	18	-19.2		11	-28.8		2	-13.4	
	MPD	28	-4.7	(26.5)	17	-6.8	(37.1)	3	1.1	(21.0)
	MAPD	28	21.4	(16.3)	17	30.5	(22.2)	3	18.9	(9.1)
	"Over"	15	21.3		8	31.9		3	57.5	
$1001 - $1600	"Under"	23	-20.0		7	-29.6		3	-21.9	
	MPD	38	-3.7	(28.7)	15	3.2	(38.3)	6	17.8	(44.1)
	MAPD	38	20.5	(20.4)	15	30.8	(23.0)	6	39.7	(26.1)
	"Over"	13	21.6		2	52.1		1	5.4	
> $1600	"Under"	6	-22.4		1	-75.1		0	-	
	MPD	19	7.8	(29.9)	3	9.7	(63.7)	1	5.4	-
	MAPD	19	21.9	(21.8)	3	59.8	(24.1)	1	5.4	-
	"Over"	50	21.2		21	37.1		5	41.6	
ALL INCOMES	"Under"	62	-20.8		25	-32.7		7	-22.7	
	MPD	112	-2.1	(28.0)	46	-0.8	(45.6)	12	4.1	(38.3)
	MAPD	112	21.0	(18.7)	46	34.7	(29.5)	12	30.6	(23.4)

uncovers no directional bias in loss forecast deviations. Thus, loss forecast deviations neither enhance or reduce sales forecast error. This conclusion holds for the global sample, for groupings by region and by national per capita income level, and for large system sizes. Small system loss forecasts appear to provide an exception to this rule; a significant bias toward underestimates was found in this case. These errors, on average, should make generation forecasts for small systems more accurate than sales forecasts.

Although losses generally account for only a fraction of total generation, in percentage terms both the magnitude (MAPD) and spread of loss forecast deviations worldwide have been almost twice the levels observed in sales forecasts of short to medium horizon (years 3 and 7).

4 THE U.S. EXPERIENCE

It is instructive to compare the record of U.S. utilities in load forecasting with the Bank's experience in developing countries. In their continual search for the load forecasting equivalent of a "better mouse trap", U.S. utilities and their consultants have spent millions of dollars in an effort to develop more sophisticated and more accurate forecasts over the years.

The U.S. experience provides useful points of reference for our analysis. More data related to U.S. experience is available, since most utilities update their forecasts annually, and often using more than one technique. Furthermore, these analyses are reported in their annual load forecast reports that generally document the approach, input data, and assumptions about key exogenous variables that influence future loads. Therefore, analysis of forecast accuracy in the U.S. provides valuable insights about whether "throwing more money" and using more complex forecasting techniques results in better accuracy and if so by how much.

In this chapter we study two independent sources of U.S. electricity sales forecasts in order to assess long-term performance. The first source is a nationwide forecast which has been compiled annually by the Edison Electric Institute (EEI) since 1945 and reported in the magazine Electrical World each September since 1964. The second source is a survey of 100 large and small U.S. utilities conducted and reported by Battelle Laboratories in 1985.

4.1 FORECASTS OF NATIONAL UTILITY SALES BY EEI

Table 4-1 presents the EEI forecasts and actual U.S. electricity sales for the years 1964 through 1987. A total of 188 separate annual forecasts are reported, far more than available for any single LDC system or region.

Table 4-2 summarizes forecast accuracy for three horizon years (Years 3, 7, and 10) for the United States and the countries studied in Chapter 3. Over the years studied, the bias toward overestimation of load forecasts is just as apparent for the U.S. as for the other countries. Mean percent deviation (MPD) is always positive in the U.S., increasing from 2.8 percent in year 3, to 16.9 percent in year 7 and 25.8 percent in year

FILE NAME : USASALES

SOURCE: "ELECTRICAL WORLD"

F = FORECAST

Table 4-1

UNITED STATES OF AMERICA
TRENDS IN FORECASTS OF 1964-1988 FOR TOTAL ELECTRIC UTILITY SALES
(TWH)

... YEAR OF FORECAST ...

	F 1	F 2	F 3	F 4	F 5	F 6	F 7	F 8	F 9	F 10	F 11	F 12	F 13
YEAR	1964	1965	1966	1967	1968	1969	1970	1971	1972	1973	1974	1975	1976
1964	990												
1965	1052	946											
1966	1107	999	1034										
1967	1194	1069	1090	1100									
1968	1285	1165	1168	1179	1186								
1969		1226	1251	1256	1241	1304							
1970	1485	1319	1346	1354	1345	1395	1386						
1971				1437	1442	1507	1482	1462					
1972					1538	1620	1597	1572	1595				
1973						1741	1727	1706	1730	1720			
1974						1872	1865	1842	1855	1868	1739		
1975	2123	1827	1809	1828	1899	2012	2013	1978	2012	1999	1864	1720	
1976								2117	2160	2144	1994	1856	1836
1977								2278	2317	2294	2110	2020	1954
1978								2438	2483	2429	2233	2151	2070
1979								2613	2666	2603	2362	2230	2187
1980	3009	2519	2463	2511	2642	2880	2901	2804	2854	2795	2504	2373	2337
1981											2609	2542	2494
1982											2754	2689	2647
1983											2911	2803	2786
1984											3071	2976	2937
1985		3348	3252	3321	3646	4030	4067	3821	3961	3826	3242	3147	3113
1986													3279
1987													
1988													
1989													
1990								5375	5356	5068	4196	4012	3938
1991													
1992													
1993													
1994													
1995											5695	5266	4938
--													
2000													

	F 14	F 15	F 16	F 17	F 18	F 19	F 20	F 21	F 22	F 23	F 24	F 25	ACTUAL	
YEAR	1977	1978	1979	1980	1981	1982	1983	1984	1985	1986	1987	1988	SALES	YEAR
1964													890	1964
1965													954	1965
1966													1039	1966
1967													1107	1967
1968													1202	1968
1969													1307	1969
1970													1391	1970
1971													1466	1971
1972													1578	1972
1973													1703	1973
1974													1701	1974
1975													1733	1975
1976													1850	1976
1977	1960												1951	1977
1978	2093	2002											2018	1978
1979	2188	2090	2088										2084	1979
1980	2237	2168	2130	2084									2126	1980
1981	2361	2269	2250	2148	2133								2151	1981
1982	2476	2371	2364	2262	2202	2122							2100	1982
1983	2610	2472	2460	2364	2313	2177	2131						2160	1983
1984	2688	2575	2552	2457	2409	2278	2205	2255					2281	1984
1985	2833	2677	2650	2545	2502	2367	2286	2312	2312				2306	1985
1986	2974	2779	2749	2634	2590	2456	2365	2379	2359	2379			2355	1986
1987	3105	2885	2853	2727	2682	2552	2441	2454	2441	2427	2437		2455	1987
1988		2993	2961	2825	2778	2632	2519	2535	2521	2452	2500	2605		1988
1989		3104	3071	2924	2873	2712	2596	2621	2600	2525	2508	2518		1989
1990	3513	3218	3181	3023	2970	2786	2672	2706	2681	2599	2550	2573		1990
1991										2677	2626	2632		1991
1992										2756	2706	2700		1992
1993										2827	2777	2757		1993
1994										2900	2849	2826		1994
1995	4348	3869	3772	3546	3454	3156	3041	3068	3052	2973	2921	[illegible]		1995
--														--
2000				4141	3977	3545	3426	3452	3439	3354	3293	318[illegible]		2000

Table 4-2

COMPARISON OF U.S. AND LDC FORECAST DEVIATION

		YEAR 3			YEAR 7			YEAR 10		
		Sample Size	Mean Annual Percent Deviation	(Std Dev)	Sample Size	Mean Annual Percent Deviation	(Std Dev)	Sample Size	Mean Annual Percent Deviation	(Std Dev)
U.S. Experience (EEI)	"Over"	15	5.1		13	16.9		7	25.8	
	"Under"	7	-2.1		0	-		0	-	
	MPD	22	2.8	(4.7)	13	16.9	(5.6)	7	25.8	(10.4)
	MAPD	22	4.1	(3.5)	13	16.9	(5.6)	7	25.8	(10.4)
LDC Experience (from Chapter 3)	"Over"	172	13.9		89	21.2		30	27.3	
	"Under"	56	-5.8		27	-15.4		7	-36.6	
	MPD	228	9.1	(14.8)	116	12.7	(22.8)	37	15.2	(34.2)
	MAPD	228	11.9	(12.6)	116	19.9	(16.8)	37	29.1	(23.6)

10. Indeed, years 7 and 10 have no reported underestimates, although the sample size is very small. Mean percent deviation of the United States forecasts is approximately a third of the LDC level in year 3, but the LDC average accuracy is better than that of the U.S. forecasts in both years 7 and 10. The year 3 differences are significant at the 99 percent level, but the differences are not significant for the longer horizons.

The average magnitude of forecast deviation (MAPD) in the United States is only 4.1 percent in year 3, but rises to 16.9 percent in year 7, and to 25.8 percent by year 10. Again, the magnitude of U.S.forecast deviations is about a third of that reported for the LDC's in year 3, but the U.S. forecast MAPD out performed the other countries only slightly over longer horizons. MAPD differences in year 3 are highly significant.

Forecast uncertainty as measured by standard deviation of forecast error is much lower for the United States forecasts. It is approximately a third of the level reported for the other forecasts studied in each horizon year.

Table 4-3 compares U.S. and LDC longitudinal forecast experience. As noted in Chapter 2, performance in spot horizon years may be more appropriate for system planning purposes, but the longitudinal data is useful for comparison of the two data sets. As might be expected, observed longitudinal deviations are lower than the cross-sectional ones, but the same trends are apparent. U.S. forecast accuracy and magnitude of deviation are much better in the short-term, but quite similar over medium and long-term forecasts. Forecast uncertainty (spread) is much lower for forecasts of all lengths.

Forecast Learning Curves

The results in Tables 4-2 and 4-3 indicate that forecast error increases as the horizon lengthens. An important corollary to this trend is also clear: The accuracy of forecasts for a given target year increases as the year of the forecast approaches the target.

Table 4-4 also illustrates this point with the EEI data series. Each column represents forecast deviations for selected target years (1965 through 1985 at five year intervals). With few exceptions, reading down the columns one observes increasing accuracy as the forecast year approaches the target year.

Table 4-3

COMPARISON OF U.S. AND LDC LONGITUDINAL FORECAST DEVIATION

		SHORT-TERM (YEARS 1 THRU 3)			MEDIUM-TERM (YEARS 4 THRU 7)			LONG-TERM (8 YEARS AND OVER)		
		Sample Size	Mean Annual Percent Deviation	(Std Dev)	Sample Size	Mean Annual Percent Deviation	(Std Dev)	Sample Size	Mean Annual Percent Deviation	(Std Dev)
U.S. Experience (EEI)	"Over"	15	1.9		12	8.4		6	13.4	
	"Under"	7	-1.7		0	-		0	-	
	MPD	22	1.4	(3.2)	12	8.4	(2.7)	6	13.4	(1.8)
	MAPD	22	1.4		12	8.4	(2.7)	6	13.4	(1.8)
LDC Experience (from Chapter 3)	"Over"	163	9.0		82	13.8		19	17.5	
	"Under"	58	-3.8		22	-6.2		5	-5.6	
	MPD	221	5.6	(14.8)	104	9.6	(12.8)	24	12.7	(14.7)
	MAPD	221	7.6		104	12.2		24	15.0	

Table 4-4

Forecast Percent Deviation
In Selected Target Years

Year of Forecast	Target Year 1965	1970	1975	1980	1985
1964	10.3	6.7	22.5	41.5	--
1965	-0.8	-5.2	5.4	18.5	45.2
1966		-3.3	4.4	15.8	41.0
1967		-2.7	5.5	18.1	44.0
1968		-3.3	9.6	24.3	58.1
1969		0.3	16.1	35.5	74.8
1970		-0.4	16.2	36.5	76.4
1971			14.1	31.9	65.7
1972			16.1	34.2	71.8
1973			15.3	31.5	65.9
1974			7.6	17.8	40.6
1975			-0.8	11.6	36.5
1976				9.9	35.0
1977				5.2	22.8
1978				2.0	16.1
1979				0.2	14.9
1980				-2.0	10.3
1981					8.5
1982					2.7
1983					-0.9
1984					0.3
1985					0.3

Reading across rows, the data indicates the level of inaccuracy in the forecasts, that were analyzed. Forecast deviation increases with horizon length, and forecast accuracy for a given target year increases as we approach that year. While our extensive data set makes it easier to demonstrate this conclusion for United States forecasts, it is reasonable to postulate a similar trend in other countries as well. Simply thinking of the deviation statistics in Chapter 3 slightly differently -- as forecasts 10 years, 7 years and 3 years before a given target year -- provides support for this conclusion.

Error Distribution

Table 4-5 summarizes the frequency distribution of mean percent deviation for the EEI forecast data. The table includes both longitudinal and cross-sectional data.

The average MPD increases with forecast horizon. Over 95 percent of forecasts have a deviation in the range "-5% to 5%" in year 1, but only 15 percent do by year 10. While the move toward overestimates may not be as extreme as that reported for LDC's in Chapter 3, there are in fact no underestimates in years 7 and 10 in the U.S. data in Table 4-5. Longitudinal data tend to smooth out the volatility inherent in the cross-sectional data, but the gradual shift toward overestimates is still clear from the longitudnal data.

4.2 U.S. UTILITY FORECAST SURVEY

Table 4-6 presents key statistics on forecast accuracy by size of U.S. utility, and forecast horizon. These results are based upon a survey of the 75 largest U.S. utilities, and 25 smaller utilities.[1,2,3] Additional data, from the same survey, regarding comparative performance of different forecasting techniques, is reported in Annex 4.

Results of the U.S. experience indicate that historically there has been an overwhelming bias towards overestimation by large as well as small utilities. As shown in Table 4-6,

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1 William Huss, "Can Electric Utilities Improve Their Forecast Accuracy? The Historical Perspective," Public Utilities Fortnightly, Dec. 26, 1985, p. 37.

2 Small utilities are defined as having 1982 sales between700 and 5,000 GWh.

3 Of the 25 small utilities, ten chose to participate.

Table 4-5
FREQUENCY DISTRIBUTION OF U.S.A. FORECAST MEAN DEVIATIONS
(percent)

LONGITUDINAL DATA BY FORECAST HORIZON

	All Forecasts	Short (1-3 yrs)	Medium (4-7 yrs)	Long (7yrs +)
< -50%	0.0	0.0	0.0	0.0
-50% to -20%	0.0	0.0	0.0	0.0
-20% to -10%	0.0	0.0	0.0	0.0
-10% to -5%	0.0	0.0	0.0	0.0
-5% to 0%	28.6	31.8	0.0	0.0
0% to 5%	14.3	54.5	8.3	0.0
5% to 10%	21.4	13.6	75.0	16.7
10% to 20%	35.7	0.0	16.7	83.3
20% to 50%	0.0	0.0	0.0	0.0
50% to 100%	0.0	0.0	0.0	0.0
> 100%	0.0	0.0	0.0	0.0
Total	100.0	100.0	100.0	100.0
Sample Size	14	22	12	6

CROSS-SECTIONAL DATA BY FORECAST YEAR

	YEAR 1	YEAR 2	YEAR 3	YEAR 4	YEAR 5	YEAR 6	YEAR 7	YEAR 8	YEAR 9	YEAR 10	YEAR 11	YEAR 12
< -50%	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
-50% to -20%	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
-20% to -10%	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
-10% to -5%	0.0	4.3	0.0	0.0	5.0	6.7	0.0	0.0	0.0	0.0	0.0	0.0
-5% to 0%	62.5	30.4	31.8	23.8	20.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
0% to 5%	33.3	52.2	40.9	23.8	10.0	6.7	0.0	0.0	0.0	14.3	0.0	0.0
5% to 10%	0.0	8.7	22.7	38.1	35.0	6.7	15.4	9.1	11.1	0.0	16.7	0.0
10% to 20%	4.2	4.3	4.5	14.3	30.0	73.3	53.8	36.4	22.2	14.3	0.0	0.0
20% to 50%	0.0	0.0	0.0	0.0	0.0	6.7	30.8	54.5	66.7	71.4	83.3	100.0
50% to 100%	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
> 100%	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Total	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0
Sample Size	24	23	22	21	20	15	13	11	9	7	6	3

Table 4-6
Forecast Performances of U.S. Utilities[1]

		Horizon		
		Two Years	Four Years	Six Years
Large Utilities	Mean	4.50	11.16	20.86
	Std. Dev.	5.57	8.03	16.99
	Avg. Med.	3.30	9.74	19.18
	No. of Resps.	203	156	107
Small Utilities	Mean	5.18	12.96	21.79
	Std. Dev.	4.41	14.56	19.29
	Avg. Med.	3.64	8.86	17.40
	No. of Resps.	41	32	22

1 Mean: Mean Absolute Percentage Error
Std. Dev.: Standard Deviation
Avg. Med.: Median Absolute Percentage Error

Source: "Can Electric Utilities Improve Their Forecast Accuracy? The Historical Perspective", Public Utilities Fortnightly, Dec. 26, 1985.

the average magnitude of this error across small and large utilities (as defined as the mean absolute percentage error,[4] and labeled "Mean"), was approximately 5 percent in year 2, 12 percent in year 4, and 21 percent six years out. Further, forecast error approximately doubles from year 2 to year 4, and increased four-fold by year 6. Forecast uncertainty/spread as measured by standard deviation also increases over time. Larger utilities had a better record than smaller utilities, four and six years out.

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4 This statistic is comparable to the MAPD statistic in our study.

5 CONCLUSIONS AND IMPLICATIONS FOR PLANNING

5.1 STUDY CONCLUSIONS AND DIRECTIONS FOR FUTURE RESEARCH

An ex-post evaluation of forecasts in 45 member counties of the World Bank was undertaken. The analysis of forecast accuracy is based upon comparing actual sales (GWh) versus forecasted sales (GWh), as identified in over 200 separate forecasts in over 100 separate power systems/regions. This resulted in a database with 1,600 data points.[1] The results of our analysis support a number of conclusions:

(1) Forecasters have been optimistic about electricity sales. Globally, there have been on average, three forecast "over-estimates" for every under-estimate. This strong historic bias toward over-estimation cuts across forecasts in all regions, for different time periods and horizons, and economic environments.

(2) Not surprisingly, forecast deviation and uncertainty increase with the forecast horizon. On a global basis, the mean absolute percent deviations were 11.9 percent for a forecast horizon of 3 years, 19.9 percent 7 years out, and 29.1 percent 10 years out. The corresponding standard deviations were 12.6 percent, 16.8 percent, and 23.6 percent respectively.

(3) There has been no trend toward improved accuracy of forecasts over time. Pre-1975 forecasts (especially the 1960-65 group) outperformed their successors. Perhaps this is due to the higher economic growth rates generally experienced during that period. Obviously, the long-term performance of more recent forecasts is still unknown. In the same breath we hasten to add that forecasts for a given target year do improve as the initial year of the forecast approaches the target year.

(4) Countries in the Latin America and Caribbean region (LAC) as a group outperformed the rest of the world, especially in the near-term. African countries lagged somewhat behind in average performance. Based on our data, we are not able to conclude whether these differences are related to the stage of

1 A data point is defined by 3 numbers; actual sales, forecast sales, and year.

development of power systems, or relative economic prosperity, or some other causal factors.

(5) The record of large utility systems seems to be better than smaller ones. This trend is especially clear over short horizons.[2]

(6) Wealthier economies -- as measured by GNP per capita -- have achieved better accuracy in forecasting than poorer ones. Forecasts in countries with higher per capita income generally had higher accuracy and lower variance than poor ones, although there are notable exceptions to this generalization. Causality is not inferred by this observation.[3]

(7) Greater forecast accuracy can be observed when national economic growth rate improves or remains high during the period of the forecast. In contrast, generally poorer accuracy and higher variance occurs when economic growth slows during the forecast period.

(8) Poorest forecast performance tends to occur in countries which received relatively low World Bank funding in their power sector. High Bank funding, however, does not appear to assure forecast accuracy.

(9) Year-to-year forecast performance is not entirely random. While there is considerable oscillation in annual mean deviation, high deviations observed in early years are seldom reversed.

(10) Forecast accuracy for utilities in the Bank's members countries was close to that of smaller U.S. utilities in years 4 and 6 of the forecast horizon, but markedly poorer in year 2. Interestingly, the mid-term (year 6) performance of large U.S. utilities that spend large sums of money in forecasting, was comparable to those of the Bank's member countries.

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2 One reason for the lower error magnitudes may be inherent in the definition of the error variable which is expressed as a percentage of actual sales. Larger utility systems by definition will have higher sales.

3 Again, to the extent that wealthier economies are "collinear" with larger utility systems, lower error magnitudes may be partly explained by the manner in which the error variable is defined.

(11) In contrast to sales forecasts, loss forecast deviations do not offset sales forecast deviations to produce more accurate generation forecasts. Loss forecasts do not reveal any clear bias toward over- or under-estimation either in terms of frequency or magnitude, so generation forecasts on average reflect the same deviations (MPD) found in sales forecasts. This result was observed in global data and in country groups classified by region and income. On a global basis, the magnitude (MAPD) of loss forecast deviations have been almost double the level observed in sales forecasts of short to medium horizon.

Recommendations and Directions for Future Research

Based on the above findings, we offer the following recommendations and directions for future research:

(1) New methods need to be employed for explicitly incorporating load forecast uncertainty in the evaluation of electric power projects. There is a substantial and growing literature on the subject of project appraisal and decision making under uncertainty. A comprehensive and incisive review of this body of knowledge can provide the basis for defining specific evaluation procedures for explicitly addressing load forecast uncertainty in power project evaluation.

A decision analysis framework for evaluating the impacts of load growth uncertainty is sketched and illustrated in the following section and in Annex 5 of this report.

(2) There appears to be considerable scope for improving the accuracy of near-term (years 2, 3, and 4) forecasts. An examination of the trending-judgement methodologies used by large U.S. utilities may prove to be useful in this regard.

(3) Greater emphasis should be placed in improving load forecasts for small power systems and in poorer countries. In absolute terms, loans to these countries are often not large. However, in relation to the country's national budget, these amounts can be significant. Thus, serious

imbalances between power demand and supply in such countries can result in substantial efficiency losses to the nation as well as gross misallocation of resources.

(4) The power market survey method should be emphasized for all systems--particularly in the industrial sector--as a means to quickly and cost-effectively improve overall forecasting accuracy in the near-to medium-term.

(5) The database problems in completing this study were immense. Some of the most desirable data for analysis was not available, including details of forecast methods, and assumptions about the key "driving variables". Guidelines should be established for documenting key aspects of the forecast on a consistent and uniform basis. In addition, Project Completion Reports should provide more detailed and complete data in a standardized format on actual sales by customer segment, and other select variables such as number of connections, tariff changes, sectoral growth rates, etc. This will enable compilation of a more complete data set. Such a data set is necessary in order to analyze the sources and causes of forecast deviation.

(6) Further research is needed to reveal the structural causes of forecast error. This task will require specific and detailed knowledge of each forecast -- e.g., level of effort (cost, manpower), data availability, level of sophistication of the methodology, experience of the forecaster, forecast assumptions and actual movement of economic variables including sectoral value added and energy prices. It will be necessary to study the determinants of forecast deviation by customer category in order to meaningfully identify causality. Additional data will be required on actual and forecasted losses due to unbilled consumption, extent of supply constraints, and their impacts on different customer segments. Such a data collection effort will require a detailed review of consultant reports on load forecasts as well as the support of the power authorities involved in providing key data elements.

Once such disaggregated data and information is assembled, analyses can proceed to determine key explanatory variables, and to assess the relative contribution of each variable to the overall forecast error.

5.2 PLANNING FOR AN UNCERTAIN FUTURE

Forecasting electricity demand requires making assumption about the values of key exogenous variables which include economic growth rates and emerging sectoral patterns, demographic and socioeconomic characteristics, prices and availability of alternate fuels, national and regional development policies, technological innovation, consumer lifestyles and attitudes, extent of energy conservation potential realized, and political and regulatory factors. These variables are essentially beyond the realm of utility control, and are subject to substantial uncertainty.

Further, informed individuals and even "experts" who have carefully studied the situation can and do arrive at different assumptions as regards the values that these variables will assume in the future. Thus, differences in load forecasts may arise due to differences in the estimates of one or more of the exogenous variables listed above. Differences may also arise due to the forecasting technique used.

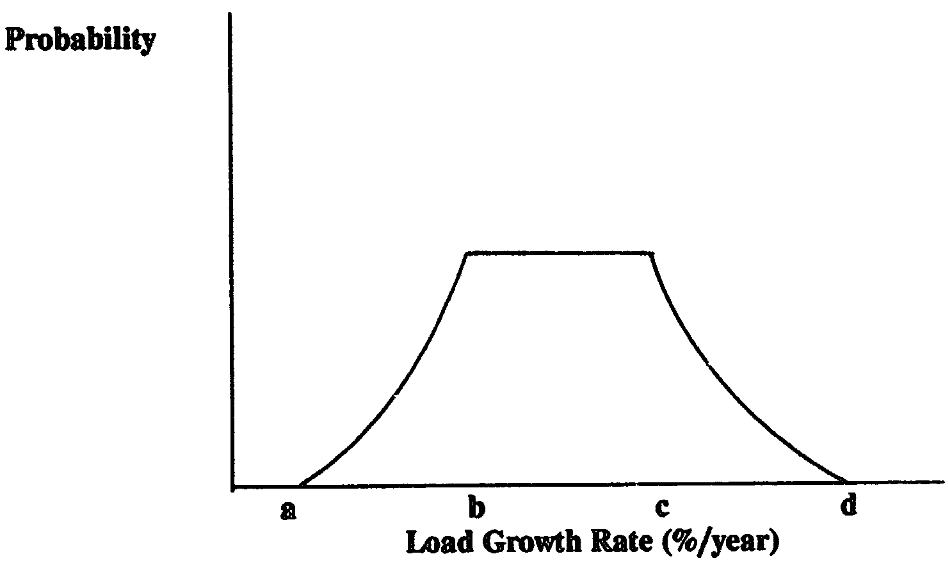
In short, uncertainties and the state-of-the-art in load forecasting preclude a definitive point load projection. The results in this report underscore this point. Forecast uncertainty is an inevitable reality and a priori there is no load forecast that is the correct forecast or the best forecast. In fact we would go so far as to say that even if a forecast turns out to be correct, ex-post, it is due to fortuitous circumstances and not because the method used to generate it was the correct method.

Therefore, the issue in generation resource planning and power project evaluation is not whether demand will grow at X percent or Y percent annually. Rather, the issue is what is the best resource development strategy given that loads are likely to grow at a rate between X percent and Y percent in the future?

In other words, the planning problem is not simply one of first identifying the correct load growth rate and then determining the least cost expansion plan for the forecast, and which provides adequate reliability. Such a perspective merely sidetracks the real issue and engenders the unresolvable nitpicking debate among "experts" that "my forecasting model is better than your model". This is not to imply that nothing can be gained by a critical comparison and review of alternate load forecasting models and their assumptions and that no attempts should be made to reconcile divergent load forecasts; or that load forecasting is not a useful exercise.

On the contrary, load forecasting is exceedingly important. However, the more important and immediate task in power system planning -- measured in terms of return on investment in effort -- is not in further refining the tools for forecasting what the future looks like precisely. Instead, the need is to devise a planning process for dealing with the inherent uncertainties in the future. In the future, load forecasting must strive to establish as accurately as possible, the range of uncertainty associated with future load growth.

This recognition has increasingly emerged among many utilities in the U.S. Indeed since around 1982, the Pacific Northwest Power Planning Council -- a public power planning agency with oversight responsibility over the Bonneville Power Administration (BPA) -- has officially adopted the position that point load forecasts are in themselves meaningless. The position adopted by the Council is typified by the trapezoidal type of probabilistic load forecast as depicted in the figure below:



The distribution above defines a band of growth rates between b and c percent per year over which the analyst has little means for discriminating the probability assessments for various outcomes. Outside this band the probabilities taper off though not necessarily in a symmetric fashion. The planning strategy adopted by the Council and BPA is to develop a resource development strategy which can be adjusted to any outcome in the range b to c. Several other leading utilities in the U.S. and Canada have recently begun to come around to this view.

For example, this view typifies the position of Southern California Edison Company, one of the five largest investor owned utilities in the U.S. A recent planning document released by the system department notes:

> "An examination of Edison's ten-year forecasts and their associated plans since 1965 indicated that, in each case, unforeseen events radically changed the business environment, rending the forecasts invalid. In retrospect, we concluded that no one could have predicted with anv degree of accuracy the nature or timing of these phenomena. Even if we had anticipated these events, we could not have foreseen their full impact on our business environment.
>
> The implication of this lesson is that it is futile to try to predict the future with any precision, and unwise to tie future plans too rigidly to any single projection or forecast. As a result of this review, we have concluded that the best way to plan for future uncertainties is to postulate a series of plausible scenarios and prepare response strategies for each. These two premises form the cornerstone of Edison's new planning philosophy."[4]

Risk Management Using Flexible Resources

The preceding discussion underscores the fact that the generation resource planning problem is one of risk management. It cannot be simply solved through a good point load forecast. Rather the problem is one of managing resources that provide sufficient flexibility in scheduling so that potential surplus and deficit situations can be continually corrected on an ongoing basis and in a cost effective manner.

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4 "Strategies for an Uncertain Future," System Planning and Research Department, Southern California Edison Company, Rosemead, California, March 1988.

Effective planning under such circumstances will require the development of a portfolio of resources that can match any reasonable eventuality within the specified range of planning uncertainty. This in turn means that the individual components of the resource strategy will consist of a menu of resource choices. Ideally, some options in this array can be readied for service quickly, whereas other choices can be "turned off" at short notice. Further, such resources should be available in varying sizes. Together therefore, these characteristics would ensure an approximate matching of loads and resources at all times.

Examples of such resources that have traditionally been considered in generation planning include building combustion turbines (CTs), negotiating firm contracts for purchases/sales, and short term purchases/sales. In recent years conservation, and load/demand management are increasingly being viewed and used as a flexible resource. This is because, once a program has been designed and tested thoroughly it can be scaled up or down relatively quickly, i.e., with a short lead time of (six months to-a-year). Further it can be acquired in small increments or on a larger scale and with energy/capacity savings being realized immediately.

A Decision Framework for Planning Under Uncertainty

In light of the preceding discussion we suggest the following decision analysis framework as a basis for evaluating alternate generation expansion strategies and selecting a prudent course of action, given the uncertain future.

The essence of our suggested approach is captured by the "decision matrix" depicted below. The rows represent different resource development strategies or simply the load growth rates one should plan to today. This simple framework can be easily made more elaborate by incorporating other futures beyond those represented by the three load growth outcomes 1, 2, and 3. However, our purpose is to simply highlight the basic interplays at work, and how alternate decisions can be evaluated under such conditions.

Plan For Outcome	Actual Outcome 1	2	3
1	X_{11}	X_{12}	X_{13}
2	X_{21}	X_{22}	X_{23}
3	X_{31}	X_{32}	X_{33}

The starting point for this analysis could be the three least cost expansion plans, corresponding to each of the three projected load growth rates 1, 2, and 3. These sequences represent the best strategy _if_ the future unfolds in accordance with the corresponding load growth rate. Next, each of these sequences is evaluated to simulate how it will "stand up" to alternate outcomes. Different economic and financial measures can be developed and estimated for this purpose. In this manner the nine entries in the decision matrix can be estimated.

For purposes of illustration, X_{12} represents the "cost" associated with planning for "outcome 1", but the future eventually evolves in accordance with outcome 2, and so on. Clearly, the diagonal cost elements -- X_{11}, X_{22}, and X_{33} -- are the lowest entries in each row.[5] This merely reflects the fact that each plan is a least cost sequence under the corresponding future. It is information about the off-diagonal cost elements in the above matrix which provides valuable insights about the robustness and flexibility of each plan to cope with different futures. This information can be effectively utilized to arrive at the final resource expansion strategy.

This procedure can be used for evaluating individual power projects as well. At a minimum, the "robustness" of the project should be evaluated by undertaking a scenario analysis. To establish the specific load growth scenarios, information in Table 3-1 can prove to be useful. For example, the record indicates that the average overestimate in year 7 was about 21 percent (on a "all region" basis), and the average underestimate was about 15 percent. This value can be used to create two scenarios around a load forecast. A probabilistic decision analysis can be carried out by defining different load outcomes and their corresponding probabilities of occurrence. In developing such a

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5 In a more complex analysis, the X_{ij}'s can represent multi-dimensional "vectors" whose components define key attributes of each outcome, such as electricity prices, fuel costs, unserved energy, environmental effects.

characterization for different forecast horizons, data on forecast error distribution as reported in Table 3-8 can be useful.

The paper in Annex 5 illustrates an actual application of this decision analysis framework in the context of an electric utility in the U.S.

ANNEX 1

POWER PROJECTS
AFRICA REGION

Page 1

Country	Loan/Credit Numbers	Project Title	SAR No.	SAR Date (yymm)	PPAR/PCR No.	PPAR/PCR Date (yymm)
ETHIOPIA	0375ET	ETHIOPIAN ELECTRIC LIGHT & POWER AUTHORITY	0413	6404		
	0596ET	FINCHAA HYDROELECTRIC (POWER II)	0009	6904	1102	7603
	1704ET	ENERGY PROJECT	5555	8605		
GHANA	0118GH	POWER DISTRIBUTION	0629	6805	1568	7704
	0256GH	SECOND POWER DISTRIBUTION	0052	7010	1568	7704
	0310GH	VOLTA RIVER HYDROELECTRIC	0281	6108		
	0618GH	VOLTA RIVER HYDROELECTRIC EXPANSION	0008	6905	1363	7611
	1380GH	KPONG HYDROELECTRIC	1299	7703	5731	8506
	1381GHL/0689GHC	THIRD POWER PROJECT	1196	7703	5731	8506
	1628GH	POWER SYSTEM REHABILITATION	4932	8508		
	1759GH	NORTHERN GRID EXTENSION PROJECT	6301	8701		
KENYA	0745KE	KAMBURU HYDROELECTRIC	0070	7105	1230	7607
	1147KE	GITARU HYDROELECTRIC	0627	7505	3505	8106
	1799KE	OLKARIA GEOTHERMAL POWER	2533	7912		
	2237KE	OLKARIA GEOTHERMAL POWER EXPANSION	3974	8301		
	2359KE	KIAMBERE HYDROELECTRIC POWER	4336	8311		
LIBERIA	0684LBR	POWER EXPANSION PROJECT	0038	7005	1551	7703
	0778LBR	SECOND POWER PROJECT	0072	7106	1551	7703
	1600LBR	FOURTH POWER PROJECT	1746	7806	4614	8306
MALAWI	0178MAI	POWER PROJECT	0024	7001	0645	7502
	0426MAI	SECOND POWER PROJECT	0174	7308	2116	7806
	1387MAIL/1388MAIL/0691MAIC	THIRD POWER PROJECT	1149	7703	4859COM	8312
NIGERIA		POWER SYSTEM IMPROVEMENT PROJECT	6923	8710		
	0372UNI	TRANSMISSION PROJECT	0380	6401		
	0383UNI	KAINJI MULTIPURPOSE	0398	6406		
	0572UNI	KAINJI MULTIPURPOSE (SUPPLEMENTARY)	0679	6810		
	0847UNI	FOURTH POWER PROJECT	0098	7206	5936	8511
	1766UNI	LAGOS POWER DISTRIBUTION	2502	7910		
	2085UNI	SIXTH POWER PROJECT (TRANS & DIST)	3041	8109		
SIERRA LEONE		POWER SYSTEM REHABILITATION PROJECT	5462	8503		
	0388SL	KING TOM POWER STATION & DIST. PROGRAM	0423	6407		
	0553SL	SECOND POWER PROJECT	0626	6806	1610	7705
	0734SL	THIRD POWER PROJECT	1183	7705	4525COM	8305
SUDAN		FOURTH POWER PROJECT	4879	8402		
	0522SU	POWER PROJECT	0608	6712	1169	7605
	0564SU	SECOND POWER PROJECT	0516	7504	5388COM	8412
	1006SU	POWER III - PUBLIC ELECT. & SUPPLY CORP.	2399	6003		
	1624SU	POWER REHABILITATION PROJECT	5333	8506		
	1788SU	FOURTH POWER PROJECT	6676	8704		
TANZANIA	0518TA	POWER DEVELOPMENT PROGRAM	0594	6710		
	0715TA	KIDATU HYDROELECTRIC	0048	7010	2765	7912
	1306TA	SECOND KIDATU HYDROELECTRIC POWER	0927	7606	4622COM	8306
	1405TA	POWER IV (MTERA HYDROELECTRIC)	4050	8306		

PPAR/PCR No. Legend: ****APP = APPRAISAL REPORT ****COM = COMPLETION REPORT

POWER PROJECTS
AFRICA REGION

Country	Loan/Credit Numbers	Project Title	SAR No.	SAR Date (yymm)	PPAR/PCR No.	PPAR/PCR Date (yymm)
TANZANIA	1687TA	POWER REHABILITATION PROJECT	6026	8604		
ZAMBIA	0145RN	KARIBA HYDROELECTRIC	0116	5606		
	0701ZA	KARIBA NORTH HYDROELECTRIC	0044	7006	4661	8308
	0919ZA	KAFUE HYDROELECTRIC	0086	7305	5566COM	8503
ZAMBIA/ZIMBABWE	0392RHS	CENTRAL AFRICAN POWER CORP. PROJECT	0438	6409		
ZIMBABWE	0058SR	POWER EXPANSION PROJECT	0156	5202		
	2212ZIM	POWER PROJECT	3884	8211		
	2900ZIM	SECOND POWER PROJECT	6642	8712		

No. of Selected Projects in Region = 51

PPAR/PCR No. Legend: ####APP = APPRAISAL REPORT ####COM = COMPLETION REPORT

POWER PROJECTS
ASIA REGION

Page 3

Country	Loan/Credit Numbers	Project Title	SAR No.	SAR Date (yymm)	PPAR/PCR No.	PPAR/PCR Date (yymm)
BANGLADESH		ASHUGANJ THERMAL POWER STATION EXTENSION	5872	8508		
	0136PAK	TA FOR EAST PAKISTAN WAPDA	0691	6812		
	0934BD	GREATER KHULNA POWER DISTRIBUTION	2476	7905		
	1254BD	ASHUGANJ THERMAL POWER	3719	8205		
	1648BD	POWER TRANSMISSION & DISTRIBUTION	5510	8512		
INDIA		MAHARASHTRA STATE KOYNA HYDRO DEVELOPMENT	0496	6508		
		SECOND KARNATAKA POWER	6988	8710		
	0019IN	FOURTH DAMODAR VALLEY CORP. EXPANSION	0310	6202		
	0023IN	BOKARO-KONAR POWER	0083	5003		
	0024IN	SECOND KOYNA HYDROELECTRIC	0325	6207		
	0037IN	KOTHAGUDEM POWER	0362	6305		
	0072IN	SECOND DAMODAR VALLEY CORPORATION	0002	5301		
	0106IN	TROMBAY THERMAL POWER STATION EXPANSION	0128	5705		
	0164IN	TROMBAY THERMAL POWER	0027	5411		
	0203IN	THIRD DAMODAR VALLEY POWER EXPANSION	0176	5807		
	0223IN	KOYNA HYDROELECTRIC	0182	5903		
	0242IN	SECOND POWER TRANSMISSION	0047	7104	3006	8006
	0377IN	THIRD POWER TRANSMISSION	0035	7302		
	0416IN	POWER TRANSMISSION	0462	6505		
	0417IN	SECOND KOTHAGUDEM POWER	0435	6505		
	0604IN	FOURTH POWER TRANSMISSION	0913	7512		
	0685IN	SINGRAULI THERMAL POWER	1159	7702	6784	8705
	0793IN	KORBA THERMAL POWER	1783	7803	6855COM	8706
	1027IN	SECOND SINGRAULI THERMAL POWER	2745	8004		
	1172IN	SECOND KORBA THERMAL POWER	3397	8106		
	1549IN	THIRD TROMBAY THERMAL POWER	1768	7803	6253COM	8606
	1648INL/0874INC	RAMAGUNDAM THERMAL POWER	2175	7812		
	1887INL/1053INC	FARAKKA THERMAL POWER	2976	8005		
	2076IN	SECOND RAMAGUNDAM THERMAL POWER	3608	8111		
	2278INL/1356INC	UPPER INDRAVATI HYDRO	4289	8304		
	2283IN	FIFTH POWER TRANSMISSION	4293	8304		
	2416INL/F020INC/1613INC	BODHGHAT (INDIRA SAROVAR) HYDROELECTRIC	4909	8404		
	2442IN	SECOND FARAKKA THERMAL POWER	4967	8405		
	2452IN	FOURTH TROMBAY THERMAL POWER	4536	8405		
	2497INL/1552INC	NARMADA RIVER DEV. - GUJARAT:SARDAR SAROVAR DAM & POW	5107	8502		
	2544IN	CHANDRAPUR THERMAL POWER	5319	8504		
	2555IN	RIHAND POWER TRANSMISSION PROJECT	5410	8505		
	2582IN	KERALA STATE POWER	5484	8505		
	2674IN	COMBINED CYCLE POWER	5831	8602		
	2827IN	KARNATAKA POWER	6695	8705		
	2844IN	NATIONAL CAPITAL POWER SUPPLY (PHASE I)	6270	8705		
	2845IN	TALCHER THERMAL POWER	6402	8705		
INDONESIA		POWER SECTOR EFFICIENCY	7122	8803		

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POWER PROJECTS
ASIA REGION

Country	Loan/Credit Numbers	Project Title	SAR No.	SAR Date (yymm)	PPAR/PCR No.	PPAR/PCR Date (yymm)
INDONESIA	0165IND	ELECTRICITY DISTRIBUTION	0018	6910	2741	7911
	0334IND	SECOND ELECTRICITY DISTRIBUTION	0095	7206	2741	7911
	0399IND	WEST JAVA THERMAL POWER	0087	7305	5104	8405
	1127IND	FOURTH POWER PROJECT	0766	7505		
	1259IND	FIFTH POWER PROJECT	1054	7604	5300COM	8410
	1365IND	SIXTH POWER PROJECT	1289	7701	6238COM	8606
	1513IND	SEVENTH POWER PROJECT	1638	7801	6762COM	8704
	1708IND	EIGHTH POWER PROJECT	2375	7905		
	1872IND	NINTH POWER PROJECT	2694	8003		
	1950IND	TENTH POWER PROJECT	3185	8101		
	2056IND	ELEVENTH POWER PROJECT	3468	8109		
	2214IND	TWELFTH POWER PROJECT	4046	8211		
	2300IND	THIRTEENTH POWER PROJECT	4356	8305		
	2443IND	FOURTEENTH POWER PROJECT	4949	8405		
	2543IND	KEDUNG OMBO MULTIPURPOSE DAM & IRRIGATION	5346	8504		
	2778IND	POWER TRANSMISSION & DISTRIBUTION	5491	8612		
MALAYSIA	0210MA	FIRST POWER PROJECT	0173	5809		
	0350MA	SECOND POWER PROJECT	0371	6307		
	0458MA	NATIONAL ELECTRICITY BOARD	0546	6607		
	0579MA	FOURTH POWER PROJECT	1697	6812	0774	7506
	0700MA	FIFTH POWER PROJECT	0043	7006	2644	7908
	1031MA	SIXTH POWER PROJECT	0347	7406	3506	8106
	1178MA	SEVENTH POWER PROJECT	0843	7511	6001COM	8512
	1443MA	EIGHTH POWER PROJECT	1528	7705	6241COM	8606
	1808MA	NINTH POWER PROJECT (BERSIA & KENERING HYDRO)	2036	8002		
	2772MA	ENERGY EFFICIENCY & PLANT REHAB.	6373	8611		
PHILIPPINES		BACON MANITO GEOTHERMAL POWER	6999	8711		
	0183PH	BINGA HYDROELECTRIC	0156	5711		
	0297PH	ANGAT HYDROELECTRIC	0298	6110		
	0325PH	MARIA CHRISTINA FALLS HYDROPOWER EXPANSION	0335	6210		
	0491PH	FOURTH POWER PROJECT	0512	6703	0980	7601
	0809PHL/0296PHC	FIFTH POWER PROJECT	0079	7202	4368COM	8303
	1034PH	SIXTH POWER PROJECT	0421	7406	4847COM	8312
	1460PH	SEVENTH POWER PROJECT	1552	7705		
SRI LANKA	0101CE	ABERDEEN-LAKSAPANA HYDROELECTRIC	0043	5406		
	0209CE	GRANPASS THERMAL POWER	0174	5806		
	0283CE	NORTON BRIDGE HYDRO & GRANPASS II THERMAL	0268	6104		
	0372CE	FIFTH POWER PROJECT	0021	7303	3711	8112
	0636CE	FOURTH POWER PROJECT	0017	6907	3710	8112
	0653CEL/0174CEC	MAHAWELI GANGA DEVELOPMENT	0029	6912	3730	8112
	1048CE	SIXTH POWER PROJECT	2905	8006		
	1210CE	SEVENTH POWER (MAHAWELI TRANSMISSION)	3599	8201		
	1736CE	POWER IX - DIST, TRANS & REHABILITATION	6032	8609		

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POWER PROJECTS
ASIA REGION

Country	Loan/Credit Numbers	Project Title	SAR No.	SAR Date (yymm)	PPAR/PCR No.	PPAR/PCR Date (yymm)
SRI LANKA	2107CE	EIGHTH (DIESEL) POWER PROJECT	3891	8205		
THAILAND		NAM CHON (UPPER QUAI YAI) HYDROELECTRIC	3813	8203		
	0036TH	CHAO PHYA IRRIGATION & COMMUNICATIONS	0090	5006		
	0175TH	YANHEE MULTIPURPOSE	0137	5700		
	0333TH	SECOND YANHEE PROJECT	0349	6302		
	0406TH	THIRD YANHEE PROJECT	0458	6503		
	0489TH	FOURTH YANHEE POWER	0574	6702		
	0514TH	PHASON DAM	0563	6706	2850	8002
	0655TH	FIRST EGAT POWER	0020	6912	1142	7604
	0790TH	SOUTH BANKOK THERMAL POWER - UNIT IV	0075	7109	1966	7803
	0977TH	BAN CHAO NEN HYDROELECTRIC	0291	7403	3999	8206
	1485TH	PATTANI HYDROELECTRIC	1447	7707	5607COM	8504
	1690TH	BANG PAKONG THERMAL POWER	2271	7904	6660COM	8702
	1770TH	KHAO LAEM HYDROELECTRIC	2568	7910	6157COM	8604
	2000TH	POWER SUBSECTOR PROJECT	3158	8104		
	2915TH	POWER TRANSMISSION PROJECT	6773	8801		

No. of Selected Projects in Region = 102

PPAR/PCR No. Legend: ####APP = APPRAISAL REPORT ####COM = COMPLETION REPORT

POWER PROJECTS
EMENA REGION

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Country	Loan/Credit Numbers	Project Title	SAR No.	SAR Date (yymm)	PPAR/PCR No.	PPAR/PCR Date (yymm)
CYPRUS	0335CY	POWER PROJECT	0345	6304		
	0494CY	SECOND POWER PROJECT	0562	6704		
	0649CY	THIRD POWER PROJECT	0025	6912	0819	7507
	0831CY	FOURTH POWER PROJECT	0093	7205	2259	7811
	1873CY	POWER DISTRIBUTION & TRANSMISSION	2932	8005	5992COM	8512
JORDAN	0386JO	HUSSEIN THERMAL POWER	0095	7305	3875	8203
	0570JO	SECOND HUSSEIN THERMAL POWER	0733	7505	3875	8203
	1688JO	THIRD POWER PROJECT	2366	7903	5172COM	8406
	1986JO	FOURTH POWER PROJECT	3329	8104		
	2162JO	FIFTH POWER PROJECT	3683	8204		
	2371JO	ENERGY DEVELOPMENT PROJECT	4626	8311		
	2710JO	SIXTH POWER PROJECT	6075	8605		
	2835JO	SEVENTH POWER PROJECT	6496	8705		
MOROCCO		DCHAR EL OUED MULTIPURPOSE	4343	8304		
	0936MOR	POWER PROJECT	0026	7308	4028	8206
	1299MOR	SIDI CHEHO-AL MASSIRA HYDRO	1156	7606		
	2910MOR	POWER DISTRIBUTION PROJECT	6916	8801		
PAKISTAN		TRANS & DIST - KARACHI ELECT. SUPP. CORP.	0062	7102		
	0120PAK	KARACHI POWER	0061	5506		
	0191PAK	SECOND KARACHI POWER	0165	5804		
	0213PAK	WAPDA POWER PROJECT	0036	7007	3410	8104
	0234PAK	THIRD KARACHI POWER	0214	5908		
	0488PAK	FOURTH KARACHI POWER	0565	6702		
	0968PAK	THIRD WAPDA POWER PROJECT	1942	7911		
	1208PAK	SECOND WAPDA POWER PROJECT	0891	7601	6004	8512
	2499PAK	FOURTH WAPDA POWER PROJECT	5047	8502		
	2556PAK	FIFTH WAPDA POWER PROJECT	5568	8505		
	2698PAK	KOT ADDU COMBINED CYCLE POWER	6020	8604		
	2792PAK	POWER PLANT EFFICIENCY IMPROVEMENT	6390	8703		
PORTUGAL	0362PO	HIDRO ELECTRICA DO DOURO HYDROPOWER	0374	6310		
	0363PO	EMPRESA TERMOELECTRICA PORTUGUESA THERMAL	0374	6310		
	0412PO	CARREGADO THERMAL POWER	0450	6504		
	0452PO	CARRAPATELLO HYDROELECTRIC POWER	0507	6605		
	0453PO	SECOND CARREGADO THERMAL POWER	0507	6605		
	1301PO	SIXTH POWER PROJECT	0995	7606	4294COM	8301
	2240PO	SEVENTH POWER PROJECT	3805	8301		
TUNISIA		SIDI SALEM MULTIPURPOSE	1215	7705		
	1355TUN	SECOND POWER PROJECT	1304	7612	4456COM	8304
	2003TUN	THIRD POWER PROJECT	3337	8104		
TURKEY		BOYABAT HYDROPOWER	7017	8712		
	0034TU	CUKUROVA ELECTRIC CO. PROJECT	0346	6301		
	0059TU	SECOND CUKUROVA ELECTRIC CO. PROJECT	0581	6702		
	0063TU	SEYHAN RIVER MULTIPURPOSE	0086	5204		

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POWER PROJECTS
EMENA REGION

Country	Loan/Credit Numbers	Project Title	SAR No.	SAR Date (yymm)	PPAR/PCR No.	PPAR/PCR Date (yymm)
TURKEY	0560TU	KEBAN TRANSMISSION LINE	0686	6810	3695	8112
	0623TU	THIRD CUKUROVA POWER PROJECT	0013	6906	1372	7611
	0763TU	POWER TRANSMISSION PROJECT	0069	7105	3695	8112
	0775TU	FOURTH CUKUROVA POWER PROJECT	0074	7106	1372	7611
	0883TUL/0360TUC	CEYHAN ASLANTAS MULTIPURPOSE	0016	7301	6756	8705
	0892TU	ISTANBUL POWER DISTRIBUTION	0020	7304	4264	8212
	1023TU	ELBISTAN LIGNITE MINE & POWER	0342	7406		
	1194TU	SECOND POWER TRANSMISSION PROJECT	0679	7511	5304COM	8410
	1844TU	KARAKAYA HYDROPOWER	2848	8004		
	2322TU	THIRD TEK TRANSMISSION	4407	8305		
	2586TU	FOURTH TEK TRANSMISSION	5571	8505		
	2602TU	POWER SYSTEM OPERATIONS ASST. PROJECT	5572	8505		
	2650TU	ELBISTAN OPER. & MAINT. ASSISTANCE	5774	8512		
	2655TUL/8014TJL/8015TUC	KAYRAKTEPE HYDROPOWER	5820	8601		
	2750TU	SIR HYDROPOWER	5919	8608		
YEMEN ARAB REPU	0837YAR	POWER DISTRIBUTION PROJECT	2006	7805	7064	8712
	1361YAR	THIRD POWER PROJECT	4321	8304		
	1701YAR	FOURTH POWER PROJECT	5802	8604		
YUGOSLAVIA		KOSOVO "A" THERMAL PLANT REHAB.	5562	6503		
		PERUCICA HYDRO STATION REHAB. & EXPANSION	5509	8503		
	0277YU	HYDROELECTRIC POWER PROJECT	0267	6102		
	0318YU	BAJINA BASTA HYDRO PLANT & TRANS. LINES	0321	6207		
	0836YU	POWER TRANSMISSION PROJECT	0087	7205	5113	8406
	1136YU	BUK BIJELA HYDROPOWER	0650	7504		
	1469YU	SECOND POWER TRANSMISSION PROJECT	1472	7706	5390COM	8412
	1561YU	MIDDLE NERETVA HYDRO1865	1865	7804		
	2338YU	POWER TRANSMISSION III (ENERGY MGT. SYSTEM)	4193	8304		
	2527YU	VISEGRAD HYDROELECTRIC	5369	8504		

No. of Selected Projects in Region = 71

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POWER PROJECTS
LAC REGION

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Country	Loan/Credit Numbers	Project Title	SAR No.	SAR Date (yymm)	PPAR/PCR No.	PPAR/PCR Date (yymm)
ARGENTINA	0308AR	BUENOS AIRES POWER PROJECT	0306	6201		
	0525AR	SECOND BUENOS AIRES POWER PROJECT	0606	6801		
	0577AR	EL CHOCON POWER PROJECT	0001	6812	1353	7611
	0644AR	THIRD BUENOS AIRES POWER PROJECT	0019	6909	1055	7602
	1330AR	FOURTH BUENOS AIRES POWER PROJECT	0675	7609	6098COM	8603
	1761AR	YACYRETA HYDROELECTRIC PROJECT	2342	7909		
	2854AR	FIFTH SEGBA PROJECT	6758	8706		
BOLIVIA		FIFTH ENDE POWER PROJECT	3617	8109		
		SAN JACINTO MULTIPURPOSE	2564	7906		
	0061BO	ENDE POWER PROJECT	0426	6406		
	0062BO	BPC POWER PROJECT	0426	6405		
	0148BO	SECOND ENDE POWER PROJECT	0003	6904	1496	7703
	0433BO	THIRD ENDE POWER PROJECT	0190	7308	2733	7911
	1238BO	FOURTH POWER PROJECT	0981	7603	3715	8112
	1818BO	POWER REHABILITATION	6636	8705		
BRAZIL	0011BR	POWER PROJECT	0036	4803		
	0025BR	PAULO ALFONSO HYDROELECTRIC	0080	5005		
	0064BR	RIO GRANDE DO SUL ELECTRIFICATION	0168	5206	0043APP	5507
	0076BR	ITUTINGA HYDROELECTRIC POWER	0011	5307		
	0093BR	SALTO GRANDE HYDROELECTRIC POWER	0042	5312		
	0095BR	PIRA THERMAL POWER	0031	5402		
	0187BR	JURUMIRIM HYDROELECTRIC	0158	5801		
	0211BR	FURNAS HYDROELECTRIC	0184	5809		
	0229BR	POWER PROJECT	0168	5906		
	0403BR	ESTREITO HYDROELECTRIC	0459	6502	2370	7902
	0404BR	XAVANTES HYDROELECTRIC	0461	6502	1652	7706
	0442BR	JAGUARA HYDROELECTRIC	0514	6602	1852	7801
	0474BR	ESTREITO HYDROELECTRIC (STAGE II)	0539	6612	2370	7902
	0475BR	COMPANHIA BRASILEIRA DE ENERGIA ELECTRICA T&D	0535	6612	0858	7509
	0476BR	COMPANHIA PARANAENSE DE ENERGIA ELECTRICA T&D	0537	6612	0858	7509
	0477BR	COMPANHIA PAULISTA DE FORCA E LUZ T&D	0538	6612	0858	7509
	0478BR	CENTRAIS ELECTRICAS DE MINAS GERAIS T&D	0536	6612	0858	7509
	0565BR	PORTO COLOMBIA HYDROELECTRIC	0682	6809	2370	7902
	0566BR	SECOND VOLTA GRANDE HYDROELECTRIC	0683	6809	1852	7801
	0677BR	MARIMBONDO HYDROELECTRIC PLANT	0041	7005	2768	7912
	0720BR	SALTO OSORIO HYDROELECTRIC PLANT	0059	7103	2709	7910
	0829BR	SAO SIMAO HYDROELECTRIC	0086	7204	3500	8106
	0887BR	POWER DISTRIBUTION & SUBTRANSMISSION	0040	7303	2708	7910
	0923BR	ITUMBIARA HYDROELECTRIC POWER	0150	7305	6099	8603
	1008BR	FOURTH PAULO ALFONSO HYDROELECTRIC	0396	7405	6578	8612
	1257BR	COPEL POWER DISTRIBUTION	1028	7604	5165COM	8406
	1300BR	NORTHWEST POWER DISTRIBUTION	1088	7606	5993COM	8512
	1343BR	ELETROSUL POWER TRANSMISSION	1265	7611	5695	8506

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Country	Loan/Credit Numbers	Project Title	SAR No.	SAR Date (yymm)	PPAR/PCR No.	PPAR/PCR Date (yymm)
BRAZIL	1538BR	SOUTH-SOUTHWEST POWER DISTRIBUTION	1846	7803		
	1721BR	COPEL SECOND POWER DISTRIBUTION	2411	7905		
	1824BR	CEEE POWER DISTRIBUTION	2732	8003		
	1895BR	SECOND POWER TRANSMISSION (ELECTROSUL)	2872	8006		
	1939BR	ELECTRIC POWER SYSTEM COORDINATION	2911	8012		
	2138BR	ELETROBRAS POWER DISTRIBUTION	3338	8204		
	2364BR	SECOND ELETROBRAS POWER DISTRIBUTION	4660	8311		
	2564BR	CHESF-FURNAS POWER TRANSMISSION	5539	8505		
	2565BR	SOUTHEAST POWER DISTRIBUTION	5578	8505		
	2720BR	ELECTRIC POWER SECTOR	6159	8605		
CHILE	0005CH	CIPRESES HYDROELECTRIC	0134	5108		
	0153CH	ENDESA POWER EXPANSION	0122	5610		
	0244CH	RAPEL & HUASCO POWER	0220	5912		
	0402CH	ELECTRIC POWER EXPANSION	0445	6501		
	0479CH	FIFTH POWER PROJECT	0564	6612	1603	7705
	1351CH	SIXTH POWER PROJECT	0788	7612	5547COM	8503
	2832CH	PEHUENCHE HYDRO & ALTO JAHUEL-POLPAICO TRANS	6687	8705		
COLOMBIA	0038CO	ANCHICAYA HYDROELECTRIC	01[illegible]	5010		
	0039CO	LA INSULA HYDROELECTRIC	01[illegible]2	5012		
	0054CO	LEBRIJA HYDROELECTRIC	0146	5110		
	0113CO	HYDROELECTRIC & THERMAL POWER	0072	5503		
	021[illegible]	YUMBO STEAM PLANT EXTENSION	0195	5812		
	0217CO	ESMERALDA POWER	01[illegible]4	5901		
	0225CO	GUADALUPE HYDROELECTRIC	0203	[illegible]905		
	0246CO	BOGOTA POWER	0219	6001		
	0255CO	YUMBO III THERMAL POWER & CALIMA I HYDROPOWER	0239	6004		
	0282CO	SECOND GUADALUPE HYDROELECTRIC	0272	6104		
	0313CO	SECOND BOGOTA POWER EXTENSION	0307	6205		
	0339CO	CVC-CHIDRAL POWER EXPANSION PROGRAM	0358	6305		
	0347CO	COSPIQUE THERMAL POWER	0354	6307		
	0369CO	NARE HYDROELECTRIC	0391	6401	0450	7405
	0537CO	THIRD POWER EXPANSION	0637	6805	1654	7706
	0575CO	POWER INTERCONNECTION	0688	6810	2720	7910
	0681CO	CHIVOR HYDROELECTRIC	0031	7005	2720	7910
	0874CO	SECOND GUATAPE HYDROELECTRIC	0104	7212	3718	8112
	1582CO	SAN CARLOS HYDROPOWER	1850	7805		
	1583CO	500KV INTERCONNECTION PROJECT	1850	7805		
	1628CO	MESITAS HYDROELECTRIC POWER	2078	7811	6638	8702
	1725CO	SECOND SAN CARLOS HYDRO POWER	2464	7905		
	1807CO	BOGOTA POWER DISTRIBUTION	2649	8002		
	1868CO	FOURTH GUADALUPE HYDRO POWER	2938	8005		
	1953CO	PLAYAS HYDROPOWER	3240	8102		
	2008CO	GUAVIO HYDROPOWER	3408	8105		

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POWER PROJECTS
LAC REGION

Country	Loan/Credit Numbers	Project Title	SAR No.	SAR Date (yymm)	PPAR/PCR No.	PPAR/PCR Date (yymm)
COLOMBIA	2449CO	RIO GRANDE MULTIPURPOSE PROJECT	5018	8406		
	2634CO	SECOND BOGOTA DISTRIBUTION	5506	8505		
COSTA RICA	0276CR	RIO MACHO HYDROELECTRIC	0238	6101	0007	7210
	0346CR	POWER & TELECOMMUNICATIONS	0365	5306	0007	7210
	0631CR	THIRD POWER PROJECT	0014	6906	0760	7505
	0800CR	FOURTH POWER PROJECT	0077	7201	2969	8005
	1126CR	FIFTH POWER PROJECT	0719	7505	4991COM	8403
	1713CR	SIXTH POWER PROJECT	2433	7905	7070COM	8712
ECUADOR		CUMBAYA POWER EXPANSION DEVELOPMENT	0291	6106		
	0137EC	QUITO POWER EXPANSION	0102	5709		
	0286EC	THIRD POWER PROJECT	0073	7201	3003	8005
	2045EC	INECEL POWER TRANSMISSION	3340	8106	6359COM	8607
EL SALVADOR	0221ES	SECOND RIO LEMPA HYDROELECTRIC	0196	5902		
	0227ES	FIFTH POWER PROJECT	0055	7012	0862	7509
	0263ES	GUAJOYO HYDROELECTRIC	0248	6007		
	0342ES	FOURTH POWER PROJECT	0360	6306		
	0889ES	SIXTH POWER PROJECT	0069	7304	3053	8006
	1288ES	AHUACHAPAN EXPANSION PROJECT	1025	7605	5399COM	8412
GUATEMALA		THIRD POWER PROJECT	0102	7211		
	0487GU	JURUN-MARINALA HYDROELECTRIC	0527	6701	0625	7502
	0545GU	GUACALATE POWER	0625	6806	0625	7502
	1426GU	AGUACAPA POWER	1361	7705		
	1605GU	CHIXOY POWER	1709	7806		
	2724GU	POWER DISTRIBUTION	4641	8605		
HAITI		FIFTH POWER PROJECT	6888	8712		
	0645HA	POWER PROJECT	1052	7605		
	0895HA	SECOND POWER PROJECT	2296	7903	6459COM	8610
	1201HA	THIRD POWER PROJECT	3592	8206		
	1527HA	FOURTH POWER PROJECT	4869	8410		
HONDURAS	0226HO	INTERIM POWER PROJECT	0206	5905		
	0261HO	CANAVERAL HYDROELECTRIC	0246	6006		
	0541HOL/0116HOC	RIO LINDO HYDROELECTRIC	0623	6805	0763	7505
	0692HOL/0201HOC	FOURTH POWER PROJECT	0042	7005	2077	7806
	0841HO	FIFTH POWER PROJECT	0090	7206	5060COM	8404
	1081HO	SIXTH POWER PROJECT	0528	7412	5060COM	8404
	1629HO	NISPERO POWER	2074	7810	5420COM	8501
	180[illegible]HOL/0989HOC	EL CAJON POWER	2388	8002		
JAMAICA	0454JM	POWER PROJECT	0518	6605		
	1516JM	SECOND POWER PROJECT	1493	7801	6637COM	8702
	2188JM	THIRD POWER PROJECT	3892	8205		
	2869JM	FOURTH POWER PROJECT	5900	8706		
MEXICO	0012MEL/0013MEL	POWER PROJECTS	0059	4812		
	0056ME	ELECTRIC POWER PROJECT	0149	5112		

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POWER PROJECTS
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Country	Loan/Credit Numbers	Project Title	SAR No.	SAR Date (yymm)	PPAR/PCR No.	PPAR/PCR Date (yymm)
MEXICO	0186ME	SECOND MEXICAN LIGHT & POWER	0140	5707		
	0194ME	THIRD CFE POWER PROJECT	0166	5804		
	0316ME	FOURTH CFE POWER PROJECT	0327	6206		
	0436ME	POWER SECTOR PROJECT	0497	6511		
	0544ME	SECOND POWER SECTOR PROJECT	0661	6806		
	0659ME	THIRD POWER SECTOR PROJECT	0027	7002	0859	7509
	0834ME	FOURTH POWER SECTOR PROGRAM	0094	7205	1775	7710
NICARAGUA	0082NI	DIESEL POWER PROJECT	0018	5308		
	0121NI	THERMAL POWER PROJECT	0059	5506		
	0122NI	POWER DISTRIBUTION PROJECT	0059	5506		
	0259NI	RIO TUMA HYDROELECTRIC	0209	6006		
	0389NI	EARTHQUAKE RECONSTRUCTION PROJECT	0134	7304	6193	8605
	0470NI	SIXTH POWER PROJECT	0530	6605		
	0543NI	SEVENTH POWER PROJECT	0621	6804		
	0840NI	EIGHTH POWER PROJECT	0092	7206	5144	8406
	1402NI	NINTH POWER PROJECT	1254	7703	6322COM	8606
PANAMA	0322PAN	CENTRAL PROVINCES ELECTRIFICATION	0324	6209		
	0661PAN	SECOND POWER PROJECT	0028	7002	2508	7905
	0948PAN	THIRD POWER PROJECT	0222	7311	4246COM	8212
	1470PAN	FOURTH POWER PROJECT	1510	7706		
	1770PAN	FIFTH POWER PROJECT	2660	7911	6512COM	8611
	2313PAN	SIXTH POWER PROJECT	4376	8305		
	2506PAN	SEVENTH POWER PROJECT	5211	8502		
PERU		AREQUIPA POWER	0068	5410		
		YUNCAN HYDROELECTRIC	4668	8308		
	0260PE	HUINCO HYDROELECTRIC	0243	6006		
	0365PE	SECOND HUINCO HYDROELECTRIC	0383	6311		
	0464PE	POWER DISTRIBUTION PROJECT	0547	6607		
	0511PE	MATUCANA POWER	0596	6708	9868	7509
	1215PE	FIFTH POWER PROJECT	0904	7602	6125COM	8604
	2179PE	SIXTH POWER PROJECT	3743	8205		
URUGUAY		SIXTH POWER PROJECT	4248	8212		
	0036UR	POWER & TELEPHONE EXPANSION PROJECT	0101	5007		
	0132UR	THERMAL POWER PROJECT	0040	5508		
	0152UR	BAYGORRIA HYDROELECTRIC POWER	0120	5610		
	0712UR	FOURTH POWER PROJECT	0049	7011	2280	7811
	1779UR	FIFTH POWER PROJECT	2022	7911		
	2622URL/8017URL	POWER SECTOR REHABILITATION PROJECT	5833	8509		
VENEZUELA		CADAFE PROJECT	0985	7601		
		EVALUACION DEL PROYECTO URIBANTE - CADAFE	2257	7810		
		GURI POWER STATION EXPANSION C.V.G. EDELCA	0801	7507		
	0353VE	GURI HYDROELECTRIC	9373	6309		
	0391VE	POWER TRANSMISSION PROJECT	0440	6408		

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POWER PROJECTS
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Country	Loan/Credit Numbers	Project Title	SAR No.	SAR Date (yymm)	PPAR/PCR No.	PPAR/PCR Date (yymm)
VENEZUELA	0482VE	EXTRA HIGH VOLTAGE TRANS. PROJECT	0572	6612		
	0629VE	GURI POWERHOUSE EXTENSION	0006	6906	1192	7606

No. of Selected Projects in Region = 174

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ANNEX 2

TOTAL IBRD COMMITMENTS TO THE POWER SECTOR
(Millions of current dollars)

Economy	Total------	(%)	Cumulative--	(%)
India	5098.7	21.1%	5098.7	21.1%
Brazil	3062.2	12.7%	8160.9	33.8%
Indonesia	2144.0	8.9%	10304.9	42.6%
Colombia	1736.9	7.2%	12041.8	49.8%
Turkey	761.4	3.1%	12803.2	53.0%
Mexico	714.8	3.0%	13518.0	55.9%
Thailand	672.7	2.8%	14190.7	58.7%
Yugoslavia	664.0	2.7%	14854.7	61.4%
Argentina	617.0	2.6%	15471.7	64.0%
Malaysia	464.3	1.9%	15936.0	65.9%
Pakistan	437.7	1.8%	16373.7	67.7%
Nigeria	402.5	1.7%	16776.2	69.4%
Egypt	373.0	1.5%	17149.2	70.9%
Romania	305.0	1.3%	17454.2	72.2%
Philippines	281.7	1.2%	17735.9	73.4%
China	262.4	1.1%	17998.3	74.5%
Panama	255.4	1.1%	18253.7	75.5%
Kenya	242.0	1.0%	18495.7	76.5%
Honduras	235.6	1.0%	18731.3	77.5%
Zimbabwe	220.7	0.9%	18952.0	78.4%
Iran	211.0	0.9%	19163.0	79.3%
Peru	208.7	0.9%	19371.7	80.1%
Zambia	197.1	0.8%	19568.8	80.9%
Guatemala	193.6	0.8%	19762.4	81.7%
Japan	178.2	0.7%	19940.6	82.5%
Chile	167.1	0.7%	20107.7	83.2%
Sri Lanka	166.7	0.7%	20274.4	83.9%
Bangladesh	160.0	0.7%	20434.4	84.5%
Taiwan	149.5	0.6%	20583.9	85.1%
Syria	145.6	0.6%	20729.5	85.8%
Venezuela	145.0	0.6%	20874.5	86.4%
Ghana	127.1	0.5%	21001.6	86.9%
Portugal	126.4	0.5%	21128.0	87.4%
Costa Rica	124.3	0.5%	21252.3	87.9%
Nepal	118.0	0.5%	21370.3	88.4%
Morocco	116.0	0.5%	21486.3	88.9%
Korea	115.0	0.5%	21601.3	89.4%
Sudan	112.0	0.5%	21713.3	89.8%
Uruguay	110.0	0.5%	21823.3	90.3%
Algeria	106.0	0.4%	21929.3	90.7%
Australia	100.0	0.4%	22029.3	91.1%
All Other Countries	2144.9	8.9%	24174.2	100.0%
Total	24174.2			

Source: Collier, H. Developing Electric Power. IBRD, 1984.
Escay, J. FY78-92 World Bank Group Lending for Energy. IBRD/IENED, 1988.

ANNEX 3

ANNEX 3: ECONOMIC GROWTH RATES DURING DIFFERENT TIME PERIODS

Economic growth rates were calculated for each of the 45 countries incorporated in this study for five-year intervals from 1960 through 1985. We then took unweighted averages of these country growth rates to approximate mean regional growth rates. Standard deviation and coefficient of variation of these region-wide means was estimated to provide some crude measure of volatility.

As shown in Table A3-1, the results confirm that there was a dramatic change in average growth rates and in volatility beginning in the early 1970's. The 1960's were characterized by high economic growth rates; the world average was over 5 percent average annual growth, and "slow growth" rates experienced in Africa averaged over 4 percent. Volatility of growth was low; no region had a coefficient of variation higher than 0.5 prior to 1970. After 1975, especially in the current decade, growth rates fell while volatility increased dramatically in some areas, notably LAC and Africa.

ANNEX 3-1

	GROSS NATINAL PRODUCTS AT MARKET PRICES (Millions of 1980 dollars)						AVERAGE ANNUAL GNP GROWTH RATES (percent)				
	1960	1965	1970	1975	1980	1985	1960-65	1965-70	1970-75	1975-80	1980-85
LAC Region											
Argentina	76797.7	95626.8	118886.6	136771.6	152444.3	132581.4	4.5	4.5	2.8	2.2	-2.8
Bolivia	2138.7	2699.9	3266.6	4369.5	4722.1	4009.0	4.8	3.9	6.0	1.6	-3.2
Brazil	..	70047.1	103392.8	167822.3	232119.4	247203.2		8.1	10.2	6.7	1.3
Chile	13916.7	16724.4	21019.4	18445.3	26641.1	24888.6	3.7	4.7	-2.6	7.6	-1.4
Colombia	11336.1	14193.4	19019.4	25269.6	33188.5	35834.4	4.6	6.0	5.8	5.6	1.5
Costa Rica	1565.0	1975.3	2772.6	3656.1	4599.5	4668.1	4.8	7.0	5.7	4.7	0.3
Ecuador	..	3782.3	4732.9	8332.6	11152.0	11931.7		4.6	12.0	6.0	1.4
El Salvador	1512.1	2028.7	2581.7	3336.2	3515.6	3100.2	6.6	4.4	5.3	1.1	-2.5
Guatemala	2639.4	3405.1	4467.7	5879.0	7808.2	7297.2	5.2	5.6	5.6	5.8	-1.3
Haiti	923.0	933.2	944.9	1098.1	1445.9	1392.0	0.2	0.2	3.1	5.7	-0.8
Honduras	1006.9	1213.1	1510.4	1714.0	2334.5	2450.4	3.8	4.5	2.6	6.4	1
Jamaica	1858.8	2266.1	2820.6	3221.5	2487.9	2242.6	4.0	4.5	2.7	-5.0	-2.1
Mexico	46457.2	65683.5	96932.8	132669.7	180318.6	191688.5	7.2	8.1	6.5	6.3	1.2
Nicaragua	1015.4	1591.8	1928.5	2545.7	2044.2	2018.6	9.4	3.9	5.7	-4.3	-0.3
Panama	927.4	1391.8	2011.8	2590.2	3331.5	3754.2	8.5	7.6	5.2	5.2	2.4
Peru	8303.9	11306.3	14018.8	17987.8	19845.2	18891.7	6.4	4.4	5.1	2.0	-1
Uruguay	6048.7	5989.1	7407.9	7996.6	10032.9	8248.6	0.2	4.3	1.5	4.6	-3.8
Venezuela	20269.3	28088.0	37769.3	50439.9	59500.1	52968.1	6.7	6.1	6.0	3.4	-2.3
Total LAC Region				Sample Size			16	18	18	18	18
				Mean Annual Growth Rate			5.0	5.1	5.0	3.6	-0.7
				Standard Deviation			2.5	1.8	1.8	3.5	1.8
Africa Region											
Ethiopia	1996.9	2560.7	3092.4	3535.8	4129.2	4022.7	5.1	3.8	2.7	3.2	-0.5
Ghana	..	12888.2	14761.5	14549.4	15516.4	15395.2		2.8	-0.3	1.3	-0.2
Kenya	..	2497.3	3252.3	5154.1	6869.0	7757.9		5.4	9.6	5.9	2.5
Liberia	..	654.1	898.7	985.8	1092.9	979.4		6.6	1.9	2.1	-2.2
Malawi	..	474.7	656.2	993.3	1149.6	1247.7		6.7	8.6	3.0	1.7
Nigeria	39251.9	47632.8	60160.4	83019.7	98153.3	87774.3	3.9	4.8	6.7	3.4	-2.2
Sierra Leone	..	709.4	898.7	1006.6	1058.3	1074.6		4.8	2.3	1.0	0.3
Sudan	..	5400.0	5470.4	6474.6	7861.8	7013.1		0.3	3.4	4.0	-2.3
Tanzani	..	2680.4	3676.5	4544.1	5124.6	5249.3		6.5	4.3	2.4	0.5
Zambia	2031.7	2908.6	3255.7	3510.3	3595.3	3643.4	7.4	2.3	1.5	0.5	0.3
Zimbabwe	..	2695.9	3336.4	5018.7	5281.7	6705.6		4.4	8.5	1.0	4.9
Total Africa Region				Sample Size			3	11	11	11	11
				Mean Annual Growth Rate			5.4	4.4	4.5	2.5	0.2
				Standard Deviation			1.5	1.9	3.2	1.5	2.1

ANNEX 3-1 (continued)

	GROSS NATINAL PRODUCTS AT MARKET PRICES (Millions of 1980 dollars)						AVERAGE ANNUAL GNP GROWTH RATES (percent)				
	1960	1965	1970	1975	1980	1985	1960-65	1965-70	1970-75	1975-80	1980-85
Asia Region											
Bangladesh	6942.6	8724.6	10340.2	9983.8	12806.0	15305.3	4.7	3.5	-0.7	5.1	3.6
India	84112.5	98847.1	124705.5	145344.0	172697.3	224600.1	3.3	4.8	3.1	3.5	5.4
Indonesia	23733.1	26075.5	36817.6	52036.1	74806.4	93751.4	1.9	7.1	7.2	7.5	4.6
Malaysia	..	8099.6	11094.8	15702.7	23607.0	28985.9		6.5	7.2	8.5	4.2
Philippines	11148.9	14866.7	18636.3	25961.2	35213.1	32569.6	5.9	4.6	6.9	6.3	-1.5
Sri Lanka	1670.4	1969.8	2611.4	3087.7	3997.5	4949.4	3.4	5.8	3.4	5.3	4.4
Thailand	7849.5	11126.9	17231.2	23302.5	32838.5	41407.9	7.2	9.1	6.2	7.1	4.7
Total Asia Region				Sample Size			6	7	7	7	7
				Mean Annual Growth Rate			4.4	5.9	4.8	6.2	3.6
				Standard Deviation			1.5	1.9	3.2	1.5	2.1
EMENA Region											
Cyprus	..	..	..	1225.5	2134.8	2803.4				11.7	5.6
Jordan	..	..	1545.1	1761.3	3351.5	4134.3			2.7	13.7	4.3
Morocco	7149.4	8489.1	10868.7	13359.5	17225.0	18911.9	3.5	5.1	4.2	5.2	1.9
Pakistan	7412.3	10600.2	14985.2	17348.7	23409.9	32324.4	7.4	7.2	3.0	6.2	6.7
Portugal	..	11236.6	15035.5	21344.0	24018.2	24564.1		6.0	7.3	2.4	0.5
Tunisia	..	3300.7	4184.9	6257.8	8511.4	10287.9		4.9	8.4	6.3	3.9
Turkey	19394.9	24821.7	34043.9	48958.9	55801.1	69924.4	5.1	6.5	7.5	2.7	4.6
Yemen AR	..	..	1145.1	1990.9	3036.9	3565.8			11.7	8.8	3.3
Yogoslavia	22911.3	30312.2	41196.3	54264.5	72281.8	73430.7	5.8	6.3	5.7	5.9	0.3
Total Asia Region				Sample Size			4	6	8	9	9
				Mean Annual Growth Rate			5.4	6.0	6.3	7.0	3.4
				Standard Deviation			1.4	0.8	2.9	3.6	2.1
World Total				Sample Size			29	42	44	45	50
				Mean Annual Growth Rate			5.0	5.2	5.0	4.4	0.9
				Standard Deviation			2.2	1.8	3.1	3.4	2.6

ANNEX 4

ANNEX 4: FORECASTS ACCURACY BY METHODOLOGY

A number of methodologies are applied to load forecasting, ranging from the simple and low-cost to the sophisticated and expensive. These methods can broadly be classified into five groups.

- trending-judgement techniques
- simple econometric models
- complex (i.e., multiple equation) econometric models
- end-use models
- customer survey (power market surveys)

We would like to compare the accuracy of LDC forecasts using these different techniques. Unfortunately, historical data is not available on the methods applied to develop the forecasts analyzed in Chapter 3. The survey of U.S. utility forecasting experience discussed in Chapter 4,[1] however, does evaluate forecasts by methodology. Although the survey's findings reflect only U.S. experience, we believe that they provide useful insights for LDC planners.

Table A4-1 presents key statistics on forecast accuracy by methodology. These results are based on a survey of the 75 largest U.S. utilities.[2] In summary, the U.S. experience indicates that:

- end-use models outperformed econometric techniques for all horizons, at a minimum of 90 percent confidence level.
- end-use models outperformed trending techniques in all years though the differences in mean error is statistically insignificant in the near-term (i.e., 2 years out).
- complex econometric models outperformed simple econometric models in the short-term (i.e., year 2) with 90 to 95 percent significance, but were only marginally better in year 4. On the other hand, simpler econometric models did better in year 6.

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1 William Huss, "Can Electric Utilities Improve Their Forecast Accuracy? The Historical Perspective," Public Utilities Fortnightly, December 26, 1985, p. 37.

2 Large utilities are defined as those with 1982 sales over 5,000 GWh.

- trending techniques outperformed econometric techniques in year 2 and year 4, but their records were comparable in year 6.

Tables A4-2 through A4-4 display the performance record of large utilities by customer segment. The U.S. experience as analyzed in the paper cited above generally support the following conclusions:

- Forecast accuracy does not appear to have improved over time. Further, larger utilities that tend to use more complex models and spend substantial resources, did not outperform smaller utilities significantly.

- In all sectors, econometric techniques -- simple or complex -- failed to outperform trend extrapolation - judgmental techniques.

- In the industrial sector, customer surveys (power market surveys) seem to be by far the best technique for near term (i.e., two-to-four year horizon) forecasts. However, in the mid-term (six years out) the performance of trending methods, econometric methods, and customer surveys was indistinguishable. This suggests that if cost and time are a factor then trending methods can be employed for mid-term forecasts. These observations further indicate that utilities can significantly improve the accuracy of industrial sector forecasts in the short to medium term through regular customer surveys. Since a relatively few industrial customers often account for 40-50 percent of total system load, these benefits can be realized at minimal investment cost.

- In the residential sector, end-use models provided superior accuracy over the near and mid-term (i.e., thru year 6). Further, the performance of trending techniques and econometric methods were statistically indistinguishable. Since the end-use method is very data intensive, a key question that needs to be answered is whether the increased accuracy justifies the extra effort.

- In the commercial sector, trending techniques were somewhat superior to econometric methods in years 2 and 6, and only marginally inferior in year 4.

In summary, the record buttresses the views of those who believe that simple trending - judgmental techniques are no worse than econometric models. Indeed, in the short-term the U.S. experience shows that the record of trending techniques is superior to econometric methods. This is perhaps attributable to their reliance on judgement gained from an understanding of the environment and the ongoing dynamics. In contrast, pure econometric techniques rely on a mechanistic application of rigid formula. Put simply, this record supports the belief that less complex models coupled with a better understanding of the power market and the ongoing dynamics can produce a superior near-term forecast than more complex ones.

As far as mid-term accuracy is concerned, end-use methods appear to be superior in the residential sector.[3] However, this evidence is based upon a small sample size. As indicated in Table 4-3, there are 12 data points in year 6. Another important consideration is that these models are extremely data intensive. The decision to use such a model should be based upon weighing the cost of utilizing such an approach versus the benefits of improved accuracy.

As far as long-term accuracy is concerned, the record is inconclusive, largely because of few data points. The accuracy of all methods is statistically indistinguishable.

3 End use techniques are generally not employed in the industrial sector because it is prohibitively expensive due to the many different types of processes involved, and because proprietary data is often not supplied by customers.

Table A4-1
Forecast Performance by Methodology
Large U.S. Utilities[1]

		Horizon Two Years	 Four Years	 Six Years
Trending	Mean	3.91	10.71	21.14
	Std. Dev.	6.45	6.31	19.17
	Avg. Med.	2.70	10.21	19.73
	No. of Resps.	79	76	68
Econometric	Mean	5.43	12.79	20.94
	Std. Dev.	5.39	10.05	11.54
	Avg. Med.	4.75	10.31	20.15
	No. of Resps.	89	61	31
End Use	Mean	3.76	6.69	13.54
	Std. Dev.	3.95	5.49	11.34
	Avg Med.	2.59	5.25	12.62
	No. of Resps	29	16	5
Simple Econ	Mean	6.78	13.23	18.39
	Std. Dev.	7.22	11.01	8.01
	Avg. Med.	4.08	10.94	19.15
	No. of Resps.	28	23	14
Complex Econ	Mean	4.82	12.53	23.05
	Std. Dev.	4.09	9.61	13.81
	Avg. Med.	4.23	9.40	20.17
	No. of Resps.	61	38	17

1 Mean: Mean Absolute Percentage Error
Std. Dev.: Standard Deviation
Avg. Med.: Median Absolute Percentage Error

Source: "Can Electric Utilities Improve Their Forecast Accuracy? The Historical Perspective", Public Utilities Fortnightly, Dec. 26, 1985.

Table A4-2

Industrial Forecast Performance: Large U.S. Utilities

		Horizon			
		Two Years	Four Years	Six Years	Eleven Years
Trending	Mean	6.43	12.51	18.92	59.63
	Std. Dev.	5.34	7.65	10.20	21.68
	Avg. Med.	5.09	11.68	18.60	63.18
	No. of Resps.	50	46	39	9
Econometric	Mean	5.81	11.58	21.55	69.74
	Std. Dev.	4.09	7.25	14.31	--
	Avg. Med.	5.13	10.98	21.39	69.74
	No. of Resps.	61	44	24	1
Customer Survey	Mean	5.38	11.56	19.21	58.47
	Std. Dev.	6.12	9.32	13.24	29.87
	Avg. Med.	3.36	8.27	18.51	53.06
	No. of Resps.	66	52	39	7
Overall	Mean	5.85	11.62	19.59	59.75
	Std. Dev.	5.20	8.13	12.27	24.01
	Avg. Med.	4.43	10.27	17.85	63.18
	No. of Resps.	189	148	103	17

Source: "Can Electric Utilities Improve Their Forecast Accuracy? The Historical Perspective", Public Utilities Fortnightly, Dec. 26, 1985.

Table A4-3

Residential Forecast Performance: Large U.S. Utilities

		Horizon			
		Two Years	Four Years	Six Years	Eleven Years
Trending	Mean	3.84	11.74	18.31	62.72
	Std. Dev.	2.32	6.19	11.10	11.14
	Avg. Med.	3.53	9.87	16.61	58.37
	Number	27	24	23	4
Econometric	Mean	4.22	10.87	20.72	47.23
	Std. Dev.	3.43	7.71	11.10	--
	Avg. Med.	3.68	10.64	19.35	47.23
	Number	37	27	17	1
End Use	Mean	3.11	6.45	16.80	62.42
	Std. Dev.	2.47	4.91	8.86	--
	Avg. Med.	2.36	4.48	15.54	62.42
	Number	44	27	12	1
Overall	Mean	3.75	9.81	18.75	62.64
	Std. Dev.	2.85	6.52	10.40	11.85
	Avg. Med.	3.21	8.95	18.34	61.38
	Number	111	80	52	7

Table A4-4

Commercial Forecast Performance: Large U.S. Utilities

		Horizon			
		Two Years	Four Years	Six Years	Eleven Years
Trending	Mean	3.16	9.60	17.12	61.29
	Std. Dev.	2.37	5.29	9.45	20.04
	Avg. Med.	3.13	9.77	14.52	53.34
	No. of Resps.	35	31	26	5
Econometric	Mean	3.31	8.62	18.45	81.58
	Std. Dev.	2.71	6.01	11.30	--
	Avg. Med.	2.93	7.54	18.05	81.58
	No. of Resps.	57	39	21	1
Overall	Mean	3.34	8.83	17.64	66.56
	Std. Dev.	2.67	6.11	10.42	18.71
	Avg. Med.	3.04	8.43	17.13	68.24
	No. of Resps.	103	73	48	7

Source: "Can Electric Utilities Improve Their Forecast Accuracy? The Historical Perspective", Public Utilities Fortnightly, Dec. 26, 1985.

ANNEX 5

Planning future electrical generation capacity

A decision analysis of the costs of over- and under-building in the US Pacific Northwest

Arun P. Sanghvi and Dilip R. Limaye

Agencies with the mandate to consider a utility's request for additional generating capacity are increasingly in the cross-fire between various special interest groups and are confronted by divergent forecasts of future load growth. The regulatory agency's decision is difficult, to say the least. The social costs of both over- and under-building can be high. It is therefore imperative that the trade-off between the costs of over- and under-capacity be evaluated. This study develops a decision analysis framework to study the need for additional electrical generating capacity in the presence of divergent load growth forecasts. A method for determining the costs of over- and under-building capacity is developed and applied to the Pacific Northwest region of the USA. Our results support the conclusion that in the Pacific Northwest the social costs of over-building are lower than the costs of under-building.

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continued on p 103

The high standard of living that the USA enjoys is based upon the vitality of its economy and its potential for growth. Historically, this growth has been supported, in part, by the availability of an inexpensive, abundant, and reliable supply of electrical energy, as evidenced by a consistent increase in electricity intensiveness since 1950. Electricity generation now accounts for about 25% of US energy requirements. This reliance is projected to increase, often at the expense of other energy sources.

There is, however, increased concern about the adequacy of future availability of electricity. Fears of major power shortages in the 1980s are growing in the light of concerns about the availability of fuel for thermal plants, longer regulatory and construction lead times for new generating facilities, financing difficulties, and marked uncertainty of future demand. The impacts of such shortages, if they materialize, can range from inconvenience and discomfort to social deprivation and severe economic loss. Experience gained from the 1965 blackout in the Northeast of the USA and the recent 1977 New York City blackout only serves to heighten, in people's minds, the consequences of potential electricity shortages. On the other side of the coin, excess capacity will impose unnecessarily high fixed costs of generation on consumers. This cost stems from the capital intensive nature of the electric utility industry – estimates of the investment required in the next decade, for providing additional generating capacity range from \$215 billion (10^9) to \$323 billion.[1]

One must consider the impassioned concerns of environmentalists. They charge that the market price of electricity does not adequately reflect the social costs of electricity generation. This leads to over-expansion of generating capacity and consequently, to over-consumption, and unnecessary depletion and degradation of society's resources. Other special interest groups, out of concern for the needs of future generations, are committed to a change in life style that will bring about reduced energy consumption levels.

All these concerns not only add to the degree of uncertainty in future demand, but have also led to a measurable increase, in the

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recent past, in the possibility of procedural delays and extended litigation in the licensing of new power plants. There is at present a growing adversary climate between the utilities and the 'intervenors'. This polarization is likely to get worse as the various special interest groups become more vocal and take their cases 'to the people'. A consequence of this division is that regulatory bodies such as the Energy Facilities Siting Council (EFSC) in the US Pacific Northwest (PNW),[2] that have the mandate to approve or disapprove a utility's request for additional generating capacity, increasingly find themselves in the middle of a heated debate.

One facet of this confrontation, reduced to its bare essentials, stems from divergent load growth forecasts – typically a 'low' forecast by the environmentalists, and a 'high' forecast by the utility to support its application for additional generating capacity.[3] Sometimes these forecasts are probabilistic in nature. Specifically, the low forecast is characterized by a probability distribution D^L, whose mass is concentrated on low load growth outcomes, and the high forecast, characterized by a distribution D^H with most of its mass concentrated on high load growth outcomes. One problem facing the siting council is: what is the appropriate generating capacity expansion rate, given distributions D^L and D^H? The decision is difficult. Even under the most rationally designed capacity expansion plan, it is virtually certain that projections of electricity demand and generating capacity, will exceed or fall short of actual demand and capacity. Society will have to bear the costs of such deviations. The choice[4] is between:

- paying the higher fixed generation costs incurred due to excess capacity;
- paying the costs of economic and other losses due to power shortfalls and/or brownouts, or the higher costs of short lead time generating capacity (such as combustion turbines) that is installed if a shortage is imminent.

Even a saving of 1 mill/kWh[5] in the price of electricity will result in a reduction that is conservatively estimated to be almost $150 million in PNW consumer's electric bills in 1988 alone. With so much at stake, it is critical that the capacity expansion decision be made following a thorough analysis of the economic and other impacts of each expansion alternative.

Previous studies

There are two published studies to date, that examine the problem of capacity planning under uncertainty. The Stanford Research Institute[6] study for the California Energy Resources Conservation and Development Commission (CERCDC) addressed the problem of capacity expansion under uncertain demand. This study was static in nature in that it did not allow adjustments in capacity as a function of perceived changes in load growth rates. Another study by Gordian Associates,[7] for the US Federal Energy Administration (now the Department of Energy), estimated the cost impacts of differences between planned and actual growth rates. For a hypothetical Eastern utility the change in revenue requirements to the utilities, and the change in oil consumption were estimated. Whereas, this study allowed for upward revisions in plant capacity, ie, capacity additions, it did not allow downward revision in capacity, by slowing down

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present study was carried out while the authors were with Mathematica Inc, Princeton, NJ, USA.

We owe a special debt of gratitude to Mike Coberley and George Fegan for their boundless effort in helping formulate the model and determining the assumptions made in this study. The study is richer because of their contribution.

[1] US Federal Energy Administration, *National Energy Outlook*, US Government Printing Office, Washington, 1976.
[2] The states of Idaho, Oregon, and Washington
[3] This study is concerned with the *need* for additional generating capacity and not with other relevant issues such as the appropriateness of a site or a generating technology.
[4] As exercised by the siting council on behalf of society
[5] A mill is one-tenth of one cent.
[6] Stanford Research Institute, *Decision Analysis of California Electrical Capacity Expansion*, Report submitted to California Energy Resources Conservation and Development Commission, February, 1977.
[7] Gordian Associates, *Optimal Capacity Planning Under Uncertainty in Demand*, Report submitted to the US Federal Energy Administration, November, 1976.

construction in progress. Adjusting capacity, by 'slipping' plant construction, or by plant additions is used very effectively by utilities to reduce potential mismatches between capacity and load. Any meaningful comparison of the costs of over- and under-building must, therefore, take this adjustment process into account. Finally, neither of the two studies addressed a decision problem facing regulatory agencies – the need for additional generating capacity in the presence of divergent load forecasts.

A decision analysis approach

This paper develops a decision analysis framework to study the problem of expanding electrical generating capacity in the PNW. It explicitly considers the possibility that even under the most carefully thought out expansion plan, projections of electricity demand and generating capacity will exceed or fall short of actual demand and capacity. Specifically, it determines the economic impact of planning for one load growth rate when another rate is realized. The model incorporates the issues that are central to the capacity expansion decision in the PNW. For example, uncertainty in the availability of hydroelectricity, a critical variable in the PNW, is considered in the model. Furthermore, the model incorporates the dynamic nature of the capacity planning process, as a function of demand growth. Specifically, it permits adjustments in the availability of future capacity by slowing down existing construction or adding plants as a function of perceived need. The impacts of alternate expansion plans and load growth outcome, are measured by the social cost of electricity in the selected target year of 1988. These costs are determined by the interaction of the corresponding market demand and supply curves, that represent the fixed and variable cost of the generating capacity, and the social cost of power shortfalls, if any. The costs of any slowdown in the given expansion plan are also reflected in the installed cost of the generating plant. The methodology developed in this paper is valuable in helping choose the best capacity expansion rate given a probabilistic load growth rate forecast. Information on the trade-offs between over- and under-building, that is provided by our analysis, is also valuable to members of a regulatory body such as the EFSC, in selecting a socially desirable capacity expansion rate when confronted by divergent load growth forecasts.

Key issues in the capacity expansion decision

Key issues that influence the capacity expansion decision in the PNW are:

- divergence and uncertainty of load growth forecasts;
- availability of hydroelectricity;
- capacity and demand for exports;
- capacity for and availability of imports;
- price of exports and imports;
- costs of power shortages;
- plant construction time;
- ability to accelerate/delay plants;
- nuclear *v* coal *v* combustion turbine plants;

- environmental considerations;
- financial constraints;
- regulatory requirements; and
- political and social climate.

The decision model that is developed in this paper incorporates, to varying degrees, all but the last two of these issues. We now discuss some of these uncertainties, and how their impacts can be measured.

Uncertainty in load growth

The 'need for power' in the USA has increased at an average rate of 7% per year in the past twenty years. For the most part, the actual growth rate was stable, seldom deviating significantly from the average. In contrast, the utility planning environment is now characterized by increased uncertainty about the future demand for electricity. For the USA as a whole, load growth forecasts to 1995 range from 2.83%[8] to 6.38%.[9] Within this range there are over two dozen different forecasts. In the PNW the degree of uncertainty about the future is no less. The West Group Forecast[10] expects firm load to grow at 4% to 1990. In contrast, the Northwest Energy Policy Project (NEPP)[11] forecasts for low, medium and high growth scenarios are 1.4%, 2.98%, and 4.4%, respectively. Finally, the Pacific Northwest Utilities Conference Committee (PNUCC) has forecast load growth to 1989 to be in the range 3.5-5.2%, with an expected growth of 4.4%. Differences in load forecasts may be due to the forecasting model/technique used and/or due to differences in the estimates of judgmental variables, such as the prices of competing fuels and the degree of mandatory or voluntary energy conservation.

Uncertainty in the forecast of future demand for electricity can significantly affect the ability of utilities to meet the electricity demand of consumers. The economic impact of over- or underestimating load growth is illustrated in Figures 1 and 2. Figure 1 depicts the interaction of the supply and demand curves for electricity in a given year in the future. The demand curve represents the quantity of electrical energy demanded for a given price. The supply curve represents the *average* cost of supplying a given quantity of electrical energy. The supply curve is U-shaped because at low levels of system utilization the fixed costs have to be allocated over fewer units of electricity. At very high levels of system utilization, on the other hand, the variable costs rise since in a fixed capacity system higher demand levels must be met by bringing higher cost plants on stream. The intersection of the two curves gives the quantity, Q, of electrical energy that will be supplied and consumed, at the prevailing market price of P.

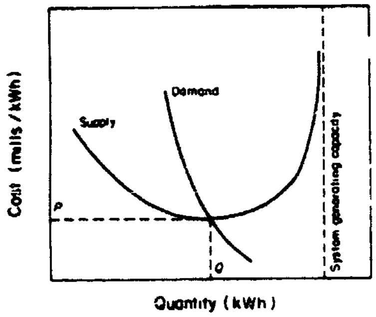

Figure 1. Relationship between electricity supply and demand and generating capacity.

The market equilibrium point defined by P and Q is a key element in quantifying the impact of alternate capacity expansion decisions as shown in Figure 2. This Figure contrasts the impact of over-building and under-building on electricity prices in the illustrative target year of 1988. Supply curves corresponding to three different capacity expansion rates are shown. Point *b* represents the market equilibrium if the utility was lucky enough to predict the true load growth outcome of 4%. Points *c* and *a* show the effects of over- and under-building. In this illustration, over-building results in underutilization of system capacity as evidenced by the fact that point *c* is located on the 'left' side of the corresponding supply curve. Analogously, under-building results in over-utilization of system capacity as evidenced by

[8] Edison Electric Institute, low growth scenario.

[9] US Federal Energy Administration, electrification scenario.

[10] PNUCC *West Group Forecast of Power Loads and Resources, July 1978-June, 1989*, March, 1978.

[11] Northwest Energy Policy Project, *Northwest Energy Policy Project, Supply Module*, 1977.

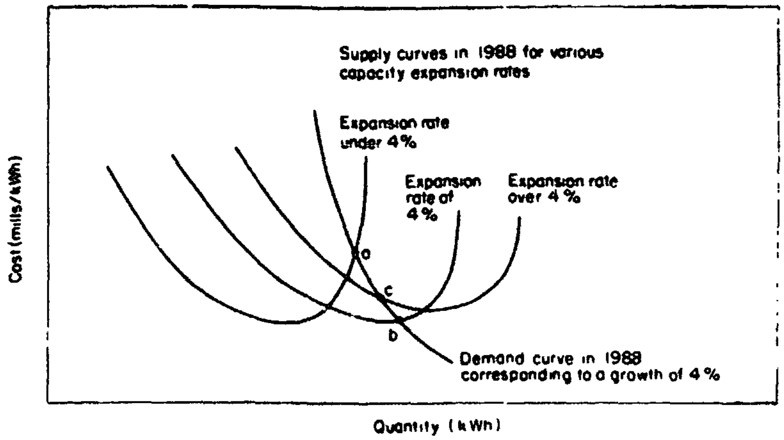

Figure 2. How over-building and under-building affects the market price of electricity.

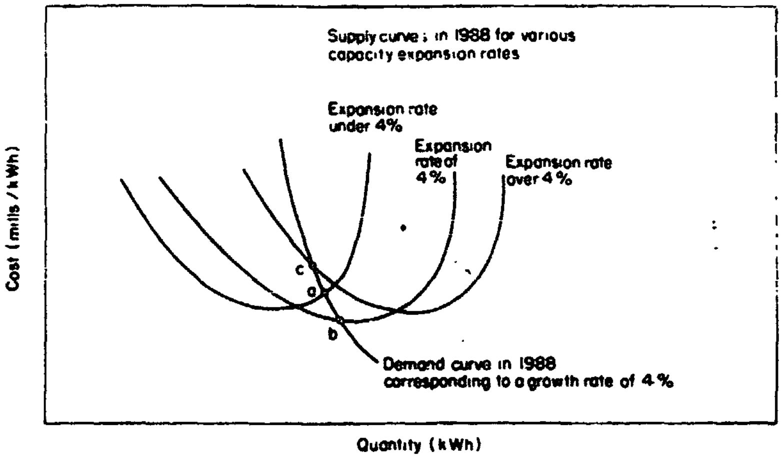

Figure 3. Case where under-building is better than over-building.

the point *a* lying on the right hand side of the corresponding supply curve. In Figure 2 point *a* lies above point *c*, ie, over-building happens to be better than under-building. In other cases the opposite may be true (see Figure 3).

The economic impact of over- and under-building can thus be measured by studying the interactions of the corresponding supply and demand curves.[12] It is true that the electricity market is regulated and therefore not likely to behave as a perfect market. However, we assume that a one year period is sufficient for the demand–supply interaction to achieve equilibrium, even with the Public Utilities Commission's rate setting procedure.

Availability of hydroelectricity

The Pacific Northwest has a relative abundance of hydroelectric power. Approximately 84% of the name plate generating capacity is hydro. Actual energy capability of the hydro system, however, also depends upon the amount of runoff in spring and early summer. This runoff can vary considerably over the years. Consequently, the energy capability of the hydro system typically ranges from around 12 000 MW in a critical water year (which determines the hydro system's firm load carrying capability (HFLCC)) to about 18 000 MW in the best water years. The abundance of hydro determines the

[12] The validity of using a demand curve based on the assumption of pricing at average cost may be questioned by some individuals. For example, welfare economists argue that price should be based upon (long-run) marginal costs, if welfare is to be maximized. In practice, utilities tend to base their tariff structure upon marginal cost considerations while trying to balance the total revenue requirements against total costs. Public utilities in particular generally end up by charging an average price that equals average cost. Therefore, it may be justifiable to use a demand curve based on the assumption that demand responds to changes in average cost.

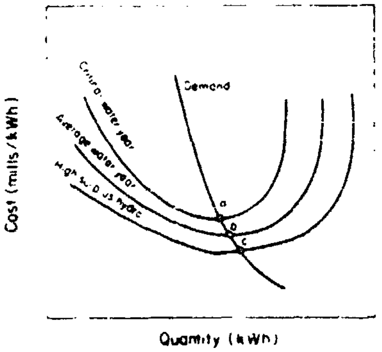

Figure 4 Effect of availability of hydro on electricity supply curve.

costs of meeting a given load. Annual fluctuation in runoff thus results in a different supply curve for each water year. This is shown in Figure 4 for three different water years. As the amount of hydro energy available increases, the cost curve shifts downwards and to the right. This reflects increased generating capability and the fact that the variable costs of hydro generation are the lowest of all generating technologies. Figure 4 also reveals that the market equilibrium is a function of the water year outcome. If the three water years in question are equally likely, then the expected market price can be determined by averaging the prices corresponding to points *a*, *b*, and *c*.

Costs of power outages

The cost of an electrical outage to a consumer is a function of the time of day and duration of outrage, the nature of activities affected, the degree to which the activities affected depend upon electricity, the availability of a backup power source, the ability to resume the affected activity normally after power is restored, the frequency of the outages, and a host of other determinants. Consequently, the cost of an outage is different for each consumer. To some it may be the mere inconvenience of being stranded in an elevator. To another it may involve loss due to fire, burglary or vandalism. To yet another, it may be the loss of production, spoilage of in-process inventory and of equipment. Information about the costs of outages is vital for several reasons. Determination of the optimal amount of generating capacity of a utility, should be based upon a careful balancing of the associated costs and benefits of each investment alternative. As system capacity is decreased, the associated direct costs decrease, but at the expense of increasing costs of energy denied, due to the more frequent generation failures.

Assessing the cost of potential electricity shortages is also important from the standpoint of a utility's decision to over-build or under-build. Consider a case where a utility faces under-capacity, say in three years time. It has the option of adding combustion turbines and restoring the proper reserve margin, or relaxing the reliability requirement.[13] If it decides to relax the requirement, to what extent should it do so? These issues beg the question: what is the social cost of an outage? Currenly, capacity planning decisions are primarily based upon value judgments which assign an implicit cost to outages. Such value judgments invariably lead to inconsistent decisions over time. We believe that the cost of outages is a key exogenous variable that should be *explicitly* used in the capacity expansion planning process. Only then can a consistent evaluation of alternative expansion plans be achieved. Such an approach affords an analysis of the sensitivity of the optimal capacity expansion rate to the costs of outages. This flexibility is especially important, since current estimates of the costs of outages vary widely in the range 0.16$ to 16$ per kWh denied.[14]

Outline of methodology

Our model assesses the economic impact of being over- or under-built and of alternative over-build and catch-up strategies to meet load in the selected target year of 1988. Figure 5 is a schematic view of the model and the linkages between the various modules.

[13] Most major utilities strive to achieve a loss of load probability (LOLP) of almost one in ten years. This typically translates to a reserve margin of 20%. The use of a LOLP of one in ten is, unfortunately, arbitrary, and most likely not optimal in a social cost-benefit sense. In fact, some recent studies argue convincingly that substantial economic gains can be achieved, with virtually no perceptible social cost, by reducing current reserve margins by only a small amount. See, for example M L Telson, 'The Economics of Alternative Levels of Reliability for Electric Power Generation Systems,' *Bell Journal of Economics and Management Science*, Vol 16, No 2, Autumn, 1976.

[14] Mitre Corporation, *Need for Power Study An Assessment of the Adequacy of Future Electric Generating Capacity*, Report MTR-7549, 1977.

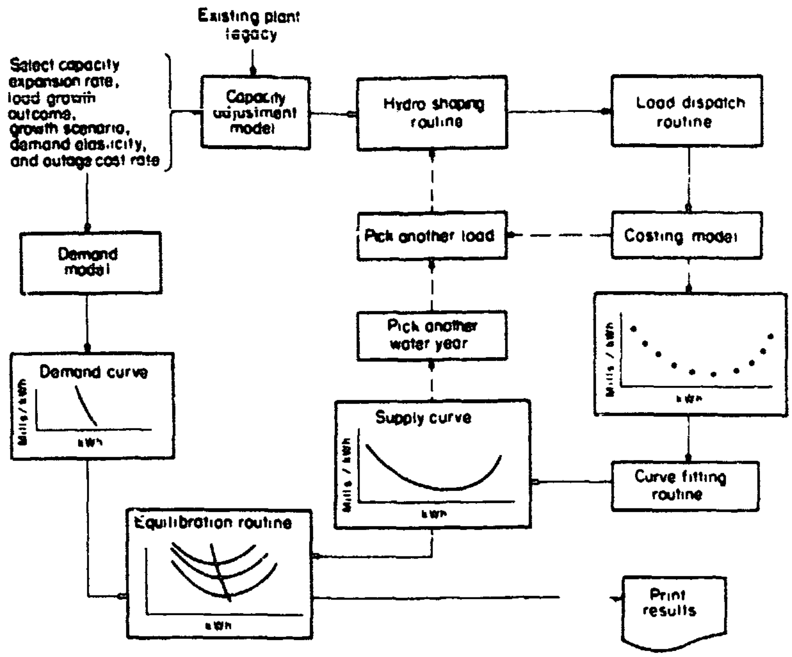

Figure 5. Overview of the model.

Fundamentally, the model attempts to compute the market price of electricity in the target year of 1988, given different capacity expansion rates, load growth outcomes, and growth scenarios. The capacity expansion rate determines the plant expansion programme to be undertaken, starting in 1977, so that sufficient generating capacity is available, under current planning procedures, in 1988.[15] The growth scenario specifies the year in which the eventual load growth outcome is discovered. This determines the exact nature and extent of any capacity adjustments made between 1977 and 1988. If discovery of the actual load growth rate is made prior to 1988, then capacity adjustments, either additions or delays, are made to ensure that there is adequate generating capacity available in 1988. If the true load growth rate is only discovered in 1988, then the capacity expansion plan initiated in 1977, with no interim adjustments, will generally lead to over- or under-capacity.

On the supply side, the model determines the average cost (to consumers) curve of electricity for a specified load growth rate and growth scenario. This is achieved by estimating the cost of meeting a number of different load levels, and then using a curve fitting routine to determine a continuous supply curve. Such cost curves are determined for each of eight representative water years. On the demand side, the load growth rate outcome and a specified demand elasticity are used to determine the demand curve for electricity in the PNW in 1988. Finally, an equilibrium routine determines the market equilibrium price and consumption quantity that will prevail under each of the eight water year conditions. The expected price and quantity under the specified load growth rate and growth scenario are then computed as simple averages of the corresponding eight values that are determined by the equilibrium routine. These and other results are then printed by the report generator.

In this study, we examine the costs of adjustments in energy capabilities rather than in the capacity of the generating system. A

[15] Under the present planning process, the capacity required in any year is determined by the projected load, and a reserve requirement that is equal to half of the increase in 'utility type' loads from that year to the next. In this report, whenever we speak of a capacity expansion rate of 3%, for example, we mean that capacity is expanded at a rate sufficient to meet the load and reserve requirements, as defined above, corresponding to a load growth rate of 3%.

hydro-dominated generation system, such as the PNW, typically offers large capacity and therefore flexibility in meeting peak loads. This is not to say that a capacity shortfall or excess will never accompany an energy shortfall or excess. Our model implicitly assumes that any adjustments made to resolve an energy shortfall or excess will automatically adjust capacity.

Capacity adjustment model

The ultimate load growth outcome may be greater than the load growth rate used to plan capacity expansion. This outcome may be known as early as 1982, at which time construction of additional coal plants can be initiated to bring on additional generating capacity on-line by 1988; or in 1985, at which time additional combustion turbines can be added, if necessary; or as late as 1988, in which case, there will be under-capacity. On the other hand, knowledge of the true load growth outcome in 1982, or in 1985, may require a slowing down of existing construction to delay bringing one or more plants on-line by 1988. Such a discovery made in 1988 will result in over-building. Additions and/or delays of the type just described, are performed by the capacity adjustment model.

Hydro shaping routine

Most of the hydro and thermal generating facilities in the PNW are located on or along the four major interconnected rivers: the Columbia, the Snake, the Willamette and the Pend Oreille. Generally, these generation sites cannot be operated in isolation. Downstream effects of up-stream generation, hydro as well as thermal, must be considered. In other instances, a spill-off may be necessary just to provide sufficient cooling water for a downstream thermal plant. A grand plan is necessary to effectively operate the hydro-thermal system, and to prevent the myopic optimization policies that are likely to be pursued by managers of individual generating facilities. Such a plan exists in the PNW and goes by the name of 'Agreement for Coordination of Operations Among the Power Systems of the Pacific Northwest' or, in short, the coordination agreement. This agreement is a legal document that spells out in detail the operating procedures, obligations and entitlements that are binding on the major utility transmission companies, the Corps of Engineers and the Bonneville Power Administration. The coordination agreement not only specifies rules for the determination of the hydro system Firm Energy Load Carrying Capability (HFLCC) for maximum advantage, but permits the shaping of this firm capability from month to month within a water year and from one water year to the next. This shaping is governed by the specification of the Energy Content Curve that determines the maximum amount of stored energy that can be drafted at any point in time. An exception is made to the extent that some provisional energy can be borrowed from the future.

The hydro shaping routine is a model of the operating rules that govern the use of hydro energy in the PNW. For a given load level and thermal generating capacity, this model shapes, within the constraints of the coordination agreement, the HFLCC into three seasons in a manner that offers the best odds of meeting the load. These seasons are:

- *Early drawdown season*, September-December; reservoirs are drawn down, and no forecasts of runoff are available.

- *Late drawdown season*, January-April; reservoirs are still being drawn, but runoff forecasts might make more storage available for use.
- *Refill-hold season*, May-August: the spring runoff allows filling, and most thermal scheduled maintenance is performed in this season

Next, for the pre-selected water year being simulated, the program determines the natural streamflow capability from historical data of actual runoffs and flows in the PNW. The surplus hydro (ie energy in excess of HFLCC) is then computed and dispatched to meet load, by regulating the system within the specified policies.[16]

In short, the output of the hydro shaping routine specifies for any given load, the availability of hydro energy, as a function of the water year being simulated, and by the season within the water year.[17]

Load dispatch routine

The variable costs of supplying a specified load is primarily a function of the generating mix dispatched to meet the load. The load dispatch routine attempts to achieve this dispatch in the most inexpensive manner. For a given load, the following dispatch merit order is used: hydro, nuclear, coal, existing small thermal plants, and new combustion turbines. The only exception to this merit order ensures that under no circumstances is the utilization factor of nuclear plants lower than 0.70. The maximum utilization factor of nuclear plants is 0.75.

The constraint of not underutilizing nuclear capacity stems from the concern of utility planners that disturbing the nuclear fuel cycle has ripple effects on future fuel cycles. The resultant cost increases in all future cycles, it is generally believed, will exceed any savings in the current cycle. The decision to underutilize nuclear plants in a good water year should be a function of the amount of surplus hydro available, and the prospects of surplus hydro in the next year or two. If the current surplus is high and prospects for the future also look good, then benefits are likely to outweigh the cumulative cost increases of future fuel cycles. The development of such a model was beyond the scope of this study. Moreover, it is extremely unlikely that information about future hydro surplus will ever be available.

A typical load dispatch proceeds as follows. For the given load, output from the hydro shaping routine specifies the amount of hydro energy available. First, 70% of the nuclear nameplate capacity is dispatched. Following this, as much of the hydro energy is dispatched as is necessary or available. Any unfulfilled load is then met by dispatching energy from mine-mouth coal plants, followed by energy from unit train coal plants and so on, down the merit order. This process culminates with specification of the amount of the load met by various generating sources. A feature not included in this study is the consideration of the load duration curve in dispatching the generating plant. A load duration curve analysis is particularly critical for predominantly thermal systems that are peak-constrained. In contrast the PNW is energy-constrained for the most part, because of the abundance of hydro energy. Incorporation of the standard mathematical programming approach to load dispatching would, however, be straightforward, given the modular component nature of

[16] For details of this program see D. Lewis, R. Duncan and M. Schultz, *Energy Reserve Planning Model*, Progress Report, Northwest Power Pool, Portland, Oregon, 1975.

[17] From historical records of stream flow data for 40 years, eight ersatz 'water years' were constructed. Each water year is characterized by the amount of surplus hydro energy that is available in that year. Furthermore, each such water year was constructed so as to be equally likely.

our model. All other model components in Figure 5 will remain unchanged.

Costing model

The costing model calculates the unit cost to consumers (mills/kWh) of supplying a specified amount of electrical energy (kWh) associated with a given growth scenario. In several growth scenarios analysed, capacity adjustments involve a slowdown of construction in progress. Under current regulatory procedures, only a small portion of construction work in progress is included in the rate base, with the entire investment in new generating plant being included in the rate base starting with initial operation of plant. Consequently, the fixed cost of a plant, that is delayed so that it comes on-stream after 1988, will no longer appear in the 1988 rate base, but will show up as a higher cost in a later year. This would pose no problem in a multi-target year study. In a single target year study, however, the use of current rate making procedures would not adequately show the impact of delaying construction in progress. Therefore, our costing model creates an artificial rate base. This base in 1988 includes a portion of the fixed cost of generating plant, still under construction in 1988, in proportion to the fraction of the plant completed as of that year, *vis-a-vis* the extended construction schedule.

Demand model

A demand curve is a functional relationship between the amount of electrical energy consumption as a function of the selling price of the energy. The nature of the demand curve is as fundamental to the capacity expansion decision as the supply curve. Together they determine the market equilibrium and provide a measure of consumer welfare.

This study assumes the following relationship between the demand and price of electricity in the target year of 1988:

$$Q = KP^{e}$$

where Q = quantity of electrical energy consumed in 1988 (10^9 kWh), P = price of electrical energy in 1988 (mills/kWh); e = short-term price elasticity of demand in 1988, ie, the percentage change in consumption for a unit percentage change in price; and K = a scaling constant.

Results

The above model is used to determine the impact of being over- and under-built assuming different load growth rates and growth scenarios. Other growth scenarios were also studied in order to assess the impact of deliberate 'over-build' and 'catch-up' strategies. Figure 6 displays the growth scenarios analysed in the base case.[18] Identical scenarios were run for deliberate over-build cases (5.5%) and under-build cases (2.5% and 3.5%). Each stop node in Figure 6 is defined by the load growth outcome and a generating mix that evolves as a consequence of the plant expansion programme undertaken in 1977 and adjusted appropriately. For each such stop node, the entire model, as depicted in Figure 5, is run to determine the expected market price of electricity in 1988. Furthermore, each of the cases

[18] This case corresponds to the expansion plan currently being implemented in the PNW.

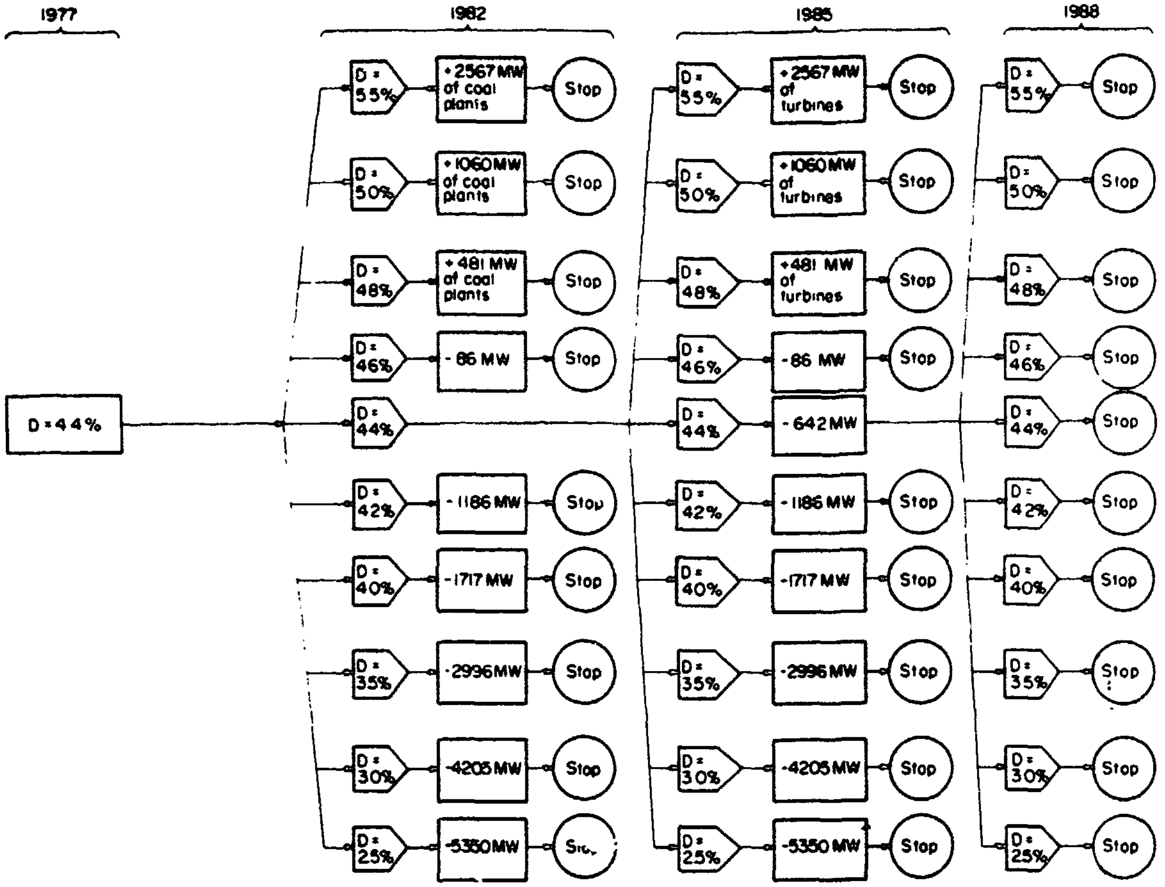

Figure 6. Alternative outcomes under the base case expansion plan. *D* is actual load growth outcome discovered in 1982, 1985 or 1988. Figures in rectangles show capacity adjustment which is necessary when actual load growth is known.

was run under different assumptions about the capability of the PNW to import and export power. However, in this paper, we only report the results for the case of zero import and export capability, ie, the PNW region is treated in isolation. Furthermore, we report results only for growth scenarios where the true load growth outcome is discovered in the years 1985 and 1988. The presentation and analysis of results in all other scenarios and import–export capability combinations is beyond the scope of this paper.[19]

Figure 7 displays the decision tree for the scenarios where the true load growth outcome is discovered in 1985, ie three years prior to the target year of 1988. The information in Figure 7 is more compactly presented in the economic impact (payoff) matrix shown in Table 1. The comparable payoff matrix for the static case[20] is shown in Table 2. The planner has a choice of adopting a deliberate under-build strategy by building for a load growth of 2.5% or 3.5%, a deliberate over-build strategy by planning for load growth of 5.5%, or planning to match the load growth of 4.4%. In each case, one of four possible outcomes will result. The economic impact of the particular decision and outcome is measured by the expected price of electricity in 1988, as measured in current mills/kWh.

As an example, if capacity expansion was planned for a load growth of 3.5% and the eventual outcome is 4.4%, then the cost is 56.3 mills if no capacity adjustments were made in the interim (Table 2). If, on the other hand, a capacity adjustment could be made in

[19] Such a comprehensive analysis is to be found in A.P. Sanghvi and D.R. Limaye, *Planning for Generation Capacity Expansion in the Pacific Northwest: A Decision Analysis of Over- and Under-Building*, Mathematica Report submitted to the Portland General Electric Company, Portland, Oregon, August, 1978.

[20] The static case is where true-load growth is only discovered in 1988. This implies that no intermediate capacity adjustments are made.

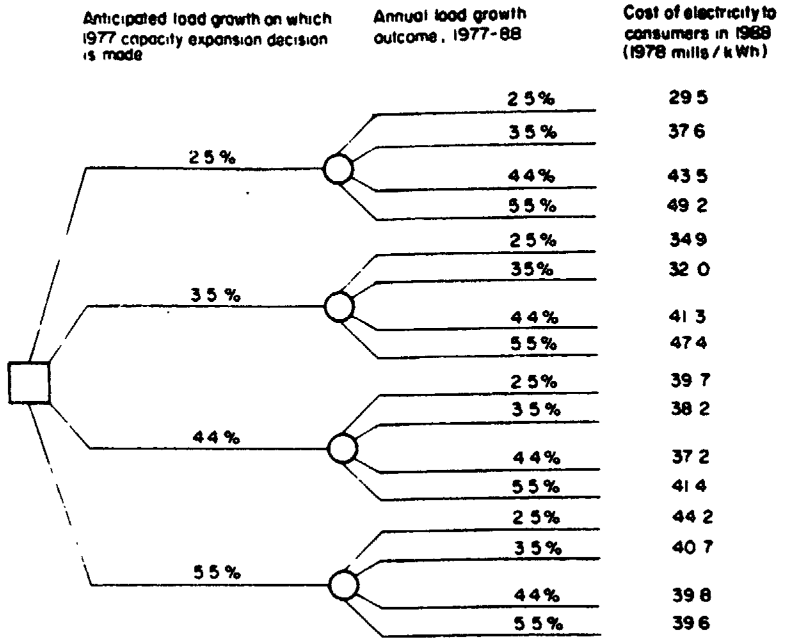

Figure 7. Decision tree of PNW capacity expansion and cost of electricity to consumer.

1985, then the cost is only 41.3 mills (Table 1). The higher costs in the former case stem from a combination of factors: the increased utilization of higher variable-cost generating equipment, and the economic cost of power shortfalls, valued at a dollar per kWh denied.[21] The results in Tables 1 and 2 support the following conclusions:

- The expected costs of ending up under-built are significantly higher than being over-built. This is because the entries above the diagonal of either payoff matrix are larger than the corresponding entries symmetrically located below the diagonal. These differences are obviously less when capacity adjustments can be made to match load growth.
- Whereas adjustments in capacity can only be achieved at some cost, the net impact is beneficial. This conclusion is supported by the fact that most off-diagonal entries in the matrix in Table 1 are smaller in magnitude than the corresponding entries in Table 2. If the load growth outcome were known *a priori*, then the optimal capacity expansion decision is to plan to match this growth. In the absence of capacity adjustments, however, capacity growth should be planned at about 0.4 to 0.5 percentage points higher than the known load growth outcome. This stems from the fact that in the capacity adjustment model, adjustments are made to match capacity and average annual load, with a reserve margin. The hydro shaping routine, however, works with seasonal loads. The loads in seasons 1 and 2 of each water year are higher than in the third season. Consequently, there can be mismatches of load and energy capacity in all three seasons, with the first two seasons requiring imports and the third season left over with surplus energy. Since imports are not permitted, any such shortfalls are priced at the outage cost of 1$/kWh denied. A lower load growth of about 0.4-0.5% does away with the need for incurring these costs.

[21] The general nature of the conclusions does not change when outage costs as low as 0.50 $/kWh denied were used. Other results, using outage costs other than 1$/kWh denied, are contained in A.P. Sanghvi and D.R. Limaye, *op cit*, Ref 18.

Table 1. Payoff matrix showing electricity costs in 1988, assuming a growth scenario in which load growth outcome is discovered in 1985 (1978 mills/kWh)

		Load growth outcome			
		2.5%	3.5%	4.4%	5.5%
Capacity expansion decision	2.5%	29.5	37.6	43.5	49.2
	3.5%	34.9	32.0	41.3	47.4
	4.4%	39.7	38.2	37.2	41.4
	5.5%	44.2	40.7	39.8	39.6

Table 2. Payoff matrix showing electricity costs in 1988, assuming a growth scenario in which load growth is discovered in 1988 (1978 mills/kWh)

		Load growth outcome[a]			
		2.5%	3.5%	4.4%	5.5%
Capacity expansion decision	2.5%	29.5	54.5	123.5	226.2
	3.5%	32.9	32.0	56.3	140.9
	4.4%	40.1	37.1	37.2	71.1
	5.5%	46.5	42.3	39.5	39.6

[a] Minimum of first row occurs at load growth outcome of 2.1%. Minimum of second row occurs at load growth outcome of 3.1%. Minimum of third row occurs at load growth outcome of 4.1%. Minimum of fourth row occurs at load growth outcome of 5.0%.

Table 3. Payoff matrix together with associated load growth probabilities and expected electricity costs, assuming load growth outcome is discovered in 1985 (mills/kWh)

		Load growth outcome				
		2.5%	3.5%	4.4%	5.5%	Expected electricity cost
Capacity expansion decision	2.5%	29.5	37.6	43.5	49.2	43.1
	3.5%	34.9	32.0	41.3	47.4	40.7
	4.4%	39.7	38.2	37.2	41.4	38.6
	5.5%	44.2	40.7	39.8	39.6	40.2
Probability of load growth outcome		0.05	0.2	0.5	0.25	

Incorporating probabilities of load growth outcomes

Table 3 reproduces the matrix of Table 1 with additional information about probabilities of various load growth outcomes. These probabilities do not represent official forecasts. However this distribution has an expected value of 4.4% per year, the current 'high' forecast of load growth in the PNW, and is typical of the D^H type of distribution, discussed above. The expected costs of each decision alternative are displayed in the column to the right of Table 3. The decision that minimizes the expected cost is to expand at 4.4%. The information that is contained in Table 1 can also be used to shed light on the capacity expansion decision when one is faced with divergent probabilistic forecasts. Suppose that another group's forecast of the odds of the four load growth outcomes of 2.5%, 3.5%, 4.4%, and 5.5% is 0.6, 0.3, 0.08, and 0.02, respectively. Under this 'low growth' forecast, the expected costs of the four decision alternatives, in the presence of capacity adjustments, are 33.4, 34.8, 39.1, and 42.7 mills/kWh. In contrast with the 'high growth' forecast, under the 'low growth' forecast, the optimal expansion decision is to plan for a load growth of 2.5%. The question now arises as to which capacity expansion rate should be used. Figure 8 displays the alternatives and expected costs under each outcome. The maximin strategy is to expand at 4.4%. The minimal regret strategy is to expand at 2.5%.

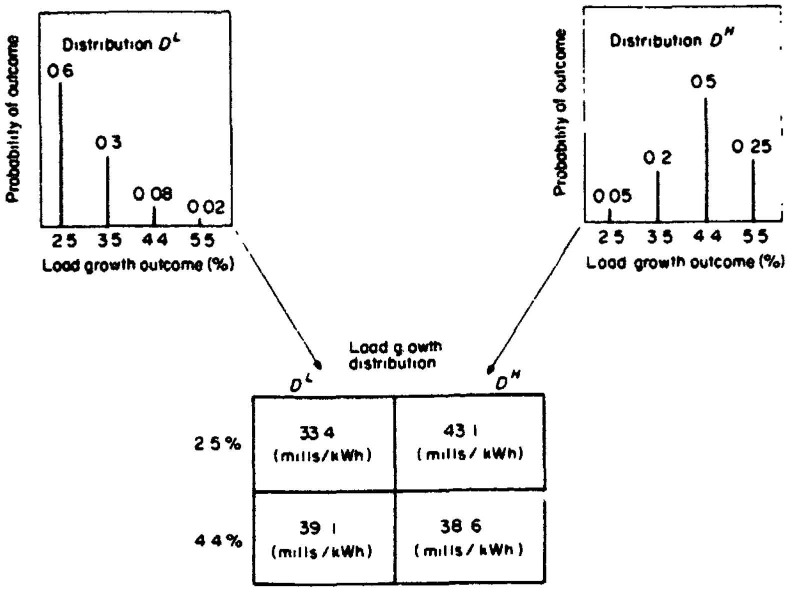

Figure 8. Capacity expansion decisions under different probabilistic load growth forecasts and expected electricity costs.

Perhaps a more meaningful way to look at the decision problem is to compare the economic impacts of choosing the 2.5% expansion rate with the outcome being determined by distribution D^H and choosing the 4.4% rate with the outcome being determined by distribution D^L. Figure 8 shows that these costs are 43.1 mills/kWh and 39.1 mills/kWh respectively. Consequently, choosing the incorrect rate results in a cost of 4 mills/kWh. This translates, conservatively, to an expected saving in PNW consumers' electricity bills of approximately 600 million dollars in the year 1988.[22] Under this criterion, the strategy is to expand at 4.4%.

A 'second order' expected value analysis can be performed on the 2 X 2 payoff matrix in Figure 8. However, this does not clarify the basic trade-offs further. Members of the regulatory body who accept or 'lean heavily' towards distribution D^-, will in all likelihood favour an expansion rate of 2.5%. By the same token, those who accept or lean heavily towards distribution D^H, will favour the 4.4% rate. The swing votes may lie with those members who truly cannot make up their minds about accepting D^L or D^H. Many of these members are likely to use the reasoning laid out in the previous paragraph and choose the 4.4% rate. Still other undecided members may assign[23] likelihoods to the occurrence of D^L and D^H. This immediately implies an unconditional distribution that lies 'between' D^L and D^H. Such distributions will favour a compromise solution, ie an expansion rate between 2.5% and 4.4%. Often, however, such 'compromise' solutions may not be feasible, since the basic decision – to grant or deny a permit for an additional plant – is discrete.

Conclusions

Without meaning to 'pass the buck', in the final analysis, the decision to accept one expansion rate over the other, rests with the regulatory body with the mandate to do so. Our decision analysis purposely falls short of recommending this final step, since the capacity expansion rate decision must also incorporate other socio-political

[22] This estimate assumes that the 1988 consumption level will be at least 110 billion kWh.

[23] This could be in a fuzzy sense, and not necessarily involve specific values.

considerations. However, our analysis provides an objective assessment of the economic and environmental impacts of each decision alternative.[24] We believe that the methodology developed in this paper will prove useful to the final arbiters in making their decision. The decision analysis approach forces a logical basis and structure to an otherwise informal reasoning process. It provides an effective medium for communicating the reasoning that underlies the final recommendation. Assumptions that are generally hidden or fuzzy, are now forced into the open. Consequently, the real differences between the various interest groups can be identified. This fosters rational debate of the specific issues and differences, instead of vague rhetoric that only serves to charge the atmosphere further. Resolution of conflict is likely to be easier on such a platform.

[24] The environmental impact of various strategies is reflected in the analysis to the extent that the costs of scrubbers, or other pollution abatement devices, mandated by legislative action, are reflected in fixed and variable costs of each generating plant.

ANNEX 6

ANNEX 6: EX-POST ANALYSIS OF ECONOMIC AND ELECTRIC SECTOR CORRELATION

It has been established in other research that the most important structural determinants of electricity growth in the commercial and industrial sector are level of economic activity, electricity price, and the price of electricity substitutes. In the residential sector, the key factors are growth in number of connections, and usage per customer, with the latter influenced by some measure of household income, electricity prices, prices of substitutes, and perhaps electrical appliance prices as well.[1] Often, data on sector specific measures of economic activity or income -- such as value added in manufacturing and commercial sectors and real disposable household income -- are not available. In such cases gross national (or domestic) product is often used as a proxy measure of income and economic activity in all the sectors and utilized in forecasting electricity sales. Whereas gross national product is not the sole determinant of electricity sales it nevertheless tends to be the most highly correlated independent variable.

Correlation is relevant to this study in one critical respect. If under certain conditions electricity requirements are highly correlated with the level of economic activity (GNP for example), then an important corollary exists: An accurate forecast of GNP is necessary for an accurate electricity demand forecast, providing there are no major structural shifts in the economy, and in the customer mix patterns, and relative prices for various energy sources that were prevalent historically.

This interdependence led us to re-explore the relationship between GNP and national electricity generation (in GWh). Specifically, we were interested in learning when the GNP-GWh correlation is strong and under what circumstances does it appear to be weak. Setting aside the problems of forecasting either variable, how good is the fit between actual GNP and actual power demand? In addition, we wish to discover conditions under which this correlation was higher or lower.

1 Glenn D. Westley, "Forecasting Electricity Demand: A General Approach and Case Study in the Dominican Republic", Project Analysis Paper No. 26, Inter-American Development Bank, (IDB), Washington, D.C., October 1984.

For this investigation, we regressed actual GNP in constant U.S. dollars (independent variable) against actual net generation in forty-two countries over the entire study horizon (1960-1985).[2] A total of 757 paired data points were included in the sample. Major findings are outlined below.

On a country-by-country basis, the overall correlation was high. Thirty-two of the forty-two countries studied have a coefficient of determination (R^2 measure of "goodness of fit") of better than 80 percent (Table A6-1).

On a regional basis, the performance was not evenly distributed. All of the weak correlations appeared in only two regions, with Africa having the highest percentage of low correlations.

Region	Number of Countries in Sample	Countries with $R^2 < .80$ Total	Percent
Africa	11	5	45%
Asia	6	0	0%
Emena	9	0	0%
LAC	16	5	31%

Regions demonstrating the highest correlation between real GNP and GWh generation were also the best economic performers over the study horizon.

Region	Average Annual Regional GNP Growth Rate (1960-85)	R^2
Africa	3.1%	.26
Asia	5.0%	.88
Emena	5.6%	.83
LAC	3.6%	.49

2 The analysis is restricted to GNP as the sole independent variable since data on electricity prices and prices for fuel substitutes was not available. A detailed analysis would focus not only on these additional variables but would seek to disaggregate demand by major sectors, and attempt to isolate key determinants of this demand, as for example, the number of connections and usage per connection in the residential sector.

The correlation is strongest among countries with the least economic volatility. Specifically, when the standard deviation of GNP is high, the correlation between GNP and GWh appears to be weak.

GNP Volatility	Number of Countries in Sample	R^2
Std Dev < 1.5	--	.86
Std Dev 1.5 - 5.0	--	.41
Std Dev > 5.0	--	.23

In closing it should be re-emphasized that restricting the proceeding analysis to GNP as the sole independent variable, is likely to have resulted in overemphasizing its importance. Nevertheless, we expect that the general findings should hold up under a more detailed analysis which includes other key independent variables as well.

Table A6-1

GNP-GWH Correlation by Country

Region/Country	Number of Years	R^2
AFRICA		
Ethiopia	24	.87
Ghana	21	.43
Kenya	14	.98
Liberia	20	.98
Malawi	21	.93
Nigeria	11	.02
Sierra Leone	8	.43
Sudan	14	.23
Tanzania	16	.87
Zambia	11	.10
Zimbabwe	23	.94
ASIA		
Bangladesh	13	.89
India	12	.97
Indonesia	20	.91
Malaysia	14	.98
Philippines	12	.81
Sri Lanka	21	.99
EMENA		
Cyprus	11	.99
Jordan	16	.96
Morocco	21	.94
Pakistan	26	.99
Portugal	21	.88
Tunisia	21	.96
Turkey	26	.96
Yemen Arab Republic	14	.83
Yugoslavia	26	.98

Table A6-1 (Continued)

GNP-GWH Correlation by Country

Region/Country	Number of Years	R^2
LAC		
Argentina	24	.72
Brazil	20	.86
Chile	19	.53
Colombia	15	.96
Costa Rica	18	.91
Ecuador	21	.87
El Salvador	12	.99
Guatemala	15	.95
Haiti	16	.89
Honduras	22	.94
Jamaica	17	.04
Mexico	21	.94
Nicaragua	16	.93
Panama	24	.94
Peru	15	.74
Uruguay	25	.79

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